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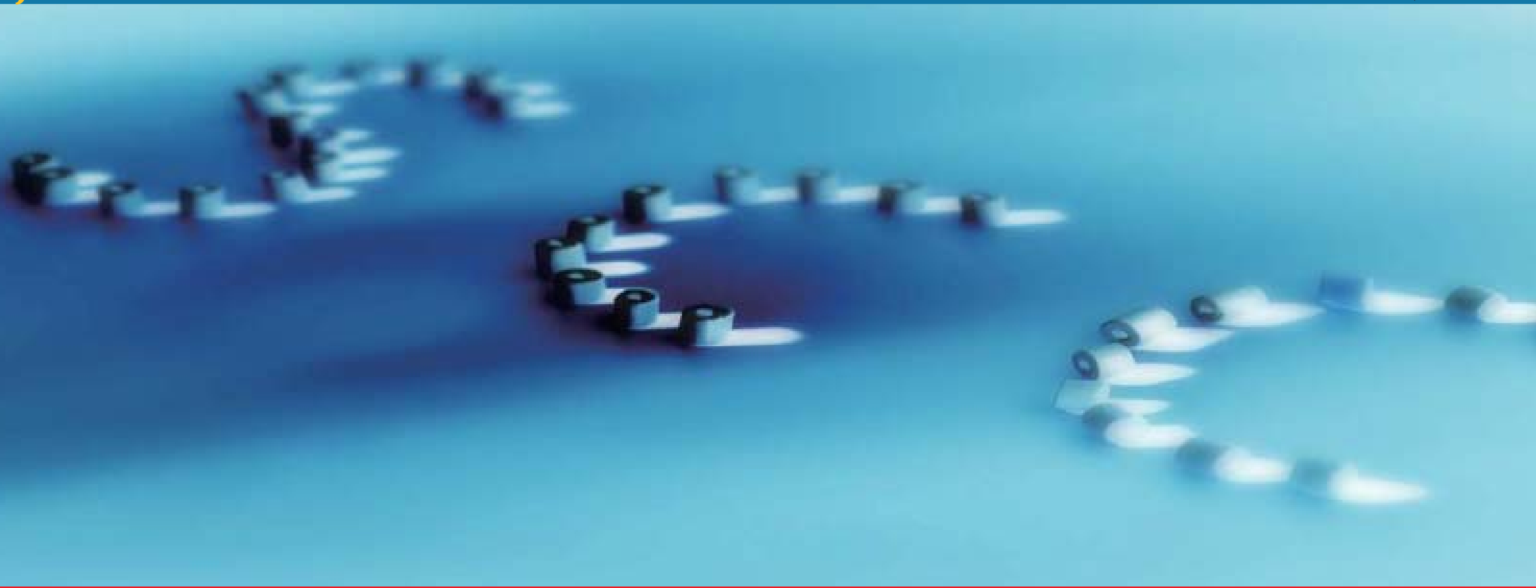
European Refining

EnCana banking heavily on unconventional gas, oil
Gulf of Mexico structure removal costs examined
Study outlines method for managing unexpected liquids



OIL&GAS JOURNAL®

June 15, 2009
Volume 107.23

European Refining

Image from Shell

Regular Features

Cover

ExxonMobil Corp. will reduce operating costs and greenhouse gas emissions through installation of a cogeneration plant at its 305,000-b/d refinery in Antwerp (cover). The plant will generate 125 Mw and reduce Belgium's CO_2 emissions by 200,000 tonnes/year. Oil & Gas Journal's exclusive European Refining report, which begins on p. 18 and continues on p. 44, analyzes the outlook for European refiners that will need to adapt their strategies to maintain competitiveness as the global recession eases, especially as the International Energy Agency has warned of a possible tightening of oil supplies over the next few years. Photo from ExxonMobil.

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General Interest

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General Interest — Quick Takes

Bill would reverse oil shale program revision

US Rep. Doug Lamborn (R-Colo.) has introduced a bill to restore the Bush administration's oil shale programs and reverse US Interior Secretary Ken Salazar's revision of them.

Salazar announced Feb. 25 that DOI would offer another round of oil shale research, development, and demonstration (RD&D) leases in Colorado and Utah. He withdrew a proposal for expanded offerings.

An earlier oil shale RD&D lease solicitation was withdrawn because it contained several flaws, Salazar said.

On June 5, Lamborn introduced his bill, saying Salazar's actions bring uncertainty to future oil sands research.

"Investors will not commit millions, or potentially billions, of dollars to the research and development needed to make oil shale a viable energy source unless they have a clear picture of the financial rewards and challenges associated with such an investment," Lamborn said.

His bill directs Salazar to issue additional RD&D leases within 180 days of enactment using bids published on Jan. 15, effectively reversing the secretary's Feb. 25 action.

Lamborn's bill would make commercial oil shale regulation guidelines that DOI published in November permanent and apply them to all commercial leasing of federal oil shale holdings. It also would give the Interior secretary authority to provide incentives to producers by temporarily reducing royalties and fees.

"Oil shale could result in the addition of more than 1 trillion bbl of recoverable oil from lands in the western United States. This is too vital a resource to keep under lock and key," said Lamborn, ranking minority member of the House Natural Resources Committee's Energy and Mineral Resources Subcommittee. "Secretary Salazar is dragging his feet with one of America's most promising new energy sources. America needs to wean itself from foreign sources of energy once and for all."

Chevron exits Kenyan marketing business

Chevron Africa Holdings Ltd. has sold Chevron Kenya Ltd. to Total Outre Mer.

The initial sales agreement, announced in November 2008, was part of Chevron's strategy to streamline its downstream operations.

In April both parties also completed the sale of Chevron Uganda Ltd. Chevron Kenya and Chevron Uganda's assets include 165 Caltex-branded service stations, one terminal, seven fuel depots, six aviation facilities, one lubricants blending plant, and a commercial and industrial fuels business.

The values of the transactions were not disclosed.

Hamm interests take Hiland Partners private

Enid oilman Harold Hamm, his affiliates, and family trusts are acquiring the interest they don't already own in Hiland Partners LP and Hiland Holdings GP LP, Enid, Okla., which will become private entities.

Hamm proposed to take the businesses private on Jan. 15. Conflicts committees have recommended for the transactions, to be completed in the third quarter.

In the mergers, Hiland Partners unitholders will receive $7.75 for each common unit they hold, and Hiland Holdings unitholders will receive $2.40 for each common unit they hold.

Hiland Partners is a public midstream energy partnership that buys, gathers, compresses, dehydrates, treats, processes, and markets natural gas and fractionates and markets natural gas liquids. It also provides air compression and water injection services for use in oil and gas secondary recovery operations.

Highland Partners owns 15 Midcontinent and Rocky Mountain gathering systems totaling 2,138 miles of pipelines, six gas processing plants, seven treatment plants, three fractionation plants, two air compression facilities, and a water injection plant.

Hiland Holdings owns the 2% general partner interest, 2,321,471 common units and 3,060,000 subordinated units in Hiland Partners, and the incentive distribution rights of Hiland Partners. ✦

Exploration & Development — Quick Takes

Pioneer updates Texas, ANS drilling

Pioneer Natural Resources Co., Dallas, completed its first horizontal well in the Eagle Ford shale play.

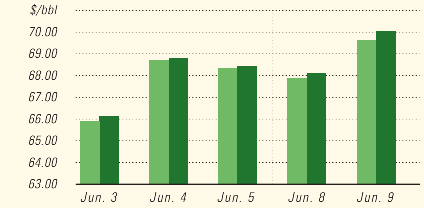
The Friedrichs Gas Unit No. 1 well, drilled in Dewitt County, Tex., initially flowed 3.7 MMcfd of gas equivalent, including 2.7 MMcfd of natural gas and 160 b/d of condensate, after partially completing only five stages of a planned eight-stage completion.

Mechanical problems in the original lateral required a sidetrack with a modified well path that reduced the well's exposure to the main reservoir section in the brittle shale at the base of the Eagle Ford formation. Pioneer estimates only two stages of the fracture stimulation, representing less than 500 ft of the 3,000-ft lateral, penetrated the brittle shale and are contributing to gas production.

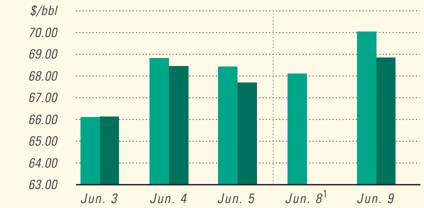
Scott Sheffield, Pioneer's chairman and chief executive, said, "We have drilled more than 150 wells through the Eagle Ford shale as we developed the deeper Edwards formation and recognize the potential that underlies our 310,000 gross acres in the play." The

Industry Scoreboard

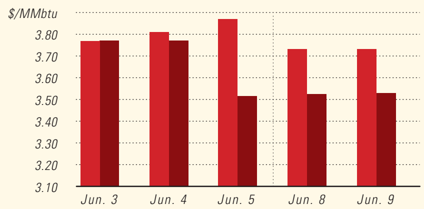
IPE BRENT / NYMEX LIGHT SWEET CRUDE



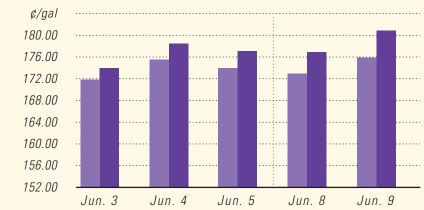
WTI CUSHING / BRENT SPOT



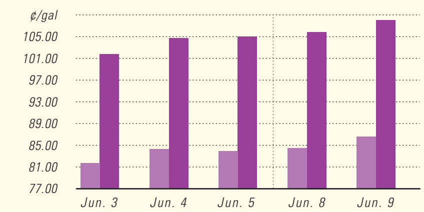
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



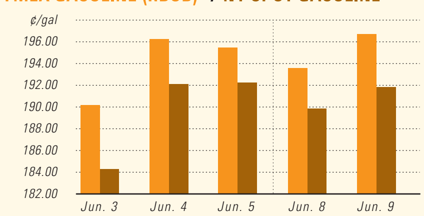
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

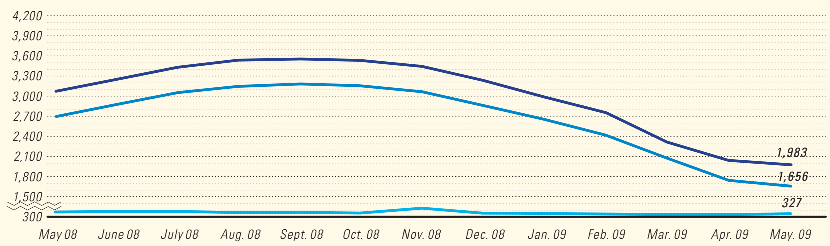
US INDUSTRY SCOREBOARD — 6/15

Latest week 5/29	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	9,175	9,216	–0.4	8,949	9,009	–0.7
Distillate	3,589	3,936	–8.8	3,795	4,131	–8.1
Jet fuel	1,381	1,564	–11.7	1,397	1,554	–10.1
Residual	416	661	–37.1	536	628	–14.6
Other products	3,646	4,352	–16.2	3,964	4,506	–12.0
TOTAL DEMAND	18,207	19,729	–7.7	18,641	19,828	–6.0
Supply, 1,000 b/d						
Crude production	5,345	5,166	3.5	5,320	5,134	3.6
NGL production[2]	1,848	2,444	–24.4	1,817	2,229	–18.5
Crude imports	8,981	9,624	–6.7	9,428	9,747	–3.3
Product imports	2,828	3,204	–11.7	3,008	3,193	–5.8
Other supply[3]	1,700	1,361	24.9	1,666	1,409	18.2
TOTAL SUPPLY	20,702	21,799	–5.0	21,239	21,712	–2.2
Refining, 1,000 b/d						
Crude runs to stills	14,306	15,800	–9.5	14,306	14,777	–3.2
Input to crude stills	14,646	15,629	–6.3	14,646	15,092	–3.0
% utilization	83.0	88.8	—	83.0	85.8	—

Latest week 5/29	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	365,977	363,111	2,866	306,757	59,220	19.3
Motor gasoline	203,202	203,417	–215	209,090	–5,888	–2.8
Distillate	150,036	148,375	1,661	111,704	38,332	34.3
Jet fuel–kerosine	41,373	40,449	924	39,751	1,622	4.1
Residual	40,132	38,468	1,664	38,166	1,966	5.2
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	25.2	25.0	0.8	20.1	25.4	
Motor gasoline	22.1	22.2	–0.5	22.5	–1.8	
Distillate	41.8	41.4	1.0	27.1	54.2	
Propane	59.2	58.5	1.2	40.9	44.7	
Futures prices[5] **6/5**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	68.10	64.32	3.78	128.46	–60.36	–47.0
Natural gas, $/MMbtu	3.96	3.72	0.25	11.72	–7.76	–66.2

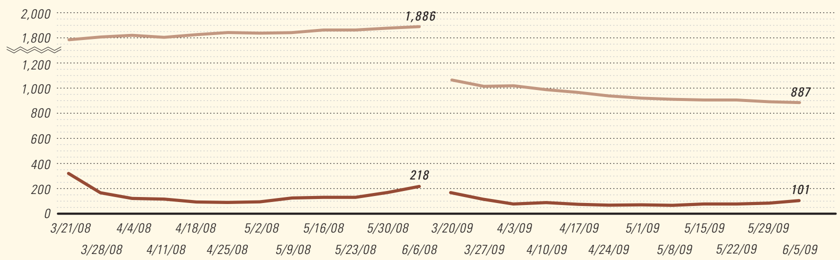
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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company plans to drill a second Eagle Ford well more than 40 miles southwest of the first location in the third quarter. Additional wells are planned to high grade that acreage, including another well in the Friedrichs area.

At Pioneer's Oooguruk project on Alaska's North Slope, operations are under way to drill four horizontal laterals in the Nuiqsut formation during the second and third quarters. Two will be fracture-stimulated producing wells, and two will be water-injection wells.

The first water-injection well was completed and is being produced temporarily to measure the unstimulated productive capability of the Nuiqsut formation. It was tested initially at 2,500 b/d of oil and was put on production at a stabilized 1,000 b/d.

Initial production exceeded expectations, Sheffield said. Pioneer's net production from Oooguruk was forecast to average 5,000 b/d in 2009, gradually increasing to 10,000-14,000 b/d in 2011 as development drilling continues. "Later this year, we will reevaluate our production profile to incorporate higher than expected performance from our Kuparuk wells, early waterflood results, and the performance of our planned fracture-stimulated Nuiqsut wells," Sheffield said.

Pioneer operates the Oooguruk project with 70% working interest, and Eni Petroleum US LLC holds a 30% working interest.

Repsol YPF consortium to explore off Falklands

A consortium led by Repsol YPF SA plans oil and gas exploration in international waters off the Falkland Islands beginning in early 2010.

Repsol YPF executives disclosed no project details. In 2006, Repsol and Energia Argentina SA (Enarsa) signed two agreements to explore and develop oil and gas off Argentina.

The first is a 10-year strategic agreement covering all areas 100% owned by Repsol or Enarsa off Argentina within three zones of interest from the Uruguay border to the Falkland Islands.

The second agreement establishes a consortium specifically to explore the Colorado Marina basin. Consortium members are Enarsa, Repsol, Petrobras, and Petrouruguay.

Repsol operates the area with 35% interest while Enarsa holds 35%, Petrobras 25%, and Petrouruguay 5%.

Argentina and Britain both claim large areas of the seabed around the islands.

Britain lodged a claim for 1.2 million sq km in May. Argentina filed a claim for the same area in April with the UN Commission on the Limits of the Continental Shelf.

British company Rockhopper Exploration PLC in May reclassified a 1998 North Falkland basin exploration well as a gas discovery with a 3.4 tcf mean contingent resource.

Shell Exploration & Production Southwest Atlantic BV drilled the 14/5-1A wildcat on the Sebald prospect to 4,525 m measured depth in 464 m of water (OGJ, Nov. 9, 1998, p. 44).

Africa Oil signs farmout for blocks

Africa Oil Corp. has announced a farmout agreement with East Africa Exploration Ltd. (EAE), a unit of Black Marlin Energy Ltd., for their entry into the production-sharing contracts in Ethiopia and Kenya.

In Ethiopia, Africa Oil said it will transfer a 30% license interest to EAE in Blocks 2/6 and 7/8, which both lie in what Africa Oil calls "the highly underexplored" Ogaden basin of southern Ethiopia.

In Kenya, Africa Oil will transfer a 20% license interest to EAE in prospective Block 10A, which is in northern Kenya's Anza basin.

In both cases, EAE will pay a disproportionate share of costs associated with the planned 2D seismic data programs to be carried out in 2009-10 as well as paying a portion of Africa Oil's past costs and future operational costs, Africa Oil said.

Africa Oil also said it has executed a seismic contract with Upstream Petroleum Services Ltd. to undertake the seismic acquisition in both Ethiopia and Kenya. Africa Oil remains operator of all blocks associated with the transaction.

The farmout transaction also is subject to approvals of the appropriate regulatory authorities from the governments of Ethiopia and Kenya, in addition to a waiver of preemptive rights by an existing partner in the Ethiopian licenses.

Centrica to buy 45% stake in Trinidad block

Centrica PLC will increase its position in Trinidadian LNG development by acquiring a 45% interest in gas development Block 5(c), off the southeast coast of Trinidad and Tobago.

The company agreed to pay $142.5 million cash to Canadian Superior Energy Inc. and will use the estimated 650 bcf of recoverable gas to supply customers in the UK, North America, or other Atlantic Basin markets from 2014. The block is close to existing gas pipeline infrastructure and LNG export facilities. The company's initial estimates of development capital expenditure attributable to its stake are £400 million.

Centrica will join BG Group, which operates the block with a 30% stake. "The agreement is subject to preemption rights from the existing field partners and subject to approvals from the Trinidad Government and Canadian courts," said Centrica.

So far BG has discovered significant contingent gas reserves, and the partners hope undrilled exploration opportunities could substantially increase the potential of the block. Centrica said its share of reserves is equivalent to half its current UK gas reserves.

Centrica Chief Executive Sam Laidlaw said, "Trinidad is one of the key export areas for Atlantic Basin LNG with substantial available reserves and infrastructure in place. Gas produced from this block could help address our long-term structural hedge position by reducing our exposure to volatile wholesale gas prices, offering a potential future gas supply option for our British Gas customers in the UK and for our Direct Energy customers in North America."

Centrica has an existing position in Trinidad and Tobago through an equity interest in Block 2(ab). ✦

Drilling & Production — *Quick Takes*

TransCanada unit sees 6.8 tcf from Montney

The Triassic Montney tight sand formation will provide the majority of the natural gas for the proposed Groundbirch gas pipeline in British Columbia and Alberta, TransCanada Corp.'s Nova Gas

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Transmission Ltd. told Canada's National Energy Board.

Of Groundbirch's projected throughput of 7.5 tcf, about 6.8 tcf would come from the Montney out of an estimated 40 tcf of marketable gas expected to be available from the formation, Nova said.

Conventional resources in the project drainage area would contribute the other 0.7 tcf. Nova noted that conventional gas production in the project drainage area comes from the Cadomin, Doig, Gething, Baldonnel, Halfway, Bluesky, and Charlie Lake formations above Montney and the Kiskatinaw below the Montney.

Construction on the 77-km, 36-in., 1.66 bcfd Groundbirch line is to start in the third quarter of 2010, and the expected service date is Nov. 1, 2010. The line is to run from Groundbirch, BC, to Gordondale, Alta., passing north of the Dawson Creek area.

Public estimates of original gas in place in the Triassic Montney tight sand formation in Northeast British Columbia range as high as 318 tcf, said Nova.

Nova said it used a 25% recovery factor compared with published estimates of 10% to more than 60% recovery from the Montney.

Nova projects flow on Groundbirch at 255 MMcfd in 2010-11 rising to more than 1 bcfd in 2015-16 and exceeding 1.4 bcfd by 2020-21 (OGJ Online, Feb. 27, 2009).

Dong E&P orders subsea production system

Dong E&P Norge AS awarded Aker Solutions a 350 million kroner engineering, procurement, and construction contract for a subsea production system for developing Oselvar field on Blocks 1/3 and 1/2 in the North Sea.

The production system includes a four-slot template with manifold, three subsea trees, control systems, subsea wellheads, and 28 km of steel-tube umbilicals.

Oselvar, discovered in 1991, is in the southwest part of the North Sea in about 70 m of water. Appraisal wells were drilled in 1995, 2007, and 2008.

The Norwegian Petroleum Directorate indicates that the field may recover 4.4 million cu m of oil and 4.8 billion cu m of gas. It says the field contains oil with a gradual transition to gas via a condensate phase. Depth of the reservoir is at 2,900-3,250 m.

Dong E&P plans to produce Oselvar with three subsea completed horizontal wells.

The subsea production system will tie back to the BP PLC-operated Ula platform on Block 7/12, about 23 km from Oselvar. Part of the gas from Oselvar will be used for injection in a water-alternating-gas scheme for enhancing oil recovery from Ula, and oil and the remaining gas will go via Ula to Ekofisk for further transport.

The contract is subject to the Norwegian government approval of the March development and operation plan for Oselvar.

Aker will manage the contract from its Oslo headquarters and manufacture most subsea equipment in its Norwegian facilities at Tranby, Moss, and Egersund. Aker Solutions is a subsidiary of Aker Subsea AS.

Aker expects to make final equipment deliveries in first quarter 2011; planned start of production is expected in fourth quarter 2011.

Operator Dong E&P holds a 40% interest in Production License 274 on Block 1/3. Partners in the license are Bayerngas Produksjon Norge 30%, Wintershall Norge ASA 15%, and Norwegian Energy Co. ASA 15%.

Dong E&P has an agreement to acquire Wintershall's interest in Oselvar.

Lacq field CCS project is France's first

Following 2 years of study and preparation, Total SA has received administrative authorization to start injecting carbon dioxide in France's first carbon capture and storage (CCS) pilot project.

Injection into the nearly depleted Rousse reservoir at Lacq gas field in southwestern France is to start in late June and last 2 years.

CO_2 will be captured from exhaust gases at one of five boilers at Lacq's steam generating plant converted to an oxyfuel combustion unit, then compressed and sent via a 27-km pipeline for injection into the Rousse at a depth of 4,500 m.

The pilot plant will produce some 40 tonnes/hr of steam, which will be used by industries in the Lacq complex. It will emit 120,000 tonnes of CO_2 in 2 years.

The Rousse reservoir, a carbonate formation, will be closely monitored through detectors set throughout the surface and subsoil to measure the injection flow and the CO_2 pressure, temperature, and concentration.

The €60 million pilot is being carried out in cooperation with Institut Francais du Petrole and Bureau de Recherche Geologique et Miniere (Mining and Geological Research Office).

Its purpose is threefold: to better master the oxyfuel combustion process, namely for applications in the production of extra-heavy oils; to halve the cost of carbon capture compared with existing processes; and to develop monitoring tools, techniques, and methods to establish that long-term and large-scale geological CO_2 storage is viable. ✦

Processing — *Quick Takes*

Valero halts two US hydrocracker projects

Valero Energy Corp. has suspended plans to add hydrocrackers at two US refineries, citing its agreement to acquire a major refining interest in the Netherlands.

Valero Chairman and Chief Executive Officer Bill Klesse said the company is "indefinitely postponing our major new hydrocracker projects at St. Charles and Port Arthur."

At the 250,000-b/d Port Arthur, Tex., refinery, Valero had planned to add a 50,000-b/d hydrocracker at an estimated cost of $1.7 billion. The project was expected to add as much as 75,000 b/d of distillation capacity through debottlenecking.

In a $1.25-billion project at the 310,000-b/d St. Charles, La., refinery, Valero planned a new 50,000-b/d hydrocracker.

It had earlier announced delays in both hydrocracker projects.

Klesse linked the postponements to Valero's recent agreement to acquire Dow Chemical Co.'s 45% interest in Total Raffinaderij Nederland NV (TRN) for $752 million (OGJ Online, May 26, 2009). TRN owns a 190,000-b/d refinery in Vlissingen with 68,000 b/d of hydrocracking capacity.

"In the current environment, it makes more sense to acquire existing capacity at a substantial discount to new construction costs," he said.

In the TRN deal, Klesse said, "we believe the purchase price is less than 50% of replacement cost for this world-class distillate hydrocracking facility."

In March, Valero won a bid to buy five ethanol plans plus one under development from bankrupt VeraSun Energy Corp. at a price it estimated to be 30% of replacement cost. It agreed to pay $477 million for total ethanol production capacity of 780 million gal/year.

Shell sells gasoline blended with cellulosic ethanol

Royal Dutch Shell PLC on June 10 launched a month-long demonstration selling gasoline blended with 10% cellulosic ethanol at a Shell service station in Ottawa, Ont.

The cellulosic ethanol, made from wheat straw, was produced at Iogen Energy Corp.'s demonstration plant in Ottawa using advanced conversion processes. Iogen and Shell are partners in the plant, which produces 40,000 l./month of fuel.

The demonstration is part of Shell's strategic investment and development program in sustainable biofuels.

Graeme Sweeney, Shell executive vice-president future fuels, said this demonstration is an indication of what is possible in the future.

"While it will be some time before general customers can buy this product at local service stations, we are working with governments to make large-scale production economic," Sweeney said.

Brian Foody, Iogen Corp. chief executive officer, said, "Building a demo plant is one thing but you then need to go through the process of operating the new technology at scale, learning, modifying and lowering costs."

Iogen, a biotechnology firm, has produced cellulosic ethanol at its Ottawa demonstration plant since 2004.

Shell also is working with German company Choren to launch a new biofuels plant that will convert biomass, such as woodchips, into synthetic fuel, which is then being marketed by Choren as SunFuel.

The fuel is being used in diesel engines and can reduce emissions. The 15,000 tonne/year plant uses waste plant material. Shell earlier signed a letter of intent with Volkswagen and Iogen to assess the economic feasibility of producing cellulose ethanol in Germany.

Texas suing BP Texas City refinery

The Texas Attorney General's Office is suing BP Products North America Inc. for 46 pollution violations at its Texas City, Tex., refinery, the site of a 2005 explosion that killed 15 workers and injured 170 others.

On June 4, Texas Attorney General Greg Abbott said BP did not report emissions to regulators by certain deadlines. Abbott's office filed a hearing for an injunction requiring BP to install additional air monitors.

