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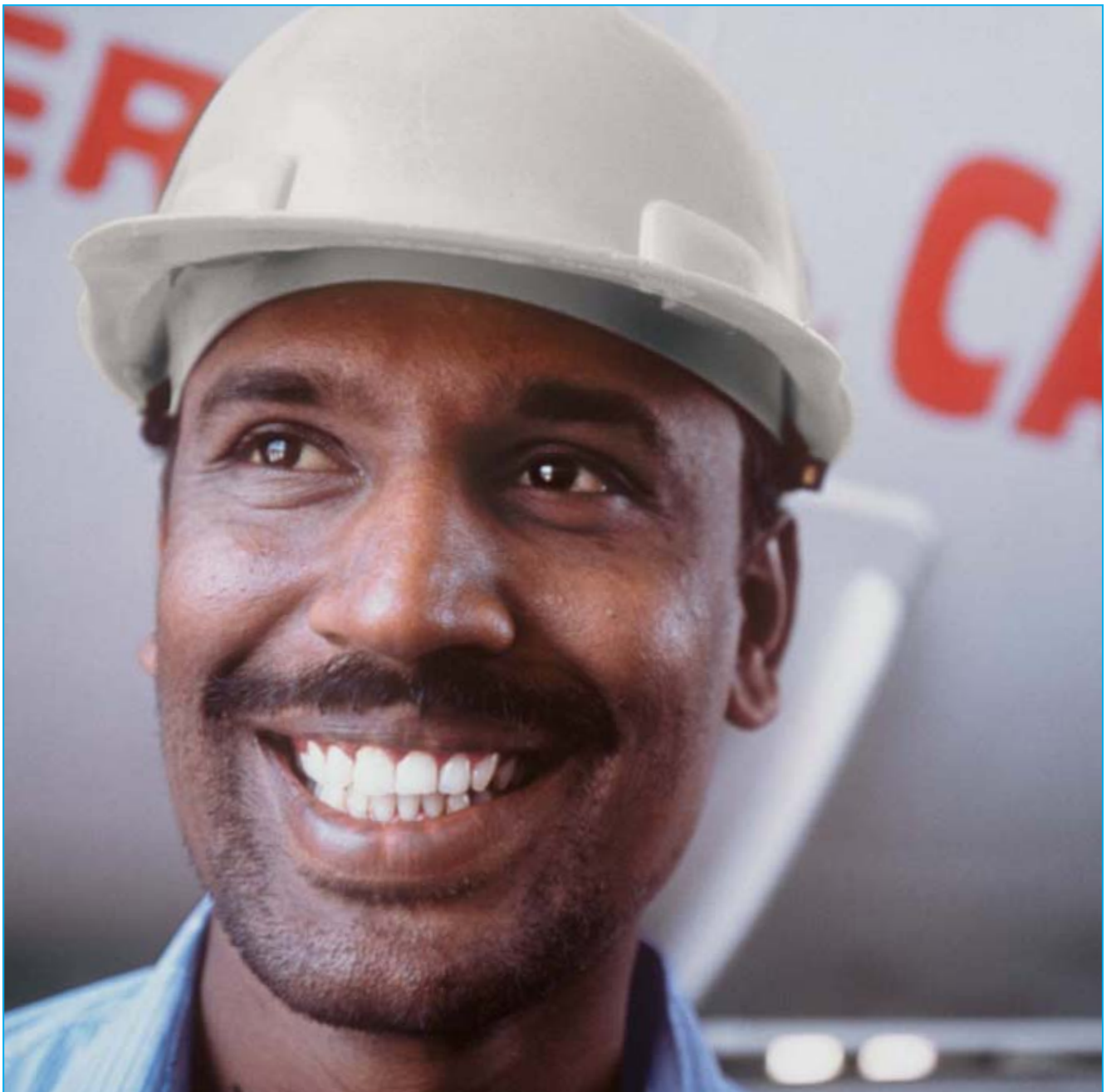
Agrifuels–Promise and Progress



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Aug. 6, 2007
Volume 105.29

AGRIFUELS—PROMISE AND PROGRESS

REGULAR FEATURES

COVER

Integrated oil companies are investing in efforts to produce energy from agricultural materials. The facility on the cover is a German biomass-to-liquids plant operated by Choren Industries GMBH. Royal Dutch Shell PLC owns a minority stake in the plant. Woodchips are converted into synthesis gas and biofuels with the Shell Middle Distillate Synthesis technology that Shell developed for gas to liquids production. Photo from Choren Industries. In the picture above on this page, corn oil is produced before ethanol fermentation at Renessen's pilot plant in Eddyville, Iowa. Photo by Doug Rushing of Renessen, a Monsanto-Cargill joint venture.

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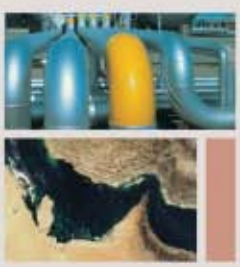


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 Oil & Gas Journal (ISSN 0030-1388) is published 48 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $60, 2 yr. $85, 3 yr. $109; Latin America and Canada: 1 yr. $64, 2 yr. $100, 3 yr. $135; Russia and republics of the former USSR, 1 yr. 1,500 rubles; all other countries: 1 yr. $109, 2 yr. $175, 3 yr. $250, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 105, No. 29) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

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OGJ Newsletter

Aug. 6, 2007

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General Interest — Quick Takes

Luthi nominated to MMS director post

US Sec. of the Interior Dirk A. Kempthorne has nominated Randall Luthi, currently deputy director of the US Fish and Wildlife Service, as director of the US Minerals Management Service. He will succeed Johnnie Burton, who resigned after 5 years on May 31.

Luthi formerly served as speaker and majority leader in Wyoming's House of Representatives, where he formulated state budgets that relied heavily on oil and gas royalties and severance taxes. He also was a senior attorney for environmental regulations in the National Oceanic and Atmospheric Administration, an attorney at DOI's solicitor's office, and a partner in the Thayne, Wyo., law firm of Luthi & Voyles before his FWS appointment in February. Luthi has served as a legislative member of the Energy Council, an organization of lawmakers from energy-producing states and provinces and private energy-related industries.

Two entities charged in gas price manipulation

The US Commodity Futures Trading Commission has charged hedge fund Amaranth Advisors and its former chief energy trader, Brian Hunter, with attempting to manipulate natural gas prices.

The two allegedly attempted to manipulate prices of gas futures traded on the New York Mercantile Exchange on Feb. 24 and Apr. 26, 2006, CFTC said in charges filed in the US District Court for the Southern District of New York.

The dates were the final trading days for the following months' NYMEX gas futures contracts, CFTC said. The settlement price of each NYMEX gas contract is determined by the volume weighted average of executed trades during 2-2:30 p.m. on such "expiry days."

Amaranth and Hunter, Calgary, allegedly acquired more than 3,000 NYMEX gas futures contracts in advance of this closing range on the expiry days, which they planned to, and for the most part did, sell during the closing range, CFTC said.

CFTC also alleged that the defendants held large short positions in financially settled gas swaps, primarily on the Intercontinental Exchange (ICE), where swap settlement prices are determined by the NYMEX gas futures settlement price. They allegedly intended to lower prices on the NYMEX gas futures contracts to favor their larger swap positions on ICE and elsewhere, CFTC said.

It also charged that Amaranth Advisors made false statements to NYMEX to cover their activities.

In September 2006, Amaranth lost more than $6 billion, or 65% of its reported assets at the end of August, after prices for gas, in which it had taken an unusually large position, plunged due to high storage levels and the absence of hurricane-related and other disruptions. The hedge fund transferred its energy portfolio to a third party, reportedly at a deep discount, when it was unable to meet margin calls and other payment demands.

Caswell nomination as BLM chief hits snag

Sen. Ken Salazar (D-Colo.) has placed a hold on James L. Caswell's nomination to be Bureau of Land Management director after the Senate Energy and Natural Resources Committee voted to send the nomination to the floor (OGJ Online, July 23, 2007).

In a meeting with US Interior Secretary Dirk A. Kempthorne, Salazar said he would not let Caswell's nomination move forward until he received commitments from BLM and the Department of Interior to cooperate with Colorado and communities on its Western Slope in development of public lands, to create sufficient opportunities for the state and its communities to comment on oil shale development, and to delay any issuance by BLM of leases on the Roan Plateau until Colorado has had time to consider options on drilling.

EU, Morocco sign energy cooperation declaration

The EU Commission and Morocco—an important transit country for Algeria's natural gas supplies to Europe—have signed a joint declaration on priorities for cooperation in the energy sector. Spain and Portugal receive natural gas from Algeria via a gas line that crosses Morocco and the Mediterranean Sea.

The joint declaration, signed in Brussels on July 23, provides "a clear political framework" with three priorities for cooperation—developing a sustainable energy policy, reinforcing Morocco's energy policy pertaining to the progressive integration of its energy market with the European Union, and enhancing security of supply. ✦

Exploration & Development — Quick Takes

West Texas Marfa basin well logs oil

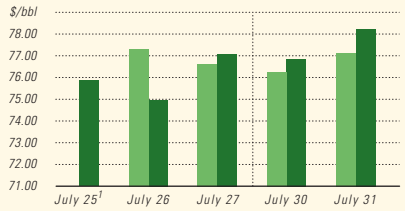
A private Dallas area independent plans to perforate and test an exploratory well that encountered oil 35 miles south of Alpine, Tex., in the nonproducing Marfa basin.

Giant Petroleum Inc., Las Colinas, Tex., set production casing near permitted depth of 6,000 ft at its Giant-Lykes DPW-1C well after logs and cuttings indicated the presence of oil in an undisclosed formation.

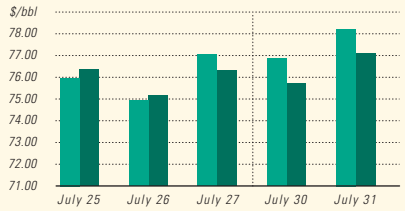
Giant's wellsite is in Brewster County. It's east of a Union Oil Co. of California well drilled to about 8,500 ft in Presidio County in the early 1980s that tested oil to surface and was deemed noncommercial (see map, OGJ, Jan. 20, 1992, p. 59). Giant owns interests

Industry Scoreboard

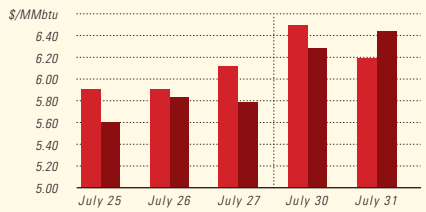
IPE BRENT / NYMEX LIGHT SWEET CRUDE



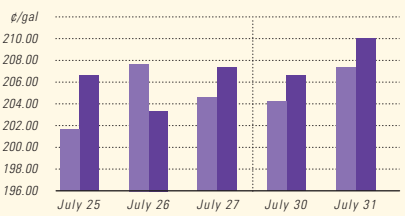
WTI CUSHING / BRENT SPOT



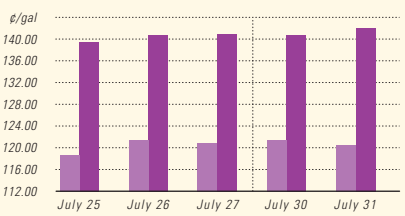
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



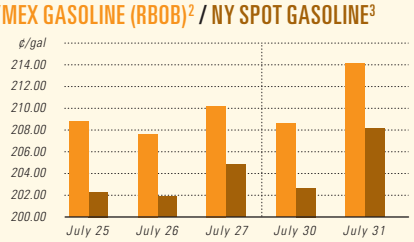
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

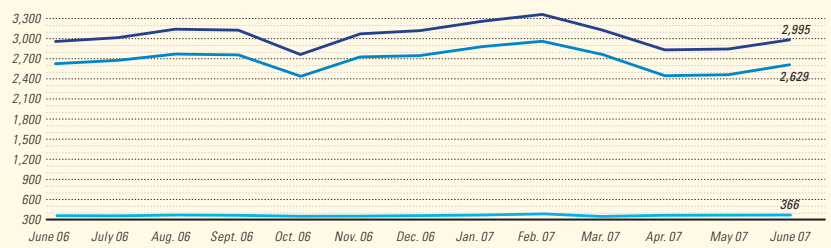
US INDUSTRY SCOREBOARD — 8/6

Latest week 7/20	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	9,688	9,710	–0.2	9,266	9,145	1.3
Distillate	4,043	4,109	–1.6	4,260	4,156	2.5
Jet fuel	1,643	1,631	0.7	1,632	1,613	1.2
Residual	693	653	6.1	775	718	7.9
Other products	4,939	4,905	0.7	4,856	4,817	0.8
TOTAL DEMAND	21,006	21,008	—	20,789	20,455	1.6
Supply, 1,000 b/d						
Crude production	5,184	5,201	–0.3	5,177	5,091	1.7
NGL production[2]	2,396	2,396	—	2,342	2,169	8.0
Crude imports	10,378	10,375	—	10,146	10,034	1.1
Product imports	3,913	3,506	11.6	3,596	3,567	0.8
Other supply[3]	1,003	900	11.4	918	1,116	–17.7
TOTAL SUPPLY	22,874	22,378	2.2	22,179	21,977	0.9
Refining, 1,000 b/d						
Crude runs to stills	15,644	15,943	–1.9	15,155	15,138	0.1
Input to crude stills	15,826	16,101	–1.7	15,418	15,486	–0.4
% utilization	90.7	92.6	—	88.5	89.1	—

Latest week 7/20	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	351,028	352,131	–1,103	335,497	15,531	4.6
Motor gasoline	204,134	203,341	793	211,030	–6,896	–3.3
Distillate	123,653	122,225	1,428	131,897	–8,244	–6.3
Jet fuel-kerosine	40,665	40,954	–289	39,874	791	2.0
Residual	37,503	36,899	604	42,157	–4,654	–11.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	22.4	22.7	–1.3	21.2	5.7	
Motor gasoline	21.1	21.1	—	22.0	–4.1	
Distillate	30.5	29.5	3.4	31.8	–4.1	
Propane	46.1	48.3	–4.6	65.1	–29.2	
Futures prices[5] **7/27**			Change		Change	Change, %
Light sweet crude, $/bbl	75.35	75.14	0.21	74.10	1.25	1.7
Natural gas, $/MMbtu	5.98	6.47	–0.50	6.83	–0.85	–12.4

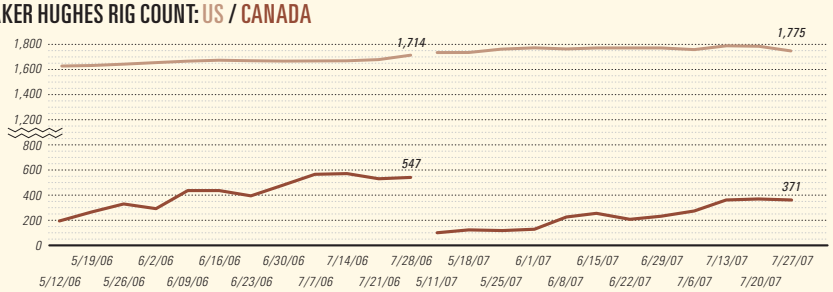
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

in 6,000 acres in the two counties and options on more, said Chris Plunkett, president.

Plunkett declined to identify the "hybrid" formation but said it is neither a shale nor a pure limestone or sandstone. It is regional in extent and similar to formations that produce in frontal Marathon-Ouachita fields to the east in Pecos County, he said.

He held most downhole information confidential for now but said the well was not drillstem-tested, and the oil has not been analyzed. Giant ran a complete log suite, including dipmeter and imaging logs, he said.

Plunkett reported difficult drilling in which the hole was lost twice due to swelling shales and lost circulation before a larger rig was brought in. Runoff from unseasonal rains in the desert area washed out the location road repeatedly, he added.

The well, originally programmed to test deeper shale gas, is near larger acreage positions held by Continental Resources Corp., Enid., Okla., and TXCO Resources Inc., San Antonio (see map, OGJ, Apr. 10, 2006, p. 33).

Giant's wellsite is southeast of a small field in Presidio County 14 miles southeast of Marfa that produced a small amount of oil from about 3,800 ft in the late 1990s (see map, OGJ, Nov. 10, 1997, p. 87).

Gulfsands to speed work on Khubert East find

Gulfsands Petroleum PLC said it intends to move rapidly to assess its Khurbert East discovery after it achieved a successful open-hole drillstem test of the first appraisal well on Block 26 in northeastern Syria.

The strong flow rate achieved on test from the Khurbet East-2 (KHE-2) well plus the geologic and reservoir data gained from the KHE-1 discovery and KHE-2 wells indicate that the Khurbet East discovery should be economic in the context of low development costs, proximity to production infrastructure, and a favorable production-sharing contract in the block, Gulfsands said.

The company also plans to shoot a 3D seismic survey over Khurbet East starting in September to identify future drilling locations and facilitate a strategy for early development and production.

The KHE-2 appraisal well encountered the Massive formation at 1,931 m. A drillstem test of the top 10 m of the fractured reservoir, flowed oil to surface at a maximum rate of 1,085 b/d during nitrogen lift of the well.

During the test period following the nitrogen lift, the average flow rate was 710 b/d of oil increasing to a final rate of 820 b/d.

Preliminary test assessment indicates excellent formation permeability and artificial lift potential. All wells in the Massive formation on Block 26 go onto artificial lift relatively soon after initial production, Gulfsands said.

The early assessment also suggests that 26° gravity oil is virtually identical to oil produced in Souedieh field, 12 km to the northeast.

PDVSA, Cupet to explore off Cuba

Petroleos de Venezuela SA said it will explore off Cuba with Cupet, the Cuban national oil company.

PDVSA said the project with Cupet involves six blocks covering 10,000 sq km, targeting light crude oil.

It said the companies will shoot 4,400 km of 2D seismic survey in deep water and 530 km in shallow water.

The announcement follows reports that Cuba is producing nearly 50% of the oil and gas it consumes (OGJ Online, July 26, 2007).

Thailand receives bids for 21 exploration blocks

Thailand's Department of Mineral Fuels (DMF) received responses from 28 international firms seeking 21 blocks in the country's 20th petroleum concession licensing round. In the first monthly submission round that closed on July 16, DMS offered 14 onshore blocks and 7 tracts in the Gulf of Thailand.

DMF Director General Krairit Nilkuha said the "overwhelming" interest in the round from petroleum exploration companies was primarily due to high oil prices.

Among bidders are Chevron Corp., Hess Corp., Total SA, BG Group, Mitsui Oil Exploration, PTT Exploration & Production PLC, Harrods Natural Resources, NuCoastal, Pearl Oil, and Adani Welspun Exploration Ltd.

DMF expects to name the preferred bidders over the next 2 months.

Companies will have until May 22, 2008, to submit bids for another 56 onshore blocks, covering a combined area of 211,687 sq km in scattered regions of the country, and nine blocks totaling 23,919 sq km offshore (OGJ Online, May 31, 2007). ✦

Drilling & Production — *Quick Takes*

Production starts from Independence Hub

Atwater Valley Producers Group reported that production has begun from the Independence Hub platform, which is moored in 8,000 ft of water on Mississippi Canyon Block 920, 123 miles southeast of Biloxi, Miss., in the Gulf of Mexico.

Gas production through the hub began July 19 from the Atlas-1 well in Atlas field on Lloyd Ridge Block 50. Atlas-1 is the first of 15 subsea wells in 10 anchor fields: Atlas, Atlas NW, Jubilee, Merganser, San Jacinto, Spiderman, Vortex, Mondo NW, Cheyenne, and Q.

Production from Atlas-1 is expected to ramp up to about 50 MMcfd soon. Most of the additional 14 wells, which on test demonstrated flow rates above 50 MMcfd, will be brought on stream one at a time during the remainder of this year. Production is expected to rise toward the hub's capacity of 1 bcfd of gas by year-end.

When operating at full capacity, the hub will process volumes of gas representing an increase of more than 10% in supplies from the gulf.

Independence Hub is thought to be the deepest production platform and largest offshore gas processing facility in the world (OGJ, Nov. 27, 2006, p. 43). It consists of a 105-ft, deep-draft, semisubmersible platform with a two-level production deck.

The platform is operated by Anadarko Petroleum Corp. and is owned 80% by Enterprise Products Partners LP and 20% by Helix

Energy Solutions Group Inc. Anadarko has reserved about 61% of the capacity on the hub, Eni SPA 20%, Norsk Hydro AS 12.5%, and Devon Energy Corp. 6.5%.

Oil flow starts from Polvo field off Brazil

Devon Energy Corp. (operator with 60% interest) and SK Energy (40%) have started production from Polvo oil field off Brazil, estimated to have 50 million bbl of reserves (OGJ, Feb. 19, 2007, p. 34).

The field lies in 300 ft of water on Block BM-C-8 in the Campos basin off Rio de Janeiro. Gross production is expected to peak by yearend 2008 at 50,000 b/d of crude oil.

Production facilities include a fixed production and drilling platform connected to a floating production, storage, and offloading vessel (FPSO). First sales are expected to begin this October when the first shipment of oil will be offloaded from the FPSO.

Systems repairs curtail Petrotrin oil output

Trinidad and Tobago's state oil company Petroleum Co. of Trinidad and Tobago Ltd. (Petrotrin) has reduced its crude oil production by nearly 15,000 b/d due to safety concerns.

Average oil production has been cut to 47,000 b/d, down from 62,000 b/d. Petrotrin's head of operations Wayne Bertrand said the company shut down some offshore production following an explosion in late May when a 12-in. pipeline on Trinmar Platform 21 ruptured in Soldado field, killing one and injuring two pipeline workers.

Petrotrin said it has had little success rerouting production through other facilities. Major problems with offshore facilities have resulted in Petrotrin's shutting down five platforms.

The company's 165,000-b/d Pointe-a-Pierre refinery also needs upgrading, and the company last week floated a $750 million issue to raise capital for the improvements. It has engaged Shell Global Solutions for 5 years to optimize the refinery and develop greater efficiencies in its existing plants. The gasoline optimization program will add five new plants that will enable the refinery to produce higher quality diesel and gasoline.

Petrotrin said natural gas production has not been affected. The company continues to produce 144 MMcfd of gas. ✦

TLP installed at Neptune field

SBM Atlantia Inc. has installed the world's fifth SeaStar tension leg platform (TLP) in BHP Billiton Ltd.'s Neptune field on Green Canyon Block 613 in 4,200 ft of water in the Gulf of Mexico. The 5,900-ton TLP hull will be equipped to produce up to 50,000 b/d of oil and 50 MMscfd of gas from an initial seven subsea wells. The TLP, fabricated at the Signal International shipyard on the Texas coast, was installed June 5 prior to Heerema Thialf heavy lift vessel setting the topsides processing facility atop the hull in a single, 5,500-ton lift on June 22. The topsides were constructed at the Gulf Island Fabrication shipyard in Houma, La. With the main installation portion of the project complete, final hookup and commissioning activities are now under way ahead of production start-up, anticipated by yearend. BHP Billiton is operator of Neptune field, and its partners include Marathon Oil Corp. 30%, Woodside Energy (USA) Inc. 20%, and Repsol YPF subsidiary Maxus (US) Exploration 15%. Photo from SBM Atlantia.

Processing — *Quick Takes*

Placid Refining to upgrade Port Allen refinery

Placid Refining Co. LLC has begun a $200 million upgrade of its 55,000 b/cd refinery in Port Allen, La. The upgrade will increase the facility's gasoline production by 30% to about 1.3 million gal/day while reducing total air emissions by about 50%.

The upgrade is being implemented in two phases.

Phase one, which started in June, involves construction of a 18,000 b/d gasoline desulfurization unit, a flue-gas scrubber for the facility's fluid catalytic cracker to reduce emissions of sulfur, and other infrastructure improvements. This work is scheduled for completion in second quarter 2008.

Phase two, which will begin in the third quarter, includes the upgrade and expansion of the FCC to 24,500 b/d from 20,000 b/d, allowing expansion by similar capacity of the alkylation unit. Placid also will expand the Rose deasphalting unit to 11,000 b/d from 7,000 b/d to convert heavier oils into gasoline and diesel. The majority of the construction for the second phase is scheduled for third quarter 2008, during a 30-day turnaround.

Placid currently supplies 35-40% of the gasoline consumed in the Baton Rouge, La., area. The company said it is considering expansion of the refinery to 80,000 b/d later this decade.

Gujarat refinery to get diesel hydrotreater

Indian Oil Corp. Ltd. has let a contract to Jacobs Engineering Group Inc. for a 44,000 b/d diesel hydrotreating unit at its 185,100 b/cd refinery in Gujarat, India.

The contract covers engineering, procurement, and construction management services.

The $200 million project, based on Axens technology, is scheduled to be completed in 3 years. It will enable the refinery to produce diesel meeting European Union sulfur standards.

Williams to extract ethane from Alberta oil sands

Nova Chemicals Corp., Pittsburgh, has signed a letter of intent with Williams Cos., Tulsa, to evaluate a process for extracting ethane from Alberta oil sands off-gas streams. Nova Chemicals would

be the exclusive, long-term customer for the ethane, which would be delivered to its Joffre, Alta., chemical plant via the Joffre feedstock pipeline.

Williams retained its olefins fractionator and a portion of the storage and distribution assets at its Redwater complex 64 km northeast of Edmonton, when it sold the gas liquids fractionation, storage, and distribution facilities in late 2003 to Provident Energy Trust. Williams will modify and own the oil sands off-gas liquids fractionation plant where it will extract the ethane. The company currently produces propylene from the off-gas liquids stream at Redwater.

The project is expected to begin operating in stages as early as 2010. ✦

Transportation — *Quick Takes*

EPNG fined $15.5 million; pipeline rehab ordered

The Justice Department and the US Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has fined El Paso Natural Gas Co. (EPNG) $15.5 million and mandated comprehensive rehabilitation of its entire 10,000 mile pipeline system.

The action stems from an investigation of the August 2000 explosion on EPNG's pipeline system in Carlsbad, NM, that killed 12 people (OGJ Online, Feb. 12, 2003).

EPNG will spend at least $86 million for widespread, comprehensive modifications of its natural gas pipeline system to resolve alleged corrosion-control violations.

The complaint, filed concurrently with the settlement agreement, alleges that EPNG failed to employ personnel qualified in corrosion-control methods, failed to investigate and mitigate internal corrosion in two of its gas pipelines, and failed to suitably monitor those pipelines to determine the effectiveness of steps taken to minimize internal corrosion.

Magellan expands Texas pipeline, terminal

Magellan Midstream Partners LP plans to invest $65 million to expand its products facilities in Texas.

