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Directory Numbers (latest counts)

Directory	Listings	HQ Offices	Personnel	Emails	Phone	Fax	Website
Pipeline	22,584	7,955	67,162	52,951	46,409	21,868	6,328
Refining & Gas Processing	20,873	8,726	58,369	45,344	39,455	20,031	6,462
Petrochemical	18,882	8,264	50,755	38,598	35,863	19,268	5,911
Liquid Terminals	8,457	2,983	28,325	22,693	19,142	8,933	2,637
Gas Utility	13,768	6,645	47,288	37,118	31,035	15,903	4,873
Electric Utility	27,586	13,117	81,906	62,193	49,642	25,432	9,160
Drilling & Well Servicing	15,275	6,745	37,279	28,303	23,639	12,974	3,691
Offshore E&P	9,197	3,842	30,382	25,032	16,240	8,518	3,313
International E&P	10,796	4,647	25,495	16,684	16,869	7,459	2,818
United States & Canada E&P	38,595	23,500	81,713	51,098	54,145	27,242	6,758
Texas E&P	11,760	7,820	31,857	22,614	19,578	9,921	3,101
Houston & Gulf Coast E&P	10,403	6,307	32,722	24,387	18,347	9,409	3,626
Mid Continent & Eastern US E&P	12,370	8,407	29,854	18,954	20,142	8,900	2,576
Rocky MTN & Western US E&P	9,539	6,256	21,603	13,119	13,860	6,710	1,647

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Dec. 21, 2009
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WORLDWIDE REPORT

REGULAR FEATURES

COVER

In September, ExxonMobil Production Co. reported progress at its Point Thomson gas-condensate field on the Alaska North Slope (right image, cover), 60 miles east of Prudhoe Bay. The first two wells are to be completed to their final depths by yearend 2010. *OGJ's Worldwide Report*, which starts on p. 18, updates global oil and gas reserves and 2008 oil production by country. New process columns (left image) were part of a 180,000-b/d expansion at Marathon Oil's Garyville, La., that came on line earlier this year, boosting the refinery's crude oil capacity to 436,000 b/d. This was one of the major developments during 2009 in global refining that is reported (beginning on p. 46) in *OGJ's Worldwide Report*. Photographs from ExxonMobil and Marathon Oil.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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PennWell, Houston office
1455 West Loop South, Suite 400, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com
Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor/News Writer Leena Koottungal, lkoottungal@ogjonline.com

Vice-President/Group Publishing Director Paul Westervelt, pwestervelt@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290
Presentation/Equipment Editor Jim Stilwell, jims@pennwell.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

Washington
Tel 703.533.1552
Washington Editor Nick Snow, nicks@pennwell.com

Los Angeles
Tel 310.595.5657
Oil Diplomacy Editor Eric Watkins, hippalus@yahoo.com

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Audience Development Manager Tommie Grigg, tommieg@pennwell.com

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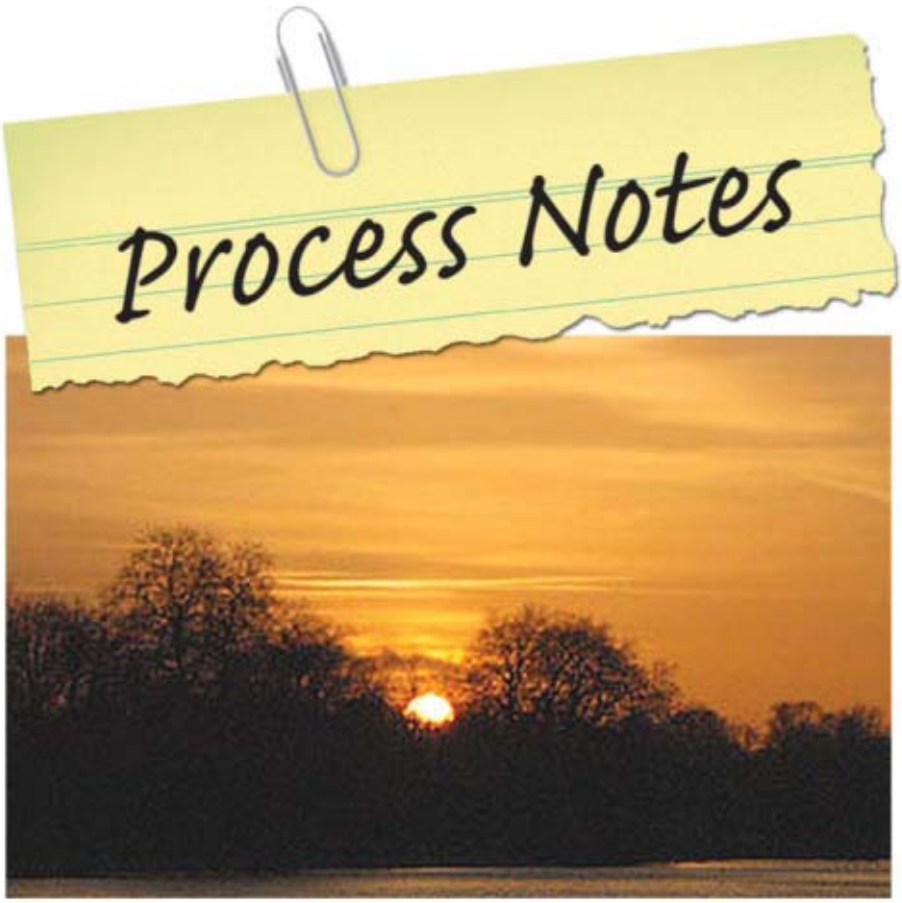

Sunrise or Sunset?

There is no doubt that while sea surface temperatures are rising and glaciers around the world are receding, as far as the global economy is concerned, the sun is setting and we are all in for a big chill. And while the atmosphere is heating, industry is putting plans for growth in the deep freeze but the more you freeze assets, the less chance there is of protecting—much less increasing—their value.

Whether you believe in what scientists say or you dispute global warming, it's certain that the sun will rise again but it's up to us to determine when it will happen. Well, how many motivational speakers have we paid to convince our employees not to wring their hands about problems but view them instead as opportunities challenging their creativity, innovative skills and productivity. Isn't it time to take our own advice?

To stop this self-destructive downward spiral we should now be thawing those plans for improvement that we've been squirreling away in the freezer and—yes!—be drawing up bold new ones too. Even the worst depression will inevitably bottom out, and there will ultimately be a climb upward again. Slow and difficult though the journey may be, the ones who start to climb first will also be the first to benefit in whatever form the new world economy will take.

Those who look to government instead of industry to remedy our current ills will be disappointed. Democracies, well-meaning and well-directed though they may be, are hamstrung by the vagaries of free elections: good administrations as well as bad can be voted out of office, and with them whatever good government-sponsored projects have been begun. And authoritarian states will never make real progress but only batten on that made in democratic societies.

Industry must do as much or more than government. And it is up to us, the petroleum industry, as the only one with the proven experience in mounting massive long-term projects and the vision and courage to take on work of truly global scope, to lead such a huge undertaking. We don't have to come hat in hand begging for bailouts. We should still have the strength, self-reliance and sheer guts of the original oil patch to turn hopes into reality.

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General Interest — Quick Takes

Chevron announces $21.6 billion capital budget

Chevron Corp. announced a $21.6 billion capital and exploratory spending program for 2010, down 5% from projected 2009 spending.

Included in the 2010 budget are $1.6 billion of expenditures by affiliates, which do not require cash outlays by Chevron's consolidated companies. Dave O'Reilly, chairman and chief executive officer, said 80% of the 2010 spending program is for upstream exploration and production projects worldwide. Another 16% is earmarked for the company's downstream businesses that manufacture, transport, and sell gasoline, diesel fuel, and other refined products.

"Much of our 2010 spending continues to be on large, multiyear projects consistent with our upstream growth strategies and on improving operating efficiency and reliability," O'Reilly said.

A total $17.3 billion is budgeted for upstream operations including $4.1 billion US and the rest international. Downstream will total $3.4 billion, including $1.6 billion US and $1.8 billion international. Chemicals, technology, power generation, and other corporate activities are budgeted at $900 million.

Major capital projects include development of the Gorgon natural gas project in Western Australia and opportunities in the deepwater US Gulf of Mexico, offshore western Africa, and the Gulf of Thailand. Funding is also planned for focused appraisal in core hydrocarbon basins.

Downstream outlays will include projects in the company's refineries in Mississippi and California. The company's 50%-owned GS Caltex affiliate also is to continue upgrading of its Yeosu refining complex in South Korea. In support of projects to commercialize the company's large natural gas resource base, downstream expenditures will be made in 2010 on gas-to-liquids manufacturing facilities.

Hess sets spending at $3.9 billion for 2010

Hess Corp. has budgeted $3.9 billion in capital and exploratory spending for 2010, $700 million more than it budgeted for 2009.

In 2010 it plans to spend $2.4 billion for production, $600 million for development, and $850 million for exploration.

Key targets of the production expending include the Bakken shale in North Dakota, where Hess plans to increase its rig count to eight from three and to expand facilities; drilling at the Okume complex off Equatorial Guinea; and drilling in deepwater Shenzi oil and gas field in the Gulf of Mexico, Beryl oil field off the UK, and Valhall oil field off Norway.