A June 29 hearing is scheduled in state district court in Austin, where the lawsuit was filed on May 22. It claims BP improperly released volatile organic compounds, carbon monoxide, hydrogen sulfide, and nitrogen oxides.

"BP Products is charged with polluting our environment, concealing information from authorities and harming Texans," Abbot said. "In recent years, more than 45 unlawful pollutant emissions occurred at BP's Texas City facility. This enforcement action holds BP accountable for failing to comply with environmental, health and safety laws that are intended to protect Texans from harm."

In response, BP said it had no comment on the lawsuit. But BP spokesmen in the past have said the company is working to reduce the number of emissions events at the Texas City refinery. ✦

Transportation — *Quick Takes*

ConocoPhillips VLCC leaves Orkneys for Chile

A very large crude carrier (VLCC), after spending 3 months as a floating storage unit, sailed from the Scapa Flow in Scotland's Orkney Islands bound for Chile with a load of North Sea Ekofisk crude.

The Orkney Islands Council Department of Harbours said the Malaysian-registered Bunga Kasturi Dua, carrying 2 million bbl of crude oil, anchored in Scapa Flow on Feb. 14, chartered by ConocoPhillips.

The departure of the VLCC "leaves the Abqaiq and the Maersk Neptune still at anchor in Scapa Flow, storing between them just under 4 million bbl of Forties Crude," the council said.

In May, the council said that a recent ship-to-ship transfer between the Leander and the Front Shanghai, which saw 2 million bbl of crude transferred, brought the total amount of oil transferred this year to just more than 10 million bbl.

Oil stored in Scapa Flow is part of 20 million bbl of North Sea oil currently stored in Europe on supertankers, creating a readily available source of supply that has helped keep a lid on North Sea crude benchmark prices (OGJ, Mar. 2, 2009).

Peru fertilizer plant would need gas line

A grassroots nitrogen fertilizer complex under consideration in Peru would require construction of about 100 miles of gas pipeline.

CF Industries, Deerfield, Ill., has let a lump-sum contract to Technip of Paris for front-end engineering design of the complex, proposed to be built near the coastal city of San Juan de Marcona.

The complex, Peru's first major nitrogen fertilizer facility, would use natural gas from Camisea area fields about 300 miles northeast.

The contract covers a 2,600-ton/day ammonia unit, a 3,850-ton/day urea synthesis plant, a 3,850-ton/day urea granulation unit, and utility and offsite facilities.

Work is to be complete by yearend, after which a decision will be made whether to proceed.

The plant would require a link to a pipeline that carries Camisea gas to fractionation facilities in Pisco, south of the site of a liquefaction plant under construction by the Peru LNG consortium (OGJ Online, Jan. 30, 2009). ✦


The bottom of the barrel: on the road or in the tank?
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Calendar

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2009

JUNE

ASME Turbo Expo, Orlando, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-17.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Santa Fe, NM, (713) 286-5930, (713) 265-8812 (fax), website: www.spee.org. 14-16.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 15.

IPAA Midyear Meeting, Dana Point, Calif., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 15-17.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16.

Atlantic Canada Petroleum Show, St. John's, Newfoundland & Labrador, 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 16-17.

IADC World Drilling Conference & Exhibition, Dublin, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17-18.

PIRA Understanding Global Oil Markets Seminar, London, 44 1493 751 316, e-mail: miles@pira.com, website: www.pira.com. 17-18.

AAPL Annual Meeting, Clearwater Beach, Fla., (817) 847-7700, (817) 847-7704 (fax). e-mail: aapl@landman.org, website: www.landman.org. 17-20.

IAEE International Conference, San Francisco, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 21-24.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 21-24.

SPWLA Annual Symposium, The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 21-24.

International Offshore and Polar Engineering Conference (ISOPE), Osaka, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 21-26.

Asia LPG Seminar, Singapore, (713) 331-4000. (713) 236-8490 (fax), website: www.purvingertz.com. 22-25.

API Exploration & Production Standards Oilfield Equipment and Materials Conference, Westminister, Colo., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

The Global LNG Congress, Istanbul, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.

theenergyexchange.co.uk. 23-25.

Moscow International Oil & Gas Exhibition (MIOGE) & Russian Petroleum & Gas Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 23-26.

Pipeline Integrity Management Seminar, Calgary, Alta., (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org/conferences/pims2009/index.asp. 24-25.

✦Annual Mid-year Forecast Event, Tulsa, (877) 715-1917, e-mail: info@energyadvocates.org, website: www.energyadvocates.org. 25.

✦American Society of Safety Engineers Professional Development Conference & Exposition, San Antonio, (847) 699-2929, e-mail: customerservice@asse.org, website: www.safety2009.org. June 28-July 1.

JULY

Rocky Mountain Energy Epicenter Conference, Denver, (303) 228-8000, e-mail: conference@epicenter2008.org, website: www.denverconvention.com. 7-9.

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE 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. 4-6.

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

Petroleum Association of Wyoming (PAW) Annual Meeting, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: suz@pawyo.org, website: www.pawyo.org. 18-19.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

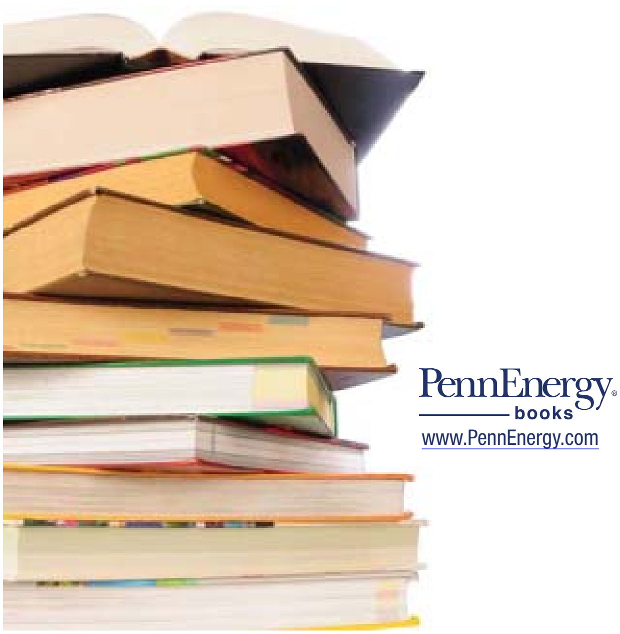
Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

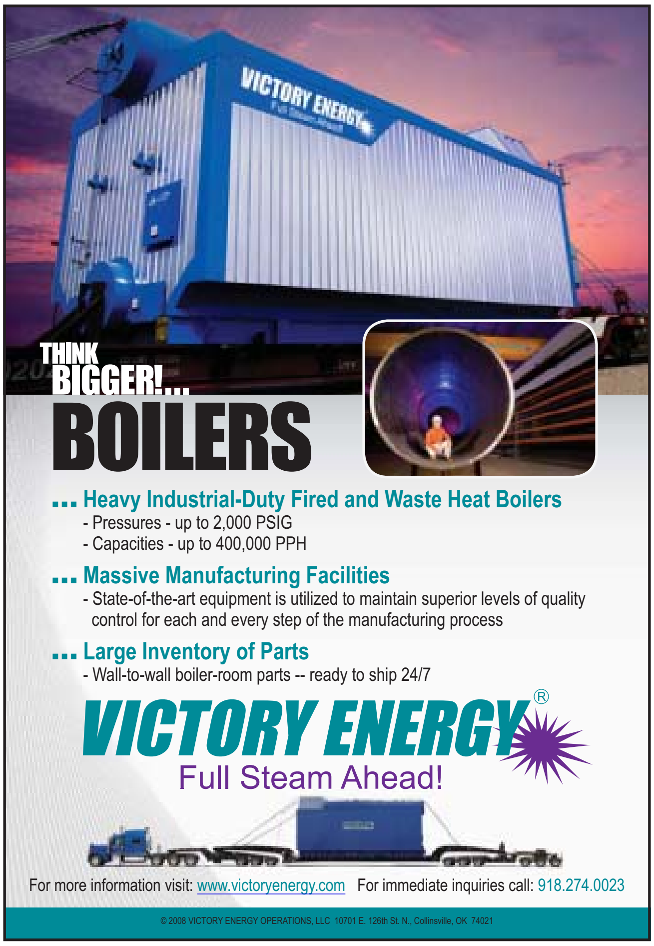
EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.





Journally Speaking

‘No regret’ warming solutions

Sam Fletcher
Senior Writer

Global warming is a reality, but many proposed solutions would be “much more costly to society than the danger it seeks to avert,” according to a June report by National Center for Policy Analysis (NCPA), a conservative Washington, DC, think-tank.

“The world will surely regret it if billions of people are mired in poverty because resources are diverted to solve a nonexistent or trivial problem. On the other hand, the world would regret doing nothing if human-made global warming is a serious problem,” said the report authored by Iain Murray with the Competitive Enterprise Institute and NCPA Senior Fellow H. Sterling Burnett.

They suggest “no regrets” programs “that would prove beneficial whether or not human activities are creating a global warming problem” without “sacrificing living standards.” This includes elimination of all subsidies for fuel use since these encourage greater consumption and raise emission levels. The International Energy Agency estimates developing countries spend $220 billion/year on subsidies for energy production and consumption, including $170 billion subsidizing fossil fuels. Even the push by US legislators to hold down consumer costs and punish oil companies for price increases only encourages greater consumption of depleting resources.

Moreover, the report said, government subsidies for energy research and development cost millions but produce minimal benefits and often are allocated “on the basis of political favoritism.” The report said, “The Congressional Budget Office and other analysts note that federal R&D money rarely produces commercially viable technologies.”

Instead, NCPA favors an “X” prize competition that rewards successful independent research—something like the government and private competitions that encouraged early development of the automobile and the airplane.

The center does favor subsidies to remove older, more-polluting cars from the road by replacing them with newer models. Auto manufacturers support this, but collectors of antique cars worry whether it might eliminate classic car rallies.

Drop flood insurance

Another likely controversial proposal is to repeal the US National Flood Insurance Program. NCPA said, “Subsidized flood insurance is responsible for much of the development in coastal areas and in flood plains. Eliminating this subsidy would make us less vulnerable to higher sea levels and increased rainfall.”

The report said, “This 41-year-old program has arguably outgrown its original purpose, which was to provide temporary flood insurance to property owners who were unaware they were in flood-prone areas. Because of full-disclosure mortgage and insurance requirements, nearly all current owners were aware of their area’s flood problems when they purchased or developed their properties. Today, federally subsidized flood insurance encourages people to build homes where they otherwise would not. It encourages lenders to finance mortgages they otherwise would not.” This encourages high-risk development and harms environmentally sensitive areas, including wetlands, floodplains, and coastal marshes.

Congestion pricing

NCPA recommends the establishment of more toll roads with “congestion pricing” rates of higher fees during peak hours and lower fees during off-peak times. “Congestion increases travel time, worsens air pollution, increases carbon dioxide emissions, and wastes fuel. According to the Texas Transportation Institute, based on wasted time and fuel, congestion in 437 urban areas cost the nation about $78.2 billion in 2005,” it reported. However, other surveys have shown motorist resistance to congestion pricing or anything else that would raise the cost of automobile travel.

The center favors reform of air traffic control systems to allow pilots to fly more direct routes and avoid lengthy holding patterns and runway delays so aircraft would save fuel and reduce emissions. “The current government-operated air traffic control system, based on a 1930s-era network of radio beacons, hinders innovations that could reduce fuel use and emissions. Specifically, allowing pilots to fly more direct routes between destinations—so-called ‘free flight’—could save substantial amounts of fuel and reduce aircraft emissions by as much as 17%,” according to the report.

Meanwhile, it said, “Barring changes in existing air travel regulations, the imposition of taxes or regulatory controls to meet 1990 emission levels could make it virtually impossible for US airlines to meet the increasing demand for air travel. The Air Transport Association estimates that reducing emissions to 1990 levels would result in a 25-35% reduction in air services.”

The report also favors reduction of regulatory barriers to greater use of nuclear power, reduction of wildfires through alternative forest management institutions, and the use of biotechnology to develop faster-growing trees that can absorb and store large amounts of carbon dioxide.

E d i t o r i a l

Where feds shouldn't stray

For the push to impose federal regulation of hydraulic fracturing, three possible motivations exist:

• The practice exposes subsurface sources of drinking water to risk and therefore should be regulated.

• An exemption from federal regulation of hydraulic fracing became law during the administration of former President George W. Bush and therefore must be presumed environmentally deficient.

• Hydraulic fracing is essential to unconventional gas resources and therefore should be resisted for its power to extend domestic supplies—and therefore use—of hydrocarbon energy.

Even as it fights political assaults on many other fronts, the US oil and gas producers must fight the developing siege on all three levels.

Limited comprehension

The first motivation is sound in its core assertion but limited in its comprehension. Education should represent sufficient response.

Hydraulic fracing does expose groundwater to risk. Politicians and their constituents just learning of the practice can find it alarming that producers pump slurries underground via wells penetrating freshwater aquifers. When they learn about proliferation of the method related to expansion of unconventional gas plays, they submit easily to fearmongering, such as that of Rep. Diana DeGette (D-Colo.).

"This is a very serious issue," she said recently after disclosing that she and Maurice Hinchey (D-NY) would introduce a bill repealing hydraulic fracing's exemption from the federal Safe Drinking Water Act. "If it is not addressed, large numbers of people are very likely to suffer. Their houses will no longer be livable."

In the absence of regulation, she might be right. What she fails to tell the people she hopes to frighten is that no such regulatory deficiency looms. State and local governments regulate injection of frac and drilling fluids. They apparently do so well. In more than half a century of underground fluid injection, no major contamination of drinking water has occurred.

In 2004, the Environmental Protection Agency published results of a comprehensive study of underground injection of frac fluids into coalbed methane wells, concluding that the practice "poses minimal threat to [underground sources of drinking water]." Earlier this year, the Interstate Oil & Gas Compact Commission, comprising state regulators, passed a resolution supporting the exemption of hydraulic fracing from federal regulation.

In 2002, IOGCC surveyed member states and found no report of groundwater damage due to hydraulic fracing. In its resolution this year, IOGCC asserted that close to 1 million wells have been hydraulically fraced in the US since the method went into use more than 50 years ago "with no known harm to groundwater." And last month, the Groundwater Protection Council reported findings of a study, funded by the Department of Energy, that found state regulation "are adequately designed to directly protect water resources."

To anyone concerned only about the safety of drinking water, facts about the regulation and safety record of hydraulic fracing should quell pressure to add a federal layer of regulation. The move would be unnecessary and wasteful. But those other motives are at work.

It's deceitful to smear hydraulic fracing's exemption from federal regulation as a Bush environmental lapse. The exemption took effect in the Energy Policy Act of 2005, which was hailed by both major political parties as a triumph of bipartisanship. Since passage of the Safe Drinking Water Act in 1974, the government never has seen the need to apply the law to already-regulated hydraulic fracing. Indeed, the study EPA reported in 2004 began not during Bush's term in office but during that of his Democratic predecessor.

Raising cost

Federal regulation of hydraulic fracing would add unnecessary cost to drilling—the American Petroleum Institute estimates it at as much as $100,000/well. And it would give drilling opponents another set of legal and administrative opportunities to impede drilling.

Cost elevation and bureaucratic obstructionism serve the interests only of those Americans who want to abolish oil and gas in all its dimensions, in every way possible, and at any cost. Most Americans know those wishes are irrational and unbearably expensive.

Most Americans also recognize the dangers of misguided regulation. Federal regulation of hydraulic fracing would be precisely that. ✦

European refiners challenged during declining gasoline, diesel markets

Uchenna Izundu
International Editor

The past year has been a challenging one for the European refining industry, particularly because of the drastic fluctuations of world oil prices. After peaking at nearly $150/bbl in July 2008, oil prices have fallen to a current level of $60-70/bbl. Refiners had very good margins where capacity and balances for gasoline and diesel were rather tight at particular points last year. Now falling margins for fuel producers, high operating costs, falling demand, and a supply glut in new capacity are major problems. A string of upgrades and conversion projects have been postponed or canceled in light of the global recession and the tightening of credit availability (Fig. 1).

Image from Shell

The global slowdown has impacted European oil product demand, which contracted by 0.3% year-on-year in March, according to the International Energy Agency's Oil Market Report published in May.

Speaking June 8 at an industry conference in Kuala Lumpur, Jeroen van der Veer, chief executive officer of Royal Dutch Shell PLC, said he believes that the Western gasoline and diesel markets are stabilizing after the slump late last year. "In the US and Europe, the gasoline and diesel markets collapsed in the fourth quarter. We see signs of stabilization but it's [still in the] very early days. It could be due to seasonal factors or destocking; we hope that we see the signs correctly, it would be good news if it stays like that."

Depressed outlook

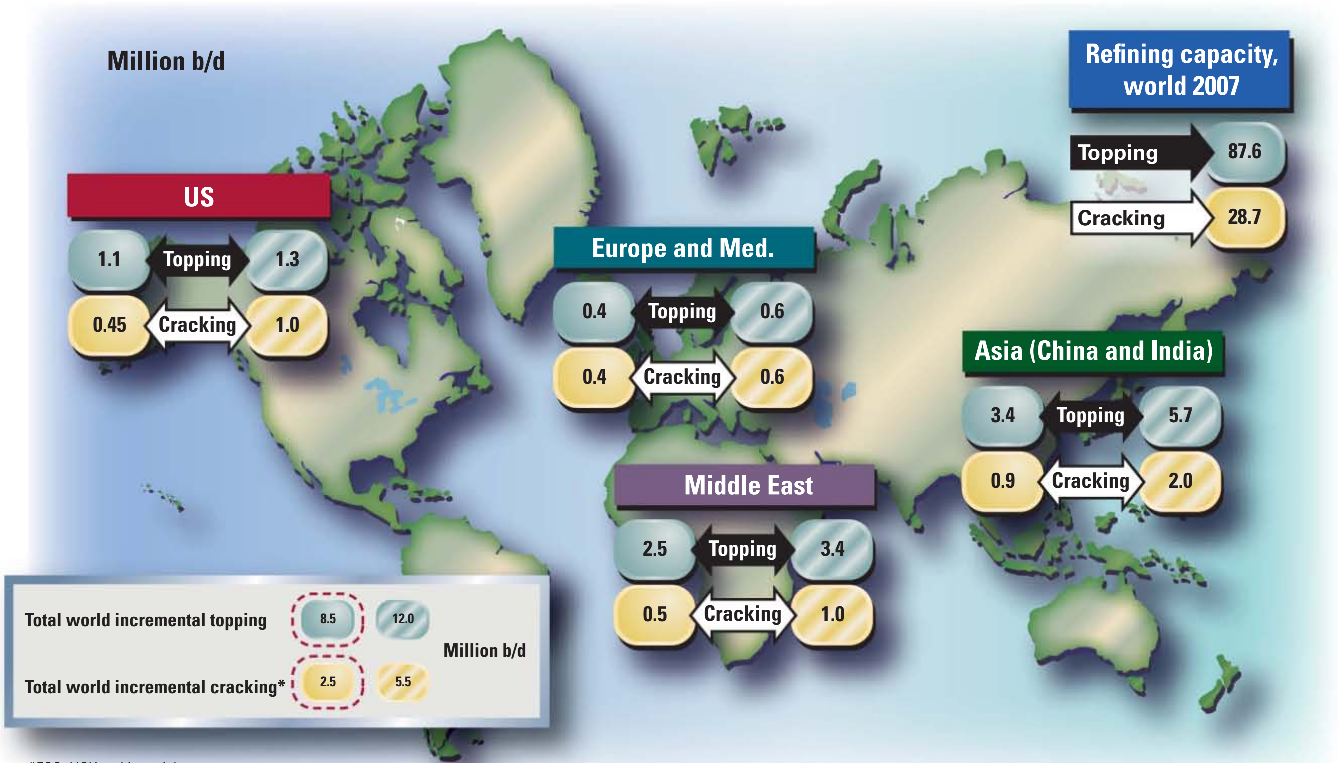
European refiners have been subdued in presenting their recent financial results as well as their forecasts for 2009. OMV AG, with refineries in central and southeast Europe, identified its challenges as being lower oil prices, weakening refining margins, and depressed demand.

Matti Lievonen, president and chief executive officer of Neste Oil Corp., which has refineries in Finland, said, "We have seen the largest drop in demand in the diesel market, which is very much tied to industrial activity and logistics."

Neste Oil has postponed construction of an isomerization unit at its Porvoo, Finland, refinery because of weaker demand for petroleum products. Instead, Neste Oil will concentrate on building NExBTL renewable diesel capacity in Singapore and Rotterdam and a base oil plant in Bahrain. The planned

WORLDWIDE INCREMENTAL TOPPING, CRACKING CAPACITIES

Fig. 1



*FCC, HCK, coking, visb.
Note: Figures on left refer to projects expected to be realized before 2015. Figures on right refer to projects announced with probability to be realized after 2015 and before 2020.
Source: Eni estimates on Parpinelli, WM, PFC, LB, P&G da

€80 million isom unit, first announced in 2008 and due for completion in 2011, was to have the capacity to process 600,000 tonnes/year of existing gasoline fractions into premium gasoline and increase the refinery's total gasoline output by 200,000 tonnes/year.

Thomas D. O'Malley, Petroplus Holding AG's chairman, stated, "We expect gasoline to be under the greatest downward pressure during this period. The middle distillate crack spread has maintained its strength, but depending on the length and severity of the global recession, it could come under pressure." O'Malley also views this downturn as a potential opportunity to pick up cheap refineries.

While presenting Total SA's yearend 2008 results, Chief Executive Officer Christophe de Margerie said the refining market faced the continuing gasoline-diesel imbalance in the Atlantic markets. The fall in US gasoline demand would impact Europe's gasoline exports, and there is a great need to reduce refinery capacity to balance product supply with consumer demand (OGJ Online, Feb. 13, 2009) (Fig. 2).

Mike Wilcox, head of global downstream oil consulting at Wood Mackenzie Ltd., told OGJ, "The recession coincided with a surge of capacity on the market. So, with demand falling, we believe that there were will be a global mismatch of around 7 million b/d of demand and refining capacity over the next 2-3 years, and how the market will react will vary by region. In Europe, we expect margins this year to be significantly lower than 2007 and 2008. The last downturn was in 2002, and the fundamentals look worse now than then; oil prices, however, are higher this time round than in that period."

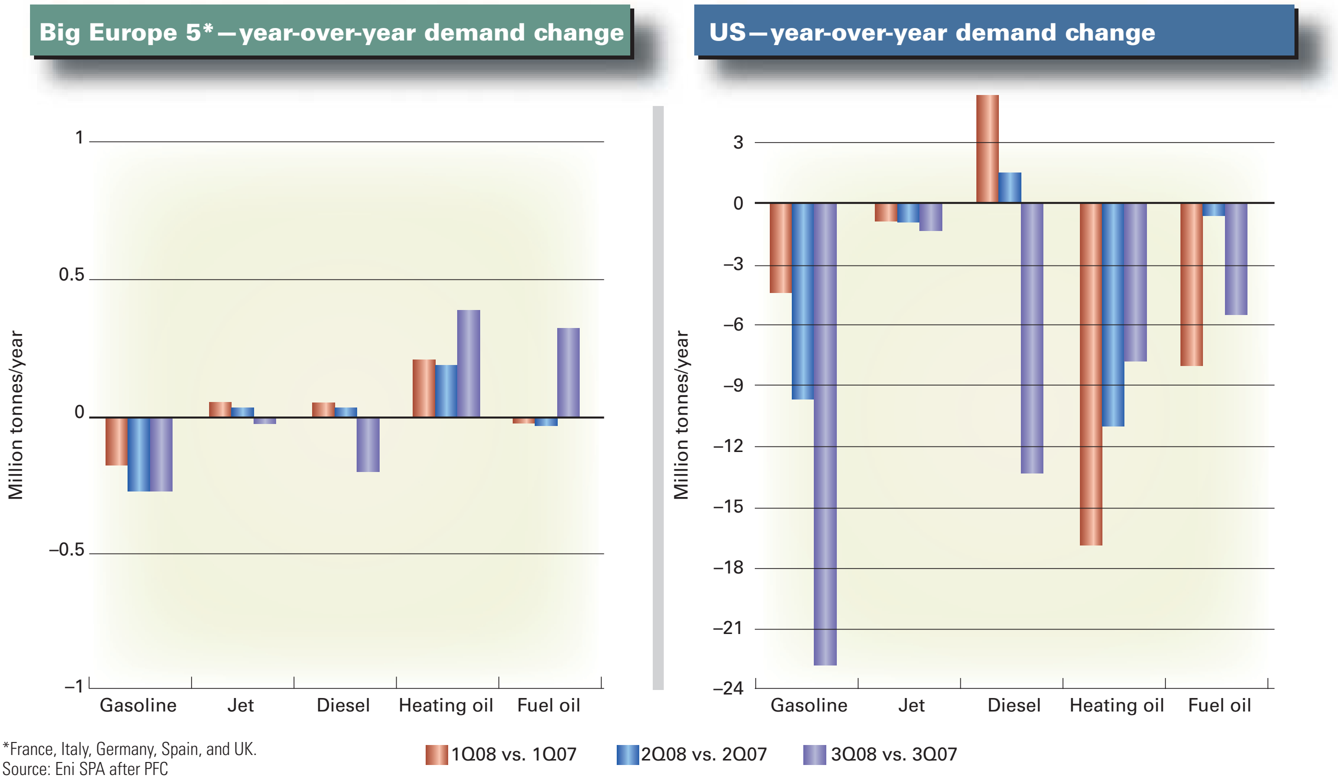
Energy efficiency

Despite these pressures on refiners, ExxonMobil Corp. has continued to invest in energy efficiency, taking a long-term view of the cyclical nature of the industry, said Darren Woods, ExxonMobil head of refineries in Europe, the Middle East, and Africa. Speaking at the inauguration of the company's 125-Mw cogeneration plant at its 305,000 b/d refinery in Antwerp, Belgium, he said, "We always work on the basis that there will be periods when margins are low. We make sure that we capture falling costs through our the procurement process."

The company's Antwerp facility, which is Europe's second-largest refinery, will be 12% more efficient because of this investment. ExxonMobil has specifically adapted the cogeneration plant for its needs: As well as generating steam, the plant uses a heat-recovery system to utilize heat created in the gas-turbine exhaust to warm crude oil. With this 4-year project that cost more than €100 million, ExxonMobil had to construct the heat-recovery unit on top of the gas turbine to which it is connected rather than next to it because space is so tight at the site.