The partnership intends to loop the existing 12-in. pipeline between its Galena Park origins and its East Houston terminal with a 16-in. line, to build 250,000 bbl of storage at its East Houston terminal, and to add a pump station north of Houston.

These projects will increase the partnership's ability to handle petroleum products originating from the Houston area for delivery throughout Texas, adding 200,000 b/d of incremental pipeline capabilities to the East Houston terminal and 65,000 b/d of incremental pipeline capabilities to Dallas and other Texas areas. The terminal is an origination point for the partnership's 8,500-mile products pipeline system.

The additions, expected to be operational in second-half 2008, will provide flexibility for future pipeline capacity increases.

The partnership also is expanding the storage and loading capabilities at its terminals in Dallas. This enhancement includes construction of 80,000 bbl of storage and expansion of the existing truck rack at its Dallas terminal to accommodate increased throughput of at least 10,000 b/d. In addition, the partnership plans to increase pipeline capacity, construct 100,000 bbl of storage at its Aledo terminal, and build a new truck rack at its Frost facility.

Based on current project plans, the terminal expansions should provide phased-in incremental capacity and be fully operational in second-quarter 2008.

Kinder Morgan line ruptures; cleanup under way

Canada's National Energy Board is leading the response of a Kinder Morgan Canada oil pipeline spill that occurred July 24 in Burnaby, BC.

Several other federal, regional, and local agencies also are responding to the spill, along with Kinder Morgan, which has enacted its emergency response plan.

Early assessments indicate the amount of oil spilled is 1,400 bbl, a company spokeswoman said.

The 24-in. pipeline, which connects the Burnaby tank farm with the Westridge marine terminal, was ruptured by a third-party construction crew.

The pipeline is part of Kinder Morgan's existing Trans Mountain system that transports oil between Edmonton, Alta., and Burnaby.

Sonatrach seeks mediation over LNG plant

Sonatrach has filed for legal mediation with a Paris arbitration court over its dispute with Spain's Gas Natural and Repsol-YPF involving a delayed LNG plant, according to media reports.

The Spanish newspaper Cinco Dias said the dispute involves the €1.6 billion Gassi Touil project and reluctance of the Spanish firms to develop a 4 million tonne/year liquefaction plant by 2011 as part of a deal signed in late 2004 to explore, extract, and market LNG in western Algeria (OGJ, Aug. 9, 2004, Newsletter). The paper noted increased construction costs.

On July 26, Spain and Algeria reached a compromise when Madrid lifted restrictions on the amount of gas Sonatrach can sell in the country, while Sonatrach promised not to sell more than 2 billion cu m/year.

Previously, Madrid had ruled that Sonatrach could sell a maximum of 1 billion cu m/year directly in Spain, a ruling Sonatrach contested.

The Algerian firm had just increased its participation in Medgaz, the consortium laying an 8 bcm/year pipeline under the Mediterranean between Algeria and Spain.

Medgaz interests are Sonatrach, 36%; Cepsa and Ibedrola, 20% each; and Endesa and Gaz de France, 12% each.

The Medgaz pipeline, including 210 km subsea, will link the Hassi R'Mel-Beni Saf gas pipeline operated by Sonatrach in Algeria with the Almería-Albacete gas pipeline belonging to Enagas in Spain. It is to begin operation in 2009. ✦

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2007

AUGUST

Diesel Engine-Efficiency and Emissions Research (DEER) Conference, Detroit, (540) 937-1739, e-mail: kim@cemamerica.com, website: www1.eere.energy.gov/vehiclesandfuels/resources/conferences/deer/index.html. 12-16.

Rocky Mountain Natural Gas Strategy Conference & Investment Form, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: cogaconference@aol.com, website: www.coga.org. 13-15.

American Chemical Society National Meeting & Exposition, Boston, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 19-23.

NAPE Summer Expo, Houston, (817) 847-7700, (817) 847-7703 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 23-24.

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

✦Rocky Mountain Crude Oil Market Dynamics Summit, Denver, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us/events.html. 4-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

Black Sea Oil & Gas Summit, Istanbul, +90 312 454 00 00-1412, +90 312 454 00 01, e-mail: bsogs2007@flaptour.com.tr, website: www.bsogs2007.org. 5-6.

Iraq Petroleum Conference, Dubai, +44 (0)20 7978 0075, +44 (0)20 7978 0099 (fax) website: www.thecwcgroup.com. 8-10.

Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

Global Refining Strategies Summit, Houston, (416) 214-3400, x3046, (416) 214-3403 (fax), website: www.globalrefiningsummit.com. 10-11.

PIRA Understanding Natural Gas Markets Conference, New York, 212-686-6808, 212-686-6628 (fax), e-mail:

sales@pira.com, website: www.pira.com. 10-11.

Annual LNG Tech Global Summit, Rotterdam, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.lngsummit.com. 10-12.

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

EXPOGAZ Gas Congress, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 11-13.

European Gas Forum, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 12-13.

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

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

Russia & CIS Petrochemicals & Gas Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 17-18.

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

Russia & CIS Refining Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 19-20.

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 15-19.

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

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

Calendar

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

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 22-24.

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

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

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

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

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

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

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

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

NOVEMBER

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

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

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

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

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

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

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

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

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

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

Asia Pacific Natural Gas Vehicle Conference & Exhibition, Bangkok, +66 0 2617 1475, +66 0 2271 3223 (fax), e-mail: angva@besallworld.com, website: www.angvaevents.com. 27-29.

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

DECEMBER

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

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

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

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

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

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

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

2008

JANUARY

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

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

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

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

FEBRUARY

Deep Offshore Technology International Conference & Exhibition, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 12-14.

MARCH

GPA Annual Convention, Grapevine, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 2-5.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

Gastech International Conference & Exhibition, Bangkok, +44 (0) 1737 855005, +44 (0) 1737 855482 (fax), e-mail: tonystephenson@dmgworldmedia.com, website: www.gastech.co.uk. 10-13.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 18-20.

Middle East Geosciences Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com/oil. 24-26.

APRIL

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

Journally Speaking

Free markets and biofuels

Paula Dittrick
Senior Staff Writer

Without exception, everyone interviewed for the special report beginning on p. 20, Agrifuels—Promise and Progress, expressed a desire to avoid unintended consequences.

They were talking about both economic and environmental consequences.

Chares T. Drevna, executive vice-president of the National Petrochemical & Refiners Association, acknowledged "universal agreement" that biofuels represent a strong, growing component of the US transportation fuel mix.

"However, NPRA opposes the mandated use of biofuels and supports the sensible and workable integration of biofuels into the marketplace based on market principles and as the market demands," Drevna said. "Energy policy based on mandates is no recipe for success."

NPRA always has opposed mandates that limit refiners' flexibility to meet demand, Drevna said.

He advises "caution and prudence" as Congress considers proposals for unprecedented expansion of ethanol and other biofuels. He said blending grain ethanol into gasoline or soy biodiesel into diesel is not always economic or energy-efficient.

Ethanol creates potential ozone emission problems, especially in warm weather. Concerns about biodiesel include nitrogen-oxide emissions and low-temperature reliability.

Drevna said Congress should preempt state and local biofuels mandates, which are not covered by a review of the Department of Energy or the Environmental Protection Agency.

"The existing federal renewable fuels standards mandate with its credit-trading provisions contains a degree of freedom that allows the distribution system to operate at a low-cost optimum by avoiding infrastructure bottlenecks (such as lack of storage or rail capacity). Mandating ethanol usage in specific areas forces a distribution pattern that is less flexible and therefore has less capability to minimize costs," he said. "These additional costs will be borne by consumers."

State or local biofuels mandates limit refiners' choices and create boutique markets, which can "balkanize the national fuel market," he said.

Drevna also called for biofuels to be developed with a clear realization of their impact on air quality. Blended ethanol increases the Reid vapor pressure of gasoline, raising evaporative emissions of volatile organic compounds (VOCs), which are ozone precursors, in the summer.

Chares T. Drevna, executive vice-president, National Petrochemical & Refiners Association

"Given that 8-hr ozone national ambient air quality standards (NAAQS) will result in many new ozone nonattainment areas, it is unlikely that the mandated level of ethanol can be distributed in 9.0 rvp conventional gasoline areas without exacerbating ozone problems in nonattainment areas or creating new nonattainment areas," Drevna said.

He believes expansion of nonattainment areas will impose constraints on ethanol use. Drevna wants Congress to defer a renewable motor fuels mandate pending analysis of additional summer VOC emissions and their effect on maintaining attainment with the 8-hr ozone NAAQS.

He notes that President George W. Bush's proposal to cut gasoline use by 20% by 2017 would drop gasoline use below current production levels and transform the US into a net gasoline exporter.

The Energy Information Administration projects that gasoline demand in 2017 will be 161 billion gal. A 20% reduction of that would result in 129 billion gal of demand. In 2006, US gasoline production was 136 billion gal supplemented by 7 billion gal of net imports.

One possible unintended consequence of proposed higher national biofuels mandates is a potential increase in the natural gas price, Drevna said. Ethanol production uses large amounts of gas.

"Converting corn and potentially cellulosic material into a usable fuel requires energy, and natural gas currently provides much of that necessary energy," Drevna said. In addition, higher volumes of fertilizer are apt to be needed if farmers are to grow more corn or soybeans for biofuel feedstocks.

"Natural gas serves as the key feedstock in fertilizer production," he said. "As natural gas demand rises due to demand from ethanol and fertilizer production, the already tight domestic market will be pressured."

Proposed mandates for higher volumes of ethanol nationwide raise logistic questions.

Drevna questions how the country will transport the ethanol to be blended at the racks. He also questions where that ethanol will come from and how much it will cost. ✦

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Editorial

Last of three parts

The final four facts

A three-part editorial series concludes here with the last of 12 points in a monograph by two former US Federal Trade Commission officials entitled "A Dozen Facts You Should Know about Antitrust and the Oil Industry." The authors are Timothy J. Muris, FTC chairman during the administration of George W. Bush, and Richard G. Parker, director of the FTC's Bureau of Competition under Bill Clinton. They cochair the antitrust and competition practice in the Washington, DC, office of the O'Melveny & Myers LLP law firm, where Muris is of counsel and Parker is a partner.

Here are monograph facts summarized in the first part of this series: 1. Economic learning and antitrust enforcement have evolved; we now know that big is no longer necessarily bad; 2. The antitrust authorities scrutinize the petroleum industry more closely than any other; 3. The American petroleum industry is not highly concentrated; and 4. Refiners have expanded domestic and global capacity significantly (OGJ, July 16, 2007, p. 17).

The second part of the series presented these facts: 5. Refineries operate at or near their practical maximum utilization rates; 6. Inventory practices have reduced costs and benefited consumers; 7. The profitability of the petroleum industry is commensurate with other industries over the long run; and 8. The FTC applies tougher standards to mergers in the oil industry than to mergers elsewhere (OGJ, July 23, 2007, p. 19).

Summaries of the last four facts in the monograph follow.

- *Fact 9: Empirical analyses of the price effects of oil mergers provide no basis for applying more-stringent merger standards.*

Oil industry critics rely on a 2004 report by the Government Accountability Office to assert that a few oil industry mergers have increased gasoline prices. The GAO report can support no such claim. GAO based its report on fundamentally flawed analysis that was unreliable at best and invalid in most instances.

Some legislative proposals favor abandoning the antitrust agencies' well-tested approach in favor of novel and unique standards for oil mergers. The bipartisan Antitrust Modernization Commission has observed that there is a general consensus that the agencies' approach to merger review is sound. Replacing the current system with industry-specific rules threatens to politicize merger policy, encourage rent-seeking behavior, create judicial confusion, and generate high administrative burdens.

- *Fact 10: Market forces provide the most effective mechanism for quickly and efficiently alleviating price spikes.*

A particularly compelling example of the effectiveness of market forces in responding even to massive supply shocks involves Hurricanes Katrina and Rita. These hurricanes severely impacted product production and distribution in the Gulf Coast and throughout the United States, substantially reducing US supply for an extended period. Firms responded by quickly restoring production and logistics capabilities and by locating alternative supply sources, including increased imports. Prices returned to prehurricane levels within 4 weeks after Rita hit.

- *Fact 11: Price-gouging legislation would harm, rather than benefit, consumers.*

Effective price-gouging legislation would create the same effects as price controls. History reveals that such measures provide false comfort for consumers. Price controls would lead to fuel run-outs by raising costs of replacement supply, tend to hit consumers in rural areas the hardest by discouraging shipments to remote areas, waste resources, create market distortions, encourage inefficiencies that cause regulated prices to exceed market prices, and diminish refiners' incentives over the long run to invest in refining capacity.

- *Fact 12: There are constructive alternatives that will benefit consumers.*

Instead of pursuing market-distorting initiatives that would harm consumers, the government should remove constraints on industry members to respond quickly to future supply disruptions. It also should continue vigorous and objective antitrust scrutiny at all levels of the oil industry; eliminate state laws that needlessly increase gasoline prices, including those addressing minimum pricing, divorcement of downstream operations, and full service; limit the number of boutique fuels; expedite waiver processes during supply disruptions; and streamline refinery permitting.

The 132-page monograph is available on the web site of O'Melveny & Myers at www.omm.com. ✦

Oil industry researching nonfood biofeedstocks

Paula Dittrick
Senior Staff Writer

Agrifuels' promise from an oil industry perspective hinges on unlocking the answers to two root questions: How can today's photosynthesis supplement the energy supplied by prehistoric photosynthesis? What are the logistics for refiners and pipelines?

Support for agrifuels is high because of the hope for extending energy supply and addressing climate change concerns. Industry is looking for ways to balance the chemistry and the economics.

Pamela Beall, Marathon Petroleum Co. LLC vice-president of business development, downstream, said it's ironic that fossil fuels and biofuels rely on essentially the same feedstocks—only at different stages in their life cycles. "Fossil fuels are really plants and animals that decomposed over the past 600 million years. What are we talking about using with biofuels?" Beall said. "We are trying to accelerate in a very short time what nature has done over a very long time to provide the fuel we use today."

The pace of crude oil discoveries is declining while world oil demand is increasing. Oil production becomes increasingly expensive as industry must explore deepwater or arctic regions. National oil companies control much of the remaining reserves, often in geopolitically sensitive areas.

"To the extent that you can harvest renewable fuels, it could be easier," Beall said. "The cost of corn has not escalated like the cost to produce oil. The two are moving in opposite trends. Corn yields are getting better and will escalate with genetic modifications."

She notes renewable fuels will not lower the cost of transportation fuels. Marathon and oil companies in general are hoping to find renewable fuels that can be integrated into today's refining and fuel delivery system.

Rick Zalesky, Chevron Technology Ventures LLC vice-president of biofuels and hydrogen, sees agrifuels as complementing fossil fuels, saying both are needed to satisfy future demand.

"The idea is that you supplement your hydrocarbon feed system with a biofeed system and utilize existing investments in refining assets to process traditional petroleum feedstock along with biofeedstock," Zalesky said.

Ron Cascone, with energy and chemical industry consultant Nexant Inc. of New York, said the ideal goal is to make gasoline from biomass.

"The Holy Grail is to produce exactly the fuel we are using now but make it from biomass—not from fuels that releases fossil carbon," Cascone said.

Zalesky said the search is for "a molecule that we already know how to deal with—a chemical identical to gasoline, jet, and diesel blendstocks.... It's probably a 10-year horizon to get that approach developed and deployable at scale."

Food vs. fuel

Currently, biofuels rely on corn or soybeans in the US, sugar cane in Brazil, and rapeseed or flaxseed in Europe. The use of food crops has triggered questions about the ethics of pulling grain away from the food and feed supply chain to produce fuel.

Chevron Technology Ventures is among proponents of using nonfood plants to create transportation fuels. Algae grown on a commercial scale

potentially could be a feedstock for refining and processing.

"Our bias would be to take bio-oil coming from algae and put it into our hydrotreaters and hydrocrackers in our refining infrastructure," Zalesky said.

Rob Routs, Royal Dutch Shell PLC executive director, downstream, said using waste plant material instead of food crops could circumvent political pressure and public controversy over using crops for fuel.

Shell is researching cellulosic ethanol through a partnership with Iogen Corp. of Canada.

In addition, Shell has a minority stake in a biomass-to-liquids plant in Germany owned by Choren Industries GMBH. The plant converts wood chips into synthesis gas and fuel for diesel engines using the Shell Middle Distillate Synthesis technology that Shell developed for gas-to-liquids production.

Separately, ConocoPhillips and Tyson Foods Inc. are working to produce renewable diesel from animal fats using a proprietary thermal depolymerization technology.

The ConocoPhillips-Tyson joint venture processes animal fats with hydrocarbon feedstocks to produce ultralow-sulfur diesel. Renewable diesel production began last year using soybean oil at the ConocoPhillips Whitegate Refinery in Cork, Ireland.

Consultant Nexant believes the fundamental aspects of the liquid biofuels industry will change dramatically by 2020. It compiled a global multiclient study, "Liquid Biofuels: Substituting for Petroleum."

Workers commissioning cooling towers in the Galveston Bay Biodiesel LP plant in Galveston, Tex. The plant is in production. Chevron Technology Ventures is an investor in the plant run by Bio Select Fuels LLC. Photo from Standard Renewable Energy LLC.

The study foresees an evolution from conventional agriculture, starch-sugar substrates, and enzyme conversions to genetically modified crops, biomass substrates, and combinations of thermochemical, catalytic, and enzyme conversions (see figure.)

Cascone believes ethanol from grains and sugar—although an excellent high-octane gasoline blendstock—represents a transition to something else long term because of grain-based ethanol's "practical problems" of fitting into the fuel distribution system.

He said while there are environmental, political, and societal benefits to using an alcohol for fuel rather than a hydrocarbon, society must make tradeoffs between the current renewable, biodegradable biofuels having low toxicity but limited in supply potential against other fuel options not as biodegradable or more noxious but more attractive in other ways.

"We agree with many others that the next phase of development is likely to be ethanol made by fermentation of sugars made by hydrolysis of biomass," Cascone said.

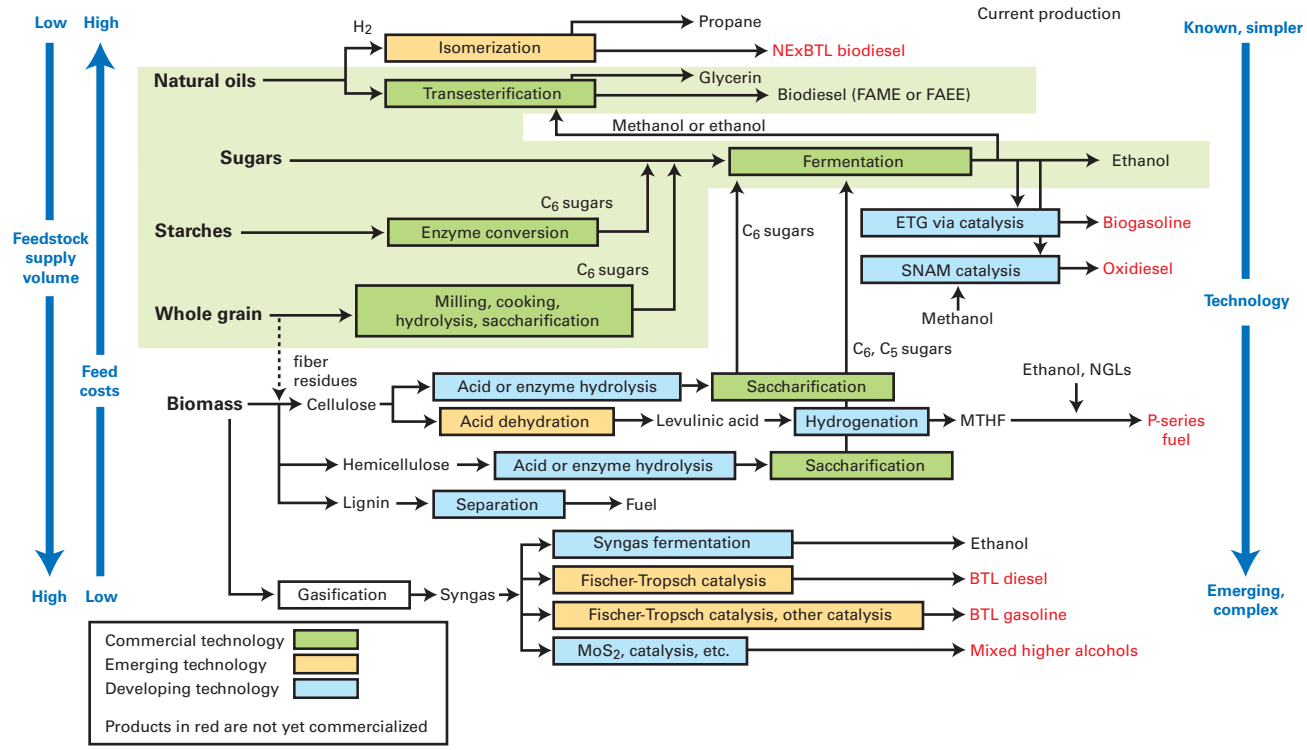
"We also conclude that...integrated thermochemical platforms will take the lead in producing both gasoline and diesel range biofuels, probably together with electric power and chemicals," he said. "This alternative should be and probably will be pursued contemporaneously with developing biomass-based ethanol. We also believe that ethanol will eventually need to be dehydrated to hydrocarbon gasoline fractions."

Biofuel economics

In 5 years, US corn ethanol production nearly tripled, and biodiesel production increased tenfold although at a much lower level than ethanol.

Among federal programs to support renewable fuels, ethanol receives a 51¢/gal volumetric excise tax credit and biodiesel receives a $1/gal tax

LIQUID BIOFUELS TECHNOLOGIES



Source: Nexant Chem Systems from Liquid Biofuels: Substituting for Petroleum A Global Techno-Economic and Market Evaluation prospectus

credit (50¢/gal for nonvirgin feedstock). These provisions expire in 2010 for ethanol and 2008 for biodiesel.

Chevron's Zalesky said biofuels of the future—subsidies or no subsidies—must be produced at scale economically.

Ethanol also benefits from a 54¢/gal tariff on imports, which ConocoPhillips Chairman Jim Mulva opposes.

"This penalizes lower-cost and less carbon-intensive imports, such as from Brazil. This tariff should be phased out," Mulva said in a July 19 speech in Washington, DC.

The Energy Policy Act of 2005 established a renewable fuels standard (RFS) phasing up to 7.5 billion gal/year in 2012, a target that analysts expect production to surpass. President George W. Bush has called for an enhanced RFS of 35 billion gal/year by 2017.

Charles T. Drevna, National Petrochemical & Refiners Association executive vice-president, warns against "an overdose of heavily subsidized products," saying the free market should set fuel specifications.

"The goal of the biofuels industry, including both corn-ethanol and cellulosic ethanol, should be economic parity, or better, with that of refined petroleum products," Drevna said (see article, p. 17).

Pearce Hammond, analyst with Simmons & Co. International, forecast that US ethanol production will reach nearly 15 billion gal by 2015 and biodiesel will reach 2 billion gal by that time. By volume, ethanol then will represent about 10% of gasoline supply.

Ethanol's progress

Existing alcohol fuels made from agriculture products or wastes—the most common one now being ethanol—are produced through fermentation of sugars, distillation, and drying. Sugar cane juice can be fermented directly into ethanol. Corn is low in sugar but high in carbohydrate cellulose that must be turned into fermentable sugar.

Researchers are seeking methods to more efficiently convert cellulose to sugar.

Marathon has a 50:50 joint venture with The Andersons Inc. to construct and operate corn-based ethanol plants. The joint venture's first plant is under construction in Greenville, Ohio. Its expected capacity is 110 million gal/year.

"Certainly one of the reasons that we decided to invest in an ethanol plant is to ensure reliability of supply," Beall said, noting Ohio has no ethanol plants now so all ethanol must come into the state by rail or by truck.

"We find it very important to have ethanol. Once you put a customer into blended ethanol gasoline, you really don't want to run out," she said. "If you don't have that gallon of ethanol, then that could hold up the sale of 9 gal of hydrocarbon if you are blending at 10%."

The Greenville ethanol plant is within 100 miles of Marathon terminals in Columbus, Cincinnati, and Indianapolis and is convenient to its Louisville, Ky., market, she said.

"We can send our transport trucks to the ethanol plant after they have made a

INVITATION TO PREQUALIFY

OLOKOLA GAS SUPPLY PROJECT

Professional and Technical Support Services

CHEVRON NIGERIA LIMITED

(Operator of the NNPC/CNL Joint Venture)

Invitation to prequalify for inclusion on the bid list for the reimbursable contract to provide professional and technical support services for the Olokola Gas Supply Project, offshore the Federal Republic of Nigeria

INTRODUCTION

Chevron Nigeria Limited (CNL), the operator of the Joint Venture between itself and the Nigerian National Petroleum Corporation (NNPC), intends, on behalf of the Joint Venture, to install offshore gas production facilities including production platforms, wellhead platforms, pipelines and flowlines as part of the Olokola Gas Supply (OKGS) Project. The facilities are to be located offshore Bayelsa, Delta, Ondo and Ogun states in Nigeria.

The NNPC/CNL Joint Venture is committed to providing opportunities for Nigerian companies and Nigerian labor to participate and develop their expertise in line with the Federal Government Policy on Local Content Development and consistent with the project objectives of safety, schedule, cost and quality.

SCOPE OF WORK

Experienced Nigerian or International Professional and Technical personnel support service companies are hereby invited to submit prequalification documentation for the OKGS project to provide professional and technical support personnel on a reimbursable basis for the following scope of work:

Successful bidder will be required to manage and implement staffing programs to recruit, hire and retain highly qualified professional and technical personnel to perform technical support activities on a worldwide basis in support of the OKGS Project Team during the execution of Company's Engineering, Procurement, Installation and Commissioning (EPIC) phases of the OKGS project as fully integrated project team members. Such services are expected to occur in at least some of the following locations, subject to award of facilities and pipeline/flowline contracts:

- Nigeria
- USA
- Middle East
- Far East
- Europe

PREQUALIFICATION CRITERIA

Qualified contractors and/or consortiums that have recent, relevant and demonstrated experience in successfully providing high-quality professional and technical personnel on projects of comparable size, scope and complexity will be considered to competitively tender for the scope of work described above. Contractor is expected to demonstrate experience in the area of professional and technical project team staffing on a global basis by demonstrating:

- Ability to recruit and screen for high-quality personnel on a worldwide basis
- Management and retention of employees provided to project teams
- Ability to provide and manage logistics for employees on international assignments, such as housing, transportation, medical and other benefits

Interested contractors are also required to submit information to establish their qualifications in areas including but not limited to the following:

- **Company Profile:** Provide full details of company profile (including but not limited to organizational structure, copy of certificate of incorporation, evidence of financial strength and stability, including audited accounts for the past three (3) years, business locations, insurance agencies, contacts and resumes of key management personnel).
- **Business Registration and Documentation:** Provide copies of the current Nigerian Department of Petroleum Resources (DPR) certificate of registration or plan for obtaining such certification, Income Tax Clearance Certificate and VAT registration number.
- **Previous work experience:**
  - Evidence of providing high-quality and skilled personnel to project teams in Nigeria and at other international locations for offshore oil and gas projects of a similar nature
  - Evidence of existing recruiting, hiring and maintaining staff, including Human Resources practices, and procedures to provide personnel for oil and gas projects of a similar nature on international assignments
- **Policies:** Submit detailed summary of existing and proposed Health, Environment and Safety policies, programs and management systems. Evidence of exemplary work site safety performance.
- **Joint Venture Arrangement:** In the case of a Joint Venture or consortium arrangement, evidence of signed agreement of interest and memorandum of understanding (MOU) by the Partners will be required including each partner's legal status, country of incorporation and residence for tax purpose. The Joint Venture shall provide evidence of joint and several liabilities among the Ventures or Consortium.
- **Subcontractors:** Provide list of any specific portions of the work which are intended to be subcontracted.
- **Payment of Taxes:** Evidence of payment of Nigerian statutory taxes (including the submission of current tax clearance certificate).