Development spending mentioned by Hess includes Valhall redevelopment, work on the oil rim of Ujung Pahgkah gas field off Indonesia, and Pony oil field in the Gulf of Mexico.

Hess plans to fund five exploratory wells on Permit WA-390-P and eight on Permit WA-404-P on the North West Shelf off Australia and one exploratory well on BM-S-22 in the Santos basin off Brazil. Other exploratory spending will include projects in the deepwater Gulf of Mexico, Ghana, and Indonesia.

Husky Energy unveils $3.1 billion budget for 2010

Husky Energy Inc., Calgary, has set a capital budget of $3.1 billion for 2010, up 20% from 2009 and focused on areas with the highest potential returns, particularly Western Canada heavy oil and oil sands, Eastern Canada offshore developments, and Southeast Asia developments.

"The company is poised to take advantage of the forecast economic cycle and to pursue business growth," said John C.S. Lau, president and chief executive officer.

Capital investments allocated in 2010 will enable Husky to position its medium and long-term growth while maintaining Canadian upstream production, officials said. The increase in annual oil production is expected to offset the reduction in natural gas production due to low gas prices. Husky is ready to increase gas tie-ins and production if commodity prices strengthen.

Meanwhile, the North Amethyst subsea tie-back work is complete, and drilling of development wells will be a major focus in 2010. Production from North Amethyst is expected in the first quarter and will ramp up during the year as new wells are tied-in.

Engineering and construction contracts will be placed to advance the Liwan gas project on Block 29/26 in the South China Sea, with project sanction expected in early 2010. The West Hercules deepwater rig will drill 6-8 exploration, delineation, and development wells during 2010. The recently discovered LiuHua gas field will be developed in conjunction with Liwan gas field, realizing synergies by sharing development facilities.

Husky holds a significant land position in Western Canada. The company's capital program is focused on growth of the upstream production through the use and application of enhanced oil recovery technology. In 2010, Husky plans to increase capital spending by over 65% to $1.2 billion focused on its heavy oil properties, EOR projects, and unconventional gas holdings.

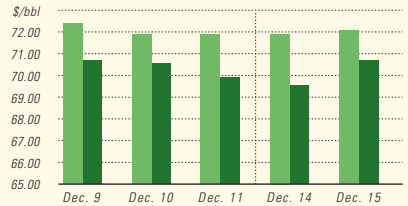
Significant progress on the Sunrise Oil Sands Project has been made, officials said. A review of the project achieved material reductions in capital costs and improved project efficiencies. Front-end engineering and design work will be completed in the first quarter, targeting first production in 2014.

Midstream, Husky will spend $170 million largely on plant maintenance, pipelines, infrastructure, and related operations. The Lloydminster upgrader is planned to have a 45-day maintenance turnaround in the third quarter.

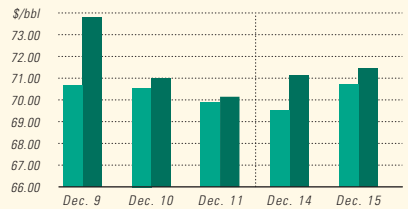
Capital expenditure for downstream is forecast at $465 mil-

Industry Scoreboard

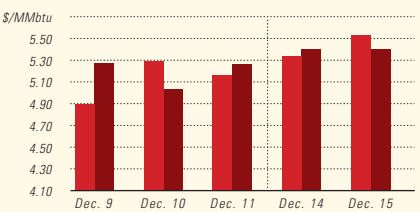
IPE BRENT / NYMEX LIGHT SWEET CRUDE



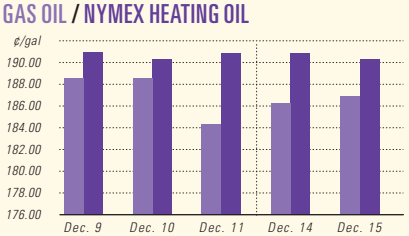
WTI CUSHING / BRENT SPOT



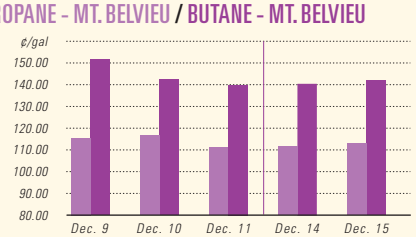
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



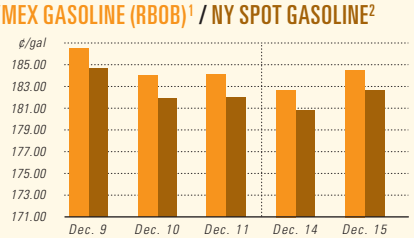
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Nonoxygenated regular unleaded.

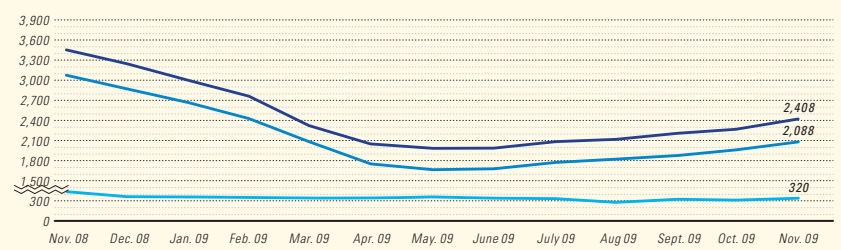
US INDUSTRY SCOREBOARD — 12/21

Latest week 12/4	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	9,016	8,907	1.2	9,009	8,994	0.2
Distillate	3,541	3,863	–8.3	3,594	3,959	–9.2
Jet fuel	1,425	1,435	–0.7	408	1,550	–73.7
Residual	505	546	–7.5	530	611	–13.3
Other products	4,012	4,311	–6.9	5,057	4,413	14.6
TOTAL DEMAND	18,499	19,062	–3.0	18,598	19,527	–4.8
Supply, 1,000 b/d						
Crude production	5,462	5,028	8.6	5,294	4,942	7.1
NGL production[2]	2,173	1,950	11.4	2,010	2,082	–3.5
Crude imports	8,517	9,888	–13.9	9,084	9,792	–7.2
Product imports	2,721	2,964	–8.2	2,745	3,127	–12.2
Other supply[3]	1,476	1,608	–8.2	1,664	1,580	5.3
TOTAL SUPPLY	20,349	21,438	–5.1	20,797	21,523	–3.4
Refining, 1,000 b/d						
Crude runs to stills	14,341	14,234	0.8	14,412	14,648	–1.6
Input to crude stills	14,641	15,075	–2.9	14,753	15,024	–1.8
% utilization	82.9	85.5	—	83.6	85.3	—

Latest week 12/4	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	336,076	339,899	–3,823	320,764	15,312	4.8
Motor gasoline	216,334	214,081	2,253	202,664	13,670	6.7
Distillate	167,317	165,698	1,619	130,587	36,730	28.1
Jet fuel–kerosine	42,546	41,820	726	39,315	3,231	8.2
Residual	36,222	38,056	–1,834	38,037	–1,815	–4.8
Stock cover (days)[4]			Change, %		Change, %	
Crude	24.2	24.5	–1.2	21.8	11.0	
Motor gasoline	24.0	23.9	0.4	22.7	5.7	
Distillate	47.3	46.1	2.6	33.3	42.0	
Propane	43.6	44.8	–2.7	49.9	–12.6	
Futures prices[5] 12/11			Change		Change	%
Light sweet crude ($/bbl)	71.53	76.84	–5.31	45.50	26.03	57.2
Natural gas, $/MMbtu	5.09	4.64	0.45	6.23	–1.14	–18.3

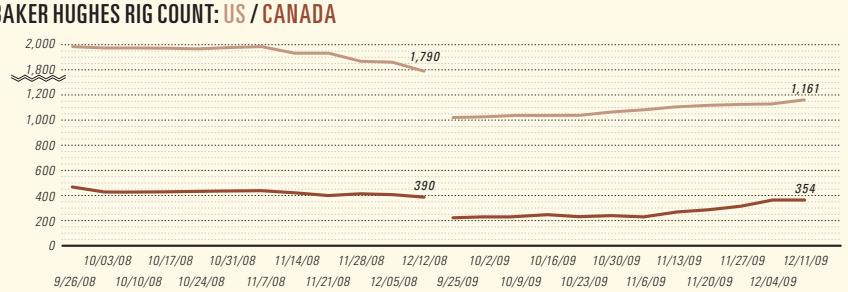
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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