Fuel demand trends in Europe, US

Fig. 2



*France, Italy, Germany, Spain, and UK.
Source: Eni SPA after PFC

Although the cogeneration unit produces enough power to satisfy the refinery's requirements, ExxonMobil still imports power for the refinery from the national grid. The company said the expected reliability of a single-gas turbine is less than that of the national grid. The cogen plant also will reduce Belgium's carbon dioxide emissions by about 200,000 tpy, equivalent to removing roughly 90,000 cars from Europe's roads.

"Energy efficiency is one of the most effective tools available for reducing greenhouse gas emissions," said Sherman Glass, ExxonMobil president of refining and supply. "Since 2004, ExxonMobil has invested in over 1,500 Mw of cogeneration capacity in five countries," he said.

With energy costs comprising as much as half of a refinery's costs, the need for energy efficiency is imperative, said Richard Henderson, technical, director at the Antwerp refinery. Net operating costs also will fall because of the cogeneration unit starting up, Henderson said. "The cogeneration plant is a long-term investment that will last for a minimum of 20-25 years. It will provide Antwerp with a competitive advantage well into the future relative to alternate configurations. This is very efficient compared with a conventional stand-alone power station to run the refinery," he said.

Gilbert Asselman, manager of the Antwerp refinery, said, "With the latest technology, cogeneration is significantly more efficient than traditional methods of producing steam and power separately."

According to the company's analysis, oil products growth will average 1%/year during 2005-30 with diesel demand driving most of this growth. Gasoline demand will slow due to the increase of biofuels, the company said. "ExxonMobil wants to grow its diesel pool, and we're working on tuning our operations to do this," said ExxonMobil's Woods.

In 2010, ExxonMobil also plans to start up its high-pressure hydrotreater at Antwerp, which will help increase the refinery's output of low-sulfur diesel, a large amount of which will be exported.

Tighter fuel standards

According to Europia, the trade association representing European refiners, more than $8 billion/year is invested in their operations. The cost of investing over the long term is rising because of the legislation to cut sulfur levels in refined products—particularly in gasoline and diesel—as governments and policymakers are increasingly concerned about the environment.

Producing fuels from lower-quality crude is another issue that refiners are grappling with. If oil prices rise in the next few years, as they did in 2008, refiners are more likely to process less-expensive, higher-sulfur content crudes.

Neste Oil, for example, has turned its attention to developing a €670 mil-

Snapshot of Europe's refinery upgrades, modernization plans

Below are some operators' plans to upgrade or expand their refining operations in Europe in 2009-12. This is not intended to be a comprehensive list.

Total SA

As the largest refiner in western Europe, Total operates 11 refineries and also holds interests in the Schwedt, refinery in Germany and in four refineries in Spain. It has dedicated nearly €1.6 billion/year during 2009-13 to address the diesel shortage in Europe, tighter fuel specifications, and a rise in supplying high-sulfur crudes. In 2015, diesel production by Total's European refineries will be up 13 million tonnes over 2005, representing a 50% increase.

Work at Total's 200,000-b/d Lindsay, UK, refinery includes:

- Installation by yearend of a 1 million tonne/year hydrodesulfurization unit (HDS) and a steam methane reformer to increase the processing of high-sulfur crudes to 70% from 10% and boost low-sulfur diesel production. Both the HDS unit and steam methane reformer will cost €300 million.

Work was suspended in February for more than a week following a strike by employees because the subcontractor, Irem SPA, had employed foreign labor for jobs instead of locals (OGJ Online, Feb. 2, 2009). Another sympathy strike happened last month in support of laggers at the Milford Haven LNG terminal who complained that they had lost out to foreign contractors for an insulation project (OGJ Online, May 21, 2009).

Work at Total's 229,834-b/d Leuna, Germany, refinery includes:

- The installation of a 1 million tpy hydrodesulfurization unit, which will produce ultralow-sulfur heating oil, at a cost of €120 million. Work on the HDS is set to finish in the summer, with the facility due to come on stream in the fall, a Total spokesman told OGJ. The unit will be capable of producing kerosine with a sulfur content of 1 ppm and light diesel with a sulfur content of 5 ppm.

Leuna is one of the most efficient refineries in Europe and can process sour crude oil without producing heavy fuel oil.

Meanwhile, Total will invest €770 million during 2009-12 for the reconfiguation of its 339,000-b/d Normandy, France refinery following consultation with employee representatives. About 249 jobs will be shed by 2013, Total said, adding that it will focus on internal placement. "The employee consultation should be over by the end of June," a Total spokesman said.

Capacity at its Normandy refinery will be cut to 12 million tpy from 16 million tpy. Annual average diesel production will increase by 10% and surplus gasoline output will drop by 60%.

Hellenic Petroleum SA

Work at Hellenic Petroleum SA's 66,500-b/d Thessaloniki, Greece, refinery includes:

- An upgrade, by 2010, with the addition of a new 15,000-b/sd continuous catalytic reformer, the modification of the existing atmospheric distillation unit, and the revamp of the existing naphtha hydrofiner.
- The upgrade of a crude light ends processing unit to process 26,000 b/sd.

Foster Wheeler Ltd. was awarded engineering, procurement, and construction management contracts in 2008 for the work. A company spokeswoman told OGJ, "Progress achieved is around 60% and activities are still on track to complete the work by end 2010."

Petrom SA

Work on Petrom SA's 69,280-b/d Petrobrazi, Romania, refinery includes:

- A modernization program that has been delayed to 2012 from 2010 because of the challenging economic environment.
- The spending of €1.5 billion to boost capacity to 6 million tpy from 4.5 million tpy.
- Commissioning in April of a €90 million, 700,000 tpy FCC gasoline post-treater that will produce EUR V gasoline.

There were difficulties revamping this refinery and the nearby Arpechim refinery because they were in worse condition than expected, demanded complicated programs, and suffered a tight market for supplies.

lion renewable diesel plant in the Port of Rotterdam, which will have production capacity of 800,000 tpy and start operations in 2011. "This would be a major step forward to reaching the [European Union's] 10% renewable fuels target in transport. NExBTL, Neste Oil's proprietary technology, is the innovation behind the world's cleanest and most advanced renewable diesel," Neste Oil said.

The Fuel Quality Directive Review (FQDR), which stated that road fuels must reduce greenhouse gas emissions by 10%, was meant to be implemented in 2005. However, FQDR has been delayed due to a number of revisions, including the respecification of fuel-quality parameters on health and environmental grounds to include GHG-affecting climate change. There also is contention regarding how FQDR would interact with existing or planned legislation that addresses carbon dioxide emission reductions, as well as boosting the use of biofuels and other renewables.

Europia said, "This concept was not part of the stakeholder consultation process and, as a result, suffered from the absence of necessary data and tools to assess its viability." It has rejected the figure as unrealistic as it doesn't believe that 16% (on energy basis) of biofuels needed to meet the GHG emissions reduction targets is attainable. Europia wants to see a methodology for GHG emissions calculation as well as a biofuels sustainability certification scheme. Furthermore, the double regulation of European refineries and oil platforms with respect to the EU Emissions Trading Scheme has not been considered.

Refineries for sale

Other companies would prefer to sell their refineries during this downturn, but they face a dilemma in doing so. Daunting questions remain: Do they embark on the expensive program of shutting down their refineries or do they run them at a loss, while faced with steep environmental clean-up costs?

In February, Italy's Eni SPA said it would seek buyers for its 84,000 b/d Livorno refinery on the Tuscan coast of northern Italy because of diminishing global oil demand, increasing energy efficiency, and the growth of biofuels (OGJ Online, Feb. 16, 2009). Twelve bids have been submitted so far and Eni is expected to reach a decision by the end of June.

Petroplus Holdings AG would like to dispose of its 117,000 b/d Teesside, UK, refinery, or perhaps convert it by yearend into an import terminal, which it may then sell. Petroplus has already shut the facility that processes Ekofisk crude and supplies about 17% of the UK's diesel.

Shell wants to divest its 93,000 b/d Hamburg and 83,000 b/d Heide refineries in Germany as part of its portfolio management. A spokesman declined to comment on the update of this sales process.

WoodMac's Wilcox said the deals will likely be completed for the better of the refinery assets now on offer. The valuation of refineries in 2007-08 compared with the pre-boom in 2003-04 has gone up by a factor of 3, he said.

Wilcox said the market turmoil means difficult times for refiners. "European refiners need to focus on their local position as much as possible to make the best of them because the international market is going to be very difficult, particularly given the need to 'push' gasoline into North America," he said.

"For the long-term outlook, there is overcapacity in the European refining industry. We expect middle distillates and diesel to grow and become tight again. We expect there to be more crude refining capacity than crude runnings and so utilization rates will be lower," he said, adding, "Refiners need to find a way of competing." ✦

APPEA: Pluto, Wheatstone fields to be developed separately

Rick Wilkinson
OGJ Correspondent

Woodside Petroleum Ltd. and Chevron Australia Pty. Ltd. are likely to develop their respective Pluto and Wheatstone gas field-LNG projects as separate entities and compete for third-party gas, company officials indicated at the recent Australian Petroleum Production & Exploration Association conference in Darwin.

Woodside Chief Executive Officer Don Voelte called for rival LNG projects to share production hubs on the Western Australian coast. Woodside's $12 billion (Aus.) Pluto LNG project on the Burrup Peninsula near Dampier has nearly completed construction of its first LNG train and is looking for more gas to support construction of a second.

Roy Krzywosinski, Chevron managing director for Australia, said gas for his company's proposed Wheatstone project would be processed at a $30 billion (Aus.) liquefaction plant to be built at Ashburton North near Onslow, 150 km south of Dampier. He said Wheatstone has enough gas to underpin a multiple-train development.

Voelte warned ad hoc developments along the coast would waste billions of dollars and risk delaying projects, leading ultimately to loss of jobs and increased competition with international rivals in the world LNG market.

Chevron wants to attract third-party gas from the western Carnarvon basin that would not be economic to transport to the Burrup Peninsula. Krzywosinski said the Wheatstone plant would lower the economic threshold for other area discoveries. A final investment decision on Wheatstone is expected in 2011.

Chevron seeks to renew its retention license over Wheatstone field. However, Woodside reportedly has submitted an alternative proposal to bring Wheatstone to Pluto. Voelte said there are no excuses for delay.

Geologically, Pluto and Wheatstone fields are two lobes of the same structure. The Artemis extension to the northeast owned by MEO Australia Ltd., Melbourne, has yet to be drilled. Preliminary work suggests it is part of the same elongated structure. MEO is seeking farm-in partners for a drilling program.

CSM LNG

ConocoPhillips may participate in reshuffling the four LNG projects planned for the Queensland port of Gladstone, based on coalseam methane (CSM) feedstock.

Company executive Ryan Lance told conference attendees that some "natural shuffling" could occur as players like BG Group PLC, Santos Ltd., Arrow Energy Ltd., and ConocoPhillips's JV partner Origin Energy Ltd. consider how to optimize costs for development of CSM fields in the Surat and Bowen basins, as well as gas transportation and LNG production facilities.

Santos Ltd. Chief Executive Officer David Knox said it makes sense in terms of improving capital efficiency and reducing environmental impact. However, he noted cooperation between rival projects will be hard to accomplish.

Australian Resources and Energy Minister Martin Ferguson said companies should do more through commercial negotiation to help speed project approvals. He said the emerging CSM-to-LNG is likely heading for a major shakeout.

Io-Jansz unitization

Under a recently signed agreement, BP PLC will sell gas from its Io field to Shell as part of the Gorgon-Jansz project on Barrow Island off Western Australia and repurchase it after it is processed at the proposed LNG plant.

BP has 12.5% interest in the WA-25-R and WA-26-R permits containing the Io field adjacent to the giant Jansz field. The deal will enable unitization of Io and Jansz.

Separate pipelines will link Jansz-Io and Gorgon fields to the proposed three-train plant on Barrow. Project partners are Chevron with 50% and Royal Dutch Shell PLC and ExxonMobil Corp. with 25% each.

More oil discoveries needed

Australia's oil and condensate production is declining, and the country urgently needs new discoveries, according to Belinda Robinson, APPEA's executive director.

Australia has gone from virtually 100% self-sufficiency in 2000 to just over 55% domestically supplied in 2009. Without new discoveries, it will drop to 32% self-sufficiency by 2017.

This translates into a decline in petroleum trade balance from a surplus of $900 million (Aus.) in 2000 to a deficit of $13.2 billion (Aus.) in 2009 and a massive deficit of $28 billion (Aus.) in 2017.

Robinson said this is cause for concern, although experts believe there is more oil to be found because Australia has vast, unexplored, and untapped petroleum basins and resources. Less than 25% of Australia's 50 potential petroleum provinces have been explored.

Federal and state governments need to work together to open onshore and offshore frontier basins if the country is to rein in its burgeoning trade deficit in petroleum, Robinson said.

A two-pronged approach is required, including continued availability of baseline geological data and a more open fiscal regime that can remove for small to mid-cap explorers some of the risks of high cost exploration of frontier areas, he said.

Safety improvement needed

Federal Resources and Energy minister Martin Ferguson told conference attendees the oil and gas production industry needs to improve its safety performance. He said that while its performance was reasonably good compared with other industries, this was overshadowed by the gas plant explosion on Varanus Island in 2008.

Ferguson said it is vital that the lessons of major incidents are learned and addressed to prevent reoccurrences. The regulatory regime, he said, needs to provide for no-blame independent safety investigations in all jurisdictions.

The Australian National Offshore Petroleum Safety Authority said personal injury rates were steady but relatively high compared with other countries.

LNG oversupply looms

Market analysts have warned of a near-term LNG surplus with new supplies predicted to rise 25% in 2010. In addition, the surge of US gas production from nonconventional sources like shale has closed that market to imports and driven down gas prices.

Richard Jones, deputy executive director of the International Energy Agency, told the conference it is a buyers' market at present. Jones was unconvinced the recent recovery in the oil price (against which LNG is priced) is supported by fundamentals.

Jones said oil stockpiles in the US are at 20-year highs. Although higher prices may be a harbinger that those stocks are going to start coming down, there are no guarantees, he said.

Analysts predict the slump in LNG demand and prices will be short-lived and strong demand will reemerge from 2013. Meantime, Australian projects are battling to secure long-term supply agreements.

Oliver field

Adelaide-based Stuart Petroleum Ltd. said geophysical and reservoir engineering studies on its Oliver oil field in the Timor Sea have upgraded the estimated volume of hydrocarbons in the Oliver structure.

The gross mean potential for the field has risen 165% over original estimates to more than 800 bcf of gas in-situ and more than 30 million bbl of condensate in place. The mean average oil in place has risen 25% to 53 million bbl.

Tino Guglielmo, Stuart managing director, said the Oliver's estimated possible reserves are 1.5 tcf of gas in place, 56 million bbl of condensate in place, and an oil leg of 100 million bbl in place.

Oliver likely will be developed as an oil and gas liquids stripping operation, with gas reinjected into the reservoir for later production and sale.

The Oliver-2 appraisal well is planned for December or January using the semisubmersible Songa Venus.

The field is in permit AC/P33 some 700 km west of Darwin. It was found by BHP Petroleum in 1988. Stuart farmed into operatorship and 50% interest last August. The Melbourne-based Albers Group has the remaining 50%.

Santos sells PNG interest

Santos in Adelaide executed a conditional agreement to sell for $20 million its 50.353% interest in the retention lease PRL 5 in the Papua New Guinea forelands to Thailand's P3Global Energy Co. Ltd. PRL 5 contains Ketu and Elevala gas-condensate fields. Santos said the permit was not strategic to its operations.

The move follows Horizon's sale of 24.82% interest in PRL 5 in May to P3GE, a private concern with core business in petroleum exploration and production as well as gas transmission and distribution.

Santos retained its interests in the PNG LNG project operated by ExxonMobil Corp., but it has executed a conditional agreement to sell its 9% interest in the Kakap Indonesian JV. ✦

CBO says HR 2454 would add $846 billion in taxes

Nick Snow
Washington Editor

A US House bill that would introduce a domestic carbon emissions cap-and-trade program would cost $846 billion in new taxes, the Congressional Budget Office said on June 5.

CBO analyzed HR 2454, the 2009 American Clean Energy and Security. The House Energy and Commerce Committee approved HR2454 on May 21 by 33 to 25 votes.

The bill's net contribution to the federal budget would be about $24 billion because the bill would increase direct federal spending by $821 billion, CBO said.

"In addition, assuming appropriation of the necessary amounts, CBO estimates that implementing HR 2454 would increase discretionary spending by about $50 billion over the 2010-19 period," it indicated. Most of that would come from auction proceeds outlined in the bill.

CBO also said that mandates under the bill would exceed thresholds under the Unfunded Mandates Reform Act by $139 million for private sector entities and $69 million for intergovernmental outlays in 2009.

American Petroleum Institute Pres. Jack N. Gerard said on June 8 that the analysis confirmed the bill would be "massively costly."

"The $846 billion price tag on emission allowances, borne disproportionately by oil consumers, will drive up costs of producing and refining gasoline, diesel, and other fuel products while doing nothing to protect fuel consumers, including American families, trucking, the airlines, the construction industry, and many other businesses that rely on oil to make or transport products," Gerard said.

API: 'A job-killer'

API said that based on allowance costs in CBO's study, impacts could be as much as 77¢/gal for gasoline, 83¢/gal for jet fuel, and 88¢/gal for diesel fuel.

"This is what happens when market-based regulation is abandoned in favor of picking winners and losers," Gerard said. "Putting most of the burden on one sector also helps explain why this legislation promises to be a job-killer."

The bill was cosponsored by Reps. Henry A. Waxman (D-Calif.), chairman of the Energy and Commerce Committee, and Edward J. Markey (D-Mass.), chairman of the committee's Energy and Environment Subcommittee.

While opening a June 9 hearing on the bill's offsets, Waxman said that it uses more than half of its allowances to protect consumers from higher energy prices with programs for electricity, natural gas, and heating oil users, for low and moderate-income families, and to provide rebates to consumers.

HR 2454 invests in developing and deploying energy efficiency programs and clean energy technology, which will create jobs, he continued. It also provides transition assistance to US industries to assure that they stay globally competitive, he said.

"The committee has worked hard on this allocation plan to ensure that it is fair. It does what a good energy bill needs to do. It balances the interest of different parts of the country, and of different stakeholders, and accomplishes much of what is important to everyone. It will go a long way to moving the country into a clean energy future," Waxman said.

But the committee's ranking minority member, Rep. Joe Barton (R-Tex.), said that it's not possible to design an allocation for an economy as complex as that of the US. "You really can't make it fair," he declared.

More industry reaction

A group of larger US independent producers warned on June 8 that the bill includes provisions that undermine its goal of reducing greenhouse gases by possibly discouraging natural gas use.

Rod Lowman, president of America's Natural Gas Alliance said, "The allowance allocation formula in the bill could eliminate the incentive to burn fuels with a lower carbon content for power generation."

HR 2454 initially would distribute for free 50% of its utility allowances based on the utility's average annual carbon dioxide emissions from retail electricity sales, Lowman said. This provides a disincentive for utilities to buy electricity from generators using gas or other cleaner fuels, he said.

Lowman said allowance allocations should instead reward utilities that acquire power from fossil fuel generators that have the lowest emissions per megawatt hour and are also the most efficient.

"The allocation policy for allowances should complement the bill's environmental goals, not cancel out the distinction between high and low carbon fossil fuels for generating electricity. Such an approach to us seems counterproductive," he said. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Calls for calm amid hyperbole

US Rep. Martin T. Heinrich (D-NM) tried to cool things off when he was finally recognized at the House Natural Resources Committee's Energy and Mineral Resources subcommittee hearing on June 4.

The discussion of unconventional natural gas production had turned into a battle over hydraulic fracturing. Proponents for bringing the technology's regulation back under the federal Safe Drinking Water Act said it poses a risk to drinking water supplies otherwise. Opponents argued that this would add a layer of redundant regulation as producers were beginning to tap an abundant new domestic gas resource.

Heinrich essentially suggested that it was time for people to step back and take a deep breath. "We should get at this less from politics and more from science and technology. My concern is how these fluids are handled once they reach the surface and how we're safely disposing of them," he said.

"Most state water directors would recognize two critical elements: construction of the well and handling of fluids on the surface," said Scott Kell, one of the witnesses and president of the Ground Water Protection Council. This has led to requiring storage of drilling and other production fluids in lead-lined storage tanks and the fluids' reinjection deep underground, he said.

Best practices

The council's recommendations include studying the most effective hydraulic fracturing procedures to develop best management practices for each state.

"A one-size-fits-all federal program is not the most effective way to regulate in this area," said Kell, who also is deputy minerals resource management division chief in Ohio's Department of Natural Resources. Zones close to underground drinking water sources, as determined by a state's regulating agency, would be of special concern, Kell said.

The subcommittee's chairman, US Rep. Jim Costa (D-Calif.), asked Kell and the four other witnesses if they knew of any best management practices which might be applicable. None of them did. So I put Costa's question to the American Petroleum Institute, which has an active standards and practices program, on June 8.

Several approaches

"We don't have a practice specifically targeted at hydraulic fracturing," said Richard L. Ranger, an API senior policy advisor, adding, "Ours deal with drilling, and we're reviewing practice documents we have including well construction and site stewardship and management."

Ranger said GWPC's recent study, which did not link contamination with hydraulic fracturing, was only the latest of several to reach that conclusion. "Contamination incidents are associated with the surface, and not what goes on below," he said.

Ranger said he suspects that some assertions simply roll up spill reports and other incidents and blame them on hydraulic fracturing. API, meanwhile, continues its recommended standards and practices on well construction and environmental operations, and is looking at its site maintenance standard, he said. ✦

API, NPRA ask EPA to consider delay of RFS-2 implementation

Nick Snow
Washington Editor

Two leading US oil industry trade associations asked the US Environmental Protection Agency on June 9 to consider delaying for a year the implementation of the new renewable fuel standards.

"Given the extremely complex and first-of-a-kind nature associated with this rulemaking, it seems that promulgation of final rules by EPA and necessary preparations by impacted industries will not be able to meet a Jan. 1, 2010, implementation date," Al Mannato, fuels manager for the American Petroleum Institute, testified at an EPA hearing on the proposed regulation.

"This rulemaking should not be rushed," added Greg Scott, executive vice-president and general counsel at the National Petrochemical & Refiners Association. "As noted, [EPA] took considerable care in drafting the proposal. Stakeholders such as NPRA need to take similar care in examining the proposal; analyzing its potential impacts on our industry, consumers, and the economy as a whole; and then drafting meaningful, informed and responsive comments to the agency."

The current US renewable fuel standard (RFS) was established under the 2005 Energy Security Act. Congress made several important revisions to it when it passed the 2007 Energy Independence and Security Act, including expanding coverage to diesel and off-highway fuels, establishing greenhouse gas reduction thresholds, and increasing renewable volume standards, according to EPA.

Scott said NPRA does not believe it can properly review the proposals under the proposed second RFS during the existing comment period, and has joined API in formally asking EPA for at least 60 additional days. Even if the federal regulator grants the request, NPRA also thinks EPA won't be able to adequately meet a Jan. 1, 2010, deadline, he continued.

"It took the agency almost 18 months to develop this proposal, and there are sure to be thousands, if not tens of thousands, of public comments on the proposal. It is hard to believe that the agency can give adequate and fair consideration to these public comments and meet this ambitious schedule," Scott said.

Stakeholders also will need sufficient time to digest the final new rule and plan for compliance, he added. The first RFS was informally released in mid-April 2007 and became effective four and a half months later on Sept. 1, he said. "Clearly, the RFS-2 regulations, when finalized, will be far more complex than the RFS-1 rule and will require more lead time for compliance," he suggested.

Mannato said it is critically important that obligated parties and all others involved in the RFS, such as biofuel producers and distributors, also have time to prepare for implementation of the proposed standard's complex four-tier mandate. "Also, the compliance issues associated with a partial year program should rule out that possibility. Therefore, it appears that the only option that is feasible is a Jan. 1, 2011, start date," he said. ✦

CSIS: Independents affected most by global recession

Nick Snow
Washington Editor

Independent oil and gas producers that rely heavily on cashflow face bigger financing challenges than major or national oil companies as the global recession depresses oil and gas demand and prices drop, experts said on June 3.

The possible consequences range from a new wave of acquisitions to slower development of natural gas from domestic shale formations, they said at a seminar at the Center for Strategic and International Studies (CSIS).

"All of the banks have credit issues and are looking for less risk," said Adam, Sieminski chief energy economist at Deutsche Bank. "They're looking at who they lend to and the prospects of getting repaid. With the economy in trouble, they're also looking for projects with a decent rate of return."

"There's a significant difference among various classes in the oil and gas industry," said Guy F. Caruso, a former US Energy Information Administration chief, who now is a senior advisor in the CSIS Energy and National Security program.

While the International Energy Agency predicts that worldwide exploration and production outlays will fall 21% year-to-year in 2009, major oil companies and state firms aren't reducing spending as much as mid-size and smaller upstream independents, he observed.

"If there's good news, it's that costs for steel, concrete, and other [exploration and production] components are coming down after nearly doubling from 2000 to 2008," Caruso said.

Some may disappear

Susan Farrell, senior director for upstream and gas at PFC Energy, said when PFC surveyed 79 independents about their 2009 spending plans, it identified several that could possibly disappear in the next few years because they can't service their debt.

The problem is that these are the companies doing most of the exploration, and that they will reduce those expenditures more heavily than other outlays, she said. "The majors are slowing projects down while the national oil companies, which have different objectives, are spending slightly more than last year. But the money is going to less expensive projects, which could have an impact on Canadian oil sands and other costly projects," Farrell said.

US shale gas development also could be affected because it has been largely driven by independents so far, she indicated. "In the last 3 years, the only US gas growth has been in unconventional formations where independents are most heavily represented. This also is the group that feels the heaviest financial pressure," she said.

Meanwhile, the majors and NOCs, which have been largely absent from US shale gas activity, could acquire properties and companies as that pressure builds, according to Farrell. "The majors definitely are interested in shale gas. The question is materiality. There will be acquisitions, but only if they think the prospects are large enough to be worth the effort," she said.

Government actions also could drive consolidation, Sieminski said. "Any tax moves that put smaller companies at a disadvantage could hurt shale gas development," he warned. At the same time, shale gas development in Europe could reduce the region's dependence on Russian gas, he said.