Any incomplete information may disqualify a respondent. CNL may also disqualify any contractor which is delinquent in its payment of Nigerian taxes.

NIGERIAN CONTENT

In line with the Federal government of Nigeria directives on Nigerian content of targets of 45% and 70% by year end 2006 and 2010, interested Contractors and/or Consortiums are to include in their Prequalification Data Package submittal, a statement that if qualified and selected to submit a technical and/or commercial bid, their Nigerian content plan submission will comply with this directive. In addition, this statement shall confirm that if qualified and selected to submit a technical and commercial bid, then their bid submission will identify the Nigerian work scope and this identification will be in the form of a percentage of the overall work scope in monetary terms (commercial submission) of the value that will be created "in-country" and use of Nigerian resources (material and labor) on this project.

Any interested Contractor and/or Consortium must include in the statement submitted in response to this Advertisement and "Prequalification Data Package Submittal" an acknowledgement and willingness to comply with the following:

- Commitment to comply with Nigerian content directives along with plans for optimizing Nigerian content in the execution of this work.
- Acknowledge that, if qualified and selected to submit a technical and commercial bid, then the technical and/or commercial bid submission will contain the following information:
  - List of Nigerian subcontractors that will participate in the execution of the project
  - Binding MOU with the in-country service providers indicating the scope of work
- Noncompliance with Nigerian Content Directives may disqualify a bid submission.

PREQUALIFICATION DATA PACKAGE

To be considered, responses must be submitted in the format and level of detail required in the CNL OKGS Professional & Technical Services prequalification data package. This package may be obtained, between the hours 08:00 and 15:00 (Monday through Thursday), by calling at either of the following locations:

Chevron Nigeria Limited
Manager of Internal Controls
2 Chevron Drive, Lekki Peninsula
P.M.B. 12825, Lagos, Nigeria
Tel: +234.1.260.0600

Chevron International Exploration and Production
CNL Gas Projects Contracts Advisor
26090A 1500 Louisiana Street
Houston, TX, 77002 USA
Tel: 832.854.3553

Packages may also be obtained via e-mail request to okgspreq@chevron.com E-mail request must provide the full company name, address, point of contact, telephone number and return e-mail address.

The OKGS Professional & Technical service contract prequalification data package will be available until August 27, 2007 at the locations specified above. Failure to obtain the prequalification package and provide all requested data within the specified time frame will automatically disqualify the applicant.

RESPONSES

Responses must be submitted in accordance with and demonstrate fulfillment of the requirements set forth in the CNL OKGS Professional & Technical Services contract prequalification data package. Responses to this invitation shall be sealed and submitted in accordance with the prequalification data package instructions. Each response shall be marked "CONFIDENTIAL – OKGS Professional & Technical Services Invitation for Prequalification". The full name and address of the responding company or entity must be clearly marked on the submittals. Responses must reach the address given below not later than 14:00 hours on September 5, 2007:

Chevron Nigeria Limited
Manager of Internal Controls
2 Chevron Drive, Lekki Peninsula
P.M.B. 12825, Lagos, Nigeria
Tel: +234.1.260.0600

This invitation does not obligate CNL to consider a responding company for prequalification, to include a responding company on a bid list, to award them a contract or to inform them of any resultant action. CNL reserves the right to either accept or reject any submittal in part or in whole, at its sole discretion. All costs incurred as a result of this prequalification and any subsequent request for information shall be to the responding companies' accounts.

delivery to wholesale locations or retail gasoline stations," she said. "On their way back, they can stop at the ethanol plant and then resupply the terminal with ethanol."

Marathon is one of the nation's leading blenders of ethanol in gasoline and has been doing so for more than 15 years because of the company's heavy marketing presence in the Midwest, Beall said.

Biobutanol potential

Many chemists see biobutanol as a potential game changer for biofuels because of its potential to integrate better than ethanol into the refining and gasoline distribution infrastructure.

Unlike ethanol, "butanol has low solubility in water and a low vapor pressure. Its Reid vapor pressure contribution in a gasoline blend is minimal," said Cascone. The same feedstocks used for ethanol could be used, including sugar cane, beets, and corn.

Butanol is currently used as an industrial solvent. Future feedstocks for biobutanol fuel could involve cellulosic material: grass, straw, sugar cane stalks after juice extraction, and corn stalks (stover). Production economics have yet to be determined.

Cascone said, "With the right regulatory regime, you could blend butanol at the refinery and distribute it as a butanol blend." Nexant is studying the process and feasibility of converting ethanol plants into butanol plants.

"There is a tradeoff and a continuum between ethanol, butanol, and gasoline," Cascone said. "While more toxic, butanol has another advantage as contrasted with ethanol in that it...has an energy density approaching that of a gasoline."

Ethanol has about 70% of the energy density of conventional gasoline.

Biobutanol was produced in commercial quantities around WWI in the UK, Canada, and the US. The plants eventually were closed because natural gas-sourced butane became commercially available as a feedstock.

BP PLC and DuPont are working with British Sugar, a subsidiary of Associated British Foods PLC, to convert an ethanol fermentation facility to produce biobutanol.

"What are we talking about using with biofuels? We are trying to accelerate in a very short time what nature has done over a very long time to provide the fuel we use today."

Pamela Beall, Marathon Petroleum Co. LLC, vice-president of business development

To begin market development of biobutanol, BP and DuPont will import small quantities of biobutanol from a manufacturing plant in China. First product is expected to arrive by yearend and will be used to carry out infrastructure and advanced vehicle testing.

Initial laboratory engine tests using conventional butanol indicated butanol has fuel performance properties similar to those of unleaded gasoline.

The joint venture plans to use sugar beets as the feedstock at British Sugar's plant in Wissington, England, east of Cambridge. Development work is under way on a biotechnology process to produce biobutanol.

The BP-DuPont venture is looking for a genetically modified microbe or some "ultimate bug" for the catalyst to boost conversion ratios in processing feedstock into biobutanol, independent chemists told OGJ.

A bioethanol plant will be built alongside a demonstration plant to advance the development work. Initial production would be bioethanol. The partners are looking at the feasibility of converting the plant to biobutanol pending technology developments.

The bioethanol plant would be built at BP's existing Saltend chemical site in the UK. The bioethanol plant is scheduled to be commissioned in late 2009. Plans call for it to have a 420 million l./year capacity from wheat feedstock.

Biodiesel production

Biodiesel refers to additives and substitutes for diesel based on methyl esters of vegetable oils or fats. An alcohol-ester mixture, methyl soyate, is separated, and excess alcohol is recycled. The ester is purified through numerous techniques.

Made from soybeans in the US and rapeseed in Europe, biodiesel is manufactured through transesterification with an alcohol such as methanol and a catalyst. Biodiesel can be blended in various concentrations. Ideally, biodiesel could be handled similarly to conventional diesel fuels, but it is being distributed primarily via trucks now because of integrity concerns about pipeline shipments.

When asked about biodiesel, Beall said Marathon blends only soy-based biodiesel because it is not yet comfortable with other feedstocks.

"The concern is too much glycerin and the potential to gum up engines and filters," Beall said. "It's more of a concern in the winter months, but we don't really want to take a chance at handling any bad products. We are going slowly and carefully with biodiesel."

Marathon recently completed biodiesel blending projects at its Robinson and Champaign, Ill., terminals, which will market soy-based B2 (2% biodie-

sel) and B11 (11% biodiesel) product. Marathon has offered biodiesel at its St. Paul Park, Minn., terminal since July 2005 and at its Louisville, Ky., terminal since February 2007.

Biodiesel manufacturers are looking to widen their distribution by integrating biodiesel plants with existing diesel capacity.

Green Earth Fuels LLC of Houston built a biodiesel plant in Kinder Morgan's Galena Park, Tex., liquids terminal on the Houston Ship Channel.

Jeffrey Trucksess, Green Earth executive vice-president of regulatory and government affairs, said biodiesel plants built near terminals help reduce product handling and lower transportation costs.

Green Earth's Galena Park plant started up in July with a production line designed to yield 43 million gal/year. A second line of the same size is scheduled for operation in September.

In conjunction with Green Earth, pipeline operator Kinder Morgan Energy Partners LP is building Galena Park terminal biodiesel tanks. KMP plans to invest up to $100 million to expand terminals for biodiesel in Houston, New Orleans, New York Harbor, and elsewhere.

James Holland, vice-president of logistics for KMP's products pipeline, said biodiesel is a business opportunity for terminal operators who can bring in a B100 that is soy-based and also a B100 that is palm-based. At the rack, they blend a common diesel with whatever biomaterial the customer wants. KMP is contemplating pipeline opportunities.

"We are more than happy to do this if we can get some definitive decisions on what the specs are going to be and what demand is going to be," Holland said. "If you can get the specs and demand to line up, it becomes a perfect pipeline opportunity."

KMP expects to run biodiesel tests on its Plantation Pipe Line system from Baton Rouge, La., to Greensboro, NC, in the third quarter. It will involve B5 or B10 biodiesel, depending upon the marketer.

Colonial Pipeline Co. last year tested biodiesel in its pipeline system, concluding that biodiesel was feasible to transport, but the test results raised concerns about potential contamination of jet fuel so biodiesel pipeline shipments are not occurring yet.

Consequently, Colonial is working with the renewable fuels industry toward ensuring the quality of jet fuel and permitting biodiesel shipments on the same pipeline.

Colonial's biodiesel tests contained compounds not allowed in jet fuel, but the company did not specify the compounds. Industry analysts told OGJ that biodiesel is basically a form of lubricity additive, incompatible with jet fuel.

Biodiesel would have to be carried in Colonial's mainline reserved for distillate products and diesel fuel. Its other mainline is reserved for gasoline shipments.

KMP's Holland said Kinder Morgan moves jet fuel in a pipeline separate from the pipeline used for diesel, and he does not foresee the company experiencing those compatibility issues.

"With biodiesel, some parties will want palm-based material and others will want soy-based material—making fungibility a real problem," Holland said. "A lot of biodiesel producers say their product is special and cannot be commingled with others. So if you were to commingle two types of biodiesel, what do you get?"

Although both biodiesel products are B5, pipeline operators might wind up with cloudy diesel or other unknown issues if the base material is different in each biodiesel. He noted B100 has specifications, but there are none yet for B5 or B10.

"Physically yes, you can move it," Holland said. "But all the product grades and specification issues have to be worked out to make it happen."

The National Biodiesel Board said regulation of fuel standards is a function primarily left to the states. However, regulation of biodiesel and blends is not uniform across all states.

NBB is working to catalog information regarding fuel regulation authority by state.

Elsewhere, BP is investing $9.4 million in India to demonstrate the feasibility of producing biodiesel from jatrapha curcas, a succulent whose seed produces an oil that can be used for biodiesel. At its Bulwer Island 85,500 b/cd refinery in Australia, BP plans to produce around 110 million l./year of biodiesel from tallow feedstock.

Refinery expansions

Although NPRA opposes the mandated use of biofuels, it supports integration of biofuels based on market demands, Drevna said.

NPRA members are among the largest users of ethanol, and refiners will continue to rely on it as a gasoline blendstock, especially pending major US refining expansions. Drevna believes mandates to increase ethanol use could supplant refining expansions.

"Refiners must make investments today on what they believe to be the 10-15 year outlook," Drevna said.

Marathon has announced an estimated $3.2 billion expansion to its 245,000 b/cd refinery in Garyville, La. The expansion will increase crude capacity by 180,000 b/d.

Beall said the investment decision confirms Marathon's commitment to support the US gasoline infrastructure of the future despite uncertainty about future gasoline standards.

"We think that there is room for conventional hydrocarbons as well as renewables in order to satisfy the demands that the country will have," Beall said, noting that the US imports a lot of feedstocks, blendstocks, and products.

"Some of the production that we make in the US will offset some of those imports and will help to meet the growth in demand. Corporate average fuel economy (CAFE) standards are increasing, and with alternative fuels growing, we think there is still a need to increase the refining capacity in the US." ✦

NPC report: All energy options should be pursued

Nick Snow
Washington Correspondent

Every option, from developing unconventional fossil fuel resources to pursuing renewable and other alternatives, will need to be pursued if the world expects to meet its growing energy demand through 2030, the National Petroleum Council concluded in a recent study.

"We don't have the option of saying that anything is off the table. We simply need to do everything we can," NPC Chairman and former ExxonMobil Corp. Chief Executive Officer Lee R. Raymond told reporters following the council's July 18 meeting, where the study was approved and relayed to US Sec. of Energy Samuel W. Bodman, who had requested it.

Formally titled "Facing the Hard Truths about Energy," the report broke new ground by involving more than 350 participants, 65% from outside the oil and gas industry, in more than 2 years of discussions and examinations that produced wide-ranging results. It said that the hard truths the US and world must face about energy in the next 25 years are:

- Coal, oil, and natural gas will remain indispensable to meeting total projected demand growth.
- The world is not running out of energy resources, "but there are accumulating risks to continued expansion of oil and natural gas production from the conventional sources relied upon

historically," which pose significant challenges.

- Expansion of all economic energy sources, including coal, nuclear, biomass, other renewable resources, and unconventional oil and gas, will be required to mitigate these risks. "Each of these sources faces significant challenges including safety, environmental, political, or economic hurdles, and imposes infrastructure requirements for development and delivery," the report said.
- The concept of "energy independence" should be replaced by one of energy security that can be enhanced by moderating demand, expanding and diversifying domestic supplies, and strengthening global trade and investment.
- A majority of the US energy workforce, including skilled scientists and engineers, is eligible to retire in the next decade. It will need to be replenished and trained.
- Policies aimed at curbing carbon dioxide emissions will alter the energy mix, increase energy-related costs, and require reductions in demand growth.

The results impressed several NPC members. "I personally think this is the most important work the council has done in the last 50 years and probably the next 50 years as well. It's not a slogan, but a strategy to be examined and embraced by policymakers," said Ray L. Hunt, chief executive officer of Hunt Oil Co. and chairman of the council's nominating committee. Hunt did not directly participate.

"It's the most comprehensive study I've seen," Daniel H. Yergin, chairman of Cambridge Energy Research Group and the council's vice-chairman for demand, told OGJ. He cited Section D of the recommendations, which looked at meeting challenges in forecasting, science, and engineering, research and data collection, and carbon constraints. "When the supply task group finished looking at more than 100 different forecasts, the importance of assumptions in reaching conclusions was apparent," Yergin said.

Yergin and another NPC member, Deutsche Bank AG Chief Energy Economist Adam E. Sieminski, separately said it was striking that the study moved beyond previous NPC efforts by including energy efficiency for the first time.

Sieminski said efforts by the Alliance to Save Energy were largely responsible. "At first, there was polite listening. Then, as the task group began to examine supply and demand conclusions that were emerging from its own work, they began to take energy efficiency more seriously. Finally, they began to examine how to formulate policies that included it," he told OGJ.

Open and transparent

John J. Hamre, president and chief executive officer of the Center for Strategic & International Studies in Washington, DC, and the council's vice-chairman for geopolitics and policy, said NPC's efforts to get views outside the oil and gas industry for the study were significant. "The industry in this town has a reputation of being secretive. This study was the most open and transparent of any I've participated in. Arguments were advanced, and minds were changed," he said.

Not every group was satisfied. US Reps. Roscoe Bartlett (R-Md.) and Tom Udall (D-NM), cofounders and cochairmen of the House Peak Oil Caucus, said on July 17 the NPC's report minimizes, rather than faces, hard truths about energy.

"I can't understand why they're upset. They obviously had an impact," one oil and gas industry official told OGJ. "This report goes farther in saying that resources aren't infinite than any I've seen from the NPC, although it doesn't say we're in immediate danger of running out."

The study used data from the US Energy Information Administration and other prominent forecasters and analysts, input from groups such as the Association for the Study of Peak Oil and Gas, and information from proprietary sources that provided insights into investment decisions that could affect unconventional and alternative sources, according to Donald L. Paul, vice-president and chief technology officer at Chevron Corp. and chairman of the study's supply task group.

"Gas is much less developed than oil, but some features emerged. One is that we should be able to meet demand through 2030, but it will consume about 50% of supply. Another is that pipelines, tankers, and other transportation elements will need to expand significantly. Some say that the need for new infrastructure overall points to as much as $20 trillion of new investments that will be needed," he indicated.

Paul said to expand and diversify supplies, declines in conventional production will have to be reduced (including output from marginal oil wells), access to resources will need to increase, and long-term production will need to be diversified. "The good news is that the US has unique and substantial alternative resources, particularly in biomass and coal," he said.

No 'silver bullet'

Paul Parker, executive vice-president of the Center for Resource Management in Salt Lake City, suggested that developing tar sands, oil shale, and other unconventional fossil fuel resources domestically will require major investments and careful consideration of environmental consequences.

"There's not a silver bullet. Often, there's a sense that biofuels and conservation will do the job by themselves. They have a lot of public and environmental groups' support which is not present for unconventional resources," he told OGJ.

Bodman praised the study. "My interest in what you've produced will not end with this meeting. These are hard facts that require us to make wise choices," he said.

Deputy US Sec. of Energy J. Clay Sell said President George W. Bush ultimately will determine how much of the study will become part of federal energy policy.

"We remain in contact with members of Congress and continue to believe that energy legislation represents one of the best bipartisan opportunities. This report presents hard truths that we've been reluctant to take on the past two decades but very much need to," he said.

Raymond, whose term as NPC chairman was extended at the meeting, said his and the council's main task now is to distribute the report as widely as possible. "The phone's been ringing off the hook. A lot of people would like to learn more about what's in this report. We intend to respond to every one of them," he told OGJ. ✦

Marathon to buy Western Oil Sands, gain Athabasca stake

Marathon Oil Corp., which is increasing capacities of its US refineries to handle heavy feedstocks, has agreed to buy Western Oil Sands Inc. for $6.5 billion (Can.) in a cash-and-stock deal that gives it a strong position in the Athabasca oil sands of northern Alberta.

Western holds a 20% interest in the Athabasca Oil Sands Project (AOSP), a joint venture operated by Shell Canada, with a 60% interest, and including Chevron Canada, 20%. The project includes the Muskeg River mine north of Fort McMurray, Alta., and the Scotford upgrader near Edmonton (see map, OGJ, July 9, 2007, p. 43).

The mine, operated by Albian Sands Energy, can produce up to 155,000 b/d of bitumen. Five capacity expansions are planned, taking maximum output eventually to 770,000 b/d. The Scotford

Upgrader, 493 km south of the mine and connected by the Corridor Pipeline, can produce 140,000 b/d of synthetic crude oil and 60,000 b/d of vacuum gas oil.

Marathon will gain interests in more than 300,000 gross acres, of which an area of over 200,000 acres is expected to be developed by mining. The other acreage holds potential for in situ development.

The total reserves net to Marathon in acquired mining projects is estimated at 436 million bbl of bitumen. The net resource from the Muskeg River mine and five planned expansions is estimated at 1.5 billion bbl of bitumen. A further 500 million bbl of net resource is ascribed to other mining expansion on this acreage.

Marathon estimates the net bitumen resource of acquired in situ acreage at 600 million bbl. It will become operator with a 60% interest in a 26,000-gross acre project and gain a 20% working interest in the 75,000-gross acre, undeveloped Ells River project operated by Chevron 42 km southwest of the AOSP acreage.

Downstream integration

In a statement, Marathon stressed the potential integration of oil sands production with the upgrading of its US refineries.

The company is conducting a front-end engineering and design study of a project to increase crude capacity at its 100,000-b/d Detroit refinery by 15,000 b/d and to add a 28,000-b/d heavy oil coker and associated units.

In a conference call, Ken Matheny, vice-president of investor relations and public affairs, said the unfinished study indicates that "we can process an incremental 80,000 b/d of heavy sour crude at Detroit for less than half of the capital investment needed to build new upgrading capacity in Alberta."

The company is evaluating similar projects at its 70,000-b/d St. Paul Park, Minn., and 192,000-b/d Robinson, Ill., refineries. Its 245,000-b/d Garyville, La., refinery and the 180,000-b/d ex-

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

A Caribbean chessboard

Oil companies from the Middle East, North America, East Asia, and South America are lining up to build refining capacity in Central America. What gives?

Perhaps the most intriguing development involves Venezuela and Nicaragua, whose leaders—Hugo Chavez and Daniel Ortega respectively—in late July launched a refinery project in the Central American nation (OGJ Online, July 23, 2007).

But Chavez has also cast his sights on other countries in the region, largely to compete with or otherwise complicate US interests. Indeed, Chavez, who seems to think Washington, DC, has a plan for his demise, is involved in a proxy war with the US with oil the main weapon, among others. As we know, at the end of June he stuck a knife in by demanding majority ownership of $31 billion worth of Venezuelan oil projects owned by US firms Chevron Corp., ExxonMobil Corp., and ConocoPhillips (OGJ, July 9, 2007, p. 20).

Guerrilla war

Chavez told his military to prepare for guerrilla warfare if Washington tries to topple him. Meanwhile, he also recently purchased $3 billion worth of conventional weapons from Russia. Meanwhile, apart from Nicaragua's Ortega—an old US foe—look at Panama, where Petroleos de Venezuela SA (PDVSA) has plans to develop a 150,000 b/d refinery in Colon under its PetroCaribe alliance aimed at increasing energy ties between countries in the region.

Venezuela's proposed cooperation with Panama in part would include reactivation of the Petroterminales de Panama's (PTP) pipeline to enable PDVSA to supply countries like China, extending the region's markets even further afield. Chavez's move in Panama coincides with a number of things, including the planned expansion of the Panama Canal, which already sees passage of some 35 million tonnes/year of oil and products. Amounts will increase when the canal expands enough to handle Suezmax tankers.

Panama Canal

Panamanian authorities are already aware of the increasing significance of their country on the map of global trade, especially in oil. Indeed, as Panama's minister of commerce and energy recently said, "It is time for Panama to maximize the value that our strategic position provides for the energy sector." At the time, he was commenting that expansion of the canal places his country on the map of petroleum companies with "excellent track records" such as Qatar Petroleum and Occidental Petroleum Corp., which recently announced their joint intention of building a 350,000 b/d refinery there.

The partners say their Panama project will increase refining capacity in Central America five times over the existing rate. Not least, the refinery will supply cities in Central America and on the US West Coast.

The proposed Oxy-QP facility's proximity to the PTP pipeline would also provide the possibility of supplying the entire Caribbean region, something Chavez desires.

Hmmmm. The region is beginning to look like a chessboard. Your move, Hugo! ✦

pansion under way at that site also can run Canadian heavy crude. Marathon will assume Western's debt, which as of June 30 was $700 million. The acquisition is subject to approval by Western shareholders and regulators.

Closing is expected in the fourth quarter. The acquisition agreement requires Western to spin off WesternZagros, a wholly owned subsidiary with a production-sharing agreement from the Kurdistan Regional Government covering 524,000 acres in northern Iraq.

Western said it will implement the spin-off by distributing shares in a new company, WesternZagros Resources Inc. to its shareholders when the Marathon deal is completed. ✦

House energy bill draws fire from producers, consumers

Nick Snow
Washington Correspondent

US House Democratic leaders announced a wide-ranging energy bill on July 30 that incorporates work by the Energy and Commerce, Natural Resources, and other committees. The bill drew criticism from industry and energy-consumer groups.

HR 3221 was scheduled to emerge from the Rules Committee on Aug. 2 in time for floor debate on Aug. 3. The 786-page bill includes most of the provisions in HR 2337 that many oil and gas producers oppose, although some compromises were achieved.

"It's not the bill I would have written, but it's a compromise," Rep. Gene Green (D-Tex.) told OGJ.

The Consumer Alliance for Energy Security warned that parts of HR 3221, notably Title VII's supply sections, will slow and reduce well completions, delay new production, and raise energy prices.

Roan Plateau language

One controversial provision was inserted at the behest of Rep. John Salazar (D-Colo.), who opposes plans by the US Bureau of Land Management to issue natural gas leases on the Roan Plateau near Grand Junction, Colo. Section 7604 contains "no surface occupancy" language, that would prevent drilling atop the plateau itself but lets BLM receive bonus and royalty bids and allows lessees to extract minerals, he said. Rep. Mark Udall (D-Colo.) and his staff helped develop the language, Salazar said.

BLM's plans to issue leases on the plateau also led Salazar's brother, Sen. Ken Salazar (D-Colo.), to place a hold on James L. Caswell's nomination as BLM director after the Senate Energy and Natural Resources Committee voted to send the nomination to the floor (OGJ Online, July 31, 2007). Earlier, Rep. Salazar and Udall unsuccessfully tried to insert language to prohibit the leasing into BLM's fiscal 2008 budget.

Udall said the current provision protects the top of the plateau while allowing development of the area's gas resources.

A leading producers' association official in the region disagreed. Marc W. Smith, executive director of the Independent Petroleum Association of Mountain States in Denver, said Section 7604 would ban drilling on what many believe is one of North America's most gas-rich areas, Naval Oil Shale Reserves (NOSRs) 1 and 3. "This amendment will cost the state of Colorado $1 billion in lost revenues and circumvents a nearly decade-long public planning process which allows extremely limited drilling on NOSRs," he said.

Other additional provisions include establishment of an oil shale community impact assistance fund, new requirements to notify recreation and other surface conservation easement holders of proposed leasing, and a requirement for contractors and subcontractors to pay locally prevailing wages.