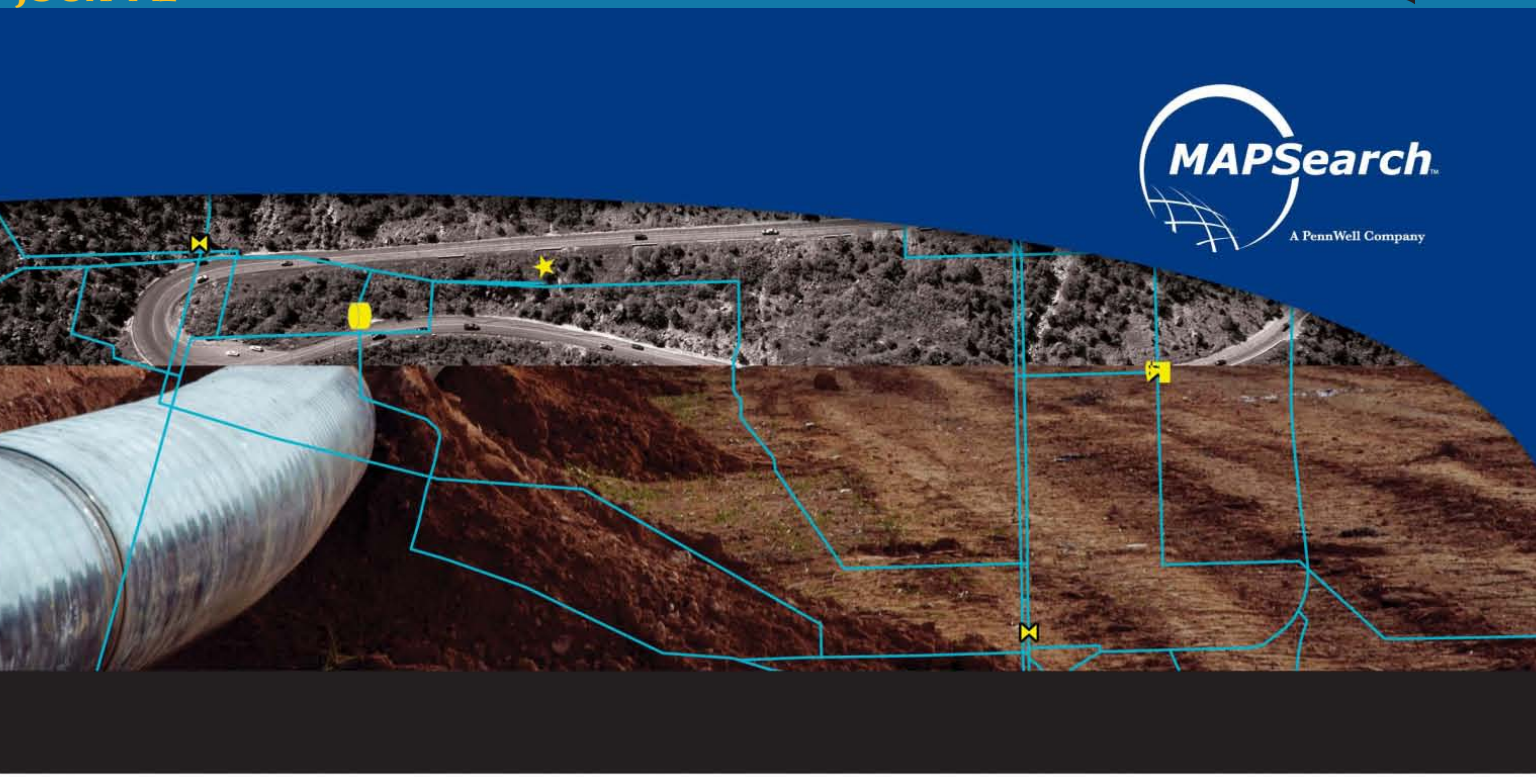


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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lion, focusing on engineering and maintenance work at the Lima refinery and the BP-Husky refinery in Ohio. Continuous improvement and maintenance work are planned for the Canadian ethanol, refining, and retail facilities in view of acquisition of downstream assets. ✦

Exploration & Development — *Quick Takes*

Shell, CNPC groups win Iraqi oil deals

The Iraqi oil ministry awarded service contracts for development of giant Majnoon and Halfaya oil fields in the first of 2 days of bidding by 45 companies.

Royal Dutch Shell PLC and Petronas won the contract for Majnoon field in southern Iraq.

The combine—Shell 60% and Petronas 40%—bid plateau production of 1.8 million b/d of oil and a fee of $1.39/bbl of increased production. The field now produces about 45,000 b/d.

The Iraqi government retains 25% participating interests in all licenses.

In 2003, former Iraqi Oil Minister Issam Al-Chalabi estimated original oil in place for Majnoon at 38 billion bbl and original reserves at 12 billion bbl (OGJ, Mar. 24, 2003, p. 42). The field is north of Basra near the Iranian border.

The contract for Halfaya field, between Majnoon and the city of Amara, went to a consortium led by China National Petroleum Corp. bidding plateau production of 535,000 b/d and a fee of $1.40/bbl. Current production is 3,000 b/d.

Combine interests are CNPC 50% and Total SA and Petronas, 25% each.

For Halfaya, Al-Chalabi estimated original oil in place of 16 billion bbl and original reserves of 4.6 billion bbl.

Six fields drew no bids during the first day, possibly due to insecurity or proximity to residential areas.

Fifteen fields were open for bidding.

New Brunswick Frederick Brook well is discovery

Corridor Resources Inc., Halifax, NS, pronounced its Green Road well in New Brunswick, Canada, as a new field discovery after it tested gas from two shaly intervals.

The Green Road G-41 well, 4 km north of Elgin, NB, stabilized at 430 Mscfd of gas at 147 psi final flowing wellhead pressure after an 83-hr flow period from a black shale at 2,000-2,050 m.

Final stabilized rate from a silty, sandy shale interval at 1,850-1,900 m was 3 MMscfd at a final flowing wellhead pressure of 699 psi. That zone produced 42.4 MMscf of gas in 184-hr at a peak rate of 11.7 MMscfd.

Both zones had been fractured with propane at the vertical well (OGJ Online, Nov. 25, 2009).

The Green Road well has been shut in as a future producer, awaiting further exploration and development in the area and a potential pipeline connection to Corridor's McCully gas plant located 20 km west.

Apache Canada Ltd. signed a farmout and option agreement with Corridor Resources to pursue gas in Frederick Brook shale in southern New Brunswick (OGJ Online, Dec. 8, 2009).

Chevron-led group makes gas find off W. Australia

A group led by Chevron Australia has made another natural gas find in its exploration permit WA-374-P off Western Australia.

The company reported that its Satyr-1 wildcat, drilled in 1,070 m of water, intersected 130 m of net gas pay.

The discovery, which is yet to be tested, follows that of the group's Achilles-1 find in October in the same permit that intersected a 100-m net gas pay zone in the Triassic-age Mungaroo sandstone reservoir target.

Both finds are south of Io-Jansz field and west of Gorgon field and are expected to provide additional gas supplies to underpin the $43 billion (Aus.) Gorgon domestic gas and LNG project.

Satyr-1 was drilled with the Ensco 7500 semisubmersible rig. It is part of a 10-well campaign being carried out by the group in Australia this year.

Chevron has a 50% interest in the permit, which lies 160 km northwest of Onslow in the Greater Gorgon Area. ExxonMobil Corp. and Royal Dutch Shell PLC each have 25%. ✦

Drilling & Production — *Quick Takes*

Range sees 200 MMcfd from Marcellus by 2010

Range Resources Corp., Fort Worth, one of the top operators in the Devonian Marcellus shale gas play, said it expects to end 2010 at a net 180-200 MMcfd of gas equivalent from the formation and believes drilling so far has derisked 390,000 acres in southwestern Pennsylvania.

The operator also said its net production has reached a net 100 MMcfd of gas equivalent from the formation and forecast that to rise to 360-400 MMcfd of gas equivalent by yearend 2011. The current output figure is a fourfold increase since late 2008.

Range is ending 2009 with 11 horizontal and vertical rigs working compared with 4 rigs last January. The count will climb to 24 rigs by the end of 2011. Production rates are rising and costs are falling, the company said.

The company also said it has drilled two horizontal wells in Lycoming County, northeastern Pennsylvania, one of which is in completion.

Range also is testing other shale formations above and below the Marcellus.

John Pinkerton, chairman and chief executive officer, said, "All of us at Range are proud to have pioneered the Marcellus shale and believe it is a shining example of the private sector working together with public agencies to create a long-lasting stimulus. Importantly, clean-burning natural gas produced in the US can

reduce our dependence on foreign oil, create jobs, strengthen our economy and dramatically reduce carbon emissions."

Statoil tests liner drilling off Norway

Statoil ASA recently completed a test of steerable drilling liner (SDL) technology from the Brage platform and expects that after a planned test from one of the Statfjord platforms in January, the technology will be ready for use in other fields. It previously had tested extensively the technology on land.

The technology involves drilling with an attached liner directly on the steerable drillstring to simplify operations in unstable formations and thereby save time and cost, Statoil said.

The technology eliminates the need to stop drilling while pulling a drillstring from a well to allow for the running and setting of a liner to prevent borehole collapse.

Statoil said it developed the technology in-house in collaboration with equipment supplier Baker Hughes Inc. to overcome challenges in drilling zones with lower pressure and difficult shale-coal layers, as well as formations with varying flow and pressure regimes.

The Brage platform is an integrated accommodation, processing, and drilling facility on a steel jacket set in 140 m of water. Production to the platform started in 1993 from wells drilled in Blocks 30/6, 31/4, and 31/7 off Norway.

Statfjord field, on Norway's Blocks 33/12 and 33/9 and on the UK's Block 211/25, produces to three integrated facilities on concrete gravity base structures. Water depth in the area is 150 m. First production from Statfjord started in 1979.

Oyo field production starts off Nigeria

Oyo oil field has started production from two subsea wells in 400 m of water about 75 km off Nigeria.