Technology and people

New technology also will determine where companies direct their E&P expenditures, the panelists agreed. "Major oil field service companies are where it is now. It has evolved dramatically in the last 20 years," said Alan R. Crain Jr., senior vice-president and general counsel at Baker Hughes Inc.

"Our major focus is on technology and people. We can't have one without the other. We will continue to hire brand-new engineers coming out of school and continue to educate the engineers we already have, but it requires a long-term commitment. It takes at least 2 years before we can send a new graduate out in the field and get productive results," Crain said.

Prices and economics are paramount,

others in the group said. The inflection point for deepwater projects is $50-60/bbl, Farrell noted. Producers also could delay projects because they expect service and supply costs to be lower later, she said.

Sieminski agreed, saying, "Actual costs matter. In places like Canada, it's at least $75/bbl. In the longer term, prices will have to rise to at least the replacement cost."

There's still a large investment challenge in meeting future oil and gas demand as production declines, Caruso said. "Decline rates could be affected by reduced investment," he said.

"In the long term, investors know that tighter supplies are on the horizon. Demand will eventually resume, but supplies will continue to be depleted," Farrell said. ✦

Venezuela seizes gas compression plants, faces union unrest

Eric Watkins
Oil Diplomacy Editor

Venezuela's President Hugo Chavez said state-owned Petroleos de Venezuela SA (PDVSA) is continuing to nationalize oil field service companies in the country, with Houston-based Exterran confirming its facilities as the latest seizure. "We continue advancing, recovering the control, property and management of all these plants and compression units. Nobody will stop us in this," said Chavez, adding, "We have a timetable to take control of the production plants in the Orinoco belt."

PDVSA Chief Executive Pedro Coronil added to Chavez's words, saying, "With the takeover of five more plants in the eastern region that produce about 224 MMcfd of gas and 35,000 b/d of oil, we are continuing the plan to renationalize activities connected with compression of gas."

In May, the Venezuelan government enacted a law that reserves to Venezuela certain assets and services related to hydrocarbon primary activities. Under the law, reserved activities are to be performed by PDVSA or its affiliates, or through mixed companies under the control of PDVSA or its affiliates.

Seizure confirmed

Exterran confirmed the seizure of its facilities, saying that "on June 2, 2009, Petroleos de Venezuela SA, or PDVSA, commenced taking possession of our assets and operations in a number of our locations in Venezuela."

Enterran said, "We cannot predict whether the Ministry of People's Power for Energy and Petroleum will name us in a resolution within the reserved activities, nor can we predict the amount of our assets and operations that PDVSA or its affiliates will seize."

For the year ended Dec. 31, 2008, Exterran said its operations in Venezuela accounted for $159.7 million, or 5%, of the firm's revenue and $84.2 million, or 8%, of its gross margin. The seizure included Exterran offices and five compression plants in Monagas state, Eastern Venezuela.

According to PDVSA, the seizure will significantly reduce its costs with Exterran, which were estimated at $210,000/month for rent, operations and maintenance.

So far, PDVSA said that 45% of all private oilfield service companies—about 76 firms—have been taken over since nationalization began 2 weeks ago.

Petrochemicals also targeted

Meanwhile, Venezuela's national assembly is reading a proposed law to put all petrochemical activity under state control, which could affect Japanese and US companies and add to the growing list of oil companies already in government hands.

Under the proposed petrochemical law, joint ventures with the private sector will be permitted only as long as the Venezuelan state has the controlling share.

It was not immediately clear which companies stand to be affected by the planned law, which is due to go to a second reading next week and is likely to be passed by the assembly, which is controlled by the Chavez government.

Japan's Matsui & Co. has a 15% stake in the Propilven chemical complex in Zulia state, while US chemical maker FMC Corp. has a stake in the Tripoliven plant. US chemical company Koch Industries part-owns Fertinitro, a fertilizer plant in Venezuela.

Workers' concerns

Meanwhile, Chavez, responding to concerns of union officials and oil workers, said PDVSA will employ all 8,000 workers from the more than 70 oil service contractors that the government nationalized last month.

According to Chavez, 668 workers have been transferred to the PDVSA payroll since May 8 when the government took over 76 oil services companies working in the Lake Maracaibo region of the western state of Zulia.

"Between [June 8 and June 9], 600 more (workers) will be absorbed (into PDVSA) and, going forward, 1,000 workers (weekly), until reaching the 8,000 who had been outsourced slaves," Chavez said on June 3 during a Cabinet meeting broadcast over national television.

The workers joining PDVSA will enjoy "social security and dignified jobs, so they can help build socialism," said the president in an effort to stave off union dissatisfaction.

Union official Rafael Zambrano stepped up the criticism, however, saying that his organization had information showing that "only 2,500 workers" from the nationalized firms in the Lake

Maracaibo region would be added to the PDVSA payroll.

Since last week, oil workers have gathered on the Lake Maracaibo piers to protest the nationalization of the oil services firms operating in the region—a point that raised the ire of government officials.

Oil Minister Rafael Ramirez blamed fugitive opposition politician Manuel Rosales for attempts to cause "chaos" and vowed that the Venezuelan government "will not allow this region to become chaotic."

Union leader German Cortez disputed the minister's view, saying, "This is not a problem of political parties, this is an economic and labor problem." ✦

Trinidad eyes gas pipeline extension to Barbados

Eric Watkins
Oil Diplomacy Editor

Even as it proceeds with plans to spend upwards of $155 million to construct a natural gas pipeline to its sister island of Tobago, Trinidad says it is still considering an extension of the line onward to Barbados.

The pipeline from Trinidad to Tobago is due for startup by first-quarter 2011, according to Arnold De Four, vice-president for commercial services of Trinidad and Tobago's National Gas Co. (NGC).

Meanwhile, De Four said Trinidad is awaiting a go ahead from the Barbados government, which is concerned about the project's financial viability, on the proposal to extend the pipeline to Bridgetown.

Although an extension of the line would add another market for the sale of Trinidad and Tobago's gas, Barbados, which recently passed key legislation regarding hydrocarbons, is hoping to discover oil and gas of its own.

Barbados' plans

The island nation has considered off-

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Hara-kiri Venezuela style

The oil and gas industry will not be surprised to learn that resurgent nationalism is killing Venezuela. That view is increasingly evident to all but a few observers—most of them named Chavez.

In case anyone does need a reminder, though, a former Venezuelan minister of mines and energy underlined problems facing the Latin American country due to its misguided policies.

"I believe that the government's level of spending, combined with this entire process of nationalizing businesses, is placing Venezuela in a difficult situation from the financial point of view," said Humberto Calderon.

Calderon, who also is a former president of state-owned Petroleos de Venezuela SA (PDVSA), told Mexico's Notimex news agency that the recovery in international crude prices could be offset in Venezuela by declining production after the recent expropriation of 76 petroleum companies.

The former minister said these companies had been involved in activities like gas and steam injection in oil fields or in operating oil platforms—operations that he described as "extremely complex and that require a high degree of specialization."

Huge debt

The nationalizations, Calderon said, were done "because the Venezuelan government did not want to pay the huge debt" it owed to these companies—a debt that analysts place at $10-13 billion.

Calderon's remarks contradicted statements by Venezuela's President Hugo Chavez, who earlier said the rise in oil prices would enable his country to cope with the global financial crisis without any major difficulties.

But Calderon estimated that Venezuela's financial difficulties are far from over, as the state has unpaid debts along with a high level of spending due to Chavez's nationalization policies.

"I simply cannot understand the government's motivations for nationalizing companies," Calderon said, adding, "Last year, Electricidad de Caracas had losses for the first time in its history, and Orinoco Steel is bankrupt, as are other metalworking companies."

Hara-kiri?

Calderon, a geologist, said what is so serious about this situation is that Venezuela's government will now have to use part of its resources to keep these companies afloat, something that he described as "economic hara-kiri."

His reference to Japanese-style suicide was timely as investors in the Asian nation are increasingly concerned about the nationalization in Venezuela, and they have good cause for concern, according to a report by the Nikkei Business Daily (NBD).

When Venezuelan Chavez visited Japan in April, the paper noted, he signed a comprehensive accord with Tokyo over the development of natural resources.

But the next month, according to NBD, Chavez did a U-turn by announcing the nationalization of a plant for steel raw materials that was 70%-owned by Japanese firms.

Meanwhile, Venezuela's national assembly is now reading a proposed law to put all petrochemical activity under state control, which could affect Japan's Mitsui & Co. ✦

shore drilling since the 1990s, when a study by Conoco Inc. noted promise in nearby areas. Barbados solicited its first bids in 2007, eventually offering 26 offshore blocks for oil and gas exploration in 2008.

In July 2008, as the bidding process was under way, Venezuela complained that Barbados was auctioning areas that would penetrate Venezuela's continental shelf in the Caribbean.

"This is an absolutely irregular situation so we're communicating with the foreign ministry, which is taking action," said Venezuelan Energy Minister Rafael Ramirez. "What is most important is that no one have any doubts that we will make our sovereignty respected."

In January, Barbados awarded rights to just two blocks, both to BHP Billiton: the 2,498-sq-km Carlisle Bay block and the 2,506-sq-km Bimshire block.

Despite Venezuela's belligerent stance, Philmore Best, deputy permanent secretary of Barbados' energy ministry, said the former British colony still plans to open as many as 26 blocks for exploration.

Andre Brathwaite, Natural Resources Department director, said the Caribbean nation plans to negotiate directly with international oil companies instead of using a bid round.

Barbados produces just 1,100 b/d of its own oil from onshore wells. Barbados National Oil Co. sends the crude to Trinidad and Tobago for refining, after which it is brought back to Barbados.

BNOC's production represents just 15% of Barbados' fuel requirements, with the remaining 85% filled by imports.

Like its neighbor Trinidad and Tobago, Barbados has rejected offers by Caracas to join the PetroCaribe plan under which Venezuela's state-owned Petroleos de Venezuela SA offers low-priced crude under long-term payment plans. ✦

Alaskan officials respond to Begich comment on gas line

Nick Snow
Washington Editor

Alaskan officials defended the state's plan to build a natural gas pipeline from the North Slope to Alberta after US Sen. Mark Begich (D-Alas.) said the Obama administration is frustrated that the project isn't farther along.

Begich told a business audience June 2 in Anchorage that he would like US President Barack Obama to elevate the pipeline on the national energy agenda instead of treating it as a state project, according to an Associated Press report. He said that Obama has indicated that the project is among the top five he would like to see move forward.

Alaska Gov. Sarah H. Palin said on June 3 that substantial progress has been made as two competing projects move ahead. "I am so very proud of our gas line team, which works hard every day to make progress on this vital project for our state. With no need for grandstanding, they have moved this project along with stakeholders and federal regulators, and that is going to pay enormous dividends in the future," she said.

Two state commissioners said in a letter to Begich that they were disappointed by his comments. Noting that it would be the biggest and most complex private sector undertaking in history, Revenue Commissioner Patrick S. Galvin and Natural Resources Commission Thomas E. Irwin said that its lead time must be measured in years instead of months.

"However, every day the Alaska gas pipeline project is making significant progress toward becoming a reality. That progress is the result of bipartisan actions taken in Congress and in the Alaska State Legislature in the past, actions that must continue to be bipartisan in the future," they said.

They said that the Alaska Gasline Inducement Act was designed to protect values critical to state and national interests by providing for lower tariffs on the pipeline, ensuring expansion opportunities for new gas discoveries, and protecting against basin control. Alaska's legislature expressed bipartisan support for these values, including Democrats who voted unanimously for the measure, Galvin and Irwin said.

"Further, President Obama has been supportive of the Alaska gas pipeline project from the very beginning of his presidential campaign to the present, and we applaud that support. Also, we have heard nothing from him or members of his administration that reflects frustration with the significant progress that is now occurring. Finally, an overwhelming majority of Democrats and Republicans in Congress have supported the pipeline as an essential element of a comprehensive energy policy," they said in their letter. ✦

Study finds US production would dip under hydraulic fracturing bill

Nick Snow
Washington Editor

US oil and gas production would drop 20.5% over 5 years if federal regulation of hydraulic fracturing becomes law, the American Petroleum Institute said on June 9 as it released a new study.

By 2014, gas production could fall by 4.4 tcf, or 22%, and oil production by 400,000 b/d, or 8%, according to the study by IHS Global Insight, "Measuring the Economics and Energy Impacts of Proposals to Regulate Hydraulic Fracturing."

API released the study as US Sen. Bob Casey (D-Pa.) said he would sponsor companion legislation to the bill which Reps. Diana DeGette (D-Colo), Maurice D. Hinchey (D-NY), and Jared Polis (D-Colo) introduced on June 9 to bring hydraulic fracturing back under the federal Safe Drinking Water Act.

The well completion process, which producers say is essential to produce oil from the Bakken shale and gas from the Marcellus and other US shale formations, was exempted from SDWA enforcement under the 2005 Energy Policy Act.

"Drilling for natural gas in the Marcellus shale across much of Pennsylvania is part of our future. I believe that we have an obligation to develop that gas responsibly to safeguard the drinking water wells used by 3 million Pennsylvanians," Casey said.

"We already have private wells contaminated by gas and fluids used in hydraulic fracturing. We need to make sure that this doesn't become a statewide problem over the next few decades as we extract natural gas," he continued.

Eliminating hydraulic fracturing would be catastrophic to US oil and gas development, resulting in 79% fewer well completions and drops of 45% in US gas production and 17% in oil production by 2014, the IHS Global Insight study found, according to API.

"More than 1 million wells have been completed using this technology. Unnecessary regulation of this practice would only hurt the nation's energy security and threaten our economy," API Pres. Jack N. Gerard said. ✦

House Republicans offer 'all of the above' energy bill

Nick Snow
Washington Editor

US House Republicans introduced an energy bill on June 10 that they said takes a more realistic approach than proposed carbon cap-and-trade legislation. The measure is an "all of the above" strategy similar to their 2008 proposal.

Its oil and gas provisions include ordering the US Interior secretary to move ahead with Outer Continental Shelf leasing, authorizing leasing on the Arctic National Wildlife Refuge's coastal plain, and restoring oil shale programs that Interior Secretary Ken Salazar scaled back in February.

Specific changes within the OCS provision include extending state territorial waters to 12 nautical miles offshore, sharing of 75% of federal revenues within 12 nautical miles and 50% farther out from new leases. The Interior secretary also would be required to offer at least 75% of available acreage within each OCS planning area for lease during each OCS 5-year leasing program. Lessees also could relinquish any part of a lease that they are not interested in producing, but that the secretary finds geologically prospective, to the secretary who would then provide a royalty incentive for production from the retained portion.

The bill also would require reviews within 60 days of legal challenges to exploration and production, and require that such lawsuits be filed in US District Court for the District of Columbia to prevent judicial forum shopping. It also would streamline the permitting process for refinery expansions and order the president to designate at least three closed military installations as potential suitable for building a new refinery, including at least one suitable for refining biomass into biofuel.

The measure also includes provisions covering nuclear energy, alternative and renewable technologies, and conservation and efficiency.

Sensible alternative

Sponsors said that their bill is a sensible alternative to House Democrats and the Obama administration's carbon cap-and-trade proposals. "The American Energy Act is a bill that will lower energy prices with the exploration and recovery of natural resources in the United States, promote alternative energy and energy conservation, and help put our neighbors back to work," said Rep. Robert E. Latta (R-Ohio). "Instead of a $3,100/year tax increase for every American family that the Cap and Tax proposal offers, the American Energy Act works to lower energy prices for American families, which is important now during this recession, but also for the future," he said.

Rep. Cynthia M. Lummis (R-Wyo.), a Natural Resources Committee member, said, "When it comes to energy, we need an America that relies on its own ingenuity and innovation. We need to use new technologies and methods to dramatically expand the use of solar, wind, nuclear, and biofuels as well as traditional energy sources such as oil, natural gas, and coal. In direct contrast to the president's proposal of a national energy tax, I believe our bill represents a step in the right direction toward achieving the goal of building a cleaner, safer, and stronger country for all Americans."

Rep. John M. Shimkus (R-Ill.) said, "Oil is once again going up, which means [gasoline] prices are going to go up. Some of my friends in Congress want to add to these costs with an energy tax disguised as cap-and-trade. Instead of adding to your heating, cooling, and gasoline bills, I want our nation to increase production of American energy such as clean-coal, nuclear, wind, solar, renewables, and offshore oil and gas."

House GOP leaders endorsed the bill. "The House Republicans' American Energy Act, not the Democrats' national energy tax, is the fastest route to a cleaner environment, lower energy costs, and more American jobs," said Minority Leader John A. Boehner (R-Ohio).

Doc Hastings (R-Wash.), the Natural Resources Committee's ranking minority member, said that Democrats should provide the House an opportunity to consider and vote on the measure "so that we have an energy policy that helps Americans by protecting our environment, providing affordable energy, and creating new high-paying jobs." ✦

Analyst takes bullish view of natural gas, LNG

Marilyn Radler
Senior Editor-Economics

Research analysts with Calgary-based Tristone Capital Inc. are optimistic on the outlook for natural gas beginning in the second half of 2009 and foresee a possible US gas supply shortage in 2010.

In a recent report, Tristone Capital sees gas supply hitting a critical inflection point in July, when sequential monthly declines take hold and accelerate into the fall of this year. The analysts expect US gas supply to fall more than 500 MMcfd each month between now and the start of next year, with supply down 5.5 bcfd by early 2010.

The drop in horizontal drilling rig count, while appearing later than expected, is here and deeper than anticipated, Tristone Capital said. As such, the drop in the rig count will not do much to stave off shut-ins this fall, but the drop in supply will begin to accelerate into this year's third quarter, with production down nearly 4 bcfd year-on-year by the start of winter.

The Tristone Capital forecast also incorporates some optimism in demand, calling for gas to gain market share on coal in the power generation market and foreseeing limited upside in volumes of US LNG imports.

"The decline in supply coupled with a modest recovery in demand should result in the market swinging to tighter than normal, and with it, inventory destocking throughout 2010. Our current model suggests the call on LNG increases to 3.1 bcfd in 2010, although in reality, the price signal required to bring LNG to the US to balance the market should trigger a recovery in shale supply in the spring," the report says.

Tristone Capital forecasts that gas on the New York Mercantile Exchange will average \$6.75/MMbtu for 2010 and believes the drop in US gas output will create a call for up to an incremental 2 bcfd in LNG imports in 2010, "which has very strong pricing implications for gas prices in the coming months."

"While near-term risks of excess supply may put pressure on front-month pricing, we see a shift in market sentiment in the coming weeks, as the market latches on to the magnitude of production declines and with it, equity investors look through the storage reset and start discounting a rising futures curve," the report says.

Tristone Capital also explains the lag in production declines. Despite the rapid decline in the gas rig count to 711 recently from a peak of 1,606 in September 2008, the low-cost, high-deliverability shale plays, including Haynesville, Marcellus, and Fayetteville, continue to add rigs, thereby changing the productive intensity of a rig in North America.

Estimating the annualized production intensity per rig in the US has increased to 12.5 MMcfd from 9.7 MMcfd at the beginning of 2007, with a notable step change in output per rig when Haynesville activity accelerated in July 2008, Tristone Capital puts the overall efficiency gain from the dominant shale plays at nearly 30%. The drop in the rig count is not directly correlated with supply, given the rising contribution from these active shale plays, Tristone Capital said. ✦

Companies ramp up Bakken participation

Several companies increased ownership in North Dakota Bakken well and production interests under an existing joint venture with Slawson Exploration Co., private Denver operator.

Northern Oil & Gas Inc., Wayzata, Minn., acquired certain North Dakota Bakken assets from Windsor Bakken LLC as part of a syndicate led by Slawson. Northern purchased a 5% interest in the undeveloped acreage, including 60,000 net acres. Price is \$7.3 million.

Northern also acquired 14% of the existing 59 gross Bakken and Three Forks well bores in North Dakota including 1,200 b/d of oil production. It also purchased 300,000 bbl of proved producing reserves and 3,000 net undeveloped acres.

GeoResources Inc., Houston, acquired a 15% interest in 60,000 net acres and 15% of varying working interests in 59 producing and productive wells, adding more than 300,000 boe of proved producing reserves. Cost was \$10.4 million.

Lario Oil & Gas Co., private Denver operator, also participated in the revised joint venture on undisclosed terms, GeoResources said.

Slawson, responsible for all operations, is expected to drill as many as 45 gross Bakken wells on the newly acquired acreage through 2010.

The joint venture, running one rig, expects to add two more in July and possibly a fourth by the first quarter of 2010, GeoResources said. ✦

EnCana banking heavily on unconventional gas, oil

Unconventional gas and oil plays represent the future for EnCana Corp. and the North American oil and gas industry, EnCana said May 27.

EnCana has established a portfolio of nine gas and four enhanced oil resource plays, said Jeff Wojahn, executive vice-president and president of EnCana's USA division. Wojahn and other principals discussed its positions in the high-pressure, high-temperature established Jurassic Deep Bossier sand and emerging Haynesville plays in East Texas and North Louisiana (Fig. 1).

Gas deliveries by all operators have grown to more than 7 bcfd in January 2009 from 2 bcfd in January 2006 from the Barnett, Fayetteville, Woodford, and Haynesville shales alone, EnCana said. Of that, the Barnett supplies about 5 bcfd.

North America consumes about 25 tcf/year of gas, and close to half of that comes from unconventional reservoirs including tight sands, shales, and coalbed methane, the company noted.

The Deep Bossier play in East Texas has the best returns in EnCana, and the Haynesville could become the company's leading resource play, said Paul Sander, vice-president, Midcontinent business unit.

Haynesville shale

EnCana, like many operators, has a 2009 priority to demonstrate the commerciality of its Haynesville shale acreage and hone its strategy to drill and prove its holding.

EnCana has diverted $290 million of its 2009 budget to retain land in the Haynesville play, most of it in the company's core area in Red River and De Soto parishes.

Efforts to prove and hold acreage are likely contributing to the current rig count of 75-80 rigs in the Haynesville, EnCana said. Nevertheless, only a few Haynesville wells have more than 6 months of production history.

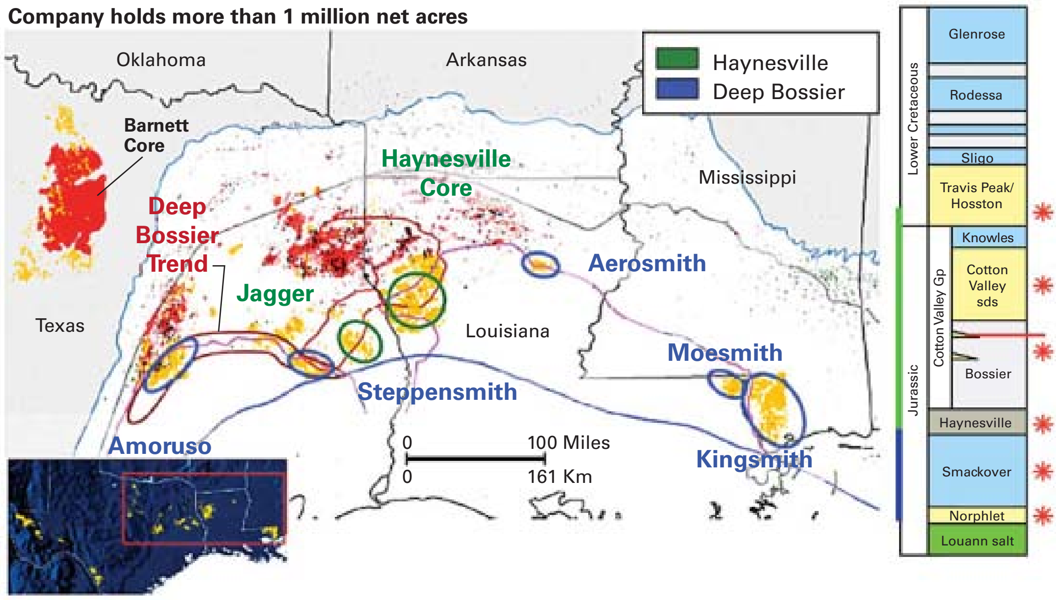
In the Haynesville, EnCana has divided its drilling staff into teams each responsible for a particular section of hole. The company has drilled 16 horizontal Haynesville wells.

EnCana has stepped up efforts to multiply and enlarge its Haynesville frac stages after noticing a direct relation-

ENCANA ACREAGE IN GULF COAST JURASSIC TREND

Fig. 1

Company holds more than 1 million net acres



Source: EnCana Corp.

ship between the volume of proppant placed and initial flow rates and estimated ultimate recovery (Fig. 2).

The company has moved from 1 million lb of proppant and eight fracs/well initially to more than 3 million lb of proppant in 12 stages.

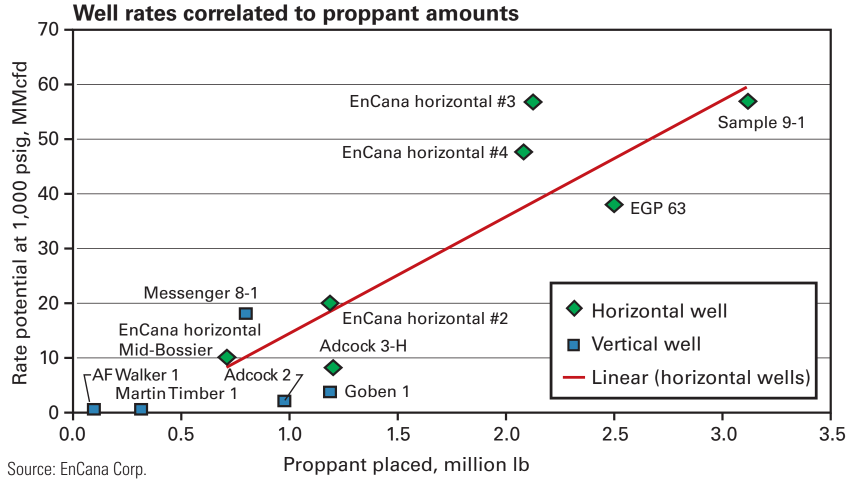
The Haynesville could rival the quality and scope of the Barnett, Sander said.

EnCana also plans to exploit the Mid-Bossier shale. Just above the Haynesville in Louisiana, it is 180 ft thick with gas in place and development costs similar to those of the Haynesville. EnCana didn't specify EURs for the Mid-Bossier but said they could be comparable to those in the Haynesville.

The Texas side of EnCana's Haynesville holding is less well known but has great potential and the company is seeking a partner to better define it.

HAYNESVILLE GAS POTENTIAL

Fig. 2



Source: EnCana Corp.