Still present

Most of the provisions in Titles I and II of HR 2337 are present in Title VII of HR 3221. The US interior secretary would be required to establish onshore drilling permit processing fees for producers to pay, and would collect $1,700/permit temporarily for each permit issued after Oct. 1 until a formal structure is established. The bill also would repeal a provision in the 2005 Energy Policy Act (EPACT) suspending such fees.

Another EPACT provision, which set a 30-day deadline for BLM to process onshore drilling permit applications, was modified further. Resources Committee Chairman Nick J. Rahall (D-W.Va.) originally wanted to remove the deadline entirely but accepted a compromise during HR 2337's markup that extended it to 90 days. That deadline would be 45 days under HR 3221.

Section 7103 retained HR 2337's final language dealing with oil shale and tar sands leasing, which effectively would remove EPACT's deadlines, extend the process to allow additional public comment, and require development of a formal leasing strategy.

Section 7104 would amend EPACT's provision dealing with categorical exclusions by requiring the interior and agriculture secretaries, in managing lands under their jurisdiction, to follow categorical exclusion regulations established by the White House Council on Environmental Quality. Two other sections deal with best management practices and consistency appeals.

HR 2337's provision requiring the US Minerals Management Service to perform at least 550 audits of oil and gas leases annually became Section 7201 in the new bill. Other sections address royalty payment liability, tolling agreements and subpoenas, interest payments, and obligation periods.

HR 3221 retained HR 2337's provisions to expand surface land holders'

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Taxing oil for biofuels

Skeptics may have wondered what a "conservation fee" on some holders of federal deepwater Gulf of Mexico leases issued in 1998 and 1999 without price thresholds had to do with a 5-year farm bill which the US House passed on July 27 with much fanfare. The provision, which the House Rules Committee added to HR 2419 a day earlier, was not simply slipped in as a last-minute amendment but was generally expected as a way of funding the farm bill's energy programs, a House Agricultural Committee spokeswoman told me. It incorporates elements of HR 6, which the House passed in January as part of the Democrats' "first 100 hr" effort, she said.

A full portion of the farm bill, Title IX, deals with energy. Its sections include loan guarantees for biofuel plants, a feedstock flexibility program for bioenergy producers, and dedicated ethanol pipeline feasibility studies.

The Congressional Budget Office estimates that putting what amounts to a new tax on 1998-99 deepwater leaseholders who have not voluntarily renegotiated terms would raise about $6.1 billion to pay for these agricultural energy programs over 10 years.

Crying foul

Most House members emphasized other aspects of the farm bill. Rep. Stevan Pearce (R-NM) was an exception. He observed during floor debate on July 26 that members of Congress cry foul when other countries abridge treaties and contracts of US companies working there.

When representatives of US oil companies in Venezuela protested after Hugo Chavez's government told them to renegotiate terms or leave, the Venezuelans essentially said they had the right because "your own government is doing it," Pearce said. "They were referring to language in this bill, and in HR 6, that affects the 1998-99 offshore leases."

Another Republican lawmaker from New Mexico, Pete V. Domenici, ranking minority member on the Energy and Natural Resources Committee, said following the House's passage of the farm bill that includes a provision aimed at recovering lost deepwater royalties was inappropriate.

"While I agree that it is unfortunate that an error made by the Clinton administration has cost the federal treasury revenues, a punitive provision such as the one in the House farm bill will not solve the problem. In fact, it will make matters worse by ensuring years of litigation," he said. Imposing fees on domestic production would only raise prices and possibly delay leasing and development, Domenici added.

Similar signal

Republicans in general and Democrats from producing states can be expected to push for the provision's removal when the farm bill reaches the Senate. But its inclusion showed where key House members turned to fund renewable and biofuel energy research and development.

The Senate Finance Committee sent a similar signal on June 19 when it proposed taxing new Gulf of Mexico production, repealing the manufacturing deduction for major oil companies' domestic activities, and rewriting the foreign tax credit. ✦

rights in split-estate situations involving public lands. It also kept the earlier bill's reclamation and additional bonding requirements, its provision dealing with produced water management, and a $1/acre annual due diligence fee collected from lessees for land not being developed.

Within its title dealing with ocean resource management, HR 3221 attempts to establish price thresholds omitted from deepwater leases MMS issued in 1998 and 1999 by barring leaseholders who do not voluntarily renegotiate terms from participating in future federal lease sales. A similar provision was inserted into a farm bill the House passed on July 27. HR 3221 also would repeal deepwater royalty relief for Gulf of Mexico producers.

Ethanol pipelines

The new bill contains at least one other provision affecting oil and gas. In the title dealing with alternative fuel research and development, Section 8311 would require the energy secretary, in coordination with the transportation secretary, to study the feasibility of constructing pipelines dedicated to ethanol. The study would consider barriers to entry, market and throughput risks, and ways to ensure safe transportation and preserve pipeline integrity. Appropriations of $1 million for fiscal 2008 and 2009 would be authorized.

Oil and gas groups criticized specific aspects of HR 3221. Provisions from the Natural Resources Committee would reverse reforms contained in EPACT that only are now beginning to produce results in the form of additional gas supplies, the American Exploration & Production Council said in an Aug. 1 memorandum to House members.

"In addition, several new restrictions on permitting are proposed that have never been in law," it said. "The bill contains restrictions on leasing in one of the most promising areas of the West, and in the Gulf of Mexico. Higher taxes in the legislation would further reduce energy investment. Those who explore for, and produce, natural gas

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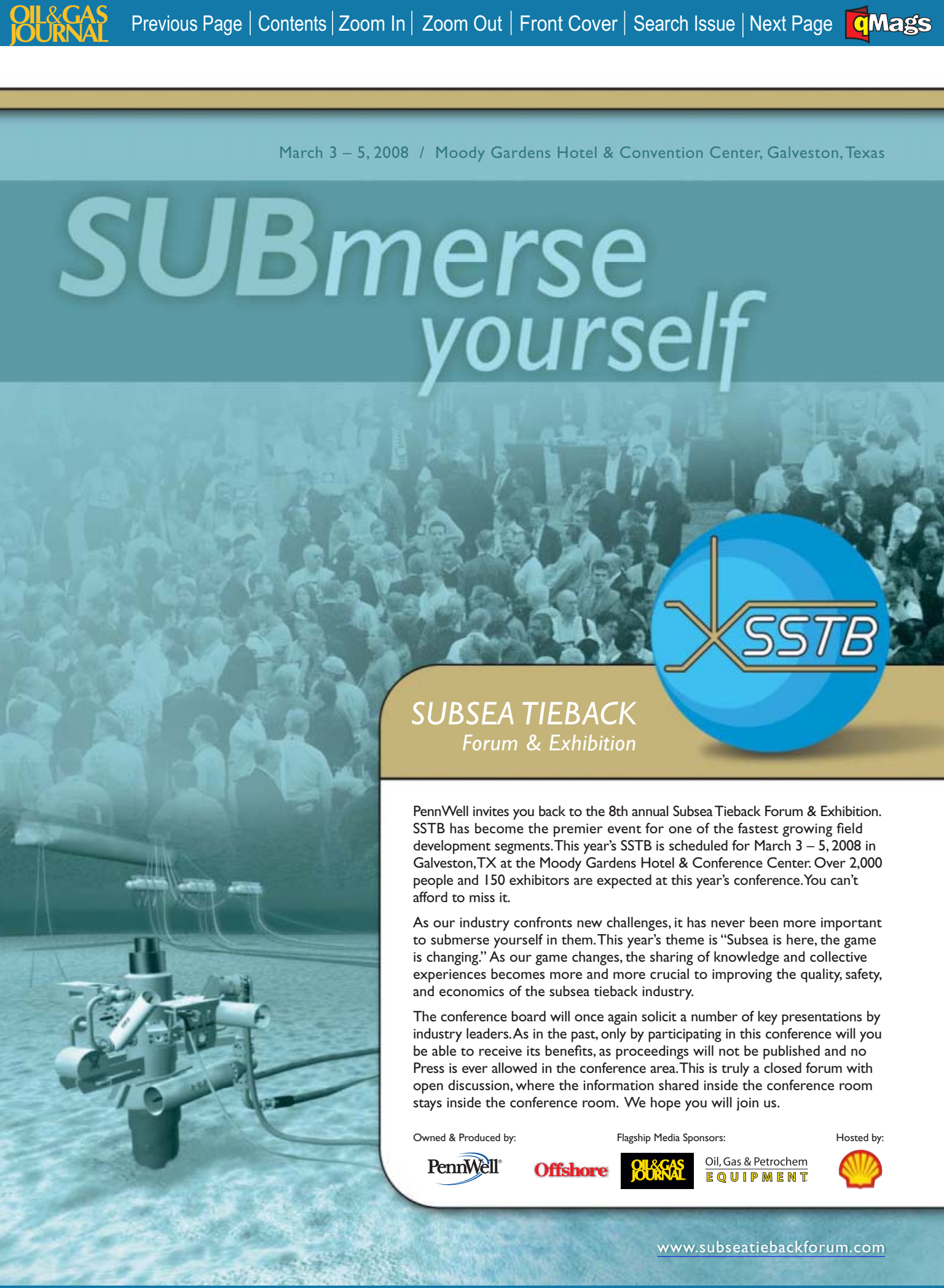

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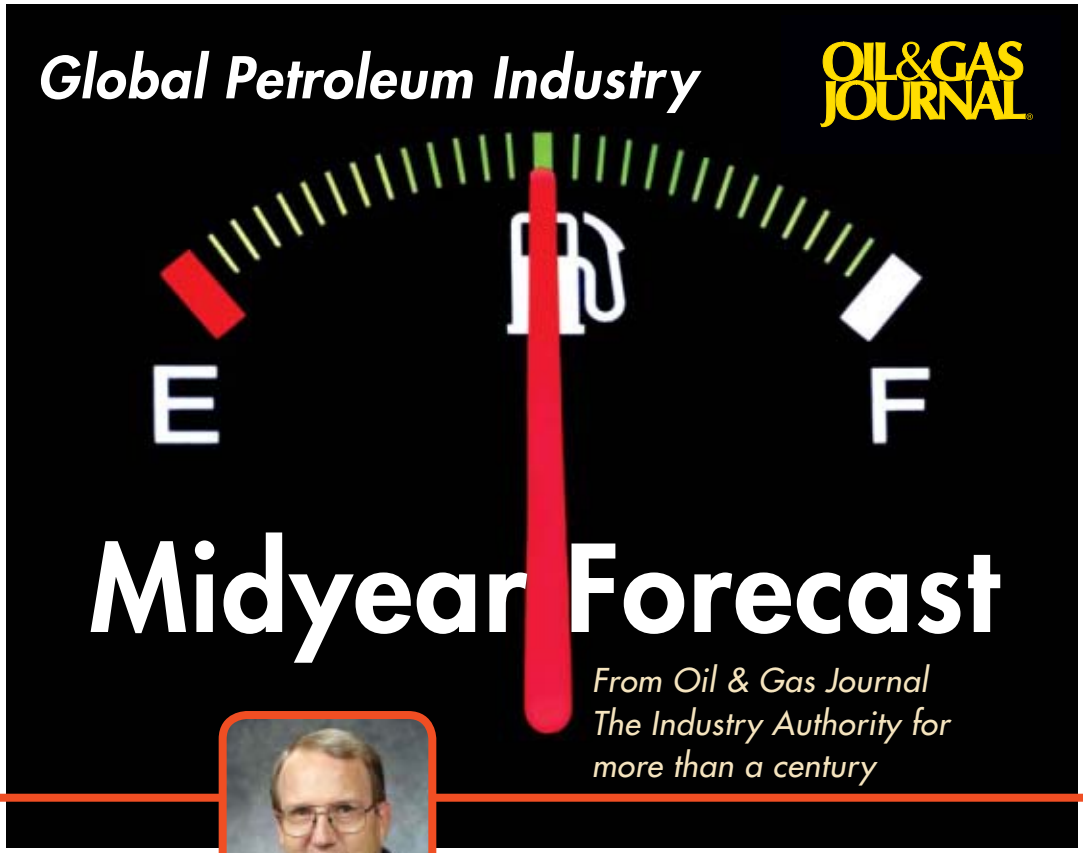

OGJ Editor, Bob Tippee

August 16, 2007

1:00 pm CST

Register free at:
www.ogjonline.com
(webcast section)

The webcast will discuss highlights of Oil & Gas Journal's annual Midyear Forecast, a special report that appeared in the July 2 edition. The Midyear Forecast uses first-half data to update projections that appeared in OGJ's Annual Forecast and Review this past January. Both reports project oil and gas markets through the end of the year worldwide, analyze demand product by product in the US, and forecast drilling activity in the US and Canada.

The webcast, to be presented by OGJ Editor Bob Tippee, will summarize the Midyear Forecast projections in key categories, note important changes from January's forecasts, and examine reasons for the adjustments. Marilyn Radler, Senior Editor-Economics, and G. Alan Petzet, Chief Editor-Exploration, will be on hand for questions. Marilyn compiles and writes the Midyear Forecast market projections. Alan assembles the drilling forecast.

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in the United States—and invest more than their earnings in the process—are frankly baffled as to why policymakers would consider such a reckless course of action."

In a joint letter to House Speaker Nancy Pelosi on Aug. 1, the chief executives of three major natural gas trade associations warned that HR 3221's Title VII would "repeal or eviscerate a number of key measures that were enacted in 2005 to facilitate new natural gas supply and infrastructure development."

Independent Petroleum Association of America Pres. Barry Russell, Natural Gas Supply Association Pres. R. Skip Horvath, and Interstate Natural Gas Association of American Pres. Donald F. Santa said the bill "would impose burdensome requirements, redundant surface owner provisions, and a complex water plan that would be extremely difficult to implement."

More criticism

Energy-consuming industry associations also were critical. The American Chemistry Council (ACC) said HR 3221's natural resources provisions would tie up or remove large amounts of gas that otherwise would have been developed.

"The new antisupply language in Title VII is far worse than the already deeply flawed language that passed out of committee last month," ACC Pres. Jack Gerard said. "House leadership took with the right hand what they tried to give with the left, and the result is that it's worse than where it started."

Other business groups criticized the bill in general. "Congress is not developing energy independence or moving toward more security," said William L. Kovacs, vice-president for environment, technology, and regulatory affairs at the US Chamber of Commerce. "It's assuming we can live without oil and gas while we develop alternatives."

He expects the House to pass HR 3221 but said the bill will have difficulty when it goes to conference with the Senate and might face a filibuster on the Senate floor and a presidential veto. ✦

Firms to explore Fergana basin in Tajikistan, Kyrgyzstan

Eric Watkins
Senior Correspondent

A large exploration block is taking shape in the underexplored Fergana basin in former Soviet Central Asia between the Caspian and Tarim basins.

The Tajikistan government in early July awarded a license covering more than 7,800 sq km to Somon Oil, owned 90% by DWM Petroleum AG. DWM is wholly owned by Manas Petroleum Corp., Baar, Switzerland.

The Tajik license is adjacent to the northern boundary of Manas' six Tuzluk, Kyrgyzstan, licenses that total 3,152 sq km.

Manas said it is in farmout discussions with major oil companies of interests in the Tajik and Kyrgyz licenses.

The Tajik license has a number of prospects and leads determined by Soviet seismic acquisition in the 1970s-80s, and a UK consultant said 10 known structures on the Kyrgyz licenses may contain a most likely 1.2 billion bbl of recoverable light oil, Manas said.

Manas's Tajik license is reportedly for exploration in the Bobojon Ghafurov, Jabbor Rasulov, and Ghonchi districts of the Sughd region. In particular, Manas reportedly will explore the Obcha-i Qalacha and Navobod fields for oil and gas.

In a statement, Manas noted that the US Geological Survey estimates 3 billion bbl of recoverable oil is contained in the Fergana basin's underthrust structures.

Tajik energy needs

The award is the latest effort by the Tajik government to boost the country's domestic energy supplies.

Impoverished Tajikistan, which relies on hydroelecticity for most of its power, has been hard-hit by an energy crisis this year. Neighboring suppliers Uzbekistan and Turkmenistan have cut its supplies of gas or electricity for lack of payment.

To overcome its energy shortage, the country's newly elected president, Emomali Rahmonov, last November vowed: "We will also step up geological prospecting, developing Tajikistan's vast coal reserves and gas and oil extraction."

Tajikistan has reserves of coal estimated at 4 billion tonnes, but output is just 70,000 tonnes/year. In May, American firm AES Corp., Russia's Unified Energy System (UES), Kazakhstan's KiTaKa, and a Chinese machinery company expressed interest in a project to develop the Fan Yagnob deposit in the Sughd region and to construct a coal-fired electric power station there.

In April, interest in Tajikistan's oil and gas potential spiked when Tajik Energy Minister Jurabek Nurmahmadov said substantial reserves of oil and gas discovered in Afghanistan might be part of a trend leading into Tajikistan.

"For the time-being, this is just a theory, but in practice this is excellent news for us," Nurmahdov said of the Afghan discoveries.

Local media reported that exploration in Afghanistan's Balkh, Samangan, Konduz, Sheberghan, and Sar-e Pol provinces revealed oil reserves of 1.6 billion bbl in the Afghan-Tajik basin, along with 15.7 trillion cu m of gas reserves in the Amu Darya River basin.

Nurmahdov said, "If all this information is corroborated, then we simply need to prospect and extract gas in the territory of our country...because Afghan reserves are likely to have the same unified source with Tajik reserves in the south of the country."

Gazprom's interest

Around the same time, OAO Gazprom Chief Executive Aleksey Miller visited Tajikistan for the second time in a year, saying that his firm hoped to find similar reserves.

Barring such large discoveries, Miller said with "certainty" that "on the basis of information we possess, that the prospected reserves can completely meet all the country's needs."

Since then, Gazprom subsidiary Zarubezhneftegaz said it will start 2D seismic exploration work at the Rengan

and Sargazon prospects in Tajikistan.

Gazprom was issued a license to explore the Sargazon and Rengan prospects, with gas reserves estimated at 30 billion cu m and 35 billion cu m, respectively, on Dec. 13, 2006. Over the next 5 years Gazprom said it plans to carry out exploration at the Rengan, Sargazon, Sarykamysh, and Western Shaambary fields.

In March Gazprom's Research Institute of Natural Gases and Gas Technologies (Vniigaz Ltd.) was said to be preparing a feasibility study for geological exploration and a gradual program for geological exploration work at the oil and gas prospects. The work is to include an evaluation of reserves and possible production volumes.

Meanwhile, in June, Russia's OOO Ecowave Technology, which specializes in emergency protection for pipelines, has been contracted to perform diagnostic work on Tajikistan's pipeline systems—including oil and gas pipelines—in the fourth quarter. ✦

Interest rising in New Zealand's East Coast basin

Angel White
Associate Editor

Exploratory drilling will be increased late next year in the onshore portions of New Zealand's East Coast basin as Trans-Orient Petroleum Ltd. begins a drilling program.

The company has identified 50 prospects and leads over its two permits—PEP 38348 and PEP 38349—covering 2 million acres. It will target potential source rocks of Paleocene and late Cretaceous age in the Whangai formation, which is "exposed in outcrop in some areas, and greater than 10,000 ft down in others," said Dave Bennett, chief executive officer of Trans-Orient.

Bennett said, "[The Whangai] is now a forearc basin with lots of active structuration going on. Up until the Oligocene, i.e., through the time of deposition of Whangai and Wapawa sequences, it was a passive margin basin."

There are fewer than 10 wells drilled on Trans-Orient's acreage. The company is obligated, per its work program, to drill two wells by November 2009. Trans-Orient, however, plans to drill additional wells but said the timing will depend on rig availability.

Bennett said drilling will most probably begin on PEP 38349 but added that a decision has not yet been made. The company has applied to extend this permit.

Later this year Trans-Orient intends to shoot more 2D seismic to enable better ranking of the prospects.

The prospects being initially targeted are all above 5,000 ft. Of particular interest to Trans-Orient are those in a fractured shale play at 1,500-3,000 ft. The play is similar in lithology to the Barnett and Bakken shales in the western US, Bennett said.

Trans-Orient's blocks lie adjacent to the Energy Corp. of America (formerly Westech Energy Corp.) block that contains the Waitahora well, an offset of the 1998 gas discovery in the Kauhauroa-1 well, which flowed on test at 11 MMscfd of gas (see map, OGJ, May 18, 1998, p. 78).

ECA, which began exploratory drilling in the East Coast basin several years ago, in mid-July conducted a flow test of the Waitahora-1 well, which was drilled to about 1,350 m and encountered a high reservoir pressure over a 70 m interval between 1,180-1,250 m.

The test revealed minor gas shows. The company plans to carry out further analysis.

Other basins

Taranaki is New Zealand's only producing basin, and Trans-Orient could soon hold producing assets there.

The company has an interest in acquiring the New Zealand assets of Swift Energy Co., Bennett said. Swift Energy is considering selling some or all of its New Zealand holdings, which consist primarily of two producing areas at Rimu-Kauri and TAWN (Tariki, Ahuroa, Waihapa, and Ngaere) in the onshore portion of the Taranaki basin.

The assets include proved reserves estimated at 106 bcfe at yearend 2006 and production, which for 2006 totaled 13.5 bcfe. Swift also maintains and operates two natural gas processing plants, an oil processing plant, and oil and natural gas pipelines.

Concerning the island's Great South basin, Bennett said the area "does have the right geology." However, he said Trans-Orient's interest is in New Zealand's onshore basins.

The Great South basin off Southland recently has received increased interest. Two consortia, led separately by ExxonMobil Corp. and OMV AG, were awarded permits to explore four areas of the Great South basin. The two groups are expected to spend $1.2 billion exploring the basin over the next 5 years (OGJ Online, July 12, 2007).

Bennett, an international oil and gas veteran with more than 25 years of experience in New Zealand, said the Great South basin is a very challenging environment. He compared it to the rough waters of the North Sea, adding that exploration of that basin is better suited for larger companies due to the risks involved. ✦

EXPLORATION & DEVELOPMENT

Albania

Manas Petroleum Ltd., Baar, Switzerland, said it is in advanced stages of finalizing a production sharing agreement covering four exploration blocks in Albania.

Previous block holders Shell and Coparex International estimated that the blocks hold a large, deep underthrust structure with potential to hold more than 800 million boe of light oil and natural gas. Numerous oil seeps are observed where the reservoir rock outcrops along a significant part of the eastern side of Manas's blocks.

Further refinement of the Shell/Coparex data set by Manas Petroleum has outlined a series of large prospects on the blocks.

Ethiopia

White Nile Ltd., London, reported that exploratory data over southern Ethiopia indicates the existence of deep basins that may contain a sedimentary section similar to that of the petroliferous Muglad and Melut basins of southern Sudan.

The company has completed ground geophysical surveys, including magnetotellurics and gravity, in the Omo River area north of Lake Turkana and is using the data "to determine basin disposition and depth in this critical area of interference between three proven petroliferous basin trends known as the Turkana Depression," White Nile said.

After interpreting the data, it will select areas it wishes to explore under a production-sharing agreement.

White Nile plans to design a reconnaissance 2D seismic program to identify drill targets in southern Ethiopia. The company has a joint study agreement with Ethiopia's petroleum operations division over the prospective East African Rift system in the southwest.

Greenland

Husky Energy Inc., Calgary, was awarded frontier exploration licenses on Block 5 (2007-22) and Block 7 (2007-24) in the Davis Strait off western Greenland in the West Disko 2006 licensing round.

The blocks total 21,067 sq km in less than 500 m of water 120 km off Disko Island (see map, OGJ, Mar. 26, 2007, p. 38). Husky is operator with 87.5% interest, and Greenland's state Nunaoil AS has 12.5%.

Husky, which plans to start an aeromagnetic and gravity survey on the blocks this summer, cited its experience operating in the North Atlantic off Newfoundland and Labrador in taking on the new exploration acreage.

TGS-NOPEC Geophysical Co. ASA began shooting 62,000 km of aeromagnetic surveys in early July covering the entire Greenland side of Baffin Bay. Data are to be available in the fourth quarter of 2007.

To follow that is a 60 by 60 km grid of 2D seismic surveys totaling 8,800 km that will include open lines into the Canadian side of the bay. Data are to be available in the first quarter of 2008.

Later in summer, TGS will begin the first phase of a new aeromagnetic acquisition project off northeast Greenland. When completed, the survey will extend from the coast to the oceanic crust as presently interpreted. It will be used to develop a new geophysical atlas of the area to further seismic and aeromagnetic planning.

Russia

OAO Gazprom completed a successful coalbed methane pilot production project in the Taldinskaya area of the Kuzbass basin and plans to begin supplying gas to customers in the second half of 2009.

Gazprom and the Kemerovo Oblast Administration signed an agreement for the pilot in May 2003. The participants plan to address the lack of a regulatory framework for CBM production in 2007-08. The Kuzbass basin, in southern Siberia north of western Mongolia, is the site of numerous coal mines and large industrial centers (see map, OGJ, Nov. 2, 1992, p. 81).

Geologopromyslovaya Co. Kuznetsk (GPK Kuznetsk) holds the license for CBM prospecting, exploration, and production in the Yuzhno-Kuzbasskaya Group of coal fields that have 6.1 trillion cu m recoverable. Gazprom holds a control stake in GPK Kuznetsk.

Gazprom subsidiary Promgaz estimated Russia's recoverable CBM at 49 trillion cu m, almost as large as the country's conventional gas reserves, including 13 trillion cu m in the Kuzbass basin.

Nevada

V.F. Neuhaus, private San Antonio operator, was to have spud a wildcat in late July in Huntington Valley in northeastern Nevada.

The Straight Flush 17-1 drillsite is in 17-28n-56e, Elko County, 120 miles north of oil fields in Railroad Valley, Nye County.

The well is projected to TD 7,000 ft to a Paleozoic target that has some similarities to Grant Canyon oil field.

Double Eagle Petroleum Co., Casper, Wyo., holds 70% working interest after a tank battery is set and expects to sell a 20% working interest.

Federal and state drilling permits have been issued for an exploratory well in SW SE 31-26n-55e, northwestern White Pine County, Nev., said Eden Energy Corp., Vancouver, BC.

Spud date is uncertain due to the need for construction of the road and location. The site is about 18 miles southeast of Blackburn oil field.

Earlier this year, Eden Energy said an undisclosed private Midland, Tex., company took a farmout to drill the Noah prospect to 7,000-9,000 ft (OGJ Online, Apr. 17, 2007).

ESTIMATING DRILLING COSTS—1

Joint association survey, mechanical risk index methods common in GOM

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Over the past several decades, various methods have been proposed to evaluate drilling costs and complexity, but because of the large number of factors and events that affect drilling performance, predictive models have been difficult to construct.