Italy's Eni SPA, whose affiliate Nigerian Agip Exploration Ltd. holds a 40% interest in the production-sharing contract and is the operator, said initial production capacity is 25,000 b/d.

The field produces through the Armada Perdana floating production, storage, and offloading vessel, which has treatment capacity of 40,000 b/d of liquids plus gas treatment and reinjection facilities. The FPSO can store as much as 1 million bbl of crude.

Associated gas is to be reinjected into the reservoir by a third well. The development plan also includes a water-injection well.

Other interests in the field are Allied Energy PLC 57.5% and CAMAC Energy Holdings Ltd. 2.5%.

CAMAC last month signed an agreement to sell its Oyo interest to Pacific Asia Petroleum Inc. in exchange for 62.74% of the common shares of Pacific Asia and $38.84 million cash.

Israel utility signs to buy Tamar field gas

Dalia Power Energies, a private power company in Israel, has signed a letter of intent to buy natural gas from the Noble Energy Inc. group's Tamar gas field in the Mediterranean off Israel.

Dalia Power has a license to build a gas-fired power plant in Israel with operations planned to begin 2013.

Noble Energy and its partners will deliver 200 bcf to Dalia Power under a 17-year supply agreement in exchange for at least $1 billion in total revenue. Sales volumes may be hiked to 700 bcf depending upon the final size of the power plant and extent of operations.

The Noble Energy group is continuing discussions with other customers regarding the supply of natural gas from Tamar and plans to begin sales in 2012.

Noble Energy operates Tamar, in the Matan license off Israel, with a 36% working interest (see map, OGJ, Feb. 2, 2009, p. 39). The discovery well exposed a resource of 5 tcf of gas in formations above 16,000 ft in 5,500 ft of water 55 miles off Haifa.

Other interest owners are Isramco Negev 2 with 28.75%, Delek Drilling 15.625%, Avner Oil Exploration 15.625%, and Dor Gas Exploration 4%. ✦

Processing — *Quick Takes*

Husky agrees to acquire Suncor outlets

Husky Energy Inc., Calgary, entered an agreement with Suncor Energy Inc. and Suncor Energy Products Inc. to purchase 98 retail gasoline outlets in the competitive Southern Ontario market, subject to approval by the Canadian Commissioner of Competition.

Suncor agreed with the commissioner to divest the retail outlets in July as part of its merger with Petro-Canada. Successful completion of the deal would increase to 571 Husky's total network of Canadian retail outlets, establishing its position as one of the leading gas retailers in the country. Terms of the acquisition were not revealed.

"These facilities are in proximity to our US refining assets, and the downstream integration grows our presence in the highly urbanized and densely populated Ontario market from 30 stations to 128," said John C.S. Lau, Husky Energy's president and chief executive. It also strengthens the company's position as one of Canada's largest fully integrated energy companies.

Husky operates a heavy oil upgrader and asphalt refinery in Saskatchewan and Alberta, a refinery in Prince George, BC, and US-based refineries in Toledo and Lima, Ohio. It also is Western Canada's largest producer of ethanol.

Decision due for Total's Dunkirk refinery

The future is in question for Total SA's 137,000 b/d Dunkirk refinery, also called the Flanders refinery, in northern France.

Shut down since mid-September because of a product surplus in France, the refinery was to have been reopened 3 months later when its inventories had been drawn down if the market strengthened, Total spokesman Michael Crochet-Voure told OGJ.

With French refining capacity still underutilized, the refinery has now come under review. A decision must be made before a planned turnaround in March. Total's options are to sell, shut down, transform, or mothball the refinery.

Crochet-Voure said no decision has been made. The facility's 370 workers are still on the site.

Caltex Australia to close lube plant at Kurnell

Citing global refinery margins "remaining under pressure" in this year's second half from depressed demand and "expected growth in global surplus refinery capacity," Caltex Australia announced Dec. 9 it will close its 3,300 b/d lube plant at Kurnell in Sydney.

The closing is part of a "major cost efficiency drive" in which the company will recognize "significant items totaling approximately $170 million (before tax)." The company expects a savings of $93 million (Aus) "for asset impairment and redundancies relating to the planned closure."

The plant, said the company, is not "viable" because it manufactures "outmoded lubricant products and faces declining feedstock sources." The announcement did not set a date for the closure, citing "further detailed work to be done." ✦

Transportation — *Quick Takes*

Turkmenistan-China gas line to be commissioned

Turkmen President Gurbanguly Berdimuhamedow said his country plans to commission the newly constructed Turkmenistan-China natural gas pipeline on Dec. 14 to coincide with a state visit by Chinese President Hu Jintao.

Berdimuhamedow said the line will supply China with 40 billion cu m/year of gas for 30 years.

According to China's vice-foreign minister Wang Guangya, the pipeline will transport 30 billion cu m of gas more than 1,800 km from Turkmenistan via neighboring Uzbekistan and Kazakhstan to China's Xinjiang Uyghur Autonomous Region.

"Such a project is a model of mutually beneficial cooperation between the four states, and displays our desire to bolster economic cooperation and realize common development," Wang said.

"The construction started in July 2008 and one of the two lines of the project will be completed in mid-December this year," said Wang ahead of Hu's Central Asia visit, which will begin in Kazakhstan on Dec. 12, followed by his stay in Turkmenistan on Dec. 13-14.

Earlier this month, Russian Prime Minister Vladimir Putin said the new Turkmen-Chinese gas line would not endanger energy cooperation between his country and China.

"We are aware of the Chinese gas needs and have close contact with our Chinese colleagues. We also offer to expand cooperation with them. We do not think that the prospective gas pipeline from Turkmenistan to China will damage our plans," the Russian leader said (OGJ Online, Dec. 7, 2009).

Export pipeline routes considered for Uganda

Uganda's government, concerned by delays over a proposed oil export pipeline through neighboring Kenya, is considering construction of an oil pipeline to Tanzania's Port of Dar es Salaam.

However, Ben Twado, Uganda's commissioner for petroleum supplies, said it is still too early to discuss the matter in detail.

The Ugandan and Kenyan governments have been negotiating extending and upgrading the pipeline that transports oil northward in Kenya from the Port of Mombassa to Eldoret. Uganda wants to reverse the flow of the Mombassa-Eldoret line so crude can be transported southward, but Kenya is said to oppose redesigning the pipeline.

Tamoil East Africa, a unit of the Libyan state-owned oil company Tamoil Holdings, was contracted last year to extend the pipeline 351 km from Eldoret to Kampala. However, work on the proposed extension—due to begin in April and last 15 months—has not yet started.

BMI analysts said Tullow Oil PLC and Heritage Oil PLC favor construction of a new oil export pipeline to Mombasa and have discussed possible funding with financial investors.

Eni SPA, which may acquire a share in the licenses from Heritage Oil, proposed constructing a 100,000 b/d refinery in Uganda that would be connected to a new export pipeline to Mombasa. "This would allow the government to maximize its revenues by keeping all of the refining operations domestically, while letting producers sell most of Lake Albert's oil internationally at market prices," BMI said.

Eni's purchase of a 50% interest in Uganda's Blocks 1 and 3A from Heritage Oil for $1.5 billion is expected to be completed in the first quarter. Eni said the blocks in the Lake Albert basin have resources for more than 1 billion boe and that 700 million bbl have already been discovered (OGJ Online, Nov. 24, 2009).

"We're hoping that within 2 years they should be able to start production," Ugnada's energy minister Hilary Onek told Reuters. Uganda wants to build a refinery with 100,000-200,000 b/d capacity to process the crude.

"Our policy is to refine domestically all oil produced in Uganda. However, depending really on the production, some excess of crude oil may be exported," Onek said.

Nippon to lease domestic oil tanks to ADNOC

Nippon Oil Corp. has reached a final agreement with Abu Dhabi National Oil Co. (ADNOC) for the UAE firm to store oil in an effort to bolster Japan's national reserves.

Under the agreement, ADNOC will store 3.9 million bbl of crude for 3 years starting this month at a reserve base in Kagoshima Prefecture in southern Japan.

The basic agreement, which will allow storage equal to a day's consumption for Japan, initially was announced in June and is expected to help improve the Asian nation's energy security.

At the time, Japan's Ministry of Economy, Trade, and Industry said the agreement also would give Japan a preferential right to purchase the stored oil reserves there in times of emergency.

The scheme will also allow Abu Dhabi to sell its oil in other East Asian countries, such as South Korea and Taiwan, by using the Japanese base as a distribution terminal. According to METI, Abu Dhabi supplies nearly 40% of Japan's oil imports. ✦

Letters

Widely held delusion

Al Gore's recent well intentioned challenge that we produce "100% of our electricity from renewable energy and truly clean carbon-free sources within 10 years" represents a widely held delusion that we can't afford to harbor.

One of the most frequently ignored energy issues is the time required to bring forth a major new fuel to the world's energy supply. Until the mid-19th Century, wood-burning powered the world. Then coal gradually surpassed wood on into the first part of the 20th Century. Oil was discovered in the 1860s, but it was a century before it surpassed coal as our largest energy fuel. Trillions of dollars are now invested in the world's infrastructure to mine, process, and deliver coal, oil, and natural gas.

As Distinguished Professor Vaclav Smil of the University of Manitoba recently put it, "It is delusional to think that the United States can install in a decade wind and solar generating capacity equivalent to that of thermal power plants that took nearly 60 years to construct."