Bossier shale

Deep Bossier activity in 2009 centers on Hilltop South and West fields, where the formation is 2,000-3,000 ft deeper than at Amoruso field, where development continues. EnCana is also completing Reagan sands deeper in the Jurassic section.

EnCana, with nine rigs running as of late May, is also exploring adjacent areas and has identified 250 locations, enough for 6 years of drilling.

The company had 94,000 acres in the play and 79 wells on production.

Almost 15 bcfd of gas pipeline capacity is to be built in the Texas Midcontinent and Gulf Coast region in 2007-12, said Renee Zemljak, vice-president, USA midstream and marketing. EnCana holds sufficient downstream capacity for all of its gas, she said.

The other gas plays in which EnCana is established are the Barnett shale in the Fort Worth and Delaware basins, Eagle Ford and Pearsall shales in the Maverick basin, Niobrara shale in the Piceance basin, Muskwa shale in the Horn River basin, and the Montney tight sand in Northeast British Columbia. ✦

Shale gas acreage, European database draw interest

Companies are seeking permits for shale gas prospects in southeast France in Languedoc Roussillon, the Cevennes mountains region, and the Savoie area near the Swiss border.

Total E&P France SA-Devon, Mouvoil SA, Bridgeoil Ltd., and Diamoco Energy are among the firms competing for the Ales, Bassin d'Ales, Plaine d'Ales, and Montelimar permits. They are competing with the Cevennes and Navacelles permits requested in 2008 by Egdon Resources Ltd. (also being eyed by Eagle Energy Ltd. and YCI Resources Ltd.) and by Cevennes Petroleum Development Ltd.

French authorities plan to assess the competing proposals for overlapping shale acreage onshore north of the Gulf of Lion and make an award in October 2009.

"There is much shale gas in France," said Francois Laurant, in charge of shale gas at Institut Francais du Petrole. "It has been seeping for centuries around the town of Grenoble in midsoutheastern France. But the disputed areas hold black shale in shallower ground than elsewhere in France like the Paris basin," he added.

East Paris Petroleum Development Ltd. requested the Moselle permit in Lorraine, in northeastern France, targeting both shale gas and coalbed methane.

Charles Lamiraux, chief geologist at France's Environment and Energy Ministry in charge of exploration, said while targeting shale gas, companies could well find conventional gas and heavy oil.

Shale gas prospects abound

France is not the only country in Europe in which shale gas is arousing interest.

The Potsdam-based GFZ German Research Centre for Geosciences designed and coordinated what it describes as the "first and biggest and most comprehensive" study on shale gas in Europe.

Brian Horsfield, one of the main collaborators in the Gash (German for shale gas) study, said the study was an interdisciplinary reservoir and regional-scale research project coupled with black shale database being carried out by a multinational expert task force that includes Geoforschungszentrum GFZ, IFP, and Dutch geosciences organization TNO.

The project started May 1 and will initially run for 3 years with a 6-month reporting of database construction and research advances, a program directly connected with exploration and production issues, the evaluation of US and European basins, Horsfield said.

Gas in place and producibility are the focus of the research activities with physical, chemical, and biological processes contributing to shale gas formation being examined by experiment, monitoring, surveying, and modeling.

Natural occurrences include but are not limited to Alum shale (Sweden), Posidonia shale (Germany), Lower Carboniferous (Germany and Netherlands), and Barnett shale and Marcellus shale (both examples from the US).

The data base spans 20 European countries and is being acquired in collaboration with geological surveys and selected universities. ✦

Kazakhstan

Ural Oil & Gas LLP shot 3D seismic earlier this year on the structure that contains its 2005 Zhaik presalt oil and gas-condensate discovery in the 593,000-acre Federovskoye block along northern Kazakhstan's border with Russia.

The Caspian unit of MOL Hungarian Oil & Gas Co., operating shareholder with 27.5% interest in Ural Oil, said the Zhaik-1 well went to 5,844 m and recovered oil and gas-condensate from presalt Lower Permian and Carboniferous carbonates. The liquid hydrocarbons were 46° gravity and had no measurable sulfur or hydrogen sulfide.

The hole's lowermost 400 m were drilled with slimhole technology, and only small amounts of fluids were recovered. MOL said.

Other block interests are SINOPEC International's First International Oil Co. subsidiary 22.5% and Exploration Ventures Ltd. 50%.

First International Oil in 1999 called the Zhaik structure, in the Precaspian basin near Kazakhstan's supergiant Karachaganak oil and gas-condensate field, a potential giant.

Morocco

Circle Oil PLC will complete the CGD-10 exploration well on the Sebou permit in Morocco's Rharb basin as a potential gas producer.

The well tested 3.9 MMscfd from the Tertiary Lower Guebbas sequence on a $^{24}/_{64}$ in. choke from 3.3 m of net gas pay perforated at 889.3-897 m. A secondary target at 847.5- 854.5 m with 2 m of calculated net gas pay is to be tested later.

The rig will start drilling the last well of the planned six-well drilling program on the permit northeast of Rabat. Thus far, Circle Oil has had four discoveries and good indications of gas in DRJ-6 well, to be tested later.

Oman

PetroTel Inc., Plano, Tex., was awarded rights to 2,378 sq km Block 17 in northernmost Oman, press reports said.

The 3-year exploration and production agreement covers the block in northern Oman near the Straits of Hormuz.

Sudan

White Nile Petroleum Operating Co. has discovered large volumes of dry gas in Sudan's Block 8, southeast of Khartoum, press reports said.

WNPOC is a 50-50 combine of Sudan National Petroleum Corp. and Malaysia's Petronas, which said the finds came at the Hosan and Tawakul wells. They estimated the potential at 16-20 tcf but said the finds are not yet proven to be commercial.

The country's only other gas discovery came in 2005 by a joint venture of China National Petroleum Corp. and Sudapet in Block 6 in the Heglig area of southwestern Sudan. It is to be used to supply a 400 Mw power plant.

Idaho

Standard Steam Trust LLC, private Denver operator, has drilled five of 22 planned temperature gradient drilling sites in an undisclosed known geothermal resource area of Idaho, said U.S. Energy Corp., Riverton, Wyo.

Results show an increase in water temperature of 5-7° F./100 ft, indicating that commercial water temperatures may be found at 3,500-5,000 ft, said U.S. Energy, which owns 25% of SST. Drilling of the 500-ft holes is to run through midsummer 2009.

SST owns 73,500 acres of federal, state, and fee leases with geothermal potential in six prospect areas in three states. Its goal is to hold 140,000 net acres by the end of 2009.

Texas

East

Common Resources LLC, Houston, let a contract to MicroSeismic Inc., Houston, to deploy a microseismic buried array in the Haynesville shale gas play.

The system will provide microseismic monitoring, mapping, and analysis for hydraulic fracturing of multiple wells. It will enable Common Resources to monitor the primary, secondary, and tertiary activity, in a variety of reservoir conditions, for its Haynesville wells during the next few years.

The system applies a proprietary analysis to seismic data collected by MSI's buried array as the reservoir undergoes fracture stimulation. It does not require dedicated monitoring wells. MicroSeismic Inc. has installed more than 75 sq miles of permanent, near-surface arrays since late 2008.

Gulf of Mexico structure removal costs examined

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TETRA Technologies Inc.
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A study examined structure removal costs in the Gulf of Mexico for operations performed by TETRA Technologies Inc. from 2003 through June 2008. The data set included 120 projects representing $178 million in expenditures and is one of the largest samples of decommissioning costs analyzed in the gulf.

The study used standard statistical analysis, and we believe the statistical measures are representative of the removal cost of independent operators in the shallow-water gulf during 2003-08.

The study reports costs for preparation, pipeline abandonment, and removal operations across several categories.

Decommissioning represents the end of the production life cycle of offshore structures and involves plugging and abandoning wells, removing infrastructure, and clearing debris from the site. Removal of the topsides equipment, deck, conductors, piles, and jacket is the core of all decommissioning projects and typically is the most expensive.

Cost categories

Decommissioning in general and removal operations in particular involve several activities that may overlap one or more categories.

Removal operations involve mobilization-demobilization of a derrick barge and other service vessels, preparation activity, diving services, explosive services, conductor and pile removal, pipeline abandonment, and structure removal. How a company allocates costs across activity and categories depends on the requirement of the job and a company's accounting system.

We grouped costs into three main categories (structure preparation, pipeline abandonment, and structure removal) and allocated in proportion to effort the activities that overlapped categories.

Structure preparation

After completion of well plugging and abandonment activities, normally a crew paid on a day rate prepares a structure for removal. Caissons and well protectors typically require little or no preparation, but fixed platform removal usually requires the dispatching of crews for inspections, cleanup, and cutting operations.

An inspection above and sometimes below water determines the condition of the structure and identifies potential problems with the salvage. Depending on the water depth, divers or remotely operated vehicles perform the inspection. Divers can operate effectively down to 300 ft of water.

On the deck, the crew flushes and cleans all piping and equipment that contained hydrocarbons. They cut loose separately all modules scheduled for removal from the deck and cut the piping, electrical, and instrumentation interconnections between modules. The crew also prepares the modules for the work needed to lift the modules off the deck.

US Minerals Management Service regulations require disposal of fluids and agents used for purging and cleaning the vessels by either pumping them into an injection well or placing them in storage tanks for disposal onshore.

TOTAL PROJECT COST, 2003-08 Table 1

Water depth, ft	Caisson	Well protector	Fixed platform	All
	million $			
0-100	16.0	6.2	28.8	51.0
101-200	11.4	—	60.7	72.1
201-300	—	—	54.6	54.6
All	**27.4**	**6.2**	**144.1**	**177.7**

Note: Includes preparation, pipeline abandonment, and structure removal operations.

AVERAGE FIXED PLATFORM PREPARATION COST

Table 2

Water depth, ft	No. of structures	Cost, $1,000
0-100	12	79 (91)
101-200	13	90 (59)
201-300	10	242 (355)
All	35	130 (206)

Note: In parentheses is the standard deviation of the category average.

AVERAGE PIPELINE ABANDONMENT COST

Table 3

Water depth, ft	No. of structures	Cost, $1,000
0-100	16	187 (256)
101-200	12	298 (269)
201-300	3	674 (737)
All	31	272 (332)

Note: In parentheses is the standard deviation of the category average.

The removal contractor will send the equipment and other metallic debris ashore for recycling or scrapping and the nonmetallic debris as waste for disposal in a landfill.

Pipeline abandonment

MMS regulations require burial to a depth of at least 3 ft below the mud line of pipelines with 8⅝-in. diameters or greater and installed in less than 200 ft of water. Companies can request a waiver of the burial requirement for lines 8⅝-in. or smaller.

Upon cessation of operations, a company may abandon a pipeline in place if it does not constitute a hazard to navigation, commercial fishing operations, or unduly interferes with other users in the Outer Continental Shelf (OCS).

Pipelines abandoned in place require flushing, filling with seawater, cutting, and plugging with the ends buried at least 3 ft below mud line. Divers or remotely operated vehicles with electrohydraulic tools perform the cutting operations.

To date, companies have abandoned in place most pipelines in the gulf, with very few removed.[1]

Structure removal

Removal of the jacket, deck, conductors, and piles forms the core of every decommissioning project. We have grouped these activities under one category because most of these activities usually use the same spread.

Typically, structure removal is the most expensive operation in decommissioning, but wellbore abandonment may exceed removal cost if the job entails a large number of unplugged wells, is unusually complex, or encounters problems in plugging the wells.

The removal process involves:

- Placing the production equipment and deck modules on a cargo barge and moving them to shore for scrap or reuse.
- Cutting, pulling and removing conductors, casing string, and piles from the ocean floor at least 15 ft below the mud line.
- Lifting the jacket and taking it onshore, to another offshore location, or to an artificial reef site.

If the structure is within a reef planning site, the operator may have a viable option of toppling it in-place or partially removing it.[2]

References 1 and 3 discuss further the activity requirements associated with structure removal.

Data source

The database created includes jobs performed in the gulf by TETRA Technologies from 2003 through June 2008. The work done was for 20 operators, mostly large and medium-size independents, and 1 major.

In total, the jobs involved 120 projects and the removal of 133 structures.

STRUCTURES REMOVED

Table 4

Water depth, ft	Caisson	Well protector	Fixed platform	All
0-100	29	15	28	72
101-200	9	—	32	41
201-300	—	—	18	18
>300	—	—	2	2
All	38	15	80	133

AVERAGE STRUCTURE REMOVAL COST

Table 5

Water depth, ft	Caisson	Well protector	Fixed platform	All
	$1,000			
0-100	499 (304)	393 (190)	865 (623)	619 (492)
101-200	1,227 (612)	—	1,634 (948)	1,545 (884)
201-300	—	—	2,579 (1,498)	2,579 (1,498)
All	672 (501)	393 (190)	1,576 (1,200)	1,150 (1,086)

Note: In parentheses is the standard deviation of the category average.

All costs reported are in current (nominal) dollars and are not adjusted for inflation. Reported cost of the sample totaled $178 million and was mainly concentrated on platform removals in the 100-300 ft water depth category (Table 1).

A review of invoice, job, and accounting reports provided the cost and operational data. The created database included structure location, customer, work performed, year of operation, total job cost, cost by work performed, contract type, structure type, number of structures, number of piles per structure, number of conductors, structure disposition, deck and jacket weight, vessels employed, and activity duration.

Also recorded were comments on the nature of the activity, such as hurricane-destroyed structures, inclement weather, and lift problems.

All jobs reviewed were in water depth less than 500 ft on a turnkey basis. The majority of the sampled projects involved one structure per job.

FIXED PLATFORMS DISPOSITION

Table 6

Water depth, ft	Onshore	Reefed	Reefed, %
0-100	19	9	32
101-200	5	27	84
201-300	1	17	94
>300	1	1	100
All	26	54	68

FIXED PLATFORM AVERAGE REMOVAL COST BY DISPOSITION Table 7

Water depth, ft	Onshore	Reefed ($1,000)	All
0-100	969	682	865
101-200	1,363	1,765	1,669
201-300	1,311	2,876	2,789
>300	1,923	3,718	2,821
All	**1,152**	**1,995**	**1,721**

AVERAGE FIXED PLATFORM REMOVAL COST BY NUMBER OF PILES Table 8

Water depth, ft	3 piles	4 piles	6-8 piles ($1,000)	8+ piles	All
0-100	654 (322)	966 (605)	986 (833)	2,065 (-)	976 (625)
101-200	1,018 (191)	1,540 (1,035)	1,517 (700)	2,579 (1,498)	1,614 (955)
201-300	1,670 (214)	3,778 (1,551)	2,718 (1,351)	—	2,721 (1,411)
All	**1,215 (506)**	**1,663 (1,364)**	**1,908 (1,176)**	**2,563 (911)**	**1,709 (1,209)**

Note: In parentheses is the standard deviation of the category average.

Work activity categories include preparation, pipeline abandonment, and removal services. Not all jobs recorded costs for all categories. Deck and jacket weight was also unavailable for all projects.

Categories

Structure type and water depth are the primary subcategories employed, but we also grouped and analyzed projects according to number of piles, structure disposition, and weight. Ideally, we would like to group structures into families with similar jacket and deck weight, design characteristics, number of wells, etc., and then compute average removal cost within these individual categories.

The difficulty with this approach is that as additional constraints (category levels) are imposed to create more homogeneous categories, the number of elements within a given category will decline and with it the minimum size for reliable statistical inference. In other words, with each new layer of description added, the size of the categories will decrease to a point where they may have only a few elements.

Water depth and structure type commonly are employed to proxy weight, design, and complexity characteristics, but we recognize that a large amount of individual variability is not captured due to differences in age, production capacity, structure configuration, and other factors. We thus expect standard deviation values per individual category to be relatively high and on-the-order of the mean values.

Structure preparation

Caissons and well protectors usually do not require preparation, and in our sample, only one caisson reported preparation cost. If the operator prepared the structure for removal or employed a third party, then the removal contractor will not need to perform this service and not report the cost for this activity.

Based on 35 job reports, the average preparation cost for fixed platforms ranged from $79,000 to $242,000, depending on water depth (Table 2).

Preparation cost mostly reflects structure complexity and age, and to the extent that water depth captures these characteristics, we cannot nor should not, assume the water depth correlation provided by the sample represents a general relation.

The average preparation cost across all water depth categories is $130,000.

Pipeline abandonment

Thirty-one projects reported pipeline abandonment cost (Table 3). Abandonment cost increased with water depth and averaged $272,000/structure across all water depth categories.

Standard deviations are of the same order of magnitude as the average, indicating that for all practical purposes, pipeline abandonment cost is not captured adequately by the water depth categorization. Unavailable for analysis were such additional factors as pipeline size, length, and connection type.

Pipeline abandonment costs in 2003-08 ranged between 1.2 to 3.3 times greater than average cost reported across similar categories for the period 1998-2003.[4]

Structure removal

Table 4 breaks down the 133 structures removed by water depth and structure type. More than half of the removals involved fixed platforms (80), followed by caissons (38), and well protectors (15).

Table 5 shows the average removal cost per water depth and structure type. The removal cost of caissons and well protectors increase with water depth. Average removal cost for a caisson in 0-100 ft of water is $500,000. The average cost for a 101-200 ft water depth is $1.2 million or slightly more than twice the 0-100 ft cost.

For fixed platforms, removal cost ranges from $865,000 (0-100 ft) to $2.6 million (201-300 ft) and are 1.5 to 2 times the cost of

AVERAGE CAISSON REMOVAL COST BY FOUNDATION TYPE Table 9

Water depth, ft	Monopile	Skirt piles ($1,000)	All
0-100	498 (321)	463 (238)	484 (286)
101-200	1,515 (772)	871 (145)	1,113 (542)
All	**659 (545)**	**590 (286)**	**628 (441)**

Note: In parentheses is the standard deviation of the category average.

FIXED PLATFORMS REMOVED Table 10

Water depth, ft	2003	2004	2005	2006	2007	2008
0-100	6	3	8	5	5	1
101-200	8	0	4	5	13	2
201-300	1	1	1	4	10	1
>300	0	0	0	1	1	0
All	**15**	**4**	**13**	**15**	**29**	**4**

Average fixed platforms removal cost by year

Table 11

Water depth, ft	2003	2004	2005	2006	2007	2008
	$1,000					
0-100	578 (373)	1,406 (573)	716 (373)	1,496 (809)	453 (168)	1,050 (—)
101-200	1,681 (1,001)	—	1,650 (1,001)	1,428 (726)	1,542 (1,191)	2,521 (1,300)
201-300	1,810 (—)	3,293 (—)	4,827 (—)	1,832 (821)	2,747 (1,770)	1,687 (—)
>300	—	—	—	1,736 (—)	3,718 (—)	—
All	**1,249 (911)**	**1,878 (1,053)**	**1,320 (1,572)**	**1,579 (634)**	**1,845 (1,605)**	**1,945 (738)**

Note: In parentheses is the standard deviation of the category average.

to $2.72 million (201-300 ft). The average removal cost of an 8+ pile structure is 2.1 times greater than a 3-pile fixed platform.

For caissons with skirt piles, removal cost ranges from $463,000 (0-100 ft) to $871,000 (201-300 ft). Caissons without skirt piles (Table 9) are more expensive to remove and cost $498,000 (0-100 ft) to $1.52 million (101-200 ft). The sample size for the 0-100 ft category has more than a dozen projects for each caisson type, and in this case, the costs for monopole and skirt-pile removal are similar.

In the 101-200 ft water depth categories, the sample sets has less than 5 elements, which is at least partially responsible for the cost differences observed between the two categories.

To underscore the variability that exists in removal operations, we considered the removal cost of fixed platforms over time. Table 10 shows the number of fixed platforms removed, with Table 11 showing the average removal cost.

Average removal cost generally increases with water depth where sample sizes are sufficiently large. It is not possible to delineate the elements that explain why cost varies in the manner shown, but the usual suspects responsible are market conditions (supply and demand, which determine day rates), structure characteristics, and environmental conditions at the time of the operation.

Total cost

Table 12

Water depth, ft	Caisson and well protector	Fixed platform
	$1,000	
0-100	686 (560)	1,131 (970)
101-200	1,525 (881)	2,023 (1,276)
201-300	—	3,468 (2,590)

Note: Includes caisson and well protector costs based on pipeline abandonment and removal operations, and fixed platform costs based on preparation, pipeline abandonment, and removal operations. In parentheses is the standard deviation of the category average.

caisson removal.

The standard deviations per category are large and frequently about half of the average—especially as water depth increases. This indicates that the water depth and structure type categories do a somewhat better job of explaining the variation in the sample data.

We expect removal cost to increase with water depth and structure complexity because these factors are proportional roughly to the size of the rig and the time of the operation. We also recognize that our results are sample dependent and may yield significant individual variations.

Removal cost depends upon the removal options available to the operator. Among the 80 fixed platforms removed, operators reefed more than half in place or towed them to a reef site (Table 6).

In 0-100 ft water depth, reefed structures represent about a third of the total number removed. This increased to 84% in 101-200 ft and 94% in 201-300 ft.

These percentages are slightly higher than aggregate gulf reef capture statistics and represent the individual characteristics and circumstances of the structure.[5] Projects in deep water cost more than onshore removal, likely due to the increased complexity of the operation or structure type (Table 7).

Without the reef option, the cost to decommission platforms would exceed the values depicted.

Table 8 reports the removal cost statistics for structures grouped according to number of piles. We employ 3-pile, 4-pile, 6-8 pile, and 8+ pile categories and compute average removal cost per category.

The data exhibit reasonably consistent patterns across water depth and number of piles, but category elements vary widely. For 3-pile structures, removal cost ranges from $654,000 (0-100 ft) to $1.67 million (201-300 ft). As the number of piles per structure increase, there is a general increase in cost with water depth.

For 6 and 8-pile structures, removal cost ranges from $986,000 (0-100 ft)

Average removal cost per ton

Table 13

Water depth, ft	Caisson	Well protector	Fixed platform	All
		$1,000		
0-100	9.5	2.3 (1.5)	1.5 (0.7)	2.0 (2.0)
101-200	6.6 (3.7)	—	2.3 (2.2)	2.8 (2.7)
201-300	—	—	2.3 (1.5)	2.3 (1.5)
>300	—	—	1.7 (0.8)	1.7 (0.8)
All	**7.6 (3.1)**	**2.3 (1.5)**	**1.7**	**2.3 (2.1)**

Note: In parentheses is the standard deviation of the category average.

Average structure installation cost

Table 14

Water depth, ft	Caisson	Well protector	Fixed platform	All
		$1,000		
0-100	534	986 (205)	1,009 (482)	909 (419)
101-200	833	1,825 (1,148)	1,675 (987)	1,619 (943)
201-300	—	—	2,809 (617)	2,809 (617)
All	**633 (212)**	**1,489 (938)**	**1,501 (879)**	**1,368 (858)**

Note: In parentheses is the standard deviation of the category average.

Total cost

Table 12 shows the total cost for removing a caisson, well protector, or fixed platform. This total includes caisson and well protector removal and pipeline abandonment and fixed platform preparation, pipeline abandonment, and removal cost.

We grouped caissons and well protectors together because they have reasonably similar functional characteristics and often do not require preparatory activity.

For caissons and well protectors, the total removal cost ranges from $686,000 (0-100 ft) to $1.5 million (101-200 ft). For fixed platforms, average removal cost ranges from $1.1 million (0-100 ft) to $3.5 million (201-300 ft).

Weight

The maximum load weights expected during the operation determines the minimum derrick barge required to remove a structure. Engineers estimate this weight using blueprint specifications and physical characteristics of the structure and derrick barge such as lift capacity, boom length, deck size, and jacket length.

Weight correlations depend on data availability and quality. We focus on the total weight relationship. In removal operations, the heaviest lift weight will determine the derrick barge required. For structures in deep water, jacket weights tend to dominate.

As foundations transect a larger water column, the deck-to-jacket weight ratio will decrease if the deck weight remains constant. For fixed platforms in shallow water, deck weight usually dominates jacket weight, but as water depth increases, jacket weights will often exceed deck weight.

Table 13 shows the average removal cost as a function of total deck, jacket, pile, and conductor weight. Caisson removal is 2-4 times more expensive on a per-ton basis than fixed-platform removal.

Structure installation

Removal operations are essentially the reverse of installation activities. The cost to remove a structure should therefore approximate installation cost for similar structures in similar water depth categories.

For 2003 to 2008, TETRA Technologies installed 20 structures: 3 caissons, 5 well protectors, and 12 fixed platforms. The sample is small and is used for illustrative purposes.

The average cost (Table 14) to install a caisson ranges between $534,000 (0-100 ft) to $833,000 (101-200 ft). Well protectors and fixed platforms exhibit more similarities in installation expenditures than for removal operations, probably due to the pile driving and barge requirements.

For jacket structures, installation cost ranges from $1 million (0-100 ft) to $2.8 million (201-300 ft), reasonably consistent with the structure removal costs (Table 5).

Analysis limitations

Various unique conditions govern decommissioning costs. These conditions include the structure, site, operator, and contractor, as well as the prevailing environmental, engineering, market, operational, and regulatory conditions at the time of the operation.

The unique nature of offshore operations drives the variability observed in cost statistics, and a factor analysis only partially can explain the costs.

Sample select problems in statistics occur when the sampling is not random. In this study, one service provider performed all removal projects, and although the data set represents a large and diverse collection of structures and water depths, the observations cannot be construed as a random sample. The projects involved only one removal company and mostly independent operator structures.

We believe the data is representative of the independent sector but does not represent project cost for majors.

The majority of jobs were in water depth less than 350 ft. Deepwater and floating structures and subsea wells are much more expensive and complex to decommission. Extrapolation of the summary statistics outside the aforementioned categories is not valid.

Observations

Removal operations usually contribute the most to decommissioning cost, and because service cost varies with market conditions, cost deserves careful and frequent review.

Removal costs vary a lot because a host of uncertain and unpredictable fac-

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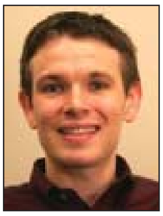

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tors influences the operation.

Cost estimates are judgments, made by managers and engineers, of the costs expected to arise based upon a comparison of similar projects, site characteristics, market conditions, and the collective experience of the estimator. Project managers try to manage and reduce uncertainty, but cost estimates will always be uncertain because of project uncertainties, unpredictable and uncontrollable conditions, and imperfect information. ✦

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New environmental challenges to test European refiners' flexibility, resources

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Purvin & Gertz
London

European refiners have enjoyed a short period of extremely good profitability caused by a tightening of refining capacity in the Atlantic Basin. The current recession, however, with the consequent loss of demand, has taken pressure off capacity and margins have reduced but not collapsed.