The joint association survey (JAS) and mechanical risk index (MRI) are the most popular methods used to evaluate drilling costs and complexity in the US Gulf of Mexico, and specialized indices have been introduced to characterize the complexity of drilling directional and extended reach wells.

Quantifying well costs and complexity is complicated by restrictions on data collection and availability, constraints associated with modeling, or combinations of these factors. Drill rates are often constrained by factors that the driller does not control and in ways that cannot be documented.

Recently, the concept of mechanical specific energy has been used to improve bit efficiency and performance and obtain a more objective assessment of drilling efficiency.

The purpose of this three-part series is to review the primary methods used to assess drilling costs and complexity and to propose a new method that combines the best features of each approach.

Part 1 describes the JAS and MRI methodologies. Part 2 introduces metrics that characterize directional and extended reach wells, along with the concept of mechanical specific energy, which has seen recent success. Part 3 introduces a generalized approach to drilling cost estimation.

Drilling factors

Drilling a hole in the ground in search for or production of oil and gas is subject to significant sources of variability. Although the physics of drilling is the same everywhere throughout the world, geologic conditions, contractor experience, equipment availability, well specification, and various other factors can lead to a wide range in drilling performance. Cost estimation is difficult and benchmarking efforts are often unreliable.

Performance comparisons are mostly done on a well-by-well, actual-vs.-plan basis or seek to correlate costs to performance indicators, metrics, or drilling parameters. Evaluating the differences that exist in drilling wells and comparing costs requires establishment of statistically reliable relationships between performance metrics and factors that impact drilling.

Formation geology at the site and location of the target reservoir are primary factors that influence drilling cost. Geologic formations vary across the world and within the same producing basin. Hard, abrasive, and heterogeneous formations typically have low penetration rates, frequent drillstring failures, and significant deviation from the planned trajectory.

Deep reservoirs are usually characterized by low permeability, high temperature and pressure, complex fracture growth and stress regimes, and contaminants such as CO_2 and H_2S that increase the complexity of the well and require operators to deal with a number of issues concerning safety and operational performance.

"JAS methodology cannot provide a reliable cost predictor on an individual well."

Drilling methods used to make hole depend upon geologic formation and technology applied, amount of information known about the formation, experience and preferences of the operator, available equipment, and the drilling contractor's experience and execution.

Characteristics of the well are speci-

fied by drilling plan, location of the target reservoir, and conditions encountered during drilling. Bit hydraulics has a major influence on drilling efficiency; its role is complex because it is closely tied to other drilling variables, such as lithology, bit type, downhole conditions, mechanical drilling parameters, circulation system and drilling mud.

Site characteristics such as water depth, operator's experience in the region, and expected environmental conditions influence the operator's selection of contract and rig type, which in turn influence drilling performance metrics. Exogenous events such as stuck pipe, adverse weather, and mechanical failure cannot be predicted and can have a significant impact on the time and cost to drill a well.

Benchmarks

Two methods are commonly used to benchmark drilling performance.

The first method is based on experimental design and controlled field studies. Typically, one or more parameters of the drilling process are varied and the impact of the variable(s) on output measures such as the rate of penetration (ROP) or cost/ft examined.[1]

One of the most common approaches is the "drill rate" test, in which the driller experiments with various weight on bit (WOB) and rotations/min (RPM) settings, and selects the parameters that result in the highest ROP. Controlled field studies are often the best way to understand the relationships between drilling factors under a set of conditions that are tightly controlled.

The analytic results derived under field studies are often based on engineering and scientific principles specific to the wellbore conditions, experimental design, equipment, and contractor, and so the ability to generalize and apply the results to other wells and locations may be limited.

The second method to study factor effects is based on an aggregate assessment of well data collected from various contractors, locations, and well bores.

In this method, data that characterize a set of wells are collected and relationships are established between the variables based on empirical modeling techniques.[2] The aggregate approach to analysis uses a set of drilling data and seeks to discover relationships between various factors of drilling and the cost and complexity of the wellbore. It is common to try to capture the best practices by comparison to an ideal well or offsets.

For instance, the approach used in "technical limit" drilling describes a level of performance defined as the "best possible" for a given set of design parameters.[3] This allows engineers to compare a variety of factors that impact drilling and to develop models that describe the behavior of the performance metrics.

Cost estimation

Since the drilling budget can represent a significant part of the capital expenditures for field development, drilling operations are carefully planned and closely watched, and operators maintain meticulous and detailed records of each well drilled.[4]

Cost estimation is performed specific to the drilling prognosis. The usual procedure is to decompose costs into eight general categories:

1. Site preparation.
2. Mobilization and rigging up.
3. Drilling.
4. Tripping operations.
5. Formation evaluation and surveys.
6. Casing placement.
7. Well completion.
8. Drilling problems.

Spreadsheet models are employed using various levels of detail. Typically, several categories are specified, with the drilling engineer itemizing the expected time and cost/category.[5-7]

Each cost component is identified and subdivided into minor cost elements, and the percentage contribution of the total cost for each major category is computed to help identify the key cost drivers. To improve the range of the estimate, the uncertainty of the cost drivers is frequently quantified.[8,9] A contingency is added to accommodate some of the uncertainty of costs before the final authorization for expenditure (AFE) is determined. The well budget is then sent to management for approval.

JAS history

The joint association survey on drilling costs has been performed in the US since 1954 in cooperation with the American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continent Oil & Gas Association. The first cost surveys were performed in 1944, but 1954 is generally recognized as the official start of the JAS. Since 1959, JAS data have been collected and published annually.

The purpose of the JAS is to provide information pertaining to drilling costs and expenditures for finding, developing, and producing oil and gas in the US. The JAS is the only publication in the US that contains annual state-by-state and offshore drilling cost data.

Questionnaires are mailed to operators to verify information on well completions performed during the year and to provide cost data for each well drilled. The response rate of the survey varies, but typically, 40-50% of operators respond to the request for information, representing 40-60% of the total number of wells and footage drilled during the year.

Because not all operators respond to the survey, it is necessary to estimate drilling costs for unreported wells. The JAS accomplishes this task by constructing models to infer the expected costs of drilling for unreported wells. The model-estimated costs are added to the reported costs to obtain the total estimated expenditures for the year.

Primary variables

The geographic—offshore or onshore—location of each well is specified and the well type (exploratory, development) and well class (oil, gas, dry) designated. An oil well is defined as a well completed for the production of crude oil from at least one oil zone

or reservoir, while a gas well is one that can produce hydrocarbons existing initially in gaseous phase.

The total depth of the well is the total feet of penetration drilled down the wellbore, including water depth and all plugged-back footage, but excluding bypassed footage from sidetrack drilling.

Well direction is classified as vertical or horizontal. Most offshore exploration wells are drilled vertically, while typically only the first development well is vertical; subsequent wells are drilled vertical to a certain depth and then kicked off to target. The majority of onshore footage is vertical, while total offshore footage is primarily directional.

Wells are evaluated after the drill bit reaches the target depth. A drillstem test may be used to evaluate the flow rates of hydrocarbons, and integrating these data with logs and other tests leads to the completion decision.

The total cost of a dry well includes the cost to set concrete plugs and to remove casing, as required by local, state, and federal regulations. The total cost of a producing well includes the cost through completion and installation of the Christmas tree.

Completion costs will typically include the cost of casing and production tubing, perforation, packers, safety devices, kits at the reservoir sands (e.g., gravel pack, wire-packed screens), and a tree at the top of the well.

Equations

JAS functional equations

$$Z = \alpha_0 + \alpha_1 TD \quad (1)$$

$$\log Z = \alpha_0 + \frac{\alpha_1}{TD} + \alpha_2 TD + \alpha_3 TD^2 + \beta_1 I_1 + \cdots + \beta_9 I_9 \quad (2)$$

$$Y^{\alpha} = \beta_0 + \beta_1 TD + \beta_2 TD^2 \quad (3)$$

$$\ln Y = \alpha_0 + \sum_{i=1}^{5} \alpha_i X_i + \sum_{i<j} \alpha_{ij} X_i X_j \quad (4)$$

MRI component and key drilling factors

$$\varphi_1 = \left(\frac{TD + WD}{1,000}\right)^2 \quad (5)$$

$$\varphi_2 = \left(\frac{VD}{1,000}\right)^2 \cdot \left(\frac{TD + HD}{VD}\right) \quad (6)$$

$$\varphi_3 = (MW)^2 \cdot \left(\frac{WD + VD}{VD}\right) \quad (7)$$

$$\varphi_4 = \varphi_1 \sqrt{NS + \frac{MW}{(NS)^2}} \quad (8)$$

$$\psi = \sum_{i=1}^{14} \psi_i(w) \quad (9)$$

$$MRI = \left(1 + \frac{\psi}{10}\right) \sum_{i=1}^{4} \varphi_i \quad (10)$$

Nomenclature

Z	=	cost/ft of well
Y	=	total well cost
TD	=	total depth of well
I_i, where i	=	1,..., 9, are indicator variables
I_1	=	(1, oil, ... exploratory, single completion well; 0, otherwise)
I_2	=	(1, oil, development, single completion wells; 0, otherwise), etc. for each of the nine classification categories: oil-gas-dry; exploratory-development; single-multiple completion
Y	=	Y(Ω) = total well cost in region Ω
X_1	=	TD = total depth, ft
X_2	=	TD^2 = total depth squared, sq ft
X_3	=	WT = well type
X_4	=	WC = well class
X_5	=	DIR = well direction
ψ_1	=	horizontal section ($\psi_1(w) = 3$)
ψ_2	=	J-curve directional ($\psi_2(w) = 3$)
ψ_3	=	S-curve directional ($\psi_3(w) = 2$)
ψ_4	=	subsea well installed ($\psi_4(w) = 2$)
ψ_5	=	H_2S/CO_2 environment ($\psi_5(w) = 1$)
ψ_6	=	hydrate environment ($\psi_6(w) = 1$)
ψ_7	=	depleted sand section ($\psi_7(w) = 1$)
ψ_8	=	salt section ($\psi_8(w) = 1$)
ψ_9	=	slim hole ($\psi_9(w) = 1$)
ψ_{10}	=	mud line suspension system installed ($\psi_{10}(w) = 1$)
ψ_{11}	=	coring ($\psi_{11}(w) = 1$)
ψ_{12}	=	shallow water flow potential ($\psi_{12}(w) = 1$)
ψ_{13}	=	riserless mud to drill shallow water flows ($\psi_{13}(w) = 1$)
ψ_{14}	=	loop current ($\psi_{14}(w) = 1$)

Development

The JAS cost-estimation procedure evolved in five distinct phases:

- **1954-65:** Wells were classified according to geological structure, drilling conditions, and economic expectations. Well cost/ft drilled by depth range was regressed against the average depth/well in each class interval for each region and well class for both tangible and intangible costs.[10]
- **1966-77:** The average cost/ft drilled was computed for wells classified according to well type, location, and depth.[11] The tangible and intangible cost categories were aggregated and regression lines computed to describe the functional relationship between cost/ft and depth for each area under consideration as shown in Equation 1.
- **1978-92:** A stepwise linear regression on the cost/ft for each sample area and well type was employed.[12] Three depth variables were applied: inverted depth, depth, and depth squared, as well as a set of dummy classification variables for well type (oil, gas, dry), well class (exploratory, development), and completion type (single, multiple).

Equation 2 specifies the function; coefficients α_i (i = 0, ..., 3) and β_i (i = 1, ..., 9), are estimated through least-squares regression. I_i (i = 1, ... 9) are indicator variables for each of the nine wellbore classification categories.

- **1993-94:** Regression models were developed for well type and geographic area with the functional relation of Equation 3, where α, β_0, β_1, and β_2 are determined by regression.[13] A "stabilizing" transformation was performed by adjusting α to convert the dependent variable to a form that was linearly correlated with the independent variables. Three transformations were found to be statistically significant: the natural log, $\alpha = 4$, and $\alpha = 0.5$. The estimates were then adjusted with a correction factor to eliminate the bias introduced by the transformation.
- **1995-present:** Wellbore data are currently aggregated into 16 geograph-

ic regions following the Gas Research Institute's hydrocarbon supply model.[14-15] A nonlinear two-factor regression model is constructed for each region based upon the model specification described by Equation 4.

The X_1 and X_2 variables are numeric, while the X_3, X_4, and X_5 variables are categorical, defined in terms of indicator variables; e.g., (0, exploratory well; 1, development well).

The coefficients α_i (i = 0,1, ..., 5) and α_{ij} (i, j = 1, ..., 5, i<j) are evaluated for each geographic region and only statistically significant variables are maintained in the final model. In most geographic areas, three to five regression terms are usually significant. Statistical tests are used to accept or reject outlier data and a correction factor is used to account for bias introduced through the nonlinear transformation.

Pipe stands ready in the derrick of Noble Drilling Corp.'s Amos Runner semisubmersible, drilling in Green Canyon Block 955 in December 2006 (photo by Nina M. Rach).

Discussion

In the JAS drilling cost model, four variables—total depth, well type, well class, and well direction—are applied in a two-factor, nonlinear regression model. Two-factor interaction terms were incorporated in the model to "build up" the number of available terms and improve the statistical fit of the regression.

The limitations of the procedure are obvious from the model construction because four variables cannot possibly describe the complexity and operational aspects involved in drilling a well except on an average aggregate gross basis. A quadratic expression is appropriate for the requirements of the survey, but it is clear that the JAS methodology cannot provide a reliable cost predictor on an individual well.

The JAS procedure is successful for estimating (unreported) cost data and reporting expenditure patterns, but to predict individual well cost the level of categorization is too broadly defined to be useful except as an average.

A single well is characterized by a large number of descriptor variables which are not captured in the survey response, and thus, inadequately represented in the output model. A more robust model would incorporate additional descriptor variables of the wellbore and drilling process and relax the quadratic specification.

MRI history

The mechanical risk index was developed in the late 1980s by Conoco engineers charged with comparing offset drilling data for a collection of offshore wells in the Gulf of Mexico.[16] They developed a "mechanical risk index" to compare operations and derived an algorithm based on empirical analysis of well data, taking into consideration factors such as water depth, measured depth, and kickoff point for sidetracks.

In the mid-1990s, Dodson modified the MRI using key drilling factors, copyrighted the formula, and incorporated the measure as part of a commercial well database (www.infogulf.com). Reference to the MRI is found in various trade publications,[17] but little systematic analysis of the metric has been performed.

The MRI is defined in terms of four "component factors" and a weighted composite "key drilling factor." The component factors are described in terms of 6 primary variables and the key drilling factor represents the composite impact of 14 qualitative indicators. The MRI is computed as an additive function of the component factors weighted by the composite key drilling term.

Primary variables

The six primary variables of the MRI include the total measured depth (TD), vertical depth (VD), horizontal displacement (HD), water depth (WD), number of casing strings (NS), and mud weight (MW) at total depth.

The depth of a well measured from the rotary table along the length of the wellbore is called the total depth (or total measured depth), while the (true) vertical depth is the distance from the rotary table measured in a vertical plane to TD. The horizontal displacement is

the distance measured in plan view from the rotary table to TD. The water depth is the distance from the waterline to mud line.

The problems, costs, and hazards of drilling depend upon both observable and unobservable factors. The deeper the hole, the more time is lost in round trips to replace worn bits and to run casing, tests, logs, etc. As the depth of the well increases, the number of formations encountered typically increases along with the number of casing strings required to maintain well control.

As the number of casing strings increases, the trip time, installation, and cementing time will increase, all increasing drilling time and cost. Beyond a certain depth, technical complications and the opportunity for problems increase drastically.

Casing serves several important functions in drilling and completion and is one of the most expensive parts of a drilling program, making up 10-20% of the average cost of a completed well.[6] A well that encounters no abnormal formation pore pressure gradients, lost-circulation zones, or salt sections usually requires only conductor and surface casing to drill to the target.

Deeper wells that penetrate abnormally pressured formations, lost-circulation zones, unstable (sloughing) shale sections, shallow water flows, or salt sections generally will require one or more strings of intermediate casing to protect formations and to prevent well problems.

The number of casing strings in a well provides an indirect measure of well complexity because complex wells are frequently associated with multiple strings, and narrow margins between formation pore pressure and fracture pressure gradients often require a greater number of casing strings.[18]

Wells are usually drilled with water or oil-based muds through the entire wellbore or one mud may be displaced for another over a selected interval. The mud weight at total depth serves as a proxy for the wellbore formation pressure. With all other factors equal, the greater the hole pressure, the heavier the mud, and the slower the drilling.

Underbalanced drilling requires the use of special equipment to handle formation fluids entering the well; its primary use has been where casing is set and cemented on top of a subnormal or pressure-depleted formation (OGJ, Dec. 1, 2003, p. 39).[19]

Component factors

The primary variables of the MRI are combined into four normalized component factors shown by Equations 5-8. Each component factor is nonlinear in the primary variables.

"The MRI currently serves as the de facto industry standard in the Gulf of Mexico."

Drilling factors

Key drilling factors are defined to capture drilling characteristics that are encountered, or are expected to be encountered, but not described by the component factors. Dodson introduced drilling factors to generalize the MRI to a larger class of wells.

The key drilling factors are user-defined qualitative variables that are assigned an integer-valued weight according to the occurrence of the condition and its degree of complexity. The composite key drilling factor is the sum of the drilling factor weights given in Equation 9, where ψ_i denotes the ith drilling factor of well w and $\psi_i(w)$ is the assigned weight.

Variables and corresponding weights are defined in the Nomenclature box.

Most exploratory wells are drilled as straight as possible, while usually only the first development well is vertical. Horizontal drilling is less stable than vertical drilling and the wells are more difficult to log and complete.[20] If a horizontal section is drilled, then a weight of "3" is assigned to the key drilling factor, while if a J-shaped or S-shaped trajectory is employed, an additional weight of "3" or "2" is included in the metric.

A subsea well is one in which the wellhead, Christmas tree, and production-control equipment are located on the seabed. Subsea well drilling tends to be more complicated and costly than a normal tree installation, and a weight of "2" is assigned to subsea completions.

Hydrogen sulfide and CO_2 environments require special operating procedures. Hydrogen sulfide is a poisonous and corrosive gas that causes embrittlement and weakening of steel casing and drill pipe. Wells with high CO_2 concentrations also suffer corrosion problems.

One of the technical problems in deepwater drilling is the formation of hydrates in the blowout preventer (BOP) or choke and kill lines. Hydrates can plug the BOP stack and well-circulation path and are difficult and time consuming to remove.

Mature fields have intrinsic drilling problems associated with their depleted reservoirs. The water-wet sands that typify depleted zones propagate seepage losses and differential sticking. Drilling-fluid losses are frequently unavoidable in large fractures, and pressured shales are often interbedded with depleted sands, requiring that multiple pressure sequences be stabilized with a single drilling fluid.[21]

Ductile salt is effective for trapping oil and gas because it can move, surround, and deform sediments, creating traps. Drilling salt is risky, however, because salt is weak and undergoes continuous deformation.[22] Sediments below salt are often disrupted and overpressured, and constructing long-lasting wells through salt requires special fluid selection, casing programs, and cementing procedures.

A slimhole well describes a borehole significantly smaller than standard and commonly less than 6-in. or 6½-in. in diameter. Mud-hole suspension systems and coring also add to the time and complexity of drilling.

Unusual geologic and environmental events, such as loop currents, eddies, and shallow water hazards, create spe-

cial problems during drilling. Loop currents and eddies subject facilities to stress and vibration, and drilling risers that are in place may bend or bow from the current to such an extent that the vessel has to change position to stay connected.

In some cases, the drill pipe may rub against the drilling riser forcing immediate shutdown. Shallow water flow occurs during drilling into over-pressured sand zones.[23] Installation of additional casing is usually required to maintain wellbore integrity in shallow flow.

MRI definition

The MRI is defined through the component factors, weighted by a normalized composite key drilling factor, shown in Equation 10.

The MRI is frequently used to compare the drilling performance of two or more wells and as a predictive tool for wells in the design stage. MRI is also correlated to drilling cost.

For a well that has previously been drilled, the input data and MRI can be calculated precisely. If a well is part of a planned drilling program, then estimates for the variables (TD, WD, VD, HD, MW, NS) and key drilling factors (ψ_1, ..., ψ_{14}) are required to estimate the anticipated drilling risk. An example MRI calculation is shown in the box on this page.

Analysis

The MRI was originally developed to compare the drilling performance of a small number of offset wells drilled in the late 1980s. As such, the formulation of the metric is closely associated to the characteristics of a particular well set drilled during a specific period of time. The MRI was later modified to incorporate additional drilling factors not covered in the original formulation.

The MRI currently serves as the de facto industry standard in the Gulf of Mexico. It has a long history, is easy to comprehend and useful in aggregate comparisons, and is defined by simple, spreadsheet-programmable relationships. The parameters of the MRI are based on a minimal set of high-quality drilling data that are readily acquired. Thus, there is much to recommend the MRI.

Several issues associated with the metric, however, deserve closer attention. Dodson introduced drilling factors to generalize the MRI to a larger class of wells, but selection of factors and their weight assignment appear arbitrary. The use of the drilling factors serves to create a cost-estimation tool, but the manner in which the parameters enter the model as a binary indicator with weighting factors may lead to ambiguity.

The application of user-defined weights is always problematic. If weights are not inferred through an empirical assessment of well data, the assignment can be considered arbitrary and may possibly be ambiguous; e.g., if a horizontal section of a well is drilled, a weight of "3" is assigned to the key drilling factor. On a cost/ft basis, however, horizontal wells are not necessarily more expensive than vertical holes.[15]

Key drilling factors are assigned weights according to the "complexity" of the characteristic or condition that is encountered (or expected to occur) without differentiating between the magnitude of the condition; e.g., if a horizontal section of a well is drilled, then regardless of its length, it is assumed to be three times more complex or difficult than if a salt section is drilled or if a loop current is encountered. A loop current that leads to a 3-hr delay is treated the same as a 3-day delay.

Primary and key drilling factors represent the drilling process in a manner superior to the JAS variable selection, but the manner in which the MRI factors are combined and the weight selection can be improved. The composite drilling factor weight is ad hoc, and it would be better to normalize the component factors prior to summation.

Although the MRI incorporates more drilling parameters than the JAS approach, the JAS methodology is more structured, and it is clear that the manner in which factors are incorporated in the MRI limits generalization. The MRI is defined by an additive functional and a fixed weight selection. Generally speaking, metrics defined through a formula assignment are not expected to be optimally specified. ✦

MRI EXAMPLE CALCULATION

1. (a) Specify well characteristics encountered/expected; e.g., TD = 15,000 ft, WD = 150 ft, VD = 13,800 ft, HD = 2,500 ft, MW = 16 ppg, NS = 6

   (b) Specify risk factors encountered/expected; e.g., ψ_1 = horizontal section, ψ_3 = S-curve directional, ψ_7 = depleted sand section, ψ_9 = slim hole, ψ_{12} = shallow water flow potential

2. Compute component factors and key drilling factors: $\varphi_1 = 229.5$, $\varphi_2 = 241.5$, $\varphi_3 = 258.5$, $\varphi_4 = 582.6$, $\varphi = 8$

3. Compute MRI:

$$MRI = \left(1 + \frac{\psi}{10}\right) \sum_{i=1}^{4} \varphi_i = 2,362$$

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Refiners suffer penalties when overtreating diesel

Bob Macomber
Oscar Brown
Albemarle Corp.
Houston

Continuously operating distillate hydrotreaters at a finished ultralow-sulfur diesel (ULSD) product target just a few ppm below the requirement for refinery specifications to maintain a certain comfort level is uneconomic and will cost the refinery a significant loss of catalyst activity. Operating with finished ULSD product several ppm below the refinery specification may, however, be necessary for a short period of time to correct an off-spec tank.

The first year of ULSD operations has gone well. As usual, actual available feed sources seldom match the design cases. Attractive economic margins drove some refiners to push units beyond the original intention of the catalyst design, with good return. Although the run cycles were shortened, the cost of catalyst activity loss was adequately covered by increased revenue.

ULSD

The switch from low-sulfur diesel to ULSD for highway use has been an obstacle for the refining sector. A large investment in capital was required in the last 2 years in order to stay in business.

EQUATIONS

$$k = \frac{LHSV}{n-1}\left(\frac{1}{C_p^{n-1}} - \frac{1}{C_1^{n-1}}\right) \quad (1)$$

$$k^* = k \exp\left(\frac{-E_A}{R}\left(\frac{1}{T_{ref}} - \frac{1}{T_{act}}\right)\right) \quad (2)$$

$$k_{ref} = \frac{LHSV_{ref}}{n-1}\left(\frac{1}{C_{ref}^{n-1}} - \frac{1}{C_f^{n-1}}\right) \quad (3)$$

$$T_{norm} = \left(\frac{R}{E_A}\ln\left(\frac{k}{k_{ref}}\right) + \frac{1}{T_{act}}\right)^{-1} \quad (4)$$

Nomenclature

k	=	reaction rate constant
n	=	reaction order
C_f	=	feed sulfur concentration, wt %
C_p	=	product sulfur concentration, wt %
LHSV	=	liquid hourly space velocity, hr^{-1}
E_A	=	Activation energy, 27,000 cal/mole
R	=	rate constant, 1.987 cal/mole-K.
T_{ref}	=	reference temperature, K.
T_{act}	=	actual temperature, K.
k_{ref}	=	reference reaction rate constant
C_{ref}	=	reference sulfur concentration, wt %
$LHSV_{ref}$	=	Reference liquid hourly space velocity, 1/hr
T_{norm}	=	Normalized reaction temperature, K.

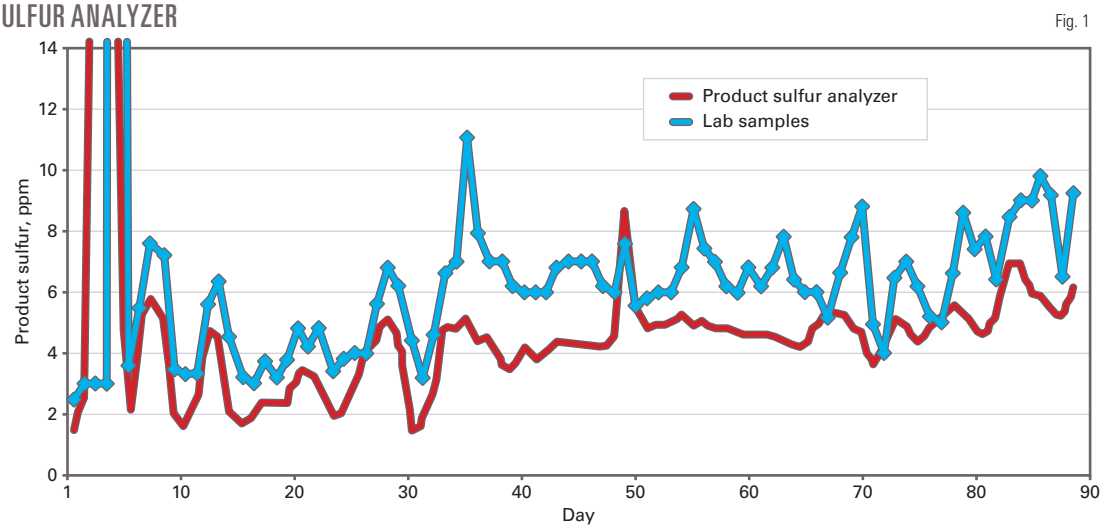
As with all new equipment, there is a period of time in which the operator wants to learn just what the unit can do and how the process can be controlled to maximize refinery profits. These units have been up and running for almost a year and there has been a full array of experience.