Texas has three times the nameplate wind capacity of any other state-8,000+ Mw. The Electric Reliability Council of Texas (ERCOT) manages the Texas electric grids. ERCOT reports that its unpredictable wind farms actually supply just a little over 700 Mw during summer power demand and provide just 1% of Texas power needs of about 72,000 Mw. ERCOT's 2015 forecast still has wind at just over 1% despite plans for many more turbines.

For the US as a whole, the Energy Information Administration is forecasting wind and solar together will supply less than 3% of US electric energy in 2020.

The Energy Independence and Security Act of 2007 is calling for 15 billion gal of ethanol from corn by 2022. This will require 40 million prime crop acres dedicated to corn for ethanol to supply just 7% of our gasoline consumption.

There is a role in our energy needs for alternatives like wind and biofuels, but the assumption that they will make a major near-term supply contribution is

distracting us from hard choices involving aggressive conservation, lifestyle changes, and major investments in energy-efficient public transport.

We do have serious issues with fossil fuel burning. Coal is an increasing environmental problem, and oil supplies may well peak in the near future. We need to improve energy efficiency with upgraded buildings, high-mileage vehicles, and electric public transport. The way we produce and transport food may have to be recast to avoid transporting so much of it for great distances. Funding and encouraging these efforts will likely require unpopular but affordable energy taxes, especially on gasoline and coal production.

Above all we need more realism and less political dreaming as we approach a difficult energy future. As we look toward our energy horizon today, energy analysts don't see those multicolored renewable rainbows our political leaders are depicting. The primary color out there for them is coal-dust black.

Rolf Westgard
St. Paul, Minn.

Calendar

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

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World Future Energy Summit, Abu Dhabi, +971 2 4090 445, +971 2 444 3768 (fax), e-mail: ludoiva.sarram@reedexpo.ae, website: www.worldfutureenergysummit.com. 18-21.

✦IPAA OGIS Florida, Hollywood, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-20.

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SPE Oil and Gas India Conference and Exhibition, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

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API Exploration and Production Winter Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222, website: www.api.org. 25-29.

Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 26-27.

The European Gas Conference and Annual Meeting, Vienna, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 26-28.

API/AGA Joint Committee on Oil and Gas Pipeline Welding Practices Conference, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

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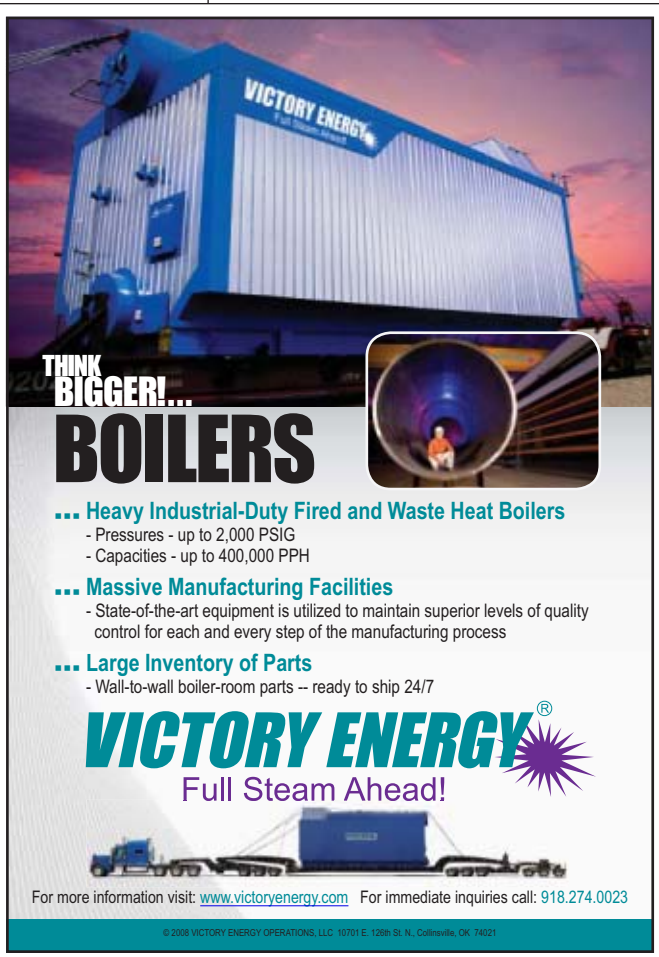

Journally Speaking

Pilots target bitumen

Guntis Moritis
Production Editor

Various companies put on hold several Alberta oil sands projects during 2009 in reaction to the global recession and lower crude prices, but other projects have continued including two proposed pilots in carbonate formations in the West Athabasca oil sands area.

Alberta's Energy Resources Conservation Board in its June reserves overview estimated that potential recoverable bitumen from Alberta's carbonate formations is 37.7 billion bbl compared with 207.6 billion bbl from Cretaceous sands.

Including mining projects, its estimate for total ultimate recovery potential from all oil sands deposits in Alberta is 315 billion bbl of which it categorizes 177 billion bbl as established. Cumulative oil sands production at yearend 2008 was 6.4 billion bbl.

In Alberta, the carbonate formations are older and underlie the Cretaceous sands. In the West Athabasca area (previously called the Wabasca deposit), the carbonates containing bitumen include the Devonian Nisku and Grosmont formations.

Some potential methods for recovering the bitumen from carbonates could involve cold solvents, cyclic steam stimulation, steam-assisted gravity drainage, solvent injection with SAGD, and electrical heating.

Pilots

ERCB's most recent approved pilot for the carbonates is for the Sunshine Oilsands Ltd. Harper acreage. Sunshine's Harper area extends over 619 contiguous sections (about 640 acres/section) and the company says a consulting firm assessed 128 sections and determined that this area contains more than 2 billion bbl of bitumen in place with a potential 536 million bbl recoverable.

Sunshine drilled, logged, and cored four wells in the area during its 2007-08 winter work program. The company plans to complete a single well, one-cycle CSS pilot during winter 2009 to demonstrate reservoir response to thermal and chemical stimulation of the 9-12 gravity bitumen at a 550-m depth. It plans no permanent installations and will remove all equipment because the area is in a winter access only, Caribou Zone.

The company notes that production from the carbonates on its Harper, Portage, Muskwa, Goffer, and Ells leases could eventually exceed 400,000 b/d.

Laricina Energy Ltd. is another company that received ERCB approval for a pilot in the carbonates. ERCB approved a pilot on Laricina's Saleski acreage in mid-2009, although still pending is a Laricina filed amendment for adding solvents to its SAGD scheme. The company notes that circulating a solvent such as propane can mobilize bitumen in advance of steam chamber growth and help lower steam requirements.

Laricina holds 60% interest in the 6,944 acres on its Saleski lease, while Osum Oil Sands Corp. holds the remaining 40%.

The 1,800 b/d Saleski pilot is within the West Athabasca oil sands area about 100 km southwest of Fort McMurray. The main target reservoir is within the Grosmont C and D formation that lies at an average 325-m depth.

Laricina describes the Grosmont formation as a dolomitized, shallow marine, and tidal flat carbonate complex that has extensive vertical fracturing, karsting, and a high-permeability reservoir with potential bitumen thickness greater than 50 m.

The company plans to start construction of the pilot in first-quarter 2010 with steam injection starting at yearend 2010 and solvent addition starting in 2012.

Its proposed pilot will have a small central processing facility including conventional diluent treating and solvent recovery systems, a single well pad with three SAGD well pairs, an access corridor, borrow pits, camp site, sumps and source water and disposal wells; and a storm water retention pond.

If the pilot succeeds, Laricina plans to install initially a 10,000 b/d commercial project and start production in 2013. Several 20,000-60,000 b/d development phases would then follow during 25 years with total bitumen production eventually reaching 270,000 b/d.

It estimates that the area contains more than 2.3 billion bbl of recoverable bitumen.

The company said a recently completed cold-solvent field test in Saleski successfully mobilized bitumen.

Other projects

Two other companies that have large leaseholds in carbonate prospects in Alberta are Shell Canada Ltd. and Husky Energy Inc.

Shell acquired its Grosmont leases in 2006 and has carried out appraisal and exploration activities. The company proposes to test an in situ bitumen upgrading process involving electric heaters that would product lighter crude and leave heavier crude components in the formation.

Husky estimates that the carbonates on its Saleski acreage contain 32 billion bbl of bitumen in place but said it has reduced its work on this acreage until economic conditions improve. ✦

Editorial

Chad's resource curse

An assessment of the World Bank's failed Chadian experiment confirms the intuition that poor countries with dodgy governments remain doomed to the resource curse. In Chad and neighboring Cameroon, the bank wove extraordinary financial and transparency controls into loans for a major energy project. It wanted development to proceed with minimum social and environmental disruption and maximum development and alleviation of poverty. Against the first two standards the experiment seems to have succeeded. Against the latter standard—the bank's priority—it did not.

The effort was noble. Too frequently, resource development does more economic harm than good in poor countries. In too many cases, a rush for riches crushes traditional economic activities, trade reversals sink local currencies, corruption dissipates wealth, and living conditions deteriorate. This is the curse, a nagging question about the social acceptability—as distinct from but no less important than legality—of expatriate work by international oil and gas companies.