European refiners face new challenges driven by environmental concerns of a different order of magnitude from earlier ones. These challenges will test the flexibility and resourcefulness of participants. They will make more important than ever before the necessity to work with regulators to ensure realistic solutions that meet reasonable environmental objectives with due consideration to consumer and industry needs.

This article defines Europe as those countries to the west of Belorussia, Moldova, and Ukraine. Most (27) are members of the European Union and many not currently members wish to join.

The region covers 38 countries, a number that has grown as some of the countries in the East have subdivided. The most recent addition to achieve full international recognition is Montenegro, which sits between Albania and Bosnia.

The EU dominates the region, accounting for 90% of the refined products market. This has meant that all countries follow or plan to follow EU regulations for product specifications.

European refining

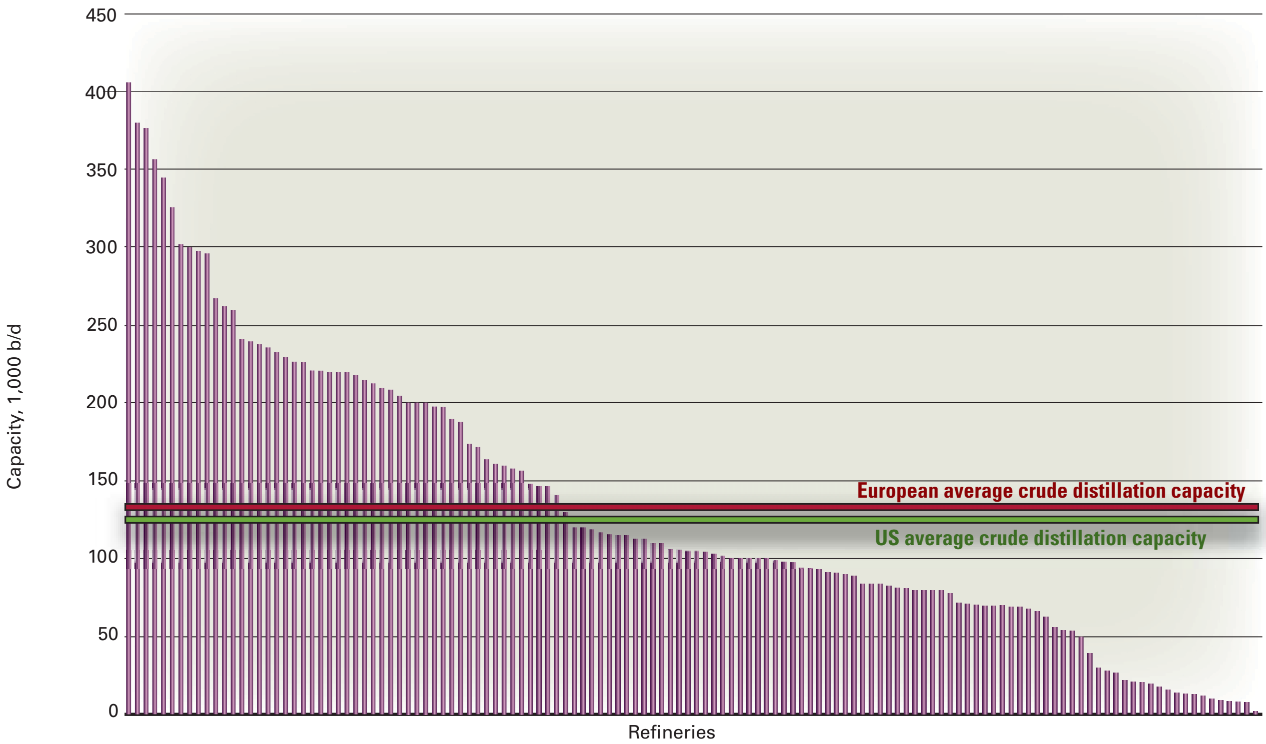
The European refining industry consists of 128 refineries with combined capacity of 17.3 million b/d. Fig. 1 shows the range of capacity is wide, with the largest refinery, Shell's plant at Pernis in the Netherlands, having a capacity of 406,000 b/d. Average capacity is 135,000 b/d.

Most very small refineries are either associated with local inland crude oil production or produce specialty products such as asphalt. Those associated with crude oil production will eventually close as their source of crude dries up.

Repsol YPF SA's 160,000-b/d Terragona refinery was one of several European refineries that in 2008 performed maintenance to units producing low-sulfur fuels to reduce carbon emissions. An EU directive on cleaner-burning diesel took effect in January 2009. Photograph from Repsol.

European refinery crude distillation profile

Fig. 1



In the late 1970s and early 1980s Europe experienced the same dramatic reduction in fuel oil demand as did the US. The level of conversion in European refineries, however, did not develop to the same extent as in the US. This period coincided with the rapid build up of North Sea crude production, and the European refiners were able to shift their slates away from heavier Middle East and West African crude to the lighter and sweeter North Sea grades.

This move, coupled with increasing demand for bunker fuel, allowed many refiners to avoid the expense of residue-destruction investment. Only those inland refineries that are away from the bunker market and have no easy access to North Sea crude have had to invest to convert fuel oil.

As a result the average Nelson Complexity of European refineries of 7.3 is below that of US refineries (Fig. 2).

The ownership structure of the European refining industry has evolved extensively over the last 2 decades. Historically, most of the capacity was owned by either the international majors or by national or regional companies. Fig. 3 shows there are only a small number of independents.

The years between 1995 and 2008 saw a marked reduction in capacity attributed to regional and European national companies. This was in part due to the privatization of some of the nationally based companies in Eastern Europe and also to the series of large acquisitions that resulted in Total becoming an international major rather than a national player.

Despite some initial aggressive acquisition policies the national oil companies of the oil producing countries made few inroads into Europe. Only Kuwait, Libya (through Oilinvest), and PDVSA remain, with Saudi Aramco in 2005 selling its only acquisition, a share in Motor Oil (Hellas). Ownership of investment funds controlled by the governments of oil producing countries has been excluded from consideration here.

Following are the three main challenges facing the industry:

- Adapting to the changing demand patterns, both in Europe and in its trading partners.
- Participating in European efforts to reduce greenhouse-gas emissions.
- Adjusting to the effects of future product-quality legislation.

Changing demand

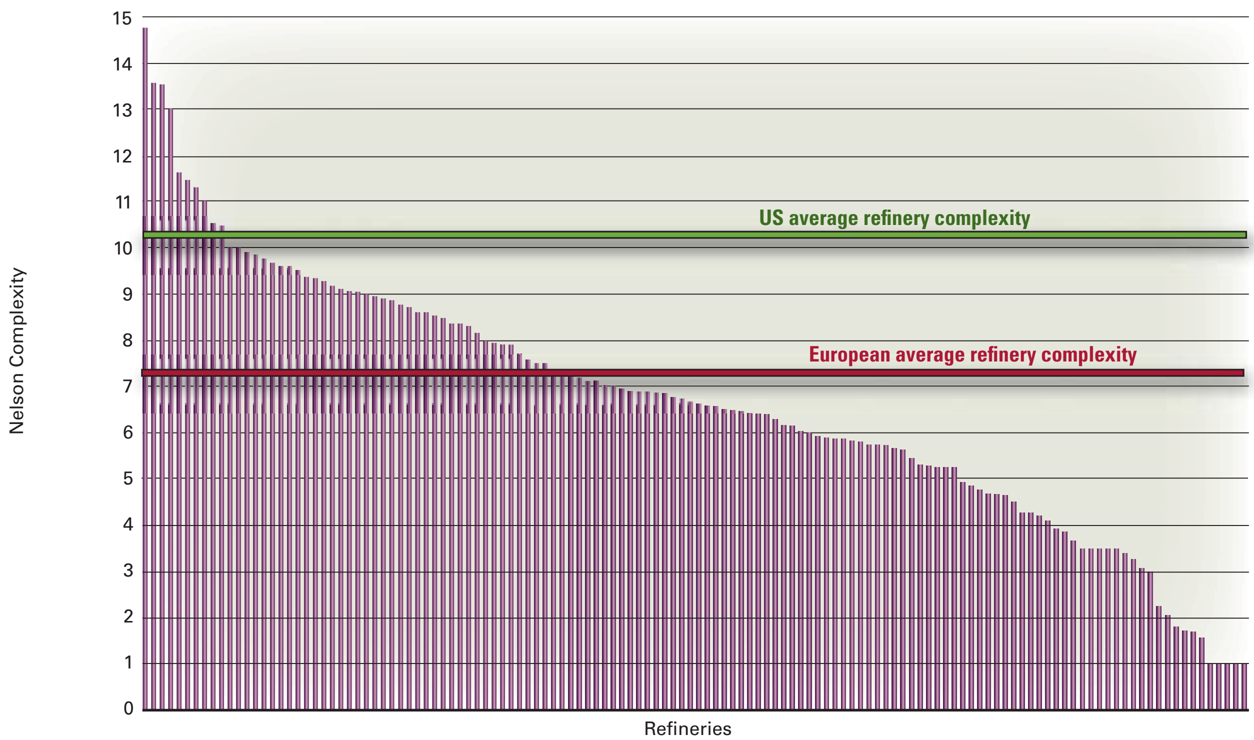
Through the 1980s and early 1990s, the European industry focused on configuring to meet the growing demand for motor gasoline.

By 1997 gasoline demand peaked and has been in decline since. The decline was in part due to the well-documented switch to diesel-powered cars by European drivers. Although sales of gasoline cars are beginning to recover in some markets, higher fuel prices will continue to drive consumers to diesel until such time as alternative power trains are developed.

Even without the shift to diesel cars,

EUROPEAN REFINERY COMPLEXITY PROFILE

Fig. 2



stringent fuel economy standards being set by the EU would lead to a decline in gasoline use. Although subject to further revision, the objective agreed with motor manufacturers is 130 g/km CO_2 emissions, which is equivalent to a gasoline consumption of 38 mpg (6.12 l./100 km). This represents a 19% reduction from the 2006 level. A further decrease under discussion targets 95 g/km CO_2 in 2020, equivalent to 50 mpg.

The result is an outlook that shows a continuing decline in gasoline consumption and moderate growth in middle distillates. Jet kerosine that had grown strongly up to 2008 is suffering from the present recession; future growth will be slower. Although there are growing concerns about the GHG emitted by aviation, the public desire for air travel, fuelled by low-cost airline expansion, is likely to prevail.

The forecast shows a gradual further decline in use of heating gasoil as the natural gas networks expand but continuing growth for diesel fuel in transportation. Despite a boost to consumption that is being driven by diesel cars, more than 70% of diesel use is for commercial vehicles. Fig. 4 shows the forecast changes in demand 2007-20.

The challenge European refiners face is to manage a growing surplus of gasoline while meeting an increased demand for middle distillates. Fig. 4 compares the anticipated demand for Europe with yields from hydroskimming Brent crude and the typical yield from a catalytic cracking refinery, still the dominant configuration in Europe. The magnitude of the gasoline mismatch is immediately apparent.

The fall in gasoline demand in Europe coincided with a period of rapid growth in the US, hence the trade of gasoline and gasoline components across the Atlantic. Gasoline trade grew to more than 600,000 b/d in 2006 from around 150,000 b/d in 2000. Through this period, European demand declined by 500,000 b/d, resulting in a balance between export volume growth and domestic demand decline.

The future looks more difficult. The 2007 US Energy Independence and Security Act will substantially increase the volumes of nonpetroleum gasoline used in the US, and more importantly it requires significant efficiency improvements from the vehicle fleet. There are indications from the administration of US President Barack Obama that emissions standards may be tightened further. This scenario couples with Purvin & Gertz's long-term oil price outlook that is likely to promote voluntary conservation.

The result of a declining export market for gasoline and declining domestic demand will be considerable pressure on the entire European refining industry and may result in closure of some marginal capacity. All refiners will see an economic incentive to minimize gasoline production; some may consider replacing FCC units with hydrocrackers. The need to increase middle distillate imports would support such a move.

On the middle distillate side, the picture is a great deal happier for European refiners. The region continues to be very short and imports primarily from Russia and the Middle East. Historically Russian imports suppressed refinery processing in Europe because they were available at lower cost than they could be produced. Now consumption has grown to a level that Europe depends on imports.

Considerable investment will be required in the region to supply the relatively modest growth that is forecast. Even with a continuing investment program, imports will rise further (Fig. 6).

Emissions trading system

The EU has positioned itself as a world leader in the mitigation of climate change and declared itself prepared to accept the economic consequences of GHG emissions reductions in view of the longer term cost of unmitigated global warming. One of the key planks of strategy is implementation of a cap-and-trade system for GHG emissions.

The EU established an emissions trading system in 2003 and subsequently modified it with other directives and decisions by various EU authorities. The scheme started in 2005 and has been implemented in trading periods:

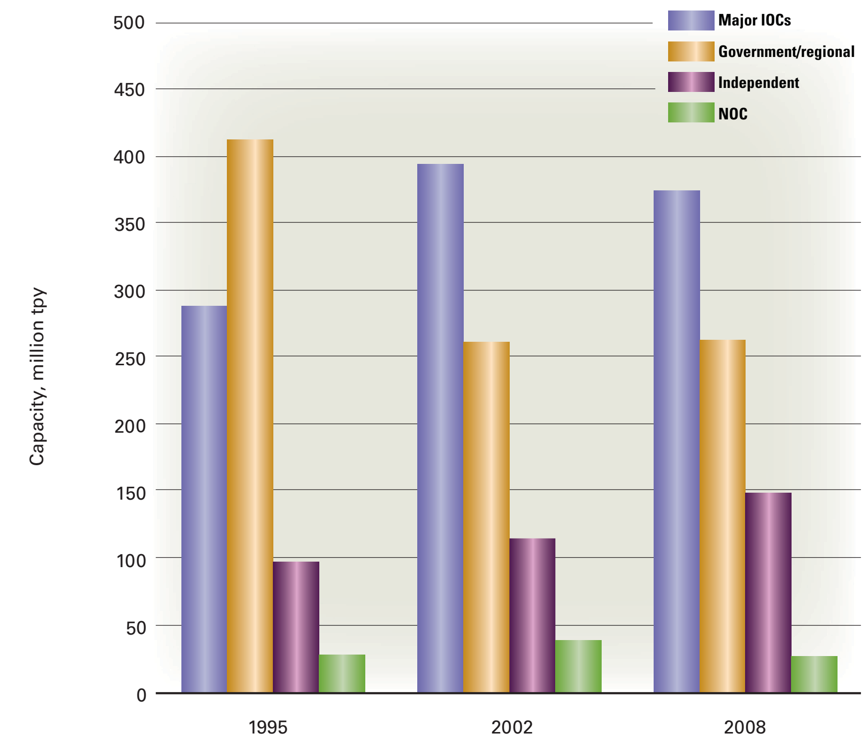
- The first trading period (Phase 1) began in January 2005 and lasted through 2007.
- The second trading period (Phase 2) began in January 2008 and runs to yearend 2012.
- The third trading period (Phase 3) will begin in January 2013.

In Phase 1, emission rights were allocated freely on the basis of national allocation plans developed by EU member countries. The main achievements of Phase 1 were establishment of a system to trade emissions and procedures to measure and verify emissions.

It is broadly recognized that Phase 1 did not lead to an actual reduction of

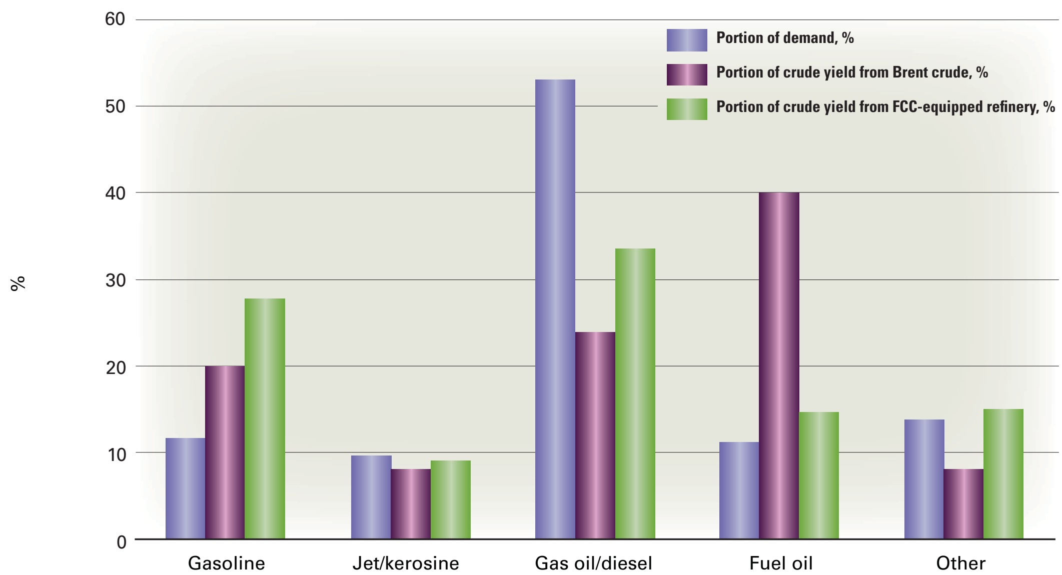
EUROPEAN REFINERY OWNERSHIP PROFILE

Fig. 3



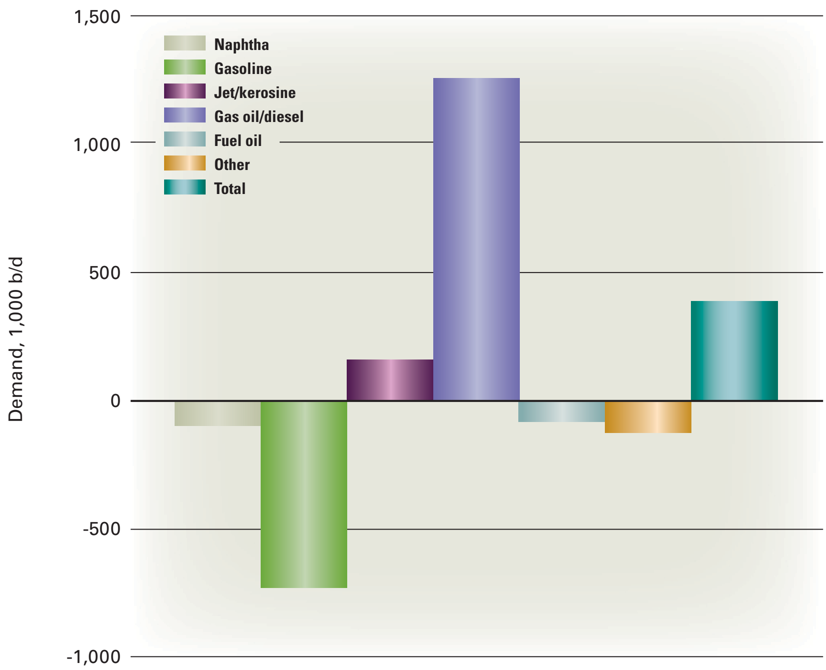
EUROPEAN DEMAND, PRODUCTION

Fig. 4



EUROPE DEMAND CHANGE, 2007-20

Fig. 5



GHG emissions primarily because too many allowances were issued and, by the end of Phase 1, the price of emission units was near zero due to lack of demand.

In Phase 2, emission rights were still allocated on the basis of NAPs, but member country plans were subject to more scrutiny and are expected to lead to a reduction of emissions. At the 2008 beginning of Phase 2, emission units started trading at more than €20/tonne of CO_2-equivalent (CO_2e) emissions, but prices have fallen to near €15/tonne of CO_2e as a result of the recession.

In Phase 2, the scope of the program has expanded in several ways. Three non-EU European countries—Norway, Iceland, and Liechtenstein—have joined the program. The aviation sector will be brought under the program in 2012. And emissions of new GHG, nitrous oxides, and perfluorocarbons were added to the program.

For Phase 3, still being defined, there is some remaining uncertainty about details of the program beyond 2012. The most recent details concerning Phase 3 were adopted by the European Council in April 2009.

The objective of the Phase 3 is to reduce CO_2e emissions by 20% by 2020, compared with 1990 levels. Considering that verified 2005 emissions were 1% greater than 1990 levels, the EU will need to reduce CO_2e emissions by 21% between 2005 and 2020.

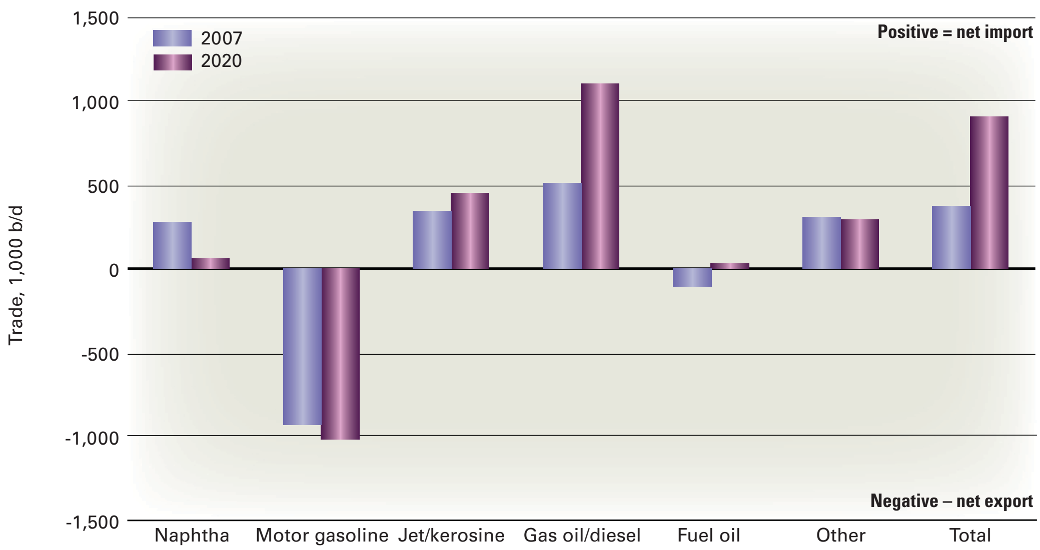
The EU, however, is considering modifying the 2020 emissions-reduction target to a 30% reduction (vs. 1990). It recognizes also that this could affect the competitiveness of several industries and that there are several provisions that refer to international cooperation.

But it is clear that the EU intends to move from a system of NAPs to an EU-wide system based on auctioning emission allowances. In this respect, industrial installations will be treated as follows:

• As of Jan. 1, 2013, the electric-

EUROPE NET TRADE: 2007 AND 2020

Fig. 6



ity generation sector will be required to buy 100% of its emission offsets through auctions.

- Other regulated industries will be put in on transitional program, whereby they will initially be given an allocation of free emissions equivalent to 80% of their average 2005-07 emissions, and will be required either to reduce emissions by 20% or buy emission credits. The free allocations would be progressively reduced by equal amounts each year, declining to 30% of 2005-07 emissions by 2020 and to zero by 2027.
- Industries deemed to be exposed to carbon "leakage" would continue to receive free allocations but would be subject to energy efficiency benchmarks. The definitions of leakage have been set, and there is now an effort under way to determine which industry segments are deemed to be exposed to leakage.

The ETS is only one item of what is referred to as the "Climate Package." It is generally recognized that the objectives of the EU ETS program will be very difficult to meet without significant contributions from renewables and from the commercial deployment of carbon capture and sequestration. For this reason, the package includes a renewables directive and a proposal for a directive to promote CCS.

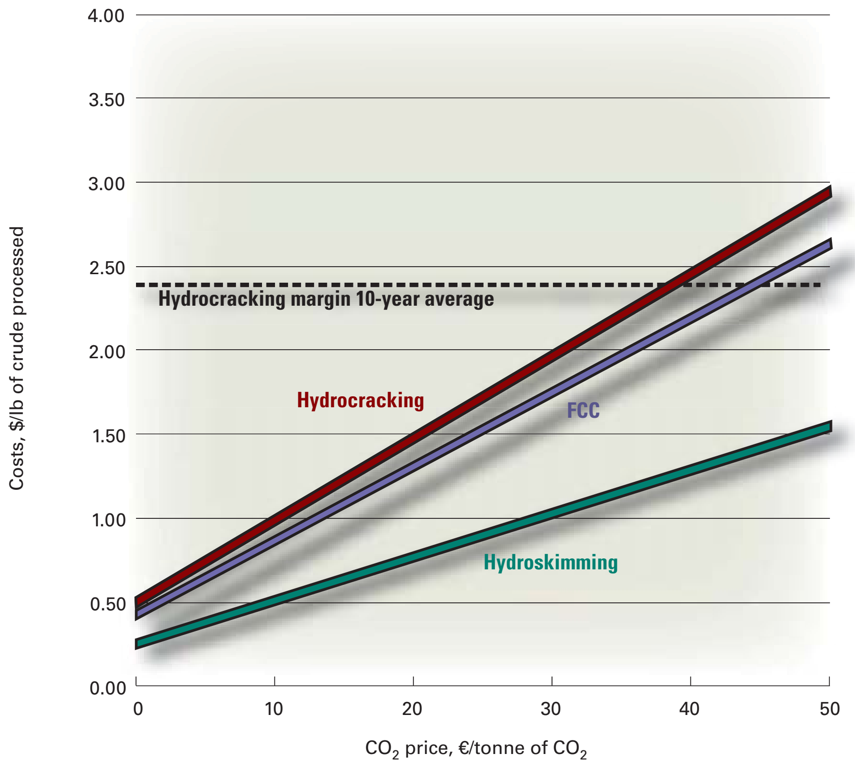
Other items of the package concern new vehicle efficiency targets referred to previously and policies aimed at improving energy efficiency in agricultural and residential sectors.

At the anticipated levels of carbon cost, the potential increase in operating cost for a European refinery that would have to purchase 100% of its required emissions permits would be substantial. Purvin & Gertz has analyzed the impact on its hydrocracking benchmark refinery at various levels of carbon cost (Fig. 7).

The anticipated range of carbon cost once a large proportion of credits is auctioned is expected to be €30-45/tonne. At this level, refinery operating cost would be substantially increased.

CO_2 PRICE, IMPACT ON REFINING COSTS

Fig. 7



It is clear that this level of cost could not be recovered from the market. Europe already must attract middle distillate imports to balance its supply needs and must export gasoline and fuel oil. It's possible the prices of these commodities will be set in locations that will not see the additional cost, such as the Middle East.