It is not unusual for these operations to process at higher-than-design rates or heavier-than-design feedstocks to take advantage of favorable price spreads. Although these decisions will reduce run lengths, it is clear there is economic incentive that overrides the higher rate of catalyst deactivation.

Although catalyst manufactures may wish to protect the integrity of their product,

SULFUR ANALYZER

Fig. 1



it is more important that the operator understand the effect of process decisions so it can be compared with the economic benefit, such as processing more material.

Kinetics

All hydrotreaters are controlled by reaction kinetics. Although some catalyst systems may have more or less activity, all will respond according to these principles. Equation 1 (see equation box) shows ideal plug flow.

Reaction orders for typical refinery feeds range between 1.0 for naphtha and 1.65 for vacuum gas oil. For most ULSD operations, reaction order is about 1.4. Feed sulfur concentration will vary from one refinery to another and perhaps from one crude cargo to another, depending on the crude type and unit configuration of each individual location.

The kinetic effect of temperature is defined in the Arrhenius equation (Equation 2).

In order to find the temperature increase requirement, one must calculate a reference reaction rate using Equation 3.

Combining Equations 2 and 3 results in a method to "normalize" a unit that is operating at different throughput (space velocity) or feed and product sulfur content (Equation 4). This normalized temperature represents the weighted average bed temperature (WABT) of the reactor.

This is a lengthy way to explain that there is a fairly simple relationship between reactor temperature and operating conditions. Furthermore, this is based on kinetics and is independent of any specific type or grade of catalyst. There is really no need for each refinery to develop software for this, because the catalyst supplier should have a spreadsheet available for its clients.

Predicting how sulfur concentrations change as the feed quality and end point changes is a much more complex issue. Typically, higher end points mean higher sulfur concentrations and more difficult-to-desulfurize molecular structures.

Run length projections

The relationship between throughput and reactor temperature, or concentrations and reactor temperatures, is now established. But is that all the refiner needs to know about monitoring and predicting ULSD units? Not quite.

To properly predict run length it is important to describe how the catalyst deactivates over time. Deactivation is very much a function of the average bed temperature. Higher temperatures mean higher deactivation rates.

Temperature is not the only indicator, however. Available hydrogen as well as contaminants also have a big influence on catalyst activity maintenance and run length. Refining companies and catalyst suppliers strive to develop more rigorous models to do this, but the details are confidential for the most part.

Because the models are developed based both on basic kinetics, as well as with empirical pilot plant data, a considerable amount of investment must be made to perfect their detailed accuracy. The one thing that is true about all models is they are never better than the accuracy of the input data.

For purposes of comparison, we simulated the design and operation of a distillate hydrotreater using the Albemarle model (Table 1).

ULSD Unit 1 processes 14,000 b/d of distillate and contains $1.3 million of catalyst, which provides a 1.0 liquid hourly space velocity (LHSV). The feed sulfur is 0.7 wt % and the product is 7 ppm at the battery limits. The unit was designed to operate at 800 psig with good quality hydrogen in sufficient quantities.

The projection indicates it will take 23 months of smooth operation to reach a 700° F. reactor inlet temperature, which is considered end of run.

Just about the time the unit was built and started up, highway diesel prices shot up and margins for this product were $5/bbl vs. the next best option for the feedstock. Fortunately, there was an extra 5% of this feedstock available and increasing feed was not limited by pumps or furnace duty. The question is: Should the refinery process this extra material?

Obviously, increasing the flow to the new unit will increase the LHSV and reduce the overall run length. The extra revenue, however, offsets the loss in catalyst activity before the end of run.

Certainly there are more costs that must be considered, including increased turnaround expenses. It is also not always possible to increase the unit charge without changing the feed composition of the incremental barrel. If the extra barrel is from increasing the FCC light cycle oil end point, the deactivation will be greater.

Conversely, moving barrels from FCC slurry (one of the lowest valued products in the refinery) to ULSD (at times the highest valued product) will have a big incentive.

Each refiner must determine the economics that fit their units and will also have to make accommodations for different change-out schedules.

Overtreating

Contrary to the economic benefits of increased throughput or even higher end point feedstock, overtreating ULSD product has a devastating effect with almost no real economic value. There is variability in the testing and no unit runs perfect all the time, but overcompensating for this costs money.

Reactor comparison

Table 1

	Case 1	Case 2	Difference
Feed flow rate, b/d	14,000	14,700	700 (105%)
LHSV, hr^{-1}	1	1.05	
Hydrogen available/consumed	5.91	5.59	
Reactor inlet temperature, °F.	653	660	
WABT, °F.	667	674	
Run length, months	23	19	–4
Total catalyst cost, $	1,308,997	1,308,997	
Catalyst cost, $/month	56,913	68,895	11,982
Incremental revenue, $/month		$5/bbl	106,750
Payout, months			12.3

We ran another case in which the feed rate does not change; we only lowered the finished product sulfur by 10%, to 6.3 ppm from 7 ppm, to quantitatively compare the results.

OVERTREATING CASE

Table 2

	Case 1	Case 3	Difference
Feed flow rate, b/d	14,000	14,000	—
Feed sulfur, wt %	0.7	0.7	
Product sulfur, ppm (wt)	7	6.3	
LHSV, hr^{-1}	1	1.05	
Hydrogen available/consumed	5.91	5.59	
Reactor inlet temperature, °F.	653	660	
WABT, °F.	667	674	
Run length, months	23	19	–4
Total catalyst cost, $	1,308,997	1,308,997	
Catalyst cost, $/month	56,913	68,895	11,982
Incremental revenue, $/month		0	0
Payout, months			None

Table 2 shows that the decline in run length for Case 3 is the same as running the extra barrels in Case 2.

The problems with finished product blending should not be oversimplified. Nothing can fix a ULSD shipment that is just a little bit high on sulfur spec unless the unit is run harder. There is certainly no room for error due to a bad line fill, leaking valve, or line up mistake. Allowing a couple of ppm here for dirty bottles and a couple ppm there for laboratory precision, however, will wind up costing the refinery a great deal in the long run.

One of the best solutions is to have an on-stream product sulfur analyzer (Fig. 1). Even this is far from perfect; but with time, operators will be able to develop a level of confidence that will allow them to make the proper corrections for inevitable process swings.

Installation and care of these on-stream analyzers cost money, but considering the risks for not staying on top of the ULSD product, the extra investment is probably worth it.

Refiners should compare daily operating sulfur levels with finished tank results to determine if they are leaving any money on the table. ✦

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

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

	1962	1980	2004	2005	2006	Apr. 2006	Mar. 2007	Apr. 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,738.8	1,833.3	1,841.8
Electrical machinery	189.5	394.7	516.9	513.6	520.2	513.2	516.8	517.7
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	956.9	969.5	969.5
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,132.7	1,251.5	1,261.4
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,104.2	1,189.2	1,193.0
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,241.5	1,388.7	1,409.7
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,478.6	2,559.6	2,560.7
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	1,983.7	2,091.2	2,100.3

Refinery operating (1956 Basis)

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

	1962	1980	2004	2005	2006	Apr. 2006	Mar. 2007	Apr. 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,615.6	1,704.0	1,526.4
Labor cost	93.9	200.5	191.8	201.9	204.2	215.8	219.7	223.8
Wages	123.9	439.9	984.0	1,007.4	1,015.4	1,035.7	1,046.9	1,078.8
Productivity	131.8	226.3	513.3	501.1	497.5	479.9	476.5	482.0
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	734.7	771.7	775.0
Chemical costs	96.7	229.2	268.2	310.5	365.4	357.5	370.0	371.6
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	582.9	609.7	596.9
*Process units**	103.6	457.5	638.1	787.2	870.7	887.3	932.4	872.6

**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.

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- Heat and Power
- Emissions
- Water
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- Mining
- In Situ

Upgrading
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GE Oil and Gas
Florence, Italy

Growing global demand for LNG has spurred an increase in LNG liquefaction capacity. An example is Qatargas II, a joint venture initiated by Qatar Petroleum and ExxonMobil for a two-train expansion (Trains 4 and 5). Ownership of Qatargas II has recently expanded to include Total (for Train 5). The project will employ the world's largest LNG refrigeration strings, while also reducing plant emissions and making efficient use of energy sources.

The project has applied APCI's AP-X process for two large LNG trains (7.8 million tonnes/year; tpy) under construction in Qatar at Ras Laffan Industrial City (RLIC). About 280 Mw of refrigeration compression will be required to achieve this goal.

The economy of scale incentives highlighted the GE Frame 9E as the ideal mechanical driver for the refrigeration strings (Fig. 1). An extensive qualification effort was required to adapt the GE Frame 9E power-generation gas turbine for variable-speed mechanical drive service. System reliability was improved through a design program that targeted reduction of the number of components.

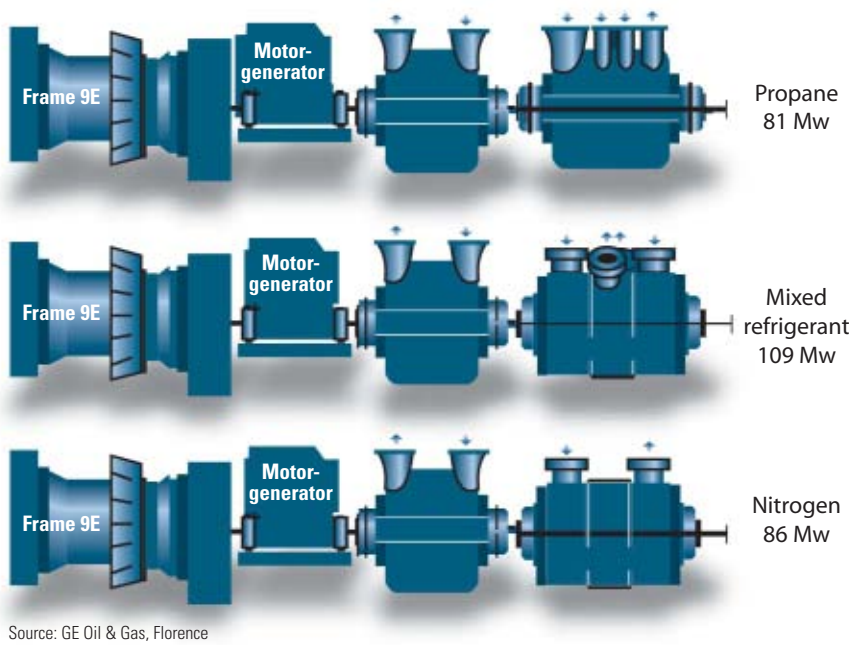
In addition, considerable effort concentrated on reducing plant emissions through qualification and use of dry low NOx (DLN) burner technology suitable for the low-btu, LNG mechanical drive application.

Further improvements to efficiency required a solution to the impact of diurnal and seasonal ambient temperature variations on the gas turbine's power output. Development of a unique, variable-speed, electric motor-generator met this requirement. The motor-generator enables pressurized starting of the compressors, ensures adequate power for refrigeration compression, and exports surplus power as electricity into the

Based on a presentation to the 15th International Conference & Exhibition on Liquefied Natural Gas, Apr. 23-27, 2007, Barcelona.

REFRIGERATION STRING FOR APCI AP-X

Fig. 1

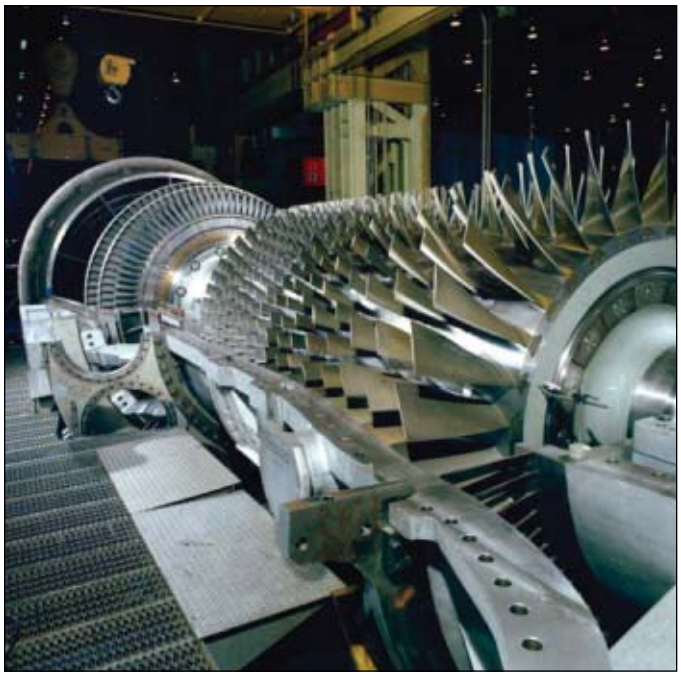


Source: GE Oil & Gas, Florence

plant grid to utilize the full capability of the gas turbine.

This article also discusses the design, manufacture, and full-load string testing for the six main refrigeration compressor casings. ExxonMobil and GE proprietary qualification processes managed the technical risks associated with this string design.

Experience called for development of single-piece manufactured impellers. Extensive use of computational flow dynamics simulation and modeling authenticated the aerodynamic design. Finally, advanced sealing technology was developed for refrigerant sealing at very large shaft diameters.



ExxonMobil initially qualified the Frame 9E gas turbine for mechanical drive LNG service based on 100% constant speed and fuel gas with 38% nitrogen content (Fig. 2; photograph from GE Oil & Gas, Florence).

Frame 9E gas turbine

Speed, fuel, and emissions studies qualified the Frame 9E gas turbine (Fig. 2).

The GEMS9001E (Frame 9E) gas turbine has an extensive operating history since 1978 in power generation. ExxonMobil initially qualified the Frame 9E for mechanical drive LNG service based on 100% constant speed and fuel gas with 38% nitrogen content.

GE then performed a study to customize the Frame 9E for variable-speed operation without compromising maintenance intervals or life expectancies.

The speed study assumptions were:

- Operating ambient temperature: 4° C. to 49° C.
- Five to 30 starts/year (mature design at 5/year).

With these assumptions, assessment of the following components verified life expectancy over a speed range of 2,850 rpm (95% speed) to 3,150 rpm (105% speed):

- Axial compressor rotating and stationary blades.
- Turbine rotor and buckets.
- Gas dynamics in combustion cans and transition pieces.
- Gas flow disturbances in the combustion system, exhaust diffuser, and collector.

Gas turbine components are subject to such failure mechanisms as low-cycle fatigue crack initiation, cycling-crack propagation, disc burst, and creep. All of these failure modes were evaluated at baseline conditions and at 105% speed.

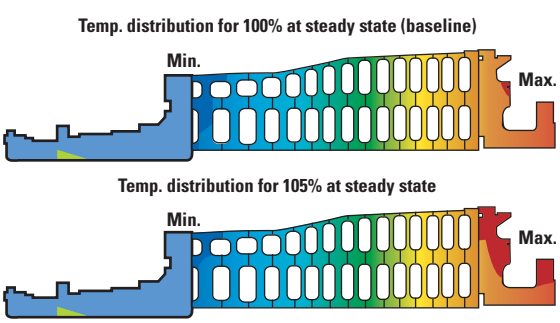
A finite-element analysis model based on parameters that defined the thermodynamic behavior of the unit (power output, pressure ratio, mass flow, speed ramps, etc.) calculated temperature distribution, aeromechanical loads, inertia loads, etc.

Another part of the study evaluated the Frame 9E compressor airfoil rotor and stator blades ability to operate in the 95% to 105% speed range. The conclusion was that stresses remained within allowable limits (Fig. 3).

Torque ripple effect contributions from the VFDs were also assessed and considered a low risk to the compressor blades. This analysis, coupled with the operating experience of the Frame 9E compressor rotor, confirmed that the Frame 9E could operate continuously as a mechanical drive in the speed range of 96% to 102 %.

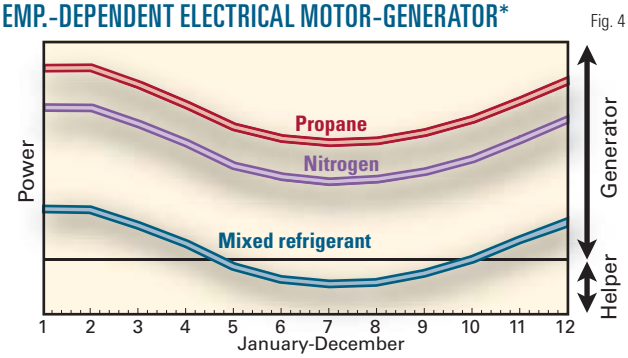
Hot gas path components were

FEA MODEL FRAME 9E ROTOR* Fig. 3



*Validated 96-102% speed range required for mechanical drive service.
Source: GE Oil & Gas, Florence

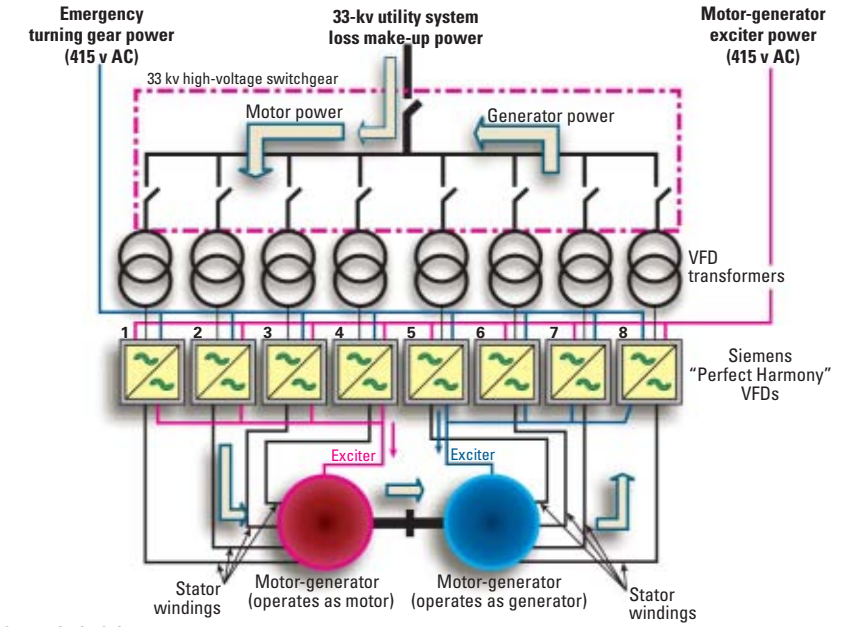
TEMP.-DEPENDENT ELECTRICAL MOTOR-GENERATOR* Fig. 4



*Used for power regeneration and/or helper for three refrigeration strings.
Source: Qatargas II

BACK-TO-BACK TEST: ONE-LINE CONFIGURATION

Fig. 5



Source: GE Oil & Gas, Florence

analyzed for aeromechanical (modal) creep and life-cycle-fatigue capability. Modal analysis revealed that resonance is avoided between bucket natural frequencies and high-strength drivers at rotor speeds between 95% and 105% speed. Creep resistance of the rotor was evaluated against the 200,000-hr limit for Frame 9E gas turbines. The turbine rotor dovetails exhibited sufficient margin to operate at 49° C. at continuous speed up to 105%.

Finally, FEA modeling to identify and quantify life-cycle-fatigue rotor components life analyzed the effect of variable speed up to 105% operating at 49° C. ambient temperatures. The life requirements were set at 300 starts over the life of the rotor for this application (10 starts/year, 30 years' operation). Results showed the components have margins beyond the conservative 300-starts requirement.

The study concluded a speed range 96% to 102% was suitable for continuous operation and transient excursions up to 105%.

In addition, the Frame 9E is equipped with a dry low NOx combustion system for emission abatement (DLN-1). In a normal application this system is capable of 25 ppm (vol, dry; ppmvd) of NOx and requires a variation of no more than ±5% from a given Wobbe Index (WI) target value for the fuel gas.

(WI is the ratio between the fuel's lower heating value (LHV) and the square root of specific gravity multiplied by fuel temperature. This can be thought of as a measure of the energy density of the fuel.)

QGII fuel gas is supplied by the LNG process and supplemented during various modes of operation. The fuel gas may have a WI variation as high as ±26%. The WI range and rate of change is limited to ensure adequate pressure ratios across the fuel nozzles. If the pressure ratio is too low, the combustion dynamics amplitudes can increase to unacceptable levels leading to shortened operating life and poor reliability.

Combustion testing was performed to verify the combustion hardware was capable of handling fuel gases ranging 4% to 48% N_2. Additional lab tests verified that the selected fuel nozzles and combustion chamber design stayed within acceptable performance limits.

NOx emissions decrease as the N_2/CH_4 ratio in the fuel gas increases. While this effect is beneficial for reducing emissions, it can reduce the reliability of the combustion system. Extremely low NOx emission values for this combustion system can indicate a weak flame, which in turn could lead to a combustion blowout or high combustion dynamics.

To compensate for the high N_2 fuel content, the dilution area of the liners was increased to achieve a robust flame over all operating conditions.

This liner modification, coupled with the redesigned fuel nozzles, produced test results that showed the combustion system can operate throughout the required QGII range. The NOx is expected to be less than 25 ppmvd while running on fuel gases with 25% to 42% nitrogen.

Complementary to the combustion design changes was the addition of GE's Extendor technology maximizing availability.

Motor-generator; VFD system

The design basis of the motor-generator, variable-frequency drive system manufactured by Siemens was to support flat LNG production by providing sufficient string torque under all ambient conditions (Fig. 4). The design and operability of the string were validated during back-to-back and string testing.

The synchronous motor-generator manufactured by Ansaldo Sistemi Industriali SPA incorporates integral shaft flanges that mechanically connect the Frame 9E and the centrifugal compressors. This design is based on a theoretical limit that allows the turbine to transfer full power to the compressors at the same time the motor-generator also supplies full power (45 Mw, 143 kN/m base, 60 Mw, 190 kN/m peak) to the compressors.

The VFDs are designed not only to support a base full motor power (45 Mw, 143 KNm) in either generation or helper motor modes. They are also designed to provide peak power up to 190 KNm of motor starting torque (corresponding to 60-Mw@3,000 rpm) for 90 sec. This enables pressurized starting

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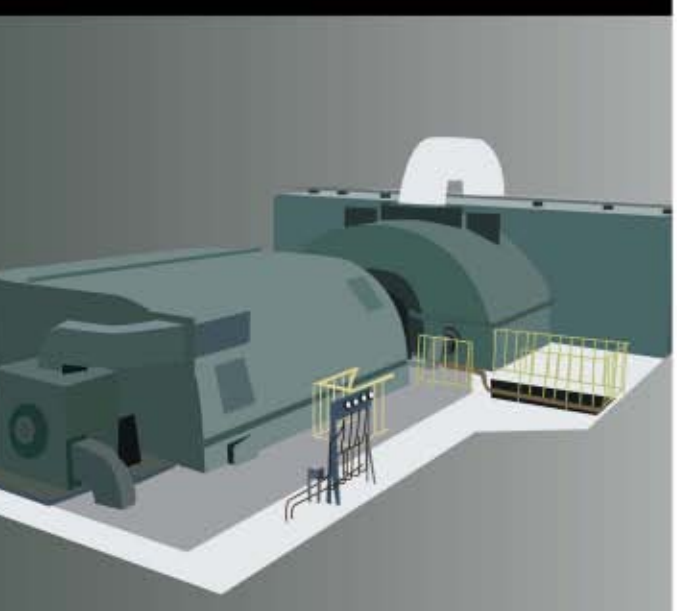

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- Unit is well preserved and stored in Las Vegas, Nevada.

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Chris Davis at Thomassen Amcot Development LLC – Email: cdavis@thomassenamcot.com | P: 817-263-3271 | C: 817-296-1967

of each string, reducing starting time as well as emissions.

Parallel operation, redundancy

High availability flat LNG production required a 60-Mw system design. Since the VFD technology selected was limited to 15 Mw/drive ("threads"), four drives were required for each compression string.

The 15-Mw limit, however, provided an opportunity for system redundancy. Each motor is normally fed from four VFDs with each VFD feeding a separate motor-generator stator winding. The design using four parallel drives, not only supports the 60-Mw requirement for pressurized starts, but can also operate continuously at 45-Mw in motor-generator mode with only three VFDs.

To provide a double level of redundancy, the VFDs are designed so that a single VFD can provide full power (15 Mw) with one of the power cells out of service in each phase (total three cells out on different phases) or two power cells out in any one phase. It is also important to note that only two VFDs are required to permit depressurized starting, flat LNG production, and turning-gear operation.

Even the simultaneous trip of all four VFDs does not necessarily imply a string trip interrupting LNG production. With the VFDs tripped, the motor simply acts as a coupling between the turbine and the compressors. Once the VFDs are available, they can be restarted without requiring shutdown of the Frame 9E.

Turning gear function

The VFDs and motor-generator were developed to provide the string's turning gear function. This replaces the standard accessory base functions of breakaway torque, slow roll turning, purge, starting, water wash, and cool down. A dedicated emergency low-power circuit has been incorporated into the design to permit 300-rpm turning gear operation in the event of a plant blackout.

Back to back testing was performed at the ASI facility in Monfalcone, Italy, to validate system design and compare its performance with predicted and guaranteed values. The back-to-back configuration consists of mechanically coupling two motors with each motor fed by four 15-Mw VFDs (Fig. 5).

During this testing, one of the units was operated as a motor simulating the turbine by providing positive torque. The second unit was operated as a generator, converting mechanical energy from the first unit to electric power. This configuration required that the utility supply only enough electric power to cover system losses.

Compressor testing at Massa, Italy, shows GE's propane compressors, the highest rated capacity of their type in the industry (Fig. 6; photograph from GE Oil & Gas, Florence).