The project

The project in the World Bank's experiment is development by an ExxonMobil group of oil fields in the Doba basin in Chad and construction of a 670-mile pipeline across Cameroon (see map, OGJ, July 28, 2008). In 2000, at the request of the operators, the bank and its affiliates approved a series of loans totaling $342.4 million for field development, pipeline construction, and "capacity-building"—enhancing governmental mechanisms—in Chad and Cameroon. The lenders attached unprecedented conditions to the financing, including stipulations about use of project revenue, creation of a "future generations fund," and establishment of an independent group to review and advise the Chadian government on the distribution of money.

Oil flow began ahead of schedule in 2003. Because of rising crude-oil prices, revenue in the early years beat expectations. By 2005, however, the desperate Chadian government was reneging commitments and dismantling the financial framework's legislative supports (OGJ, Feb. 13, 2006, p. 19). In September 2008, the World Bank collected loan balances and withdrew.

Last month, a World Bank independent evaluation group (IEG) reported on the Chadian experiment. "The evaluation finds that the program's fundamental development objective of reducing poverty and improving governance in Chad through the best possible use of oil revenues in an environmentally and socially sustainable manner was not achieved," wrote Vinod Thomas, director general of evaluation, in a cover letter. The overall program rating: unsatisfactory.

The project itself, which was producing 118,000 b/d at midyear, drew high marks. In Cameroon, the IEG called handling of environmental and social issues surrounding the pipeline "among the best in extractive industries projects in Africa." The group approved of the management of environmental and social effects in Chad, too. But those issues were secondary in program importance to developmental goals. Although money available to the Chadian government leaped from $112 million in 2000 to more than $2 billion in 2008, almost 90% from oil, conditions in Chad have deteriorated. "The macroeconomic, development, poverty reduction, governance, and institutional development outcomes were disappointing, and there is as yet no evidence of the hoped-for positive improvement," the IEG said.

Although oil development and the pipeline were physically, technically, and financially successful, the IEG said, the early arrival of unexpectedly large amounts of money hampered development. "The management arrangements devised for a comparatively limited amount of oil revenue cracked under the weight of the much larger revenue that materialized," the assessment said. "The larger revenue also generated temptations and competing claims that were in part associated with the reemergence of political instability and violent rebellion."

Furthermore, the system for managing oil revenue proved to be too prescriptive, detailed, and rigid, the IEG said. But the main downfall, however, was "the borrower's performance," including "repeated government violations of its commitments."

Escaping the curse

Chad, the IEG said, still can escape the resource curse. "But the most important factor would be a new and genuine determination by Chad's government to use the oil resources for development and poverty reduction, and do so responsively and efficiently."

The oil industry has strong reason to encourage any change that promises to lift the curse—in Chad and everywhere it works. ✦

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Oil, gas reserves rise as oil output declines

Marilyn Radler
Senior Editor-Economics

New estimates for Australia, China, and Turkmenistan have resulted in an increase in reported worldwide oil and gas reserves, according to Oil & Gas Journal's annual survey of proved reserves.

The world's oil reserves total 1.35 trillion bbl, up from 1.34 trillion in last year's survey (OGJ, Dec. 22, 2008, p. 20). Total gas reserves are 6.6 quadrillion cu ft, up almost 355 tcf from those reported a year ago.

The recession-driven drop in global oil demand in 2008 and 2009 led to a decline in this year's worldwide oil production. OGJ estimates that worldwide oil production this year will fall 3% from 2008 to average 70.5 million b/d.

In 2008, global oil production averaged 72.8 million b/d, climbing from 72.16 million b/d a year earlier. This increase was spurred by strong oil demand in the first half of 2008, which led to record oil prices.

OGJ compiles the estimates of proved reserves from an annual survey of official sources, including government agencies and ministries. Since most countries do not assess their reserves annually, many of the figures in this report are unchanged from a year ago.

Reserves changes

The region with the largest percentage changes in oil and gas reserves is Asia-Pacific, where total reserves of oil are up 18% from a year ago and gas reserves are up 25%. New reserves estimates for Australia peg economic oil reserves at 3.318 billion bbl and gas reserves at 110 tcf. These figures, obtained from Geoscience Australia, were derived under the McKelvey classification system.

China's reserves also jumped. The new figure for oil reserves is 20.35 billion bbl, while China's gas reserves are now pegged at 107 tcf.

Gas reserves in Turkmenistan are now estimated at 265 tcf, up from 90 tcf in the previous survey. The country's giant gas field, South Yolotan, was discovered in 2006 and drove this increase, which helped boost total gas reserves in Eastern Europe and the former Soviet Union by 8.5%. The region's oil reserves are unchanged from a year ago.

Since the previous edition of this report, the Organization of Petroleum Exporting Countries has reported increases in oil and gas reserves for Iran, Qatar, and Nigeria. Venezuela's gas reserves are reported 3% higher, although OGJ is holding its oil reserves steady from a year ago at 99.377 billion bbl.

With Ecuador rejoining and Indonesia leaving the group, OPEC's oil reserves have increased 0.8%, and its gas reserves have declined 1% from a year ago.

Canada's reserves estimate for oil declined 2%, while its gas reserves are up 7%. Conventional crude and condensate reserves in Canada are 4.814 billion bbl,

according to the Canadian Association of Petroleum Producers, and the country's oil sands reserves now are 170.4 billion bbl.

The only region to record a decline in both oil reserves and gas reserves this year is Western Europe. Lower estimates for the UK and Turkey resulted in a nearly 3% decline in oil reserves in the region and a nearly 2% dip in gas reserves as compared with last year's report. In the UK, oil reserves are down 10%, and gas reserves are down 15% from the figures reported during 2008.

A DECADE OF RESERVES CHANGES

Table 1

Jan. 1	World 1,000 bbl	OPEC 1,000 bbl	World gas, bcf
2010	1,354,182,395	951,277,000	6,609,346
2009	1,342,207,320	944,017,000	6,254,363
2008	1,331,698,077	927,482,000	6,185,693
2007	1,317,447,415	902,343,000	6,182,692
2006	1,293,344,534	901,659,000	6,101,158
2005	1,277,701,992	885,188,000	6,040,208
2004	1,265,811,583	869,521,000	6,068,302
2003	1,212,880,852	819,007,000	5,501,424
2002	1,031,100,681	818,842,000	5,451,332
2001	1,028,457,585	814,398,710	5,278,484

Source: OGJ Worldwide Production Reports

US reserves

The latest estimates from the US Energy Information Administration show an increase in proved gas reserves and a decline in proved oil reserves in the US. Accounting for discoveries, revisions, and production, gas reserves climbed 2.9% from a year earlier to 244.656 tcf, and oil reserves shrank 10.3% to 19.121 billion bbl. EIA estimates that natural gas liquids reserves in the US are 1.4% larger than a year earlier, totaling 9.3 billion bbl.

EIA also reported that using the new Securities and Exchange Commission rules that go into effect next year, which allow companies to assess their reserves using an average of first-day-of-the-month prices throughout the year rather than the current method based on what they could produce with reasonable certainty at the market price on the last day of the year, there would likely have been a smaller drop or possibly even an increase in crude oil proved reserves this year.

In 2008, gas reserves attributable to shale reservoirs grew 51% to a total of 32.8 tcf. Of this, 8.9 tcf was from discoveries, and 4.2 tcf was from upward revisions and other adjustments. Production from shale formations was 2 tcf in 2008, up 65% from a year earlier.

Proved reserves of coalbed methane declined by about 5% and now accounts for about 8.5% of US gas reserves. Coalbed gas production continues to grow and totaled nearly 2 tcf in 2008, IEA reported.

Oil production

Oil production from OPEC slid more sharply this year than the worldwide total, averaging an estimated 29.5 million b/d this year vs. 2008 average production of 32.2 million b/d.

RUSSIAN OIL PRODUCTION

Table 2

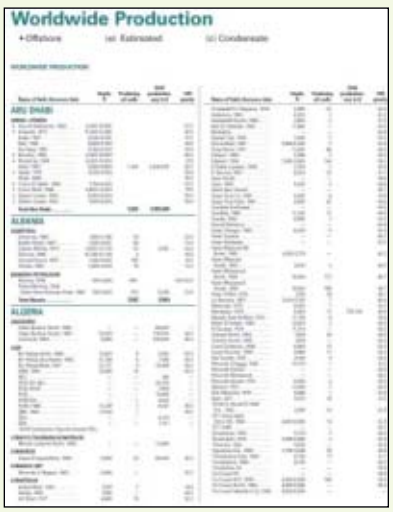
	1,000 b/d
2009	9,915*
2008	9,750
2007	9,830
2006	9,498
2005	9,190
2004	8,887
2003	8,216
2002	7,405
2001	6,781
2000	6,325

*Estimate.

Russian production rebounded from its 2008 slump. OGJ estimates that oil production in Russia will be up almost 2% from a year ago, averaging 9.9 million b/d. Big boosts to production in Azerbaijan and Kazakhstan as well helped push up 2009 output for Eastern Europe and the former Soviet Union by 3%.

The UK, Norway, and Denmark led a nearly 8% decline in this year's oil output in Western Europe, while in the Middle East, OGJ estimates that production fell 8.3%.