The magnitude of the price increase required to recover the carbon cost for the refinery is far more than the freight costs that might be incurred by an importer. Coincidently, if for example the product came from the Middle East, the carbon emissions from the shipping would be almost the same as the refinery emission to produce the incremental fuel. Thus, European refiners would be penalized for no benefit to the global climate.

This illustrates the care that regulations must take to ensure that "unintended consequences" don't negate what is trying to be achieved.

Product quality

The final challenge facing European refiners is the continued tightening of refined-product quality.

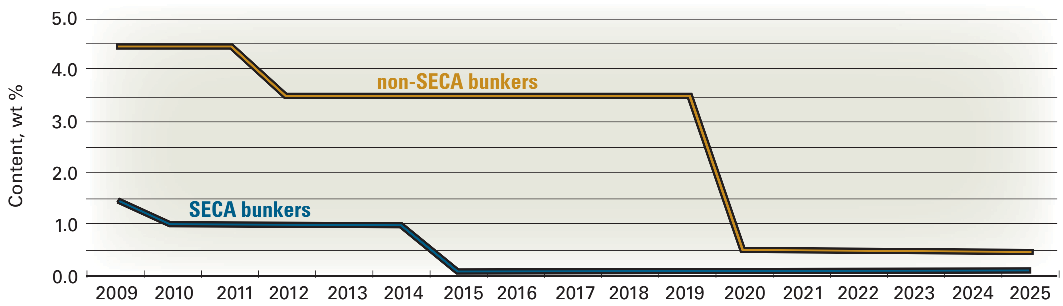
Since the mid-1990s, successive regulations have sought to improve the quality of fuels used in the EU. The benefit to air quality, particularly in urban areas, is readily apparent. Gasoline and diesel fuel have become almost designer products containing no sulfur and low levels of aromatics and olefins.

The sulfur part of the EU's liquid fuels directive mandates the use of low sulfur (<1%) fuel oil inland, unless the sulfur emissions are captured, and reduces the sulfur content of heating gas oil to 0.1%. A subsequent amendment imposes a lower sulfur content on the fuel used in off-road machinery (10 ppm) and domestic marine sectors (300 ppm, reducing to 10 ppm in 2012).

As hydrotreating capacity in the region is fully utilized, the increase in the volume required to be desulfur-

MARINE BUNKER FUEL MAX. SULFUR CONTENT

Fig. 8



ized to 10 ppm will place an additional burden on the industry. Purvin & Gertz estimates this volume to be around 20 million tonnes/year (400,000 b/d).

Probably the most fundamental change to the European refining industry is potentially the impact of the proposed changes to bunker-fuel quality. Since the 1970s, the International Maritime Organization has controlled and sought to reduce the environmental impact from international shipping.

The overall program comes under the International Convention on the Reduction of Pollution from Ships (MARPOL). That treaty has been in force for decades and has been effective in reducing waterborne pollution arising from oily-water wastes, bilge-water disposal, tank-cleaning emissions, and others.

MARPOL Annex VI governs air pollution from marine shipping. The original Annex VI introduced a global bunker-fuel sulfur limit at 4.5%. In October 2008 the IMO's Marine Environment Protection Committee ratified Annex VI amendments that potentially have a dramatic impact on global refining.

Annex VI amendments

The key feature of the Annex VI amendments will be the substantial reduction in the allowable sulfur in bunker fuels. The amendments call for emissions control areas, which are a development of the sulfur emissions control areas (SECA) that were introduced in the earlier amendment. The ECA can apply either to SOx, NOx, or particulate matter, or all three. The current SECAs are the Baltic Sea area and the North Sea-English Channel area.

The US, a signatory of MARPOL and Annex VI, has submitted a request for an SOx ECA roughly 200 miles off the full US coastline. Separately, California recently imposed a distillate-only bunker requirement.

Currently the ECA requirement specifies that bunker fuel with maximum sulfur of 1.5% must be used. As both of the current SECAs lie within the EU, the legislation to enforce the limits is an amended version of the Sulfur in Liquid Fuels Directive. In modifying this directive, the EU added a provision that ferries traveling among EU ports should also use low-sulfur bunkers. This imposed a demand for some lower-sulfur bunker fuel in the Mediterranean. It is estimated that at present around 12 million tonnes/year of low-sulfur bunker is supplied in Europe.

The Annex VI Amendments provide for a substantial reduction in the allowed sulfur levels both within and outside ECAs. Fig. 8 shows the proposed progression.

In 2010 the sulfur in fuel used in an ECA will drop to 1% maximum, with a further reduction in 2015 to 0.1%. Outside of the ECAs, the maximum sulfur would drop to 3.5% in 2012, with a further reduction to 0.5% in 2020. The reduction to 0.5% will be subject to a study in 2018 and, if availability appears to be an issue, the move can be delayed to 2025.

The Annex VI amendments provide for "equivalent" means of meeting sulfur emissions requirements. Effective emissions scrubbing technology on-vessel may allow shippers to use bunker fuels with higher sulfur levels.

The technology takes advantage of naturally occurring calcium carbonate dissolved in seawater to remove SOx emissions. As part of the scrubbing process, soot, unburned fuel, and other particulates such as fuel-derived metals are also recovered in a waste material that can be disposed of onshore.

Formal approval of scrubbing technology has not occurred and ultimately may depend on approval of the maritime states' environmental and marine safety regulators.

The SOx ECA program could expand considerably. ECAs could be established in various areas around the world where ship-derived emissions contribute to onshore pollution. Such areas may include most of North America and European waters, including the Mediterranean and Straits of Malacca, and seas off Northeast Asia.

Impacts

The refining industry faces major obstacles in producing higher-quality marine fuels. The average sulfur content of intermediate fuel oil-grade marine fuels is currently more than 2.5%. Refiners may need to reduce sulfur to 0.5%. In the short term, many refiners can blend acceptable fuels for the ECAs because they currently account for only a small portion of marine fuels burned.

The longer term difficulties are greater. The reduction to 3.5% sulfur outside the ECAs is unlikely to cause widespread problems and the move to 1% in the ECAs is also likely not to be difficult as blends can be modified to redistribute the higher sulfur components.

The drop to 0.1% sulfur and 0.5%, however, is much more challenging. At this level, reblending will not be an option because there are limited volumes of crudes available that meet the lower sulfur level. Current technology is unable to reduce the sulfur of residues to 0.1% unless very low sulfur feed is used. Even if technology were to develop to achieve this, the likelihood is that the cost would be equivalent to converting the fuel oil to lighter, more valuable fuels. Refiners that could afford to invest would simply leave the bunker market.

Some bunker fuel could be produced at 0.5% sulfur by segregating the residues from very low sulfur crudes. Once again, however, desulfurization would be required to meet the limit and even at this level, the cost would be prohibitive and refiners would preferentially invest to convert rather than just remove sulfur.

In Europe the change would be exacerbated by the lack of alternative outlets for the high-sulfur components. Refiners would be faced with having either to change crude slate, export high-sulfur components to the few remaining and rather distant markets that would be able to accept them, or make a major investment.

Unlike other specification changes such as the reduction of diesel sulfur, the investment cost to desulfurize or convert residue is very large and location-specific and requires economy of scale. A typical hydrocracking plus coker complex with associated units can cost in the order of $2 billion, a sum that is beyond the financing capability of many smaller regional refineries. Purvin & Gertz has studied the proposals and calculated the range of compliance investment for European refiners lies between $20 and $25 billion.

The investment required to supply the higher quality bunker fuels would push up prices into the range of middle distillate. Consequently the most likely outcome is that refiners convert fuel oil to distillates. The fuel cost to shipowners will rise dramatically. The higher intensity of processing in refineries will cause an increase in CO_2 emissions that governments struggling to meet national emissions reduction targets will find burdensome.

Lastly, the possibility that on-board scrubbers may be widely adopted adds to the uncertainty surrounding the regulation. The potential investment is huge and the lead time correspondingly long. The refining and shipping industries along with the regulators need to come to an understanding soon on future action if the IMO timetable is to be met. ✦

The author

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Study outlines method for managing unexpected liquids

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Jing Gong
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Beijing

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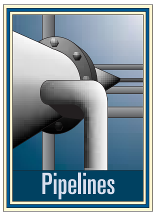
West-East Pipeline (Marketing) Co.
Shanghai



Preventing hydrate formation when wet gas is introduced to a trunkline designed for dry service requires a combination of careful modeling and diligent operation.

The West-East Gas Pipeline runs 4,000 km from Lunnan, Xinjiang, to Shanghai. Three gas sources at Lunnan initially draw from Tarim natural gas field: Kela 2, Yaha, and Sangji.

A May 2005 accident at Kela 2's gas treatment facilities forced the pipeline to operate under emergency procedures and rapidly reduce the amount of gas transported. Starting June 9, 2005, rough processing gas from Kela 2 entered the trunk pipeline gradually. The trunklines transported a wet gas mixture from Kela 2, Yaha, and Sangji, leading to many operational problems before the low-temperature treatment facility at Kela 2 resumed production in November 2005.

West-East Pipeline (Marketing) Co. pigged the west leg of the trunkline between late May and early June, forcing an ice-like object into a pig receiver (Fig. 1). The flammable nature of the object (Fig. 2) confirmed hydrate formation in the pipeline.

West-East Pipeline (Marketing) hired China University of Petroleum (CUP) to conduct experiments and research on hydrate-forming conditions of the source gas to ensure the pipeline, designed to deliver dry gas, could still operate normally. This article discusses

Operators of China's West-East Gas Pipeline found this ice-like object upon opening a pig receiver (Fig. 1).

EQUATIONS

$$f_i = x_i^* f_i^0 \left(1 - \sum_j \theta_j\right)^a \quad (1)$$

$$\sum_i x_i^* = 1.0 \quad (2)$$

$$\sum_j \theta_j = \frac{\sum_j f_j C_j}{1 + \sum_j f_j C_j} \quad (3)$$

$$f_i^0(T) = \exp\left(\frac{-\sum_j A_{ij}\theta_j}{T}\right) \cdot \left[a_i \exp\left(\frac{b_i}{T - c_i}\right)\right] \quad (4)$$

Where: A_{ij} are the binary interaction parameters specifying the guest-guest interaction between components i and j ($A_{ij} = A_{ji}$, $A_{ii} = A_{jj} = 0$).

Nomenclature

f = fugacity of gas species, Pa
θ = fraction of the linked cavities occupied by guest molecules
x^* = mole fraction of basic hydrate formed by gas species in mixture hydrate
f^0 = fugacity of gas species in basic hydrate, Pa

the results of these experiments and research.

Sampling gas

Seven gas samples taken from different sites defined the pipeline's gas composition. Four samples came from Tarim field, Lunnan station, and three were taken along the West-East Gas Pipeline trunk. These included:

- Sangji field at Lunnan station(S1).
- Yaha field, Kela 2 at Lunnan station (S2).
- Yaha field at Valve Room 4 (S3).
- Kela 2 field at Valve Room 4 (S4).
- Gulang pigging station (S5).
- Valve Room 53 at Jinchang (S6).
- Shandan compressor station (S7).

The last three of these came from the trunk line. An HP6890 chromatograph at CUP determined gas sample composition. Table 1 lists the results.

Hydrate formation

Water and small gas molecules such as CH_4, C_2H_6, C_3H_8, CO_2, H_2S, N_2, and SO_2 form natural gas hydrates; crystals with the appearance of snow or ice powder. Hydrate formation needs proper gas composition and thermal conditions: a certain quantity of water and small gas molecules, and the appropriate temperature and pressure.

Hydrates form more easily when temperature is lower and pressure higher. A sapphire autoclave determined hydrate formation conditions of the gas samples (Fig. 3). The autoclave's maximum effective volume measured 60 cc, with a maximum operating pressure of 20 MPa and operating temperature ranging between –90° C. and 150° C.

The common experimental method to determine hydrate forming conditions in the laboratory is the pressure-search method, which changes system pressure at a constant temperature to determine equilibrium conditions. System temperature and pressure remaining constant for >4-6 hr with a small amount of hydrate particles remaining in the system define temperature and pressure as at equilibrium. This method determined hydrate forming conditions for all gas samples.

Pressure ranged between 2.80 and 7.1 MPa and temperature between 276.15 and 288.15 K. Table 2 lists the experimental results.

The gas samples taken along the trunk line have similar composition, so that only the forming condition at S5 was measured. Since gas transported in the West-East Gas Pipeline mixed the three gas sources in different ratios, gas composition varied. The predicting model developed in this article can measure varied gas compositions.

The object's flammable nature suggested hydrocarbon content, helping confirm hydrate formation in the pipeline (Fig. 2).

GAS SAMPLE COMPOSITION

Table 1

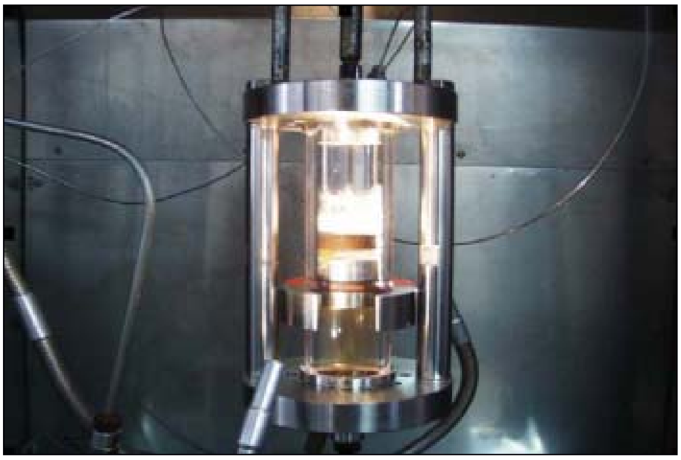
Composition	S1	S2	S3	S4	S5	S6	S7
				Mol %			
CO_2	0.6038	0.6361	0.6535	0.6440	0.8898	0.5685	0.8354
N_2	3.6349	2.1626	3.6884	0.5877	2.2867	2.2638	2.7168
C_1	93.8378	92.0601	83.1499	98.1315	92.8345	92.7476	93.0915
C_2	1.3461	3.7828	9.0730	0.5299	2.7773	2.8987	2.2165
C_3	0.3203	0.9256	2.3620	0.0482	0.7201	1.0378	0.7408
Iso-C_4	0.0466	0.1387	0.3629	0.0069	0.1375	0.1429	0.1032
Normal C_4	0.0788	0.1562	0.4014	0.0092	0.1778	0.1779	0.1398
Iso-C_5	0.0253	0.0402	0.1032	0.0034	0.0513	0.0503	0.0400
Normal C_5	0.0347	0.0345	0.0844	0.0031	0.0514	0.0503	0.0437
C_6	0.0358	0.0254	0.0575	0.0040	0.0736*	0.0622*	0.0723*
C_7	0.0241	0.0305	0.0501	0.0268			
C_8	0.0118	0.0073	0.0137	0.0053			
Sum	**100**	**100**	**100**	**100**	**100**	**100**	**100**

*C_{6+}.

HYDRATE FORMATION, EXPERIMENT RESULTS

Table 2

Sample 1 Temp., K.	Sample 1 Pressure, MPa	Sample 2 K.	Sample 2 MPa	Sample 3 K.	Sample 3 MPa	Sample 4 K.	Sample 4 MPa	Sample 5 K.	Sample 5 MPa
278.15	2.81	282.15	3.14	285.15	3.25	276.15	3.30	283.15	3.45
281.15	4.05	284.15	4.04	287.15	4.20	278.15	4.10	284.15	3.93
283.15	5.34	286.15	5.24	289.15	5.54	281.15	5.63	285.15	4.65
284.15	6.11	287.15	6.01	290.15	6.40	282.15	6.22	286.15	5.30
285.15	7.05	288.15	6.95					287.15	6.05
								288.15	7.10



This transparent sapphire autoclave determined the hydrate-forming conditions of natural gas samples (Fig. 3).

Average soil temperatures

Table 3

Station	Summer	Hottest month	Annual	Winter
	°C.			
Lunnan	24.5	25.2	17.0	8.8
Shanghai	21.9	22.6	15.8	9.6

Most existing thermodynamic models for predicting hydrate formation modify the vdWP model proposed by van der Waals and Platteeuw. These models, however, have a relatively large deviation. The Chen-Guo model, based on statistical mechanics and a two-step hydrate formation mechanism, has a clearer physical meaning, simpler mathematical expression, and more accurate results.[1, 2]

Equations 1-3 express the Chen-Guo model. Taking the interactions between guest molecules in linked cavities and basic cavities into account yields Equation 4.

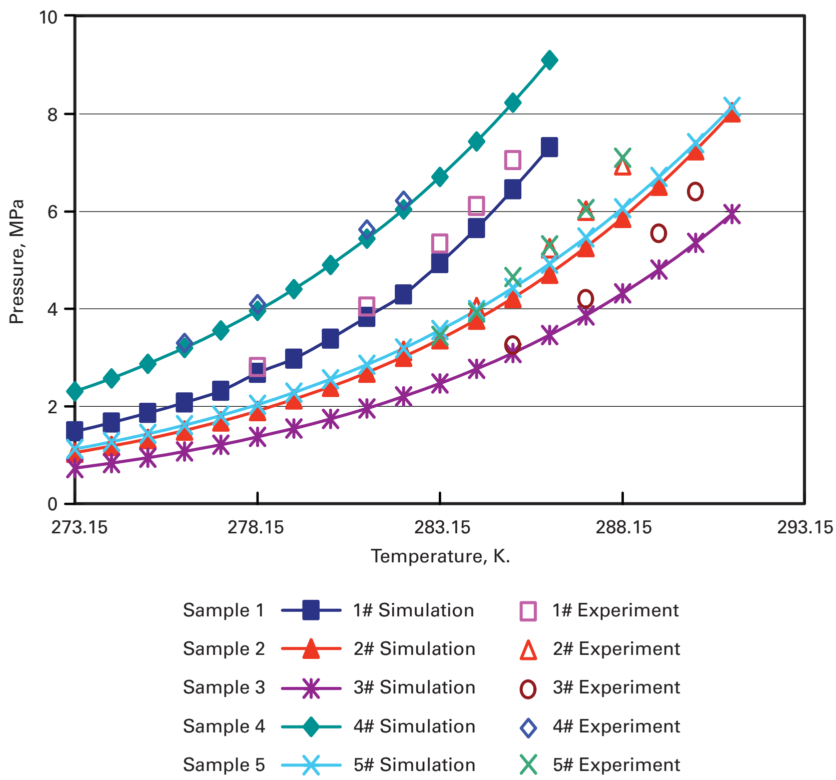
This article used the PR-Equation of State,[3] before achieving gas-liquid-liquid-hydrate flash equilibrium and determining hydrate forming conditions.

A comparison between simulation results and experimental data verified the model. Fig. 4 shows the simulation results in good agreement with the experimental results, verifying the models usability in predicting hydrate-formation conditions on the West-East Gas Pipeline.

Fig. 4 shows hydrate-forming temperature of 283.15-293.15 K. when the pipeline operates between 7 and 10 MPa. Once free water exists in a pipeline hydrates may be formed, requiring its exclusion regardless of operating conditions. The temperature of gas in the pipeline equals the temperature of soil in situ (Table 3).

Hydrate formation conditions

Fig. 4



Hydrate prevention

Hydrate formation requires free water in the pipeline. All the water in wet gas sourced from Kela 2 field will not enter the West-East Gas Pipeline, as some will deposit in the 138-km branch line from Kela 2 to Lunnan before it joins the other two gas sources. The water content in the trunkline therefore is the average of those of three gas sources, with precipitation of Kela 2 wet gas in the branch line taken into account and decreasing the water content.

Controlling and adjusting the ratios of gas from the three sources during different months ensured secure operation (no hydrate formation) under these conditions.

From June to August gas from Yaha field measured 3.5×10^6 cu m/day, gas from Sangji field 3×10^6 cu m/day, and gas from Kela 2 field 4×10^6 cu m/day. Small amounts of water precipitated with these ratios, but no hydrates formed because the temperature of soil was higher than the forming temperature. In September and October volumes from Kela 2 field dropped to 3×10^6 cu m/day to lower the water content, and remaining gas containing more saturated water was forced to the east section from the west section to prevent water precipitation.

Wet gas supplies from Kela 2 stopped in November, with the newly returned dry gas gradually displacing the wet gas from west to east, ensuring free water did not precipitate and completing successful operation of the pipeline through the accident period. ✦

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Equipment/Software/Literature

New offshore drilling power module

Here's the new QSK60 offshore drilling power module.

It's rated at 1,855 hp at 1,200 rpm with a 10% overload capability and is integrated with an AvK DSG99 alternator at 2,150 kVa and 690 v. The maker says its unit is suited for durability, reliability, and power density requirements of high-hour and hard-duty cycle applications such as drilling power modules with no major midlife top-end overhaul requirement.

The modular common rail (MCR) fuel system enables full-authority electronic control over fuel timing, quantity, pressure, and delivery rate shape. Precision control over the number of injection events enables optimum performance, fuel economy, smooth power delivery, better idle stability, and reduced engine noise, as well as providing the capability for an in-cylinder Tier 2 emissions solution, the firm notes. The company points out that

it has optimized the MCR fuel system for load requirements in drilling applications, allowing the power module to achieve a 4-9% fuel economy advantage over competitive Tier 1 and Tier 2 products of similar speeds and ratings. The MCR fuel system also gives the QSK60 power module a fine-tuned fuel calibration to meet all marine regulations, including EPA Marine Tier 2, IMO Tier 1, and EC Directive Regulations.

The firm designed its product for the lowest installation cost for repowers by using customer interfaces similar to competitor packages for quick installation in rigs that allow for the easiest accessibility. The QSK60 is also designed with common mounting arrangements for drilling applications.

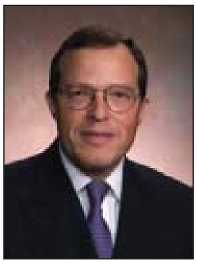
The power module offers an electronic information system with a C-Command Elite and Elite Plus panel designed to protect and enhance engine performance and manage cost. The electronic information system and special panels provide customers rugged controls that are able to stand up to marine environments and use flexible presentations of engine parameters, multilingual touch screens with full-color text and graphics, and remote panel options to simultaneously monitor up to eight engines.

Source: **Cummins Inc.,** 500 Jackson St., Columbus, IN 47202-3005.

Services/Suppliers

Transocean Ltd.,

Zug, Switzerland, has named Richard H. Rosa senior vice-president and CFO effective Sept. 1. He will be based in Geneva and will succeed Gregory L. Cauthen. Rosa is currently senior vice-president of the company's Europe and Africa unit. Previously, he served as senior vice-president of Transocean's Asia and Pacific unit. Prior to that role, he was vice-president and controller and in a variety of international positions in finance for 19 years. Rosa has an MA from Oxford University and was qualified as a chartered accountant with the Institute of Chartered Accountants in England and Wales.



Rosa

Transocean Ltd. is the world's largest offshore drilling contractor and a leading provider of drilling management services worldwide.

Capstone Turbine Corp.,

Chatsworth, Calif., has named Aqua Nishihara as its distributor in Thailand. Aqua Nishihara will focus on microturbine system opportunities with oil and gas operations, offshore oil rigs, landfills, agricultural/biogas, and combined heat and power applications, as well as selling Capstone microturbines for wastewater treatment systems.

Capstone is a leading producer of low-emission microturbine systems to the energy industry and was the first to market commercially viable microturbine energy products.

Cegelec,

Paris, has signed a turnkey contract with Cote d'Ivoire refiner Societe Ivoirienne de Raffinage (SIR) to design, procure, build, and commission a new control system for the HSK3 hydroskimming unit at SIR's 60,000 b/d refinery in Cote d'Ivoire. Work will begin this summer.

Cegelec is an international group that designs, installs, and maintains instrumentation and control systems and subsystems to the industrial, infrastructure, and service sectors.

Mustang Engineering,

Houston, has entered into a joint venture with Malaysia's Petronas and Petronas's shipping subsidiary MISC Bhd. to develop integrated floating LNG liquefaction, storage, and offloading solutions using Mustang's LNG Smart liquefaction technologies. The JV is owned by Petronas 60%, MISC 30%, and Mustang 10% and will be headquartered in Kuala Lumpur. The first project will be the development of front-end engineering design for a floating LNG vessel, to be located off Malaysia. The project is expected to achieve first gas from a floating LNG FPSO facility in 2013.

Mustang, part of the UK-based Wood Group, specializes in design, engineering, procurement, project management, and construction management to the upstream oil and gas, midstream, pipeline, automation and control, refining and petrochemicals, and process and industrial sectors.

PennEnergy EQUIPMENT
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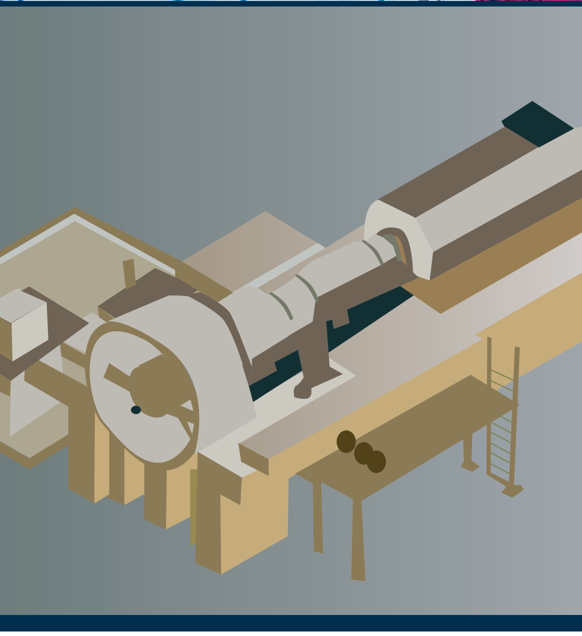


Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment.

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

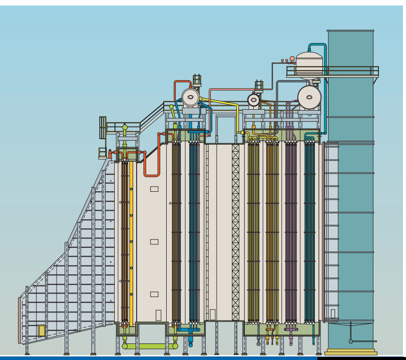
- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.