Back-to-back testing confirmed system performance not only met guaranteed values but also exceeded the less conservative predicted values. For example, the motor-generator had to operate below a Class F temperature rise at full load (45 Mw) with only three VFDs (i.e., one "failed" VFD). Back-to-back testing, however, determined actual temperature rise was well below this value and in fact below a Class B temperature rise.

Compression power generation

Each VFD is provided with an active front end (AFE) capable of supplying real power or reactive power to the plant grid, whenever excess turbine power is available. Reactive power is also controlled by the AFE by adjustments to the voltage to control the export of reactive power to the plant grid.

Since VFDs isolate the motor-generator from the plant grid by converting plant power from 50-cycle AC to DC and then to a variable AC, power flows between the plant grid and the motor-generator are independent of motor-generator shaft speed.

Each compression string is capable of supplying up to 45 Mw of real power, depending on excess turbine torque availability, and 30 Mv amp (reactive) power to the plant electrical grid continuously at variable speed.

Pressurized starting

On most gas turbine mechanical-drive applications, the centrifugal compressor load (function of process loop pressure) at string start-up usually is maintained as low as possible. The compressors are then loaded once the turbine reaches the minimum continuous speed.

The same concept is applied to generator drive units (normally single-shaft units), in which the gas turbine reaches full speed in an unloaded condition. This allows reduction in the size of the starting devices and reduces loading of the gas turbine axial compressor during the start-up transient phase.

In an LNG plant this depressurized starting method results in:

- Loss of refrigerant to depressurize refrigeration loops after any plant shutdown.
- Flaring.
- Increased plant downtime (about 8 hr required to complete plant start-up).

As a consequence, pressurized starting capability can help to increase plant

availability by greatly reducing starting times, while at the same time reducing plant flaring and associated emissions. The incentives of pressurized starting capabilities led to a major development effort.

An initial feasibility study formed the basis for starter motor sizing. Since the required start-up torque is a function of compressor load-loop pressure and rotating inertia, it was critical fully to understand fully the complete compression system as well as the Frame 9E and motor.

A rigorous dynamic simulation took into account the Frame 9E transients, using a GE proprietary model based on Frame 9E actual control software and cycle deck performances. The simulation included the electric motor-supplied torque, compressor load, and train inertias. Pressurized starting was considered feasible with a 45-Mw motor with 60-Mw peak load capability.

Dynamic simulations performed by GE using site conditions showed the need for extra-torque from the Frame 9E for speeds greater than 82% for N_2 and C_3 and above 70% speed for the mixed-refrigerant train.

Additional starting torque was obtained by modifying the standard turbine generator drive's start-up sequence, increasing fuel flow rate, and anticipating the turbine-inlet guide vane opening. This resulted in a dedicated augmented start-capability test campaign designed to explore higher Frame 9E axial pressure ratios.

A nonstandard development engine approach explored the new operating line limit. In order to take into account engine deterioration with accumulated operating hours and engine-to-engine variation, a 10% margin in terms of pressure ratio was necessary to validate the final operating line limit. This margin forced a higher level of pressure ratios during the test campaign.

In summary, achieving initial project objective of pressurized starting at nearly all site conditions not only simplifies starting and greatly improving plant availability, but also minimizes plant emissions.

Centrifugal compressors

From early stages, GE and ExxonMobil shared centrifugal compressor design development. ExxonMobil performed technical reviews covering many aspects of the compressor design.

QGII compressors are the largest centrifugal compressors designed by GE for LNG applications (Fig. 6). Although the compressor architecture is not completely new, GE introduced several innovations to mitigate risks associated with manufacturability and performance of these compressors.

The process compressors are in two bodies on each string. The inboard compressor connected to the motor-generator is a drive-through horizontally split casing (MCL type). The outboard compressor is either an MCL type or a barrel type (BCL), depending on the pressure rating. Positioning the barrel compressor outboard in the string reduces time required to remove the inner barrel assembly axially.

A worker inspects a single-piece 5-axis milled compressor impeller (Fig. 7; photograph from GE Oil & Gas, Florence).

The large, horizontally split compressors were designed for ease of maintenance by the upper half diaphragm being separated from the upper half casing to reduce the heaviest maintenance lift and avoid the need to rotate the upper half casing to service upper half diaphragms. Removal of the upper half casing leaves the upper half diaphragm in place. The diaphragms are then removed to reveal the rotor.

These barrel compressors are the largest ever built by GE, with a maximum weight of 115 tons.

Single-piece impellers

The QGII compressors are equipped with three-dimensional impellers machined from a solid forging. Each impeller is machined with a five-axis milling machine, eliminating the need for welding.

This manufacturing process provided excellent control of the blade geometry without reducing tensile properties associated with weld joints. This technology also increased steel alloy options without the constraints of material weldability.

A computerized measuring device then checked each impeller to assess the possible impact of geometrical deviations. The single-piece impeller method guarantees repeatability and improves performance (Fig. 7).

QGII compressors were designed to optimize both rotordynamics and aerodynamic performance. In particular, propane compressors are often limited by an impeller-eye Mach number resulting in premature choking of the stage.

Splitting the propane compressor into two bodies allowed the high-pressure section to have a smaller shaft. This solution reduced the impeller-eye Mach number, avoiding premature choke.

All barrel compressors completed aerodynamic performance testing in Florence, Italy. Their large size forced the horizontally split compressors to be aerodynamically tested while in the string configuration in Massa, Italy. Barrel compressor performance was revalidated during the string tests to ensure consistency of testing results between sites. The results showed better than expected efficiencies. A broad operating range was demonstrated between surge and overload.

Massa string test

As final validation before shipping, GE performed a full-power string test

on each of the three compressor strings at GE's Massa facility (Fig. 8). These tests were to replicate as much as possible the plant site configuration.

The tests used the contract Frame 9E gas turbine, compressors, motor-generator, and associated VFDs. Also included were such subcomponents as inlet-air filtration system, inlet-bleed heating, oil system, and the dry-gas sealing system. The only difference with the site configuration was the use of a temporary on-base Frame 9E enclosure instead of the contract off-base enclosure.

A large portion of the string testing involved final validation of the VFD system and its integration with the main equipment as well as with the power supply grid. Engineering Dynamics Inc. used an advanced recording system closely to monitor shaft torque ripple (a well-known weak point of variable-frequency systems) and the amount of harmonic disturbances injected by the system into the surrounding electrical grid. Results validated low torque ripple, well within the design basis, therefore requiring no external suppression.

Testing achievements

Flow measurement at each bearing inlet as well as bearing temperatures throughout various operating conditions fully validated the oil system.

Massa testing simulated loss of complete AC power under full load. The emergency oil pump and overhead rundown tank provided adequate oil to protect the string during coast and cool down. The system also demonstrated the capability to maintain minimum lube-oil pressure with only one of the 3x100% AC pumps running.

Functional testing of the dry-gas-seal system validated the requirement to support the seals during all operating conditions. This included the ability to supply buffer gas during compressor settle out conditions through use of an on-board booster compressor, eliminating the need for external buffer gas that can often contaminate the compressor refrigeration loops, which can lead to additional delays in train restart and flaring.

Before shipment, each of the three compressor strings underwent a full power string test at Massa. These tests sought to replicate plant site configuration (Fig. 8; photograph from GE Oil & Gas, Florence).

The load test was the final validation of the train alignment procedure (especially for the rigid shaft line Frame 9E + motor-generator supported by five bearings). In addition to the contract string bearing's vibration-monitoring system, an extensive temporary vibration-monitoring system was installed on the piping, casings, bearing pedestals, and support structure. This provided a complete picture of the string rotor dynamics. All measurements were well within specified limits, validating lateral analysis studies.

The Frame 9E is equipped with DLN-1 NOx combustion system and IBH to improve system operability. The DLN-1 system allows very low NOx emissions, provided that all combustion control parameters are properly adjusted to take into account site conditions and unit-to-unit variations.

DLN-1 system tuning is normally performed at the site as one of the commissioning activities. In this case, a pretuning was performed in Massa to demonstrate the system's capability in terms of operability and emissions. This has the additional benefit of reducing the site-commissioning schedule. Measured NOx emissions were well within the 25-ppmvd target over a wide load range.

The commissioning sequence of the main equipment started with the motor solo run in which the electric motor is disconnected from the Frame 9E and from the compressors. For this operation, a temporary thrust bearing was added to the motor shaft.

The motor was then connected to the Frame 9E to perform the turbine solo runs. Finally the string was coupled and full load testing was initiated, validating the ability of the VFD motor to perform all string starting and cool down functions.

This validated the early decision to utilize the VFD motor in lieu of the standard Frame 9E accessory gearbox, thus improving string reliability by reducing the number of system components.

The Frame 9E's response at low power, combined with peaking mode, will be used in the field to avoid tripping of the MR string during loss of VFD when in helper mode.

Additional tests validated VFD double level of redundancy, in particular the capability to supply uninterrupted power (45 Mw) with one cell failed in one thread and a second one in a second drive, as well as with a complete thread

(VFD) out of service.

The first turbines started shipping to RasLaffan in 2006. Installation took place throughout 2006-07.

Operation is to commence in 2008 ✦

The authors

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Andrea Fibbi (andrea.fibbi@ge.com) is currently manager–auxiliary and systems engineering team for GE Oil & Gas, Florence, Italy. He previously served as Qatargas II project leader for GE Oil & Gas during project development and validation phases. He has 13 years of experience in turbomachinery systems design and system integration and holds a degree in mechanical engineering from the University of Florence (Italy).

New process designed to solubilize NORM waste

Researchers at the University of Mississippi, in collaboration with an independent researcher now with the Mississippi Office of Geology, have a patent pending on a process for solubilizing naturally occurring radioactive materials (NORM) scale and sludge wastes from oil and gas production.

This process, which requires no expensive chemicals, can be mobilized with all of the necessary equipment skid mounted for land and-or offshore based applications. The processed NORM can be dissolved in produced waters to generate stable solutions that can then be disposed of via existing saltwater disposal or other injection wells.

Features include 1) solid NORM wastes can be processed and disposed of at sites near their production, eliminating the need to transport them over long distances; 2) injection returns the material into geologic reservoirs, thus the potential for creating on site (including the production facility) environmental and other liabilities is eliminated; and 3) relative to other disposal options this process is significantly less expensive, the specialists say.

Source: **Department of Pharmacology, University of Mississippi, School of Pharmacy**, University, MS 38677; Dr. John C. Matthews, Phone (662) 915-5153, Fax (662) 915-5148, E-mail: pljcm@olemiss.edu

New pipeline repair manual

A new, updated pipeline repair manual from Pipeline Research Council International (PRCI) provides an overview of currently used pipeline repair technologies with a standard template and detailed information for pipeline operators to extend the safe life of pipelines through proper assessment of defects and guidelines for the appropriate selection of pipeline repair techniques and methods.

The manual is intended to help operators avoid unexpected operational costs and provide guidance for operator qualification for repair of in-service pipelines. The manual has been used by PRCI member companies to generate company standards and procedures related to in-service repairs of pipeline and related surface facilities. It also provides guidance to pipeline operators and service vendors as they:

- Choose appropriate repair techniques for specific defects in pipelines.
- Develop or enhance their own procedures and-or manuals for pipeline repairs.
- Train or qualify maintenance personnel.

The manual outlines and describes known and commonly accepted techniques for pipeline repairs, with major emphasis on methods that can be applied to in-service pipelines repairs.

It includes pipeline repair methods used in Europe and discusses the various types of pipeline defects that lend themselves to being repaired in-service.

Source: **Technical Toolboxes Inc.**, Box 980550, Houston, TX 77098.

Parker Drilling Co.

Houston, has announced the appointment of David C. Mannon as president and chief operating officer. He succeeds Robert L. Parker Jr., who resumes his role as chairman and chief executive officer.


Mannon

Mannon earned a BS degree in civil engineering from Southern Methodist University and an MBA from the University of Houston. He has 27 years of experience in the drilling industry, beginning as a drilling engineer with Sedco-Forex. He joined Triton Engineering Services Co., a subsidiary of Noble Drilling, in 1988, and held a number of positions there, culminating with his appointment as president and CEO. He joined Parker Drilling in 2004 as senior vice-president and COO.

Parker Drilling Co. is a drilling contracting firm specializing in offshore drilling and workover services in the Gulf of Mexico, as well as international land and offshore markets. The company also owns Quail Tools, a provider of premium industry rental tools.

OpenSpirit Corp.

Stafford, Tex., has opened an office in Abu Dhabi to cover the Middle East/Africa region. Sebastien Ferreira, business development manager for Middle East/Africa/South Asia, will head the new operation. Arbaab Muzaffar, a pre-sales technical advisor, will also locate in the region.

The company also has expanded its UK office by appointing Nick Cabot as business manager for Europe/CIS/Libya, and David Wright as pre-sales technical advisor for the region. They are based in Woking, Surrey.

Len Chia has joined the company in Perth, Australia, as pre-sales technical advisor for the Asia Pacific region. He reports to region business development manager, Mike Slee.

Ferreira comes to OpenSpirit from Schlumberger (SIS). Cabot previously was with Geotrace.

OpenSpirit Corp. is an independent software company focused on providing integration solutions for upstream applications and data.

Acteon Group Ltd.

Norwich, Norfolk, UK, has completed acquisition of three companies from the Aberdeen-based Craig Group. They are Seatronics, International Mooring Systems (IMS), and Chain Corp. International (ChainCo). David Currie will continue to lead Seatronics. Alan Duncan will head IMS and ChainCo.

Seatronics is a leading provider of subsea electronics rental, and takes Acteon into the advanced marine survey sector, new ground for Acteon.

IMS focuses on the sale, rental, and management of mooring equipment, while ChainCo specializes in inspection and certification of mooring chain, and the repair or upgrade of heavy-duty mooring systems.

Acteon Group Ltd. is comprised of specialist engineering companies serving the global offshore oil and gas industry.

Emer International Group Ltd.

Hong Kong, has announced its acquisition of Zhengzhou Highlight Energy Technology Co. Ltd., manufacturer and marketer of machinery and equipment for the oil industry. Zhengzhou Highlight's major product is a solid control system for processing mud in the drilling process.

Emer International Group Ltd. provides products and services to the worldwide oil and gas drilling industry, both onshore and offshore. The company has manufacturing centers in China, and a large sales center in Houston.

Gas Technology Institute (GTI) and Instituto Superior de la Energia (ISE)

Des Plaines, Ill., and Madrid, Spain, respectively, have announced the signing of an agreement whereby GTI will present LNG courses at ISE and license its CD-based e-learning courses to ISE. The collaboration will aid the industry in reducing the shortage of trained workers caused by the rapidly expanding LNG industry.

GTI has offered LNG information and training since the 1960s. The organization has served the natural gas industry and energy markets for more than 65 years with research, development, and training.

ISE, which belongs to the Repsol YPF Foundation, is a pioneering educational institution that began offering programs in 1999. The institution designs and teaches postgraduate programs targeting young graduates who wish to enter the energy and petrochemical industries, and related service companies.

Basic Systems Inc.

Derwent, Ohio, has promoted Dave Eisenbarth, Doug Law, and Jean Roe to senior project manager positions. Each will lead a Basic Systems group of engineers, designers, programmers, drafters, and support staff in the completion of design projects for the natural gas industry.


Eisenbarth

Eisenbarth, a graduate of Washington Technical College, will lead the automation group.


Law

Law earned his engineering degree from Ohio University.

Roe holds a management degree from Marietta College, and has been with Basic Systems since 1984.

Basic Systems Inc., a part of the BSI Group, provides project management, facility engineering, industrial control system integration, engine and compressor automation, material procurement, commissioning, and start-up services for the natural gas, refining and petrochemical, and power generation markets.


Roe

The BSI Group is an affiliation of US companies: World Energy Services Inc., Basic Systems Inc., Bi-Con Services Inc., ACI Services Inc.; and international companies: Beta SA, Warsaw, and WES, Moscow.

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Imports of crude and products

	Districts 1-4 7-13 2007	Districts 1-4 7-6 2007	District 5 7-13 2007	District 5 7-6 2007	Total US 7-13 2007	Total US 7-6 2007	Total US *7-14 2006
	1,000 b/d						
Total motor gasoline	858	1,281	57	142	915	1,423	1,050
Mo. gas. blending comp.	480	852	30	57	510	909	541
Distillate	240	238	11	40	251	278	222
Residual	308	428	127	0	435	428	242
Jet fuel-kerosine	123	48	71	257	194	305	172
Propane-propylene	223	224	1	1	234	225	51
Other	905	364	62	62	967	426	1,160
Total products	**3,147**	**3,435**	**359**	**559**	**3,506**	**3,994**	**3,438**
Total crude	**9,340**	**8,926**	**1,035**	**1,099**	**10,375**	**10,025**	**10,701**
Total imports	**12,487**	**12,361**	**1,394**	**1,658**	**13,881**	**14,019**	**14,139**

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

Purvin & Gertz LNG netbacks—July 20, 2007

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.43	4.40	5.63	4.29	4.98	5.60
Everett	5.08	3.09	4.70	3.19	3.58	5.37
Isle of Grain	4.69	2.25	4.25	2.11	3.04	4.15
Lake Charles	3.74	1.95	3.50	2.11	2.36	4.35
Sodegaura	4.76	6.89	4.96	6.60	5.93	4.23
Zeebrugge	5.65	3.77	5.04	3.70	4.24	5.06

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

Crude and product stocks

	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	13,365	56,403	27,216	11,350	46,095	14,498	4,195
PADD 2	68,369	48,916	15,955	6,948	28,719	1,235	18,932
PADD 3	197,998	61,839	26,101	12,994	33,046	14,808	22,789
PADD 4	14,163	6,170	1,874	406	3,057	338	[1]1,794
PADD 5	58,236	30,013	20,444	9,256	11,308	6,020	—
July 13, 2007	**352,131**	**203,341**	**91,590**	**40,954**	**122,225**	**36,899**	**47,710**
July 6, 2007	**352,580**	**205,576**	**91,892**	**41,158**	**122,370**	**35,499**	**46,280**
July 14, 2006[2]	**335,467**	**214,194**	**93,337**	**39,754**	**131,098**	**42,030**	**53,052**

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

Refinery report—July 13, 2007

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d						
PADD 1	1,619	1,618	1,916	95	542	152	71
PADD 2	3,220	3,210	2,097	191	884	64	217
PADD 3	7,662	7,527	3,281	714	1,888	264	681
PADD 4	600	596	333	22	186	15	[1]145
PADD 5	2,779	2,699	1,538	419	480	191	—
July 13, 2007	**15,880**	**15,650**	**9,165**	**1,441**	**3,980**	**686**	**1,114**
July 6, 2007	**15,729**	**15,561**	**9,229**	**1,477**	**4,010**	**681**	**1,139**
July 14, 2006[2]	**16,161**	**15,906**	**9,228**	**1,541**	**4,249**	**642**	**1,047**
	17,443 operable capacity		**91.0% utilization rate**				

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

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

OGJ crack spread

	*7-20-07	*7-21-06	Change $/bbl	Change, %
SPOT PRICES				
Product value	87.28	88.12	–0.84	–1.0
Brent crude	78.20	73.48	4.72	6.4
Crack spread	9.08	14.64	–5.56	–38.0
FUTURES MARKET PRICES				
One month				
Product value	89.27	90.18	–0.91	–1.0
Light sweet crude	74.94	73.80	1.14	1.5
Crack spread	14.33	16.38	–2.05	–12.5
Six month				
Product value	86.41	86.20	0.20	0.2
Light sweet crude	74.00	76.86	–2.86	–3.7
Crack spread	12.41	9.34	3.06	32.8

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

OGJ GASOLINE PRICES

	Price ex tax 7-18-07	Pump price* 7-18-07	Pump price 7-19-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	258.4	298.1	295.1
Baltimore	253.2	295.1	302.1
Boston	247.1	289.0	296.1
Buffalo	239.0	299.1	306.1
Miami	249.8	300.1	309.1
Newark	251.1	284.0	294.1
New York	239.9	300.0	304.1
Norfolk	250.5	288.1	297.5
Philadelphia	250.5	301.2	310.1
Pittsburgh	239.4	290.1	295.1
Wash., DC	259.7	298.1	315.1
PAD I avg.	249.0	294.8	302.3
Chicago	259.7	310.6	329.1
Cleveland	219.2	265.6	288.5
Des Moines	249.1	289.5	278.5
Detroit	254.7	303.9	292.5
Indianapolis	253.5	298.5	286.1
Kansas City	247.7	283.7	281.8
Louisville	260.4	297.3	293.5
Memphis	251.4	291.2	289.1
Milwaukee	245.1	296.4	293.1
Minn.-St. Paul	238.8	279.2	284.1
Oklahoma City	244.8	280.2	275.1
Omaha	262.7	309.1	286.5
St. Louis	262.2	298.2	278.5
Tulsa	248.8	284.2	272.1
Wichita	247.0	290.4	279.1
PAD II avg.	249.7	291.9	287.2
Albuquerque	254.4	290.8	288.8
Birmingham	245.5	284.2	281.8
Dallas-Fort Worth	245.0	283.4	292.5
Houston	245.5	283.9	291.1
Little Rock	244.9	285.1	281.8
New Orleans	250.0	288.4	286.5
San Antonio	242.8	281.2	277.5
PAD III avg.	246.9	285.3	285.7
Cheyenne	256.9	289.3	277.8
Denver	269.3	309.7	296.8
Salt Lake City	266.7	309.6	301.1
PAD IV avg.	264.3	302.9	291.9
Los Angeles	253.5	312.0	327.1
Phoenix	264.6	302.0	309.8
Portland	266.7	310.0	300.5
San Diego	264.6	323.1	334.4
San Francisco	261.6	320.1	333.4
Seattle	248.6	301.0	319.5
PAD V avg.	259.9	311.4	320.8
Week's avg.	**251.5**	**295.1**	**296.0**
June avg.	**265.9**	**309.4**	**288.4**
May avg.	**264.1**	**307.6**	**288.5**
2007 to date	**226.5**	**270.1**	—
2006 to date	**217.7**	**260.9**	—

*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

	7-13-07 ¢/gal		7-13-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	216.73	New York Harbor	210.34
Gulf Coast	216.85	Gulf Coast	207.09
Los Angeles	221.85	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	211.61	ARA	207.93
Singapore	206.57	Singapore	208.57
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	227.10	New York Harbor	136.83
Gulf Coast	233.85	Gulf Coast	138.10
Los Angeles	234.85	Los Angeles	148.88
		ARA	130.22
		Singapore	140.17

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

BAKER HUGHES RIG COUNT

	7-20-07	7-21-06
Alabama	5	4
Alaska	9	8
Arkansas	52	26
California	38	32
Land	37	29
Offshore	1	3
Colorado	106	89
Florida	1	0
Illinois	0	0
Indiana	3	0
Kansas	14	16
Kentucky	11	6
Louisiana	181	188
N. Land	59	58
S. Inland waters	25	16
S. Land	28	34
Offshore	69	80
Maryland	1	0
Michigan	3	5
Mississippi	15	7
Montana	20	20
Nebraska	0	0
New Mexico	80	93
New York	5	5
North Dakota	38	29
Ohio	13	7
Oklahoma	189	189
Pennsylvania	12	17
South Dakota	3	1
Texas	838	765
Offshore	8	10
Inland waters	0	3
Dist. 1	24	21
Dist. 2	32	23
Dist. 3	70	68
Dist. 4	88	76
Dist. 5	179	136
Dist. 6	124	111
Dist. 7B	33	47
Dist. 7C	55	38
Dist. 8	109	98
Dist. 8A	22	30
Dist. 9	35	34
Dist. 10	59	70
Utah	38	43
West Virginia	32	27
Wyoming	71	102
Others—NV-4; TN-5; VA-2; WA-1	12	4
Total US	**1,790**	**1,683**
Total Canada	**377**	**533**
Grand total	**2,167**	**2,216**
Oil rigs	287	299
Gas rigs	1,497	1,381
Total offshore	80	93
Total cum. avg. YTD	**1,750**	**1,588**

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

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

SMITH RIG COUNT

Proposed depth, ft	7-20-07 Rig count	7-20-07 Percent footage*	7-21-06 Rig count	7-21-06 Percent footage*
0-2,500	62	6.4	52	1.9
2,501-5,000	107	50.4	89	40.4
5,001-7,500	254	24.8	229	18.7
7,501-10,000	417	2.8	392	3.5
10,001-12,500	462	1.5	414	1.2
12,501-15,000	273	—	275	—
15,001-17,500	103	—	110	—
17,501-20,000	65	—	80	—
20,001-over	34	—	24	—
Total	**1,777**	**7.8**	**1,665**	**5.9**
INLAND	38		41	
LAND	1,674		1,552	
OFFSHORE	65		72	

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

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

OGJ PRODUCTION REPORT

	[1]7-20-07	[2]7-21-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	770	706
California	674	679
Colorado	51	61
Florida	7	7
Illinois	32	27
Kansas	97	97
Louisiana	1,374	1,362
Michigan	15	14
Mississippi	50	49
Montana	94	99
New Mexico	166	158
North Dakota	108	111
Oklahoma	169	172
Texas	1,350	1,355
Utah	46	48
Wyoming	146	133
All others	60	72
Total	**5,229**	**5,171**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	7-20-07
Alaska-North Slope 27°	57.84
South Louisiana Sweet	80.50
California-Kern River 13°	66.10
Lost Hills 30°	74.10
Southwest Wyoming Sweet	71.07
East Texas Sweet	71.75
West Texas Sour 34°	65.40
West Texas Intermediate	72.25
Oklahoma Sweet	72.25
Texas Upper Gulf Coast	69.00
Michigan Sour	65.25
Kansas Common	71.25
North Dakota Sweet	67.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	7-13-07
United Kingdom-Brent 38°	76.90
Russia-Urals 32°	74.36
Saudi Light 34°	72.19
Dubai Fateh 32°	69.57
Algeria Saharan 44°	78.98
Nigeria-Bonny Light 37°	79.41
Indonesia-Minas 34°	76.54
Venezuela-Tia Juana Light 31°	70.85
Mexico-Isthmus 33°	70.74
OPEC basket	74.04
Total OPEC[2]	73.73
Total non-OPEC[2]	73.09
Total world[2]	73.44
US imports[3]	70.63

[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]

	7-13-07	7-6-07	Change
	bcf		
Producing region	903	896	7
Consuming region east	1,396	1,348	48
Consuming region west	393	383	10
Total US	**2,692**	**2,627**	**65**
	May 07	**May 06**	**Change, %**
Total US[2]	**2,179**	**2,310**	**–5.7**