OGJ subscribers can download, free of charge, OGJ Worldwide Report 2009 tables from the OGJ Online home page at www.ogjonline.com. Click "OGJ Survey Downloads," then "Worldwide Production" or "Worldwide Refining."



Africa's 2009 oil production is estimated to be down 6% from last year, with Libya, Algeria, Angola, and Nigeria each posting a sizable decline.

A rise in US oil production this year outpaced production contractions in Canada and Mexico such that overall output in the Western Hemisphere will post an increase of almost 1% to average an estimated 16.78 million b/d.

US crude and condensate production in 2009 will average 5.337 million b/d, up from last year's 4.95 million b/d, according to the EIA. This will be the first year that US oil production has increased since 1991.

OGJ estimates that oil production in Canada in 2009 will average 2.53 million b/d, down almost 3% from last year. Meanwhile, production in Mexico will fall 7% from 2008 to an average of 2.6 million b/d. Mexico has not recorded an increase in oil production since 2004. ✦

WORLDWIDE LOOK AT RESERVES AND PRODUCTION

COUNTRY	ESTIMATED PROVED RESERVES Jan. 1, 2010 Oil (1,000 bbl)	Jan. 1, 2010 Gas (bcf)	Jan. 1, 2009 Oil (1,000 bbl)	Jan. 1, 2009 Gas (bcf)	OIL PRODUCTION Producing oil wells* Dec. 31, 2008	Estimated 2009 (1,000 b/d)	Change from 2008 (%)	Actual 2008 (1,000 b/d)
ASIA-PACIFIC								
Afghanistan	—	1,750	—	1,750	—	—	—	—
Australia	3,318,000	110,000	1,500,000	30,000	1,305	465.0	0.3	463.8
Bangladesh	28,000	6,900	28,000	5,000	40	6.0	–7.7	6.5
Brunei	1,100,000	13,800	1,100,000	13,800	779	148.0	–7.9	160.7
China	20,350,000	107,000	16,000,000	80,000	71,542	3,773.0	–1.0	3,810.0
China, Taiwan	2,380	220	2,380	220	71	0.8	—	0.8
India	5,624,640	37,960	5,624,640	37,960	3,686	664.0	–1.9	677.0
Indonesia	3,990,000	106,000	3,990,000	106,000	8,331	850.0	–0.9	857.3
Japan	44,115	738	44,115	738	145	15.3	–19.0	18.9
Malaysia	4,000,000	83,000	4,000,000	83,000	788	730.0	–3.5	756.7
Myanmar	50,000	10,000	50,000	10,000	450	20.0	5.3	19.0
New Zealand	60,000	1,200	60,000	1,200	72	52.0	–3.9	54.1
Pakistan	313,000	29,671	339,000	31,266	204	63.0	–5.1	66.4
Papua New Guinea	88,000	8,000	88,000	8,000	46	37.0	–9.8	41.0
Philippines	138,500	3,480	138,500	3,480	11	30.0	100.0	15.0
Thailand	430,000	12,079	441,000	11,198	1,178	236.0	3.5	228.1
Vietnam	600,000	6,800	600,000	6,800	34	300.0	8.2	277.3
Total Asia-Pacific	**40,136,635**	**538,598**	**34,005,635**	**430,412**	**88,682**	**7,390.1**	**–0.8**	**7,452.6**
WESTERN EUROPE								
Austria	50,000	570	50,000	570	905	18.4	5.7	17.4
Denmark	1,060,000	2,165	1,060,000	2,165	232	265.0	–7.6	286.7
France	101,150	250	103,300	245	421	18.3	–6.6	19.6
Germany	276,000	6,200	276,000	6,200	1,141	55.5	–9.2	61.1
Greece	10,000	35	10,000	70	12	1.6	33.3	1.2
Ireland	—	350	—	350	—	—	—	—
Italy	423,678	2,466	406,500	3,325	205	80.0	–20.0	100.0
Netherlands	100,000	50,000	100,000	50,000	203	25.5	–25.0	34.0
Norway	6,680,000	81,680	6,680,000	81,680	801	2,025.0	–7.1	2,180.0
Spain	150,000	90	150,000	90	16	1.9	–24.0	2.5
Turkey	262,200	215	300,000	300	897	45.0	10.0	40.9
United Kingdom	3,084,480	10,312	3,410,000	12,110	1,317	1,305.0	–7.8	1,415.5
Total Western Europe	**12,197,508**	**154,333**	**12,545,800**	**157,105**	**6,150**	**3,841.2**	**–7.6**	**4,158.9**
EASTERN EUROPE and FSU								
Albania	199,140	30	199,140	30	1,945	9.8	–1.0	9.9
Azerbaijan	7,000,000	30,000	7,000,000	30,000	58	1,000.0	11.7	895.0
Belarus	198,000	100	198,000	100	—	32.0	–3.0	33.0
Bulgaria	15,000	200	15,000	200	281	1.0	—	1.0
Croatia	73,350	1,080	79,300	1,080	846	13.8	–6.8	14.8
Czech Republic	15,000	140	15,000	140	—	4.1	–6.8	4.4
Georgia	35,000	300	35,000	300	283	1.0	—	1.0
Hungary	26,566	286	20,180	286	875	13.7	–4.9	14.4
Kazakhstan	30,000,000	85,000	30,000,000	85,000	1,006	1,330.0	9.9	1,210.0
Kyrgyzstan	40,000	200	40,000	200	—	1.0	—	1.0
Lithuania	12,000	—	12,000	—	—	2.0	–33.3	3.0
Poland	96,375	5,820	96,375	5,820	512	12.0	–26.8	16.4
Romania	600,000	2,225	600,000	2,225	6,000	90.0	–3.2	93.0
Russia	60,000,000	1,680,000	60,000,000	1,680,000	105,339	9,915.0	1.7	9,750.0
Serbia	77,500	1,700	77,500	1,700	646	15.0	—	15.0
Slovakia	9,000	500	9,000	500	—	1.0	—	1.0
Tajikistan	12,000	200	12,000	200	—	—	—	—
Turkmenistan	600,000	265,000	600,000	94,000	2,460	220.0	—	220.0
Ukraine	395,000	39,000	395,000	39,000	2,494	75.0	–3.2	77.5
Uzbekistan	594,000	65,000	594,000	65,000	2,190	85.0	–5.6	90.0
Total Eastern Europe and FSU	**99,997,931**	**2,176,781**	**99,997,495**	**2,005,781**	**124,935**	**12,821.4**	**3.0**	**12,450.4**
MIDDLE EAST								
Abu Dhabi	92,200,000	198,500	92,200,000	198,500	1,200	2,135.0	–12.3	2,435.0
Bahrain	124,560	3,250	124,560	3,250	496	29.5	–10.3	32.9
Dubai	4,000,000	4,000	4,000,000	4,000	200	92.0	–11.5	104.0
Iran	137,620,000	1,045,670	136,150,000	991,600	1,128	3,725.0	–4.7	3,910.0
Iraq	115,000,000	111,940	115,000,000	111,940	1,685	2,400.0	–1.0	2,424.0
Israel	1,940	1,075	1,940	1,075	6	—	—	—
Jordan	1,000	213	1,000	213	4	—	—	—
Kuwait	101,500,000	63,000	101,500,000	62,860	790	2,010.0	–13.0	2,310.0