Four 58-MW Rolls-Royce Trent GTGs Available for Delivery Within 120 days

The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Three New Vogt F-class HRSGs Now Available for Completion and Delivery by Vogt Within 14 Months



- Product type: natural circulation – unfired, triple pressure reheat heat recovery steam generators (HRSGs) designed for F class gas turbines.
- The HRSGs are designed for duct firing and feature a horizontal gas path; three pressure levels and reheat unfired.
- The buyer will have some flexibility to incorporate certain modifications before final completion by Vogt.
- Units come complete with all normally supplied auxiliaries.

Offered by THOMASSEN AMCOT INTERNATIONAL, LLC exclusively through PennEnergy

For Info or Pricing Contact

Randy Hall rhall@pennenergy.com P: 713-499-6330 | Bart Zaino bzaino@thomassenamcot.com P: 817-263-3273

Statistics

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1–4 5-29 2009	Districts 1–4 5-22 2009	District 5 5-29 2009	District 5 5-22 2009	Total US 5-29 2009	Total US 5-22 2009	Total US *5-30 2008
	1,000 b/d						
Total motor gasoline	925	960	24	45	949	1,005	1,310
Mo. gas. blending comp.	643	695	24	45	667	740	916
Distillate	159	203	49	0	208	203	211
Residual	383	454	44	34	427	488	216
Jet fuel–kerosine	75	60	27	13	102	73	162
Propane–propylene	86	128	2	4	88	132	111
Other	515	515	(25)	11	490	526	349
Total products	**2,786**	**3,015**	**145**	**152**	**2,931**	**3,167**	**3,275**
Total crude	**8,448**	**7,873**	**1,198**	**905**	**9,646**	**8,778**	**9,786**
Total imports	**11,234**	**10,888**	**1,343**	**1,057**	**12,577**	**11,945**	**13,061**

*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

	*6-5-09	*6-6-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	76.80	143.52	–66.72	–46.5
Brent crude	67.30	127.77	–60.47	–47.3
Crack spread	9.49	15.75	–6.26	–39.7
FUTURES MARKET PRICES				
One month				
Product value	78.52	147.15	–68.63	–46.6
Light sweet crude	68.10	128.14	–60.04	–46.9
Crack spread	10.42	19.01	–8.59	–45.2
Six month				
Product value	77.91	142.29	–64.38	–45.2
Light sweet crude	71.94	128.33	–56.39	–43.9
Crack spread	5.97	13.96	–7.99	–57.2

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

PURVIN & GERTZ LNG NETBACKS—JUNE 5, 2009

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.31	4.72	6.51	4.62	5.28	6.43
Everett	3.15	1.20	2.80	1.30	1.70	3.45
Isle of Grain	3.10	1.17	2.53	1.08	1.67	2.56
Lake Charles	1.30	–0.37	1.09	–0.23	–0.07	1.95
Sodegaura	3.42	5.49	3.67	5.22	4.55	2.83
Zeebrugge	4.59	2.62	4.06	2.51	3.18	4.11

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

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	14,394	52,575	35,465	11,057	59,846	16,699	4,120
PADD 2	84,676	47,182	21,590	8,099	32,313	1,233	19,643
PADD 3	190,743	70,246	39,714	12,336	42,265	17,519	26,357
PADD 4	17,218	5,592	1,931	673	2,916	382	[1]1,117
PADD 5	58,946	27,607	21,836	9,208	12,696	4,299	—
May 29, 2009	**365,977**	**203,202**	**120,536**	**41,373**	**150,036**	**40,132**	**51,237**
May 22, 2009	**363,111**	**203,417**	**120,128**	**40,449**	**148,375**	**38,468**	**49,352**
May 30, 2008[2]	**306,757**	**209,090**	**103,474**	**39,751**	**111,704**	**38,166**	**38,002**

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

REFINERY REPORT—MAY 29, 2009

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,279	1,283	2,306	62	367	139	50
PADD 2	3,251	3,230	2,033	185	875	42	263
PADD 3	7,417	7,118	2,820	645	2,153	279	662
PADD 4	561	558	285	27	153	12	[1]63
PADD 5	2,735	2,536	1,353	415	504	129	—
May 29, 2009	**15,243**	**14,725**	**8,797**	**1,334**	**4,052**	**601**	**1,038**
May 22, 2009	**15,040**	**14,733**	**9,378**	**1,439**	**4,036**	**552**	**1,072**
May 30, 2008[2]	**15,785**	**15,480**	**9,113**	**1,566**	**4,506**	**710**	**1,126**
	17,672 Operable capacity		**86.3 utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 6-3-09	Pump price* 6-3-09	Pump price 6-4-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	202.1	248.6	408.7
Baltimore	204.4	246.3	396.1
Boston	207.8	249.7	397.1
Buffalo	199.3	260.2	414.1
Miami	212.7	264.3	417.7
Newark	205.6	238.2	393.3
New York	193.2	254.1	405.1
Norfolk	199.1	237.5	390.6
Philadelphia	206.1	256.8	406.3
Pittsburgh	204.6	255.3	397.7
Wash., DC	219.4	257.8	408.7
PAD I avg	204.9	251.7	403.2
Chicago	230.3	294.7	435.1
Cleveland	218.2	264.6	390.2
Des Moines	215.7	256.1	389.5
Detroit	219.6	279.0	401.5
Indianapolis	207.3	266.7	393.3
Kansas City	205.2	241.2	386.4
Louisville	221.4	262.3	399.7
Memphis	200.2	240.0	382.7
Milwaukee	221.3	272.6	407.4
Minn.-St. Paul	215.1	259.1	393.0
Oklahoma City	207.8	243.2	379.6
Omaha	207.3	252.6	389.2
St. Louis	203.9	239.9	389.0
Tulsa	201.7	237.1	376.8
Wichita	201.5	244.9	373.0
PAD II avg	211.8	256.9	392.4
Albuquerque	208.3	244.7	382.9
Birmingham	200.7	240.0	389.5
Dallas-Fort Worth	204.8	243.2	393.5
Houston	201.3	239.7	386.5
Little Rock	198.0	238.2	387.8
New Orleans	202.2	240.6	390.6
San Antonio	197.2	235.6	384.9
PAD III avg	201.8	240.3	388.0
Cheyenne	201.3	233.7	379.0
Denver	199.8	240.2	391.9
Salt Lake City	193.2	236.1	388.9
PAD IV avg	198.1	236.7	386.6
Los Angeles	211.1	278.2	436.7
Phoenix	202.2	239.6	401.0
Portland	220.8	264.2	413.0
San Diego	215.0	282.1	445.5
San Francisco	222.7	289.8	443.9
Seattle	218.9	274.8	421.8
PAD V avg	215.1	271.4	427.0
Week's avg.	**207.8**	**253.4**	**399.0**
May avg.	**179.0**	**224.6**	**372.9**
Apr. avg.	**156.7**	**202.3**	**339.3**
2009 to date	**154.5**	**200.1**	—
2008 to date	**287.0**	**330.6**	—

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

REFINED PRODUCT PRICES

Spot market product prices

	5-29-09 ¢/gal		5-29-09 ¢/gal
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	184.20	New York Harbor	163.63
Gulf Coast	185.45	Gulf Coast	161.86
Los Angeles	192.21	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	182.01	ARA	165.29
Singapore	183.07	Singapore	166.50
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	190.75	New York Harbor	141.67
Gulf Coast	188.58	Gulf Coast	143.93
Los Angeles	203.21	Los Angeles	120.61
		ARA	134.05
		Singapore	140.46

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

BAKER HUGHES RIG COUNT

	6-5-09	6-6-08
Alabama	4	3
Alaska	6	8
Arkansas	45	48
California	21	43
Land	20	42
Offshore	1	1
Colorado	46	106
Florida	1	0
Illinois	1	0
Indiana	2	2
Kansas	18	9
Kentucky	10	11
Louisiana	132	160
N. Land	72	58
S. Inland waters	4	24
S. Land	10	25
Offshore	46	53
Maryland	0	1
Michigan	0	1
Mississippi	9	11
Montana	0	14
Nebraska	0	0
New Mexico	35	74
New York	2	7
North Dakota	34	70
Ohio	8	11
Oklahoma	76	207
Pennsylvania	33	20
South Dakota	0	2
Texas	327	931
Offshore	2	11
Inland waters	0	3
Dist. 1	10	27
Dist. 2	14	32
Dist. 3	21	66
Dist. 4	34	101
Dist. 5	78	183
Dist. 6	51	121
Dist. 7B	14	31
Dist. 7C	7	73
Dist. 8	39	131
Dist. 8A	11	26
Dist. 9	21	43
Dist. 10	25	83
Utah	15	38
West Virginia	22	26
Wyoming	31	68
Others—HI-1;NV-3;VA-5;	9	15
Total US	**887**	**1,886**
Total Canada	**101**	**218**
Grand total	**988**	**2,104**
US Oil rigs	179	385
US Gas rigs	700	1,493
Total US offshore	52	66
Total US cum. avg. YTD	**1,171**	**1,805**

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	6-5-09 Rig count	6-5-09 Percent footage*	6-6-08 Rig count	6-6-08 Percent footage*
0-2,500	49	10.2	71	4.2
2,501-5,000	68	55.8	128	51.5
5,001-7,500	113	15.9	242	11.5
7,501-10,000	182	4.3	427	3.9
10,001-12,500	179	5.0	470	2.7
12,501-15,000	151	0.6	302	0.3
15,001-17,500	116	—	124	—
17,501-20,000	46	—	76	—
20,001-over	35	—	37	—
Total	**939**	**8.4**	**1,877**	**6.8**
INLAND	11		27	
LAND	885		1,791	
OFFSHORE	43		59	

*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]6-5-09	[2]6-6-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	712	678
California	657	651
Colorado	63	65
Florida	7	3
Illinois	28	25
Kansas	103	105
Louisiana	1,450	1,301
Michigan	16	17
Mississippi	61	59
Montana	95	86
New Mexico	166	161
North Dakota	197	156
Oklahoma	177	170
Texas	1,358	1,345
Utah	57	56
Wyoming	151	144
All others	67	81
Total	**5,386**	**5,124**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	6-5-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	68.25
California-Kern River 13°	60.75
Lost Hills 30°	69.15
Wyoming Sweet	57.94
East Texas Sweet	64.50
West Texas Sour 34°	59.00
West Texas Intermediate	65.00
Oklahoma Sweet	65.00
Texas Upper Gulf Coast	58.00
Michigan Sour	57.00
Kansas Common	63.75
North Dakota Sweet	54.00

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	5-29-09
United Kingdom-Brent 38°	60.59
Russia-Urals 32°	60.37
Saudi Light 34°	57.09
Dubai Fateh 32°	59.94
Algeria Saharan 44°	61.57
Nigeria-Bonny Light 37°	62.62
Indonesia-Minas 34°	64.71
Venezuela-Tia Juana Light 31°	62.20
Mexico-Isthmus 33°	62.09
OPEC basket	60.68
Total OPEC[2]	59.61
Total non-OPEC[2]	60.37
Total world[2]	59.94
US imports[3]	59.36

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

US NATURAL GAS STORAGE[1]

	5-29-09	5-22-09	5-29-08	Change, %
		bcf		
Producing region	900	870	618	**45.6**
Consuming region east	953	892	838	**13.7**
Consuming region west	360	345	232	**55.2**
Total US	**2,213**	**2,107**	**1,688**	**31.1**
	Mar. 09	**Mar. 08**	**Change, %**	
Total US[2]	**1,656**	**1,247**	**32.8**	

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

INTERNATIONAL RIG COUNT

Region	May 09 Land	May 09 Off.	May 09 Total	May 08 Total
WESTERN HEMISPHERE				
Argentina	46	1	47	69
Bolivia	4	—	4	3
Brazil	32	31	63	46
Canada	71	1	72	135
Chile	2	—	2	2
Colombia	25	—	25	39
Ecuador	10	—	10	9
Mexico	105	28	133	104
Peru	3	1	4	8
Trinidad	—	2	2	7
United States	864	54	918	1863
Venezuela	52	14	66	78
Other	1	—	1	2
Subtotal	**1,215**	**132**	**1,347**	**2,365**
ASIA-PACIFIC				
Australia	8	10	18	28
Brunei	1	3	4	3
China-offshore	—	24	24	21
India	51	23	74	81
Indonesia	49	14	63	68
Japan	6	—	6	5
Malaysia	—	16	16	13
Myanmar	3	1	4	7
New Zealand	3	1	4	4
Papua New Guinea	3	—	3	4
Philippines	3	—	3	2
Taiwan	—	—	—	—
Thailand	4	10	14	14
Vietnam	—	6	6	10
Other	—	—	—	3
Subtotal	**131**	**108**	**239**	**263**
AFRICA				
Algeria	28	—	28	26
Angola	—	3	3	3
Congo	1	1	2	3
Gabon	—	1	1	3
Kenya	—	—	—	—
Libya	14	1	15	15
Nigeria	1	5	6	9
South Africa	—	—	—	1
Tunisia	2	1	3	4
Other	3	1	4	2
Subtotal	**49**	**13**	**62**	**66**
MIDDLE EAST				
Abu Dhabi	8	3	11	12
Dubai	—	1	1	1
Egypt	39	7	46	54
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	—
Kuwait	13	—	13	10
Oman	50	—	50	55
Pakistan	19	—	19	21
Qatar	1	8	9	12
Saudi Arabia	58	10	68	77
Sudan	—	—	—	—
Syria	24	—	24	21
Yemen	10	—	10	14
Other	2	—	2	1
Subtotal	**224**	**29**	**253**	**278**
EUROPE				
Croatia	—	—	—	—
Denmark	—	3	3	3
France	—	—	—	—
Germany	9	—	9	8
Hungary	2	1	3	5
Italy	3	—	3	6
Netherlands	1	3	4	3
Norway	—	16	16	22
Poland	2	—	2	1
Romania	7	1	8	18
Turkey	3	2	5	5
UK	1	19	20	23
Other	9	—	9	7
Subtotal	**37**	**45**	**82**	**101**
Total	**1,656**	**327**	**1,983**	**3,073**

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

OIL IMPORT FREIGHT COSTS*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	125	1.43
Caribbean	Houston	Resid.	380	73	0.94
Caribbean	Houston	Resid.	500	68	0.88
N. Europe	New York	Dist.	200	148	2.74
N. Europe	Houston	Crude	400	81	2.17
W. Africa	Houston	Crude	910	51	1.58
Persian Gulf	Houston	Crude	1,900	21	1.22
W. Africa	N. Europe	Crude	910	54	1.22
Persian Gulf	N. Europe	Crude	1,900	—	—
Persian Gulf	Japan	Crude	1,750	30	1.00

*May 2009 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

WATERBORNE ENERGY INC. US LNG IMPORTS

Country	Apr. 2009	Mar. 2009	Apr. 2008	Change from a year ago, %
	MMcf			
Algeria	0	0	0	—
Egypt	23,220	11,670	3,100	649.0
Equatorial Guinea	0	0	0	—
Nigeria	8,650	0	3,030	185.5
Norway	5,820	2,890	0	—
Qatar	0	0	0	—
Trinidad and Tobago	26,230	17,050	28,630	-8.4
Total	**63,920**	**31,610**	**34,760**	**83.9**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
Data not available at press time.

PROPANE PRICES

	Apr. 2009	May 2009	Apr. 2008	May 2008
	¢/gal			
Mont Belvieu	63.82	70.10	159.03	170.01
Conway	64.45	69.04	157.08	169.06
Northwest Europe	60.20	61.78	168.13	177.58

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

MUSE, STANCIL & CO. REFINING MARGINS

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
May 2009						
Product revenues	71.94	66.63	72.02	70.13	64.84	62.09
Feedstock costs	–64.64	–59.95	–59.48	–55.61	–58.14	–60.74
Gross margin	7.30	6.68	12.54	14.52	6.70	1.35
Fixed costs	–2.13	–2.46	–2.40	–2.80	–2.40	–1.86
Variable costs	–1.40	–1.08	–1.28	–2.28	–2.56	–0.84
Cash operating margin	**3.77**	**3.14**	**8.86**	**9.44**	**1.74**	**–1.35**
Apr. 2009	3.06	0.57	4.82	8.91	1.73	–0.11
YTD avg.	3.96	1.51	5.90	12.70	3.31	0.89
2008 avg.	9.09	3.04	11.53	13.42	6.35	3.07
2007 avg.	12.60	6.65	18.66	20.89	5.75	2.25
2006 avg.	12.54	6.38	14.97	23.69	5.88	0.90

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

MUSE, STANCIL & CO. GASOLINE MARKETING MARGINS

Apr. 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	217.40	205.33	232.53	214.20
Taxes	51.15	38.40	54.60	47.55
Wholesale price	156.15	150.70	164.63	155.90
Spot price	146.66	139.31	157.26	139.73
Retail margin	10.21	16.23	13.30	10.75
Wholesale margin	9.49	11.39	7.37	16.17
Gross marketing margin	**19.70**	**27.62**	**20.67**	**26.92**
Mar. 2009	20.73	14.92	16.91	27.23
YTD avg.	20.75	20.40	12.14	27.86
2008 avg.	33.11	32.15	27.22	41.81
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	20.34	18.03	27.90

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

MUSE, STANCIL & CO. ETHYLENE MARGINS

	Ethane	Propane	Naphtha
	¢/lb ethylene		
May 2009			
Product revenues	38.02	57.75	71.67
Feedstock costs	–17.11	–40.22	–85.59
Gross margin	20.91	17.53	–13.92
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–2.85	–3.29	–4.28
Cash operating margin	**12.68**	**7.88**	**–25.39**
Apr. 2009	15.45	12.46	–10.19
YTD avg.	14.56	10.01	–11.38
2008 avg.	21.00	22.89	–5.91
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.54	22.45	1.36

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

MUSE, STANCIL & CO. US GAS PROCESSING MARGINS

May 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	3.61	2.76
Liquids	0.78	1.94
Gas purchase cost	4.02	3.70
Operating costs	0.07	0.15
Cash operating margin	**0.30**	**0.85**
Apr. 2009	0.26	0.75
YTD avg.	0.19	0.74
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	57%	54%

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

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Oil sands attack lifts doubt about activists' motives

A stepped-up attack on the Canadian oil sands strengthens doubt about the motives of environmental activists.

A declaration by the chief executives of 30 US and Canadian environmental organizations calls, among other things, for a moratorium on expansion of oil sands development.

It also seeks to "halt further approval of infrastructure that would lock us into using dirty liquid fuels from sources such as tar sands, oil shale, and liquid coal."

This is the standard environmentalist remedy: stop commercial activity. It's the political equivalent of snake oil.

The environmental leaders would replace oil sands development and petroleum consumption with the magic elixir of uneconomic energy and forced conservation.

"Strengthen investments in renewable energy and in energy efficiency and conservation through creating new, clean energy jobs and increasing prosperity through new technologies," the declaration urges.

This is fantasy. "New technologies" can't increase prosperity when applied in service to the displacement of activities that make economic sense by alternatives that do not.

Furthermore, the declaration makes clear that the environmental groups don't want to limit their obstructionism to oil sands.

"Energy security is best achieved through investment in the cleanest available energy and through ending our dependence on fossil fuels," it says.

Wrong again. Economies caught in money-losing spirals, which wholesale energy subsidization inevitably becomes, can hope for little security of any type.

In their demand for an economically untenable energy system, the environmental groups show alarmingly little interest in practical environmental progress.

To be sure, the oil sands of Alberta present the full spectrum of environmental problems: widespread surface disturbance, air and water issues, and byproduct handling to name a few.

But oil sands operators have strong economic, political, and societal pressures to find solutions—stronger, perhaps, than do energy operators anywhere.

Solutions developed to environmental problems in Alberta will become methods applicable to fossil energy production, processing, and consumption everywhere. Many already have emerged; many more lie ahead.

Because fossil energy won't vanish from the energy mix on command, this progress is supremely important. To curtail it because some groups favor stopping work over solving problems would be environmentally irresponsible.

(Online June 5, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

'Goldilocks range' of prices

Top producers—especially key members of the Organization of Petroleum Countries—seek a "Goldilocks range" of crude prices, "neither too hot nor too cold for both producers and consumers," said Paul Horsnell, head of commodities research at Barclays Capital, London, in a recent report.

"It should be a range that maintains investment incentives and continuing macroeconomic equilibrium for producers, without creating too powerful a feedback effect on consumer economies and without overly endangering oil's share of the longer-term energy mix," Horsnell said. That's likely to be $75-85/bbl, with $100/bbl apparently "fairly close to the maximum level that could be accepted" before stimulating major resistance from consumers, he said.

Prior to the May 28 OPEC meeting, Saudi Arabia Oil Minister Ali I. al-Naimi said the world economy was showing enough signs of recovery to cope with $75-80/bbl oil.

In early June, analysts with the Goldman Sachs Group Inc. raised their 2009 crude price forecast to $85/bbl from $65/bbl previously, with the possibility of approaching $100/bbl by the end of 2010.

However, at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, analysts noted, "As recently as the end of April, Goldman forecast that $45/bbl was in sight due to stubbornly high oil stocks and weak oil demand. Adding more confusion to this about-turn is that in March Goldman forecast a 'super-spike' to $105/bbl, and, of course, who can forget last summer's forecast of $200/bbl oil. But are they right this time?"

Analysts in the Houston office of Raymond James & Associates Inc. said, "Overall economic optimism is running rampant," partly fueled by reports of a slowdown in job losses and a drop in initial clams for unemployment benefits.

A $70/bbl ceiling

Olivier Jakob at Petromatrix, Zug, Switzerland, said, "Bears have shown that they have a weak hand, but Bulls will now have to show that they are strong enough to go through the resistance of $70/bbl."

On June 5, the front-month crude contract temporarily topped $70/bbl on the New York Mercantile Exchange for the first time in 7 months, climbing to $70.32/bbl before closing at $68.44/bbl. The price rise was tempered by comments from the International Energy Agency and others that the recent rally was not supported by market fundamentals.

Meanwhile, the dollar strengthened as the US economy appeared to stabilize. "Should dollar strength persist, it is possible the current rally in crude and commodities could pause," said analysts at Pritchard Capital Partners LLC, New Orleans.

They said, "If crude does not break $70[/bbl], the momentum players may lose interest. However, strength in oil and most commodities will most likely be dictated by the direction of the US dollar and US government bond yields."

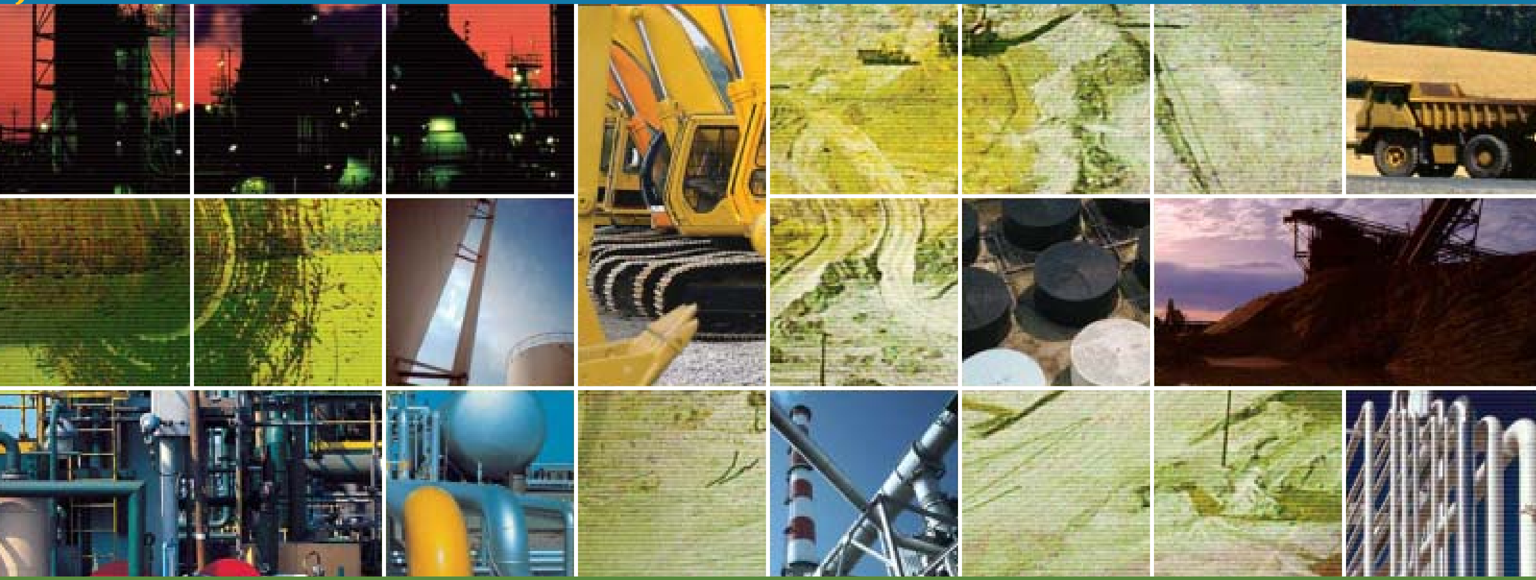
KBC analysts said, "One of the justifications for oil prices within spitting distance of $70/bbl is that recovery is on the way and commodities investors are getting in on the ground floor. But good economic news is pretty thin on the ground, and you have to be an incurable optimist to believe that demand is going to recover any time soon in the Organization for Economic Cooperation and Development economies."

They cited "the sobering forecast" by the IEA that global electricity demand will fall this year for the first time since 1945, down 3.5%. "Even in past recessions electricity demand has never fallen," they said.

KBC analysts earlier said, "For front-month prices to continue to rise, traders will need to be prepared either to elevate the whole forward price curve, which would seem to be premature given the extent of OPEC spare capacity, or to accept a further flattening of the forward curve, which would accelerate the movement ashore of oil from floating storage. This in turn would show up in onland stocks and weaken market sentiment." They said, "This now seems to be unfolding in the market, with $70/bbl possibly a short-term ceiling to oil prices until all oil in floating storage has been brought ashore. Moreover, a downward correction cannot be ruled out especially given the speculative length. However, crude may continue to trade higher with equities. All outcomes are possible in a market driven by others' perceptions of the future."

KBC analysts added, "It seems that OPEC cohesion is weakening with May output rising to 28.2 million b/d and compliance with agreed cutbacks slipping to 75%. But the surge in oil prices has spared OPEC the difficult task of either seeking to boost compliance or making a further cut that might have been met by some disbelief in the oil market."

(Online June 8, 2009; author's e-mail: samf@ogjonline.com)



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