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

Imports of crude and products

	Districts 1-4 7-20 2007	Districts 1-4 7-13 2007	District 5 7-20 2007	District 5 7-13 2007	Total US 7-20 2007	Total US 7-13 2007	Total US *7-21 2006
	1,000 b/d						
Total motor gasoline	1,503	858	149	57	1,652	915	1,008
Mo. gas. blending comp.	1,009	480	110	30	1,119	510	566
Distillate	206	240	51	11	257	251	566
Residual	315	308	0	127	315	435	409
Jet fuel-kerosine	128	123	61	71	189	194	167
Propane-propylene	83	233	0	1	83	234	185
Other	225	905	73	62	298	967	524
Total products	**3,469**	**3,147**	**444**	**359**	**3,913**	**3,506**	**3,425**
Total crude	**9,328**	**9,340**	**1,050**	**1,035**	**10,378**	**10,375**	**10,507**
Total imports	**12,797**	**12,487**	**1,494**	**1,394**	**14,291**	**13,881**	**13,932**

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

Purvin & Gertz LNG netbacks—July 27, 2007

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.43	4.40	5.63	4.57	4.98	5.60
Everett	4.59	2.64	4.22	2.73	3.20	4.88
Isle of Grain	4.79	2.18	4.16	2.09	2.85	4.09
Lake Charles	3.30	1.50	3.07	1.66	1.91	3.86
Sodegaura	4.92	6.89	5.12	6.76	6.09	4.38
Zeebrugge	5.66	3.83	5.14	3.73	4.35	5.16

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

Crude and product stocks

	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	15,052	55,319	26,462	10,432	47,711	14,695	4,309
PADD 2	68,077	48,931	15,659	7,033	27,062	1,159	19,972
PADD 3	196,049	62,978	27,191	13,578	34,273	15,594	21,990
PADD 4	13,784	6,233	1,933	492	3,051	348	[1]1,787
PADD 5	58,066	30,673	21,276	9,130	11,556	5,707	—
July 20, 2007	**351,028**	**204,134**	**92,521**	**40,665**	**123,653**	**37,503**	**48,058**
July 13, 2007	**352,131**	**203,341**	**91,590**	**40,954**	**122,225**	**36,899**	**47,824**
July 21, 2006[2]	**335,497**	**211,030**	**91,392**	**39,874**	**131,897**	**42,157**	**55,262**

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

Refinery report—July 20, 2007

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,552	1,557	1,945	77	503	133	66
PADD 2	3,237	3,230	2,100	229	851	44	215
PADD 3	7,820	7,736	3,388	708	2,101	354	644
PADD 4	595	593	303	27	180	13	[1]139
PADD 5	2,785	2,706	1,535	405	498	188	—
July 20, 2007	**15,989**	**15,822**	**9,271**	**1,446**	**4,133**	**732**	**1,064**
July 13, 2007	**15,880**	**15,650**	**9,165**	**1,441**	**3,980**	**686**	**1,114**
July 21, 2006[2]	**16,088**	**15,817**	**9,090**	**1,622**	**3,839**	**610**	**1,051**
	17,443 operable capacity		**91.7% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*7-27-07	*7-28-06	Change $/bbl	Change, %
SPOT PRICES				
Product value	85.20	89.53	–4.33	–4.8
Brent crude	77.08	73.63	3.45	4.7
Crack spread	8.12	15.90	–7.78	–48.9
FUTURES MARKET PRICES				
One month				
Product value	86.97	90.49	–3.52	–3.9
Light sweet crude	75.26	74.10	1.16	1.6
Crack spread	11.71	16.39	–4.67	–28.5
Six month				
Product value	85.36	86.82	–1.46	–1.7
Light sweet crude	73.67	77.22	–3.55	–4.6
Crack spread	11.69	9.61	2.09	21.7

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

OGJ GASOLINE PRICES

	Price ex tax 7-26-07	Pump price* 7-25-07	Pump price 7-26-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	258.3	298.0	297.0
Baltimore	253.1	295.0	304.0
Boston	247.0	288.9	298.0
Buffalo	238.9	299.0	308.0
Miami	249.7	300.0	311.0
Newark	251.0	283.9	296.0
New York	239.8	299.9	306.0
Norfolk	250.4	288.0	299.8
Philadelphia	250.3	301.0	312.0
Pittsburgh	239.3	290.0	297.0
Wash., DC	259.6	298.0	317.0
PAD I avg.	248.8	294.7	304.1
Chicago	288.6	339.5	330.3
Cleveland	218.1	264.5	289.4
Des Moines	244.0	284.4	280.1
Detroit	246.0	295.2	293.4
Indianapolis	235.1	280.1	287.3
Kansas City	249.8	285.8	284.5
Louisville	249.5	286.4	294.4
Memphis	239.2	279.0	290.3
Milwaukee	236.6	288.1	294.3
Minn.-St. Paul	243.9	284.3	285.3
Oklahoma City	239.3	274.7	278.3
Omaha	248.6	295.0	288.6
St. Louis	244.0	280.0	283.4
Tulsa	250.6	286.0	275.3
Wichita	238.0	281.4	281.6
PAD II avg.	244.8	287.0	289.1
Albuquerque	253.8	290.2	289.9
Birmingham	245.3	284.0	282.2
Dallas-Fort Worth	244.3	282.7	293.1
Houston	245.5	283.9	291.6
Little Rock	244.8	285.0	282.5
New Orleans	249.7	288.1	287.1
San Antonio	242.6	281.0	278.1
PAD III avg.	246.6	285.0	286.4
Cheyenne	256.3	288.7	278.5
Denver	268.6	309.2	297.2
Salt Lake City	265.6	308.5	301.3
PAD IV avg.	263.5	302.1	292.4
Los Angeles	248.8	307.3	323.0
Phoenix	243.2	280.6	309.2
Portland	252.0	295.3	298.8
San Diego	255.8	314.3	330.4
San Francisco	273.5	332.0	329.7
Seattle	245.2	297.6	318.4
PAD V avg.	253.1	304.5	318.2
Week's avg.	**248.7**	**292.2**	**297.0**
July avg.	**251.6**	**295.2**	**295.2**
June avg.	**265.9**	**309.4**	**288.4**
2007 to date	**227.2**	**270.8**	—
2006 to date	**218.8**	**262.1**	—

*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

	7-20-07 ¢/gal		7-20-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	209.21	New York Harbor	208.68
Gulf Coast	208.83	Gulf Coast	204.80
Los Angeles	213.08	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	204.53	ARA	207.61
Singapore	204.36	Singapore	209.40
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	217.83	New York Harbor	138.76
Gulf Coast	231.58	Gulf Coast	140.48
Los Angeles	228.08	Los Angeles	154.53
		ARA	137.57
		Singapore	151.03

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

BAKER HUGHES RIG COUNT

	7-27-07	7-28-06
Alabama	5	5
Alaska	7	9
Arkansas	51	26
California	37	33
Land	36	28
Offshore	1	5
Colorado	101	94
Florida	1	0
Illinois	0	0
Indiana	3	0
Kansas	15	16
Kentucky	10	6
Louisiana	185	187
N. Land	59	56
S. Inland waters	26	17
S. Land	32	35
Offshore	68	79
Maryland	1	0
Michigan	3	5
Mississippi	14	13
Montana	20	22
Nebraska	0	0
New Mexico	82	89
New York	5	7
North Dakota	39	32
Ohio	13	6
Oklahoma	188	191
Pennsylvania	16	17
South Dakota	4	1
Texas	825	777
Offshore	8	11
Inland waters	0	3
Dist. 1	25	19
Dist. 2	32	25
Dist. 3	70	64
Dist. 4	85	79
Dist. 5	173	136
Dist. 6	112	116
Dist. 7B	37	48
Dist. 7C	58	41
Dist. 8	110	100
Dist. 8A	23	29
Dist. 9	29	37
Dist. 10	63	69
Utah	37	43
West Virginia	32	28
Wyoming	70	104
Others—NV-3; TN-5; VA-2		
WA-1	11	3
Total US	**1,775**	**1,714**
Total Canada	**371**	**547**
Grand total	**2,146**	**2,261**
Oil rigs	296	302
Gas rigs	1,474	1,408
Total offshore	79	96
Total cum. avg. YTD	**1,750**	**1,592**

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	7-27-07 Rig count	7-27-07 Percent footage*	7-28-06 Rig count	7-28-06 Percent footage*
0-2,500	61	6.5	53	1.8
2,501-5,000	108	52.7	83	38.5
5,001-7,500	243	24.2	233	20.1
7,501-10,000	410	3.1	396	4.2
10,001-12,500	467	1.2	407	1.2
12,501-15,000	280	—	285	—
15,001-17,500	105	—	111	—
17,501-20,000	65	—	76	—
20,001-over	35	—	23	—
Total	**1,774**	**7.8**	**1,667**	**6.1**
INLAND	38		42	
LAND	1,671		1,553	
OFFSHORE	65		72	

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

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

OGJ PRODUCTION REPORT

	[1]7-27-07	[2]7-28-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	761	681
California	669	677
Colorado	50	61
Florida	6	7
Illinois	31	27
Kansas	95	96
Louisiana	1,362	1,374
Michigan	14	14
Mississippi	50	49
Montana	92	99
New Mexico	164	157
North Dakota	105	110
Oklahoma	167	173
Texas	1,343	1,356
Utah	44	49
Wyoming	144	136
All others	60	71
Total	**5,176**	**5,158**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	7-27-06
Alaska-North Slope 27°	57.84
South Louisiana Sweet	81.75
California-Kern River 13°	67.75
Lost Hills 30°	75.70
Southwest Wyoming Sweet	72.52
East Texas Sweet	73.00
West Texas Sour 34°	66.65
West Texas Intermediate	73.50
Oklahoma Sweet	73.50
Texas Upper Gulf Coast	70.25
Michigan Sour	66.50
Kansas Common	72.50
North Dakota Sweet	69.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	7-20-07
United Kingdom-Brent 38°	78.35
Russia-Urals 32°	76.01
Saudi Light 34°	73.08
Dubai Fateh 32°	69.82
Algeria Saharan 44°	79.79
Nigeria-Bonny Light 37°	80.03
Indonesia-Minas 34°	77.97
Venezuela-Tia Juana Light 31°	72.33
Mexico-Isthmus 33°	72.22
OPEC basket	75.03
Total OPEC[2]	74.50
Total non-OPEC[2]	74.35
Total world[2]	74.43
US imports[3]	71.71

[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]

	7-20-07	7-13-06	Change
	Bcf		
Producing region	912	903	9
Consuming region east	1,455	1,396	59
Consuming region west	396	393	3
Total US	**2,763**	**2,692**	**71**
	May 07	**May 06**	**Change, %**
Total US[2]	**2,179**	**2,310**	**–5.7**

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

PACE REFINING MARGINS

	May 2007	June 2007	July 2007	July 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	28.98	21.60	19.19	18.22	0.97	5.3
Composite US Gulf Refinery	26.18	20.91	17.87	20.40	–2.52	–12.4
Arabian Light	26.42	21.51	16.67	18.94	–2.27	–12.0
Bonny Light	18.30	13.76	9.63	13.31	–3.68	–27.6
US PADD II						
Chicago (WTI)	39.21	25.07	24.99	21.82	3.17	14.5
US East Coast						
NY Harbor (Arab Med)	23.61	18.40	16.70	17.62	–0.93	–5.3
East Coast Comp-RFG	26.23	21.60	18.77	21.63	–2.86	–13.2
US West Coast						
Los Angeles (ANS)	28.30	20.46	16.09	18.43	–2.34	–12.7
NW Europe						
Rotterdam (Brent)	7.42	6.52	1.84	2.41	–0.57	–23.7
Mediterranean						
Italy (Urals)	12.07	9.68	10.13	8.89	1.24	13.9
Far East						
Singapore (Dubai)	9.71	8.47	8.42	1.34	7.08	529.9

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	May 2007	Apr. 2007	May 2006	May 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,541	1,798	1,543	–2	10,454	9,683	771
Addition to storage	498	274	420	78	1,100	1,046	54
Exports	79	68	63	16	351	292	59
Canada	43	32	21	22	204	139	65
Mexico	32	32	36	–4	125	125	0
LNG	4	4	6	–2	22	28	–6
Total demand	**2,118**	**2,140**	**2,026**	**92**	**11,905**	**11,021**	**884**
SUPPLY							
Production (dry gas)	1,605	1,549	1,554	51	7,757	7,601	156
Supplemental gas	3	4	3	0	25	25	0
Storage withdrawal	39	154	52	–13	1,984	1,373	611
Imports	345	378	350	–5	1,888	1,713	175
Canada	251	279	283	–32	1,493	1,473	20
Mexico	0	0	0	0	18	3	15
LNG	94	99	67	27	377	237	140
Total supply	**1,992**	**2,085**	**1,959**	**33**	**11,654**	**10,712**	**942**

NATURAL GAS IN UNDERGROUND STORAGE

	May 2007	Apr. 2007	Mar. 2007	May 2006	Change
	bcf				
Base gas	4,251	4,246	4,242	4,202	49
Working gas	2,179	1,720	1,603	2,310	–131
Total gas	**6,430**	**5,966**	**5,845**	**6,512**	**–82**

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

WORLDWIDE NGL PRODUCTION

	Apr. 2007	Mar. 2007	4 month average Production 2007	4 month average Production 2006	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	83	85	85	84	1	1.3
Canada	697	712	723	701	21	3.0
Mexico	420	416	413	437	–24	–5.4
United States	1,749	1,767	1,723	1,695	29	1.7
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	162	160	161	168	–7	–3.9
Western Hemisphere	**3,311**	**3,340**	**3,306**	**3,285**	**21**	**0.6**
Norway	317	276	305	295	10	3.2
United Kingdom	164	159	163	166	–3	–2.0
Other Western Europe	19	19	19	20	–1	–3.2
Western Europe	**500**	**455**	**487**	**481**	**6**	**1.1**
Russia	422	426	425	411	13	3.2
Other FSU	160	160	160	160	—	—
Other Eastern Europe	15	15	16	19	–3	–16.2
Eastern Europe	**597**	**601**	**600**	**590**	**10**	**1.7**
Algeria	340	340	340	295	45	15.3
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	198	193	196	185	11	5.8
Africa	**663**	**658**	**661**	**605**	**56**	**9.2**
Saudi Arabia	1,439	1,439	1,439	1,439	—	—
United Arab Emirates	400	400	400	400	—	—
Other Middle East	680	680	680	670	10	1.5
Middle East	**2,519**	**2,519**	**2,519**	**2,509**	**10**	**0.4**
Australia	82	62	76	77	–2	–2.0
China	180	180	180	180	—	—
India	—	—	9	44	–34	–78.3
Other Asia-Pacific	217	218	218	221	–2	–1.1
Asia-Pacific	**479**	**460**	**484**	**522**	**–38**	**–7.3**
TOTAL WORLD	**8,068**	**8,033**	**8,057**	**7,993**	**64**	**0.8**

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

OXYGENATES

	May 2007	Apr. 2007	Change	YTD 2007	YTD 2006	Change
			1,000 bbl			
Fuel ethanol						
Production	12,573	11,716	857	58,597	44,481	14,116
Stocks	8,950	8,791	159	8,950	7,848	1,102
MTBE						
Production	2,003	1,959	44	9,857	14,973	–34,624
Stocks	1,353	2,324	–971	1,353	2,314	–961

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

US COOLING DEGREE-DAYS

	June 2007	June 2006	Normal	2007 % change from normal	Total degree days Jan. 1 through June 30 2007	2006	Normal	% change from normal
New England	87	109	64	35.9	117	124	73	60.3
Middle Atlantic	156	141	120	30.0	205	176	151	35.8
East North Central	176	115	150	17.3	248	173	209	18.7
West North Central	203	208	193	5.2	300	315	273	9.9
South Atlantic	349	333	320	9.1	734	727	689	6.5
East South Central	353	311	297	18.9	603	564	498	21.1
West South Central	416	452	432	–3.7	856	1,074	870	–1.6
Mountain	267	306	239	11.7	450	482	400	12.5
Pacific	112	178	108	3.7	136	217	181	–24.9
US average*	**236**	**237**	**216**	**9.3**	**415**	**436**	**387**	**7.2**

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

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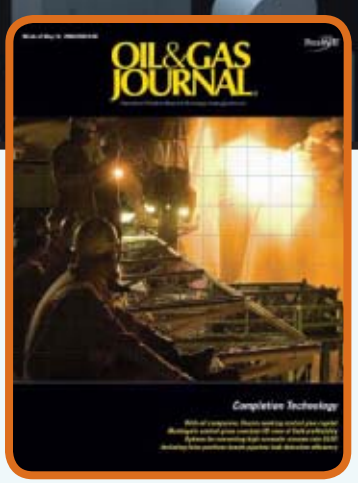

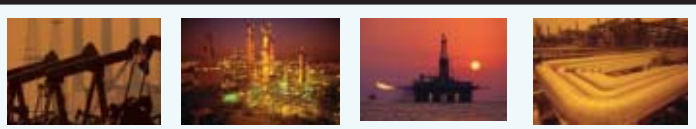

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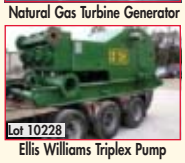

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Explosion? Fire? Must be an oil and gas disaster

Ignorance and suspicion frolic again at the expense of oil and gas.

On the morning of July 25, an explosion and fire in Dallas shut down two busy interstate highways. News reports, apparently starting with an Associated Press story, attributed the blast to liquefied natural gas.

Well into the afternoon, for example, the web site of the Dallas NBC television affiliate was reporting this: "Explosions at

The Editor's Perspective

by Bob Tippee, Editor

a liquefied natural gas plant Wednesday morning injured three people and shut down Interstate 35E and Interstate 30 near downtown Dallas, forcing evacuations within a half-mile."

The facility that blew up was an acetylene distribution center owned by Southwest Industrial Gases Inc. LNG played no role.

As mistakes go, this one's a whopper. But the chance that initial reports might have been wrong didn't forestall opportunistic publicity-seeking.

"This morning's Dallas liquefied natural gas plant explosion is another incident in a long line of recent oil and gas infrastructure disasters," began an afternoon press release pitching interviews with "an expert in oil and gas facility/pipeline safety and maintenance."

Such an expert might be expected to question news of an LNG explosion in Dallas.

But the prospective interview subject had no chance to apply constructive doubt. William Schutt, founder and president of MATCOR Inc., a corrosion engineering firm in Doylestown, Pa., didn't see the press release that offered his expertise while parroting false reports in the context of multiple oil and gas "disasters."

"We were being proactive on our end and went with what we saw in the AP story," explained Matthew McLoughlin, senior account executive of Gregory FCA Communication, Ardmore, Pa., source of the release. Alerted to the error by Warren True, Oil & Gas Journal chief technology editor and editor of LNG Observer, "I sent a correction immediately," McLoughlin said.

Corrections eventually found their ways into news accounts of the explosion, too. Future hearings on LNG terminal siting will show how effective they were.

Here's betting that somewhere, some project opponent will brandish the Dallas LNG explosion that never happened—which was, after all, just one of those oil and gas disasters everybody expects.

(Online July 27, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Equities market, GDP rattle oil prices

Futures prices for crude and petroleum products took unusual bounces in the last full week of July, influenced by a falling equities market and US economic growth with virtually no immediate changes in supply and demand.

The September contract for benchmark US light, sweet crudes traded at $73.10-76.38/bbl July 25 before closing at $75.88/bbl, up $2.32 for the day to recoup virtually all losses from the previous three sessions on the New York Mercantile Exchange as traders shrugged off a bearish inventory report. The Energy Information Administration said US crude inventories fell 1.1 million bbl to 351 million bbl in the week ended July 20. Gasoline stocks increased 800,000 bbl to 204.1 million bbl in the same period, still below average.

One reason for the bullish market was that US refineries operated at 91.7% of capacity during the week ended July 20, the highest level since September 2006. US gasoline production rose to 9.3 million b/d, while gasoline imports increased to 1.65 million b/d, the highest weekly average ever. That "created a counterseasonal build in gasoline," said Paul Horsnell, Barclays Capital Inc., London. While 700,000 bbl of the gasoline build was on the West Coast, East Coast inventories fell for the first time in 6 weeks. Total distillate inventories rose 1.5 million bbl yet stayed below their 5-year average. Diesel inventories fell, and heating oil inventories rose by 2.9 million bbl.

The September crude contract traded as high as $77.24/bbl July 26 before closing at $74.95/bbl on NYMEX. The commodities market was pulled down as the Dow Jones Industrial Average (DJIA) plunged 311.5 points in its second worst session of the year as fears of shaky credit markets and the troubled housing industry swept Wall Street. NYMEX "reluctantly gave up the early session gains when it was apparent that the stock market slide would be too large to ignore," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland.

However, September crude jumped to $77.02/bbl July 27, just 1¢ short of tying the record-high NYMEX closing on the New York market after the Commerce Department reported a second-quarter jump in the US economy. The record high closing price for a front-month crude contract was $77.03/bbl on July 14, 2006, amid fears that fighting between Israel and Muslim militia in Lebanon might spread.

Gross domestic product growth—the best national barometer of economic fitness—jumped to 3.4%/year in the latest quarter from just 0.6%/year in the first, which marked the lowest GDP growth in 4 years. Although the DJIA continued to tumble as a result of the sour housing market, crude traders saw the increased GDP as indicating a greater demand for fuel.

Natural gas

Crude prices were choppy but trended upwards during the week. Natural gas futures prices also vacillated but followed a downward trend from a July 20 closing at $6.45/MMbtu to $6.11/MMbtu on July 27, despite a rally in the last three sessions before the August contract expired. The diverging paths of the two commodities further illustrated the breakdown of the pricing relationship between crude and natural gas, said analysts at the Societe Generale Group (SG) in Paris. "This week natural gas broke out of the competing fuel band and is now cheaper than residual fuel oil," said SG analysts.

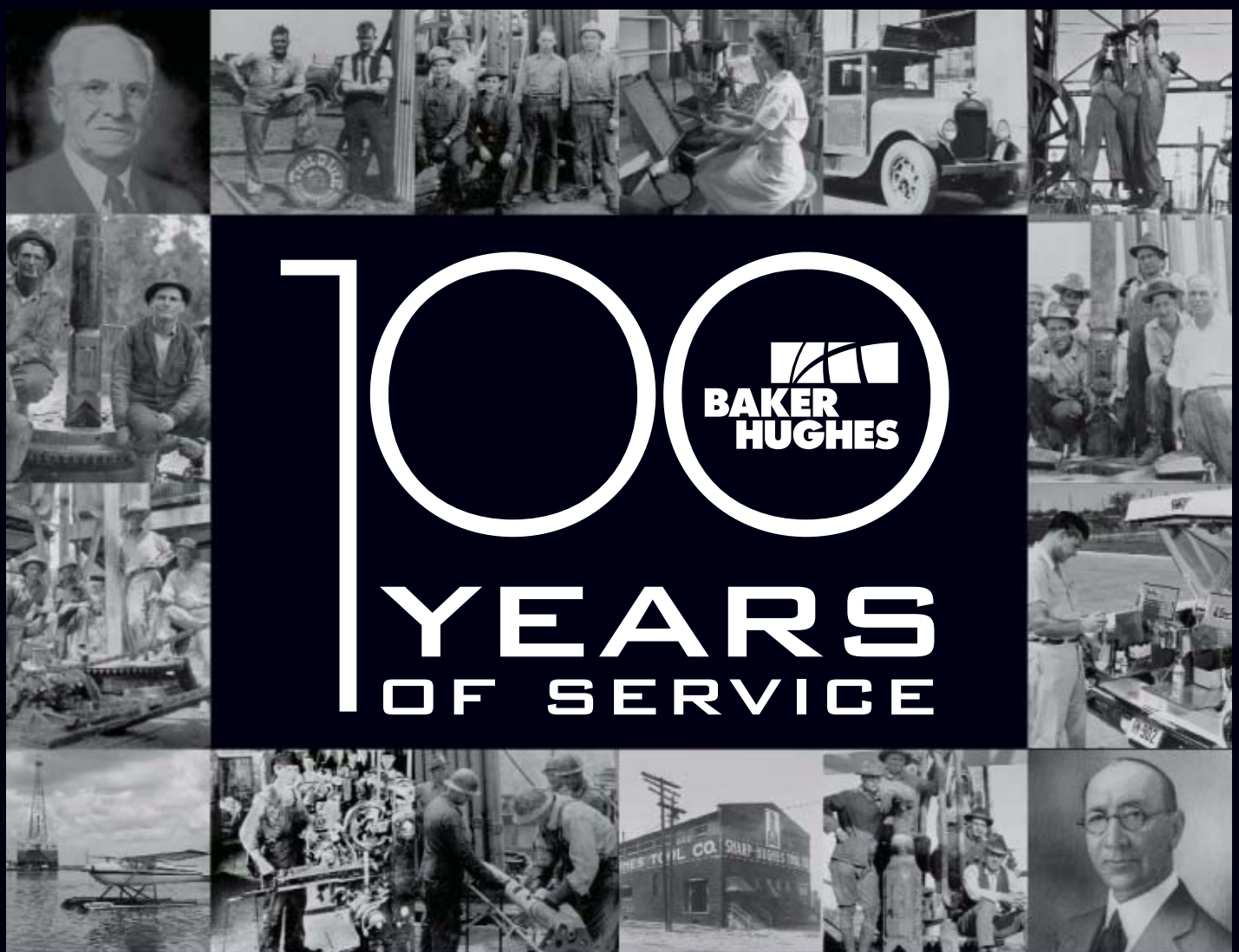
Analysts in the Houston office of Raymond James & Associates Inc. said, "Gas markets could be headed for a late summer melt-down similar to...last year," when front-month gas contracts "plunged from nearly $8/Mcf in early August to the low of $4/Mcf at the end of September." Raymond James lowered its gas price estimates to $6/Mcf from $6.50/Mcf for the third quarter and to $6.50/Mcf from $7.50/Mcf for the fourth quarter. However, it raised its oil price estimate to $73/bbl from $67/bbl for the third quarter.

Adam Sieminski at Deutsche Bank AG, New York, warned that the recent earthquake that shut down the Kashiwasaki-Kariwa nuclear power plant in Japan will soon tighten world energy supplies by increasing demand for competitive fuels in an already stretched market.

The Kashiwasaki-Kariwa plant could be closed for a year, and other Japanese nuclear plants potentially may come down for safety inspections. Sieminski noted that in 2003, the Tokyo Electric Power Co., which operates the Kashiwasaki-Kariwa plant, had to close all 17 of its nuclear reactors for inspection and maintenance. "This consequently led to increases in Japan's fuel oil and LNG imports because the marginal swing power supply capacity in Japan is mainly fossil fuel-based owing to their higher variable running costs," said Sieminski.

(Online July 30, 2007; author's e-mail: samf@ogjonline.com)

A Century of Innovation



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