COUNTRY	ESTIMATED PROVED RESERVES Jan. 1, 2010 Oil (1,000 bbl)	Jan. 1, 2010 Gas (bcf)	Jan. 1, 2009 Oil (1,000 bbl)	Jan. 1, 2009 Gas (bcf)	OIL PRODUCTION Producing oil wells* Dec. 31, 2008	Estimated 2009 (1,000 b/d)	Change from 2008 (%)	Actual 2008 (1,000 b/d)
Neutral Zone	5,000,000	1,000	5,000,000	1,000	578	540.0	–5.3	570.0
Oman	5,500,000	30,000	5,500,000	30,000	2,298	800.0	6.7	750.0
Qatar	25,410,000	899,325	15,210,000	891,945	421	765.0	–9.8	848.0
Ras al Khaimah	100,000	1,200	100,000	1,200	7	0.7	–12.5	0.8
Saudi Arabia	259,900,000	263,000	264,210,000	257,970	1,560	7,920.0	–11.0	8,900.0
Sharjah	1,500,000	10,700	1,500,000	10,700	49	43.0	–14.0	50.0
Syria	2,500,000	8,500	2,500,000	8,500	136	365.0	–6.4	390.0
Yemen	3,000,000	16,900	3,000,000	16,900	1,649	270.0	–4.6	283.0
Total Middle East	**753,357,500**	**2,658,273**	**745,997,500**	**2,591,653**	**12,207**	**21,095.3**	**–8.3**	**23,007.7**
AFRICA								
Algeria	12,200,000	159,000	12,200,000	159,000	1,285	1,240.0	–9.6	1,372.0
Angola	9,500,000	9,600	9,040,000	9,530	1,064	1,790.0	–5.5	1,894.0
Benin	8,000	40	8,000	40	8	—	—	—
Cameroon	200,000	4,770	200,000	4,770	255	74.0	–11.7	83.8
Chad	1,500,000	—	1,500,000	—	521	145.0	—	145.0
Congo (former Zaire)	180,000	35	180,000	35	150	25.0	—	25.0
Congo Brazzaville	1,600,000	3,200	1,600,000	3,200	460	240.0	—	240.0
Egypt	3,700,000	58,500	3,700,000	58,500	1,491	635.0	–2.3	650.0
Equatorial Guinea	1,100,000	1,300	1,100,000	1,300	73	320.0	—	320.0
Ethiopia	428	880	428	880	—	—	—	—
Gabon	2,000,000	1,000	2,000,000	1,000	395	230.0	9.5	210.0
Ghana	15,000	800	15,000	800	3	6.0	—	6.0
Ivory Coast	100,000	1,000	100,000	1,000	9	30.0	—	30.0
Libya	44,270,000	54,362	43,660,000	54,380	1,543	1,545.0	–10.4	1,725.0
Mauritania	100,000	1,000	100,000	1,000	—	—	—	—
Morocco	752	53	752	53	7	0.3	—	0.3
Mozambique	—	4,500	—	4,500	—	—	—	—
Namibia	—	2,200	—	2,200	—	—	—	—
Nigeria	37,200,000	185,280	36,220,000	184,160	2,524	1,810.0	–7.2	1,950.0
Rwanda	—	2,000	—	2,000	—	—	—	—
Somalia	—	200	—	200	—	—	—	—
South Africa	15,000	—	15,000	—	28	14.0	—	14.0
Sudan	5,000,000	3,000	5,000,000	3,000	9	500.0	2.0	490.0
Tanzania	—	230	—	230	—	—	—	—
Tunisia	425,000	2,300	425,000	2,300	237	82.0	–3.9	85.3
Total Africa	**119,114,180**	**495,250**	**117,064,180**	**494,078**	**10,062**	**8,686.3**	**–6.0**	**9,240.4**
WESTERN HEMISPHERE								
Argentina	2,520,300	14,070	2,616,000	15,600	15,799	610.0	0.1	609.3
Barbados	1,789	4	2,171	5	92	0.8	—	0.8
Belize	6,700	—	6,700	—	—	—	—	—
Bolivia	465,000	26,500	465,000	26,500	361	40.0	—	40.0
Brazil	12,801,500	12,862	12,623,900	12,890	11,995	1,950.0	7.6	1,812.5
Canada	175,214,000	61,950	178,092,000	57,906	62,519	2,530.0	–2.6	2,597.0
Chile	150,000	3,460	150,000	3,460	315	2.5	8.7	2.3
Colombia	1,355,000	3,955	1,355,000	3,739	7,600	660.0	13.8	580.0
Cuba	124,000	2,500	124,000	2,500	251	50.0	—	50.0
Ecuador	6,500,000	282	4,660,000	315	1,296	470.0	–5.6	498.0
Guatemala	83,070	—	83,070	—	20	14.0	7.7	13.0
Mexico	10,404,000	12,702	10,501,200	13,162	3,052	2,605.0	–6.9	2,798.8
Peru	447,382	11,800	415,769	11,842	5,035	106.0	30.1	81.5
Suriname	79,600	—	79,600	—	1,188	16.0	–0.6	16.1
Trinidad and Tobago	728,300	15,400	728,300	18,770	3,903	107.0	–5.1	112.7
United States	19,121,000	244,656	21,317,000	237,726	512,560	5,337.0	7.8	4,950.0
Venezuela	99,377,000	175,970	99,377,000	170,920	15,669	2,170.0	–7.7	2,350.0
Total Western Hemisphere	**329,378,641**	**586,111**	**332,596,710**	**575,335**	**641,655**	**16,668.3**	**0.9**	**16,512.0**
TOTAL WORLD	**1,354,182,395**	**6,609,346**	**1,342,207,320**	**6,254,363**	**883,691**	**70,502.6**	**–3.2**	**72,822.0**
Total OPEC	**951,277,000**	**3,182,829**	**944,017,000**	**3,216,020**	**29,456**	**29,505.7**	**–8.4**	**32,198.1**

*Does not include shut in, injection, or service wells.

Stanislaw: Shift energy focus from 'green' to 'clean'

A global low-carbon future is possible if policymakers and economic leaders—including the oil and gas industry—shift focus from "green energy" to "clean energy," said energy expert Joseph A. Stanislaw Dec. 9 at the Deloitte LLP Oil & Gas conference in Houston.

"It is now clear that the all-consuming global obsession with anything green has subsided" as the world moves "from breathless anticipation of a green dawn, to the more sober work of systematically and thoughtfully building toward a low-carbon future," said Stanislaw, who heads the JA Stanislaw Group LLC and is a senior advisor to Deloitte. He is also cofounder and former president and chief executive officer of Cambridge Energy Research Associates.

There has been growing public recognition in recent years that oil, natural gas, and coal have the potential to be clean fuels, Stanislaw said. Fossil fuels, previously the black sheep of the new renewable energy era, "are easing their way back into the conversation as the essential bridge to a cleaner age," he said. "There is a growing understanding that this bridge to the future will be longer than has been widely acknowledged. And there is a realization that the pylons of this bridge—oil, natural gas, and coal—are at risk."

An October survey by the Pew Research Center showed 57% of Americans polled see "solid evidence" the earth is warming. While still a strong majority, that's down 14% from April 2008 and an even sharper fall from 77% acceptance in 2006 and 2007. The poll was taken prior to the current "Climategate" scandal surrounding leaked e-mails from the University of East Anglia indicating some key scientists fudged scientific data to support evidence of anthropogenic global warming.

"It does not necessarily reflect a more benighted public—just one that has more immediate existential concerns. It also might indicate that the public became skeptical about climate change because, despite the overheated rhetoric, they did not see politicians taking concrete actions," Stanislaw said.

"The principle goal of policymakers should be to establish a level playing field that makes it easier to identify the cleanest fuels producible at the lowest cost, while also reducing energy use through efficiency and other technologies," he said.

Moreover, Stanislaw said, "The current schism between the old and new energy industries—wherein the green evangelists mock the traditional fuels and the oil and gas crowd reciprocate—should end. This transformation also could be led by policymakers who admit there is no silver bullet in our common effort to build a low-carbon future. All energy forms, provided they can meet standards for being clean and cost-effective, should be able to compete for market share and funding.

He called on oil and gas companies to commit "to developing carbon-neutral technology. The top goal could be to produce ever-cleaner oil, natural gas, and coal. Within a generation, we could well be talking about clean oil, clean natural gas, and clean coal."

For industry, he said, "Moving to a clean energy world represents the largest economic opportunity of the 21st century. The Chinese market alone for clean technology is expected to reach $1 trillion annually."

He predicted, "There will probably be more money spent in the energy sector in a broad sense in the next 50 years than has been invested in the past 100 years, if not in the history of mankind. Channeling these investments well, into an era of clean energy, is the challenge that policymakers, the private sector, and the public all face together. The bridge to tomorrow's energy future depends on a sensible transition plan—one that takes advantage of all of the clean fuel sources available to us." ✦

IEA medium-term update hikes oil demand projection

The International Energy Agency has raised its projection for average global oil consumption during 2009-14 by 1.9 million b/d in an update to the medium-term market forecast it published last June.

The update appeared in IEA's December Oil Market Report.

The increase in projected demand from the June forecast reflects stronger economic growth in 2009-10 than was assumed in June plus the effects of economic and fiscal stimulus programs, especially among members of the Organization for Economic Cooperation and Development.

In IEA's high-growth scenario, with global gross domestic product increasing at an average rate of 3.2%/year, worldwide oil demand rises to 90.9 million b/d in 2014 from 86.2 million b/d in 2008.

In a lower-growth case, in which GDP rises 2.2%/year, global oil demand reaches 87 million b/d in 2014.

IEA's updated oil-supply projection for 2008-14 is an average 1.1 million b/d higher than in June, with more crude and NGL expected from members of the Organization of Petroleum Exporting Countries than in the earlier forecast. Much of the increase occurs late in the forecast period as previously deferred projects are revived and come on stream.

In the higher-GDP scenario, global non-OPEC supply plus OPEC production capacity rises from 90.94 million b/d in

2009 to 95.6 million b/d in 2014, with implied spare capacity among OPEC members of 6.08 million b/d in 2009 and 4.74 million b/d in 2014.

The non-OPEC global supply numbers include NGL production by OPEC members of 4.86 million b/d in 2009, rising to 7.35 million b/d in 2014.

They also include biofuels supply expectations raised by an average of 35,000 b/d over 2008-14 from the June projection. IEA expects global biofuels production to rise from 1.6 million b/d in 2009 to 2.2 million b/d in 2014.

IEA hiked its projection for refining capacity growth by 1.1 million b/d from the June report to 8.7 million b/d for 2008-14.

Dominating growth are China, 2.9 million b/d; other Asia, 2.1 million b/d; and the Middle East, 1.5 million b/d.

IEA said delays on some large refining projects proved shorter than it originally assumed. ✦

IHS CERA: Downstream capital costs turn upward

Costs of designing and building refineries and petrochemical plants have ended a brief decline, according to IHS Cambridge Energy Research Associates.

An IHS CERA downstream capital costs index, which assigns 2000 costs a value of 100, rose to 172.5 for the 6 months ending in the third quarter of 2009 from 170 in the previous 6-month period.

The first-quarter index was down 9% from the 2008 peak. The index provides a benchmark for comparing global costs. It is based on proprietary databases and analytical tools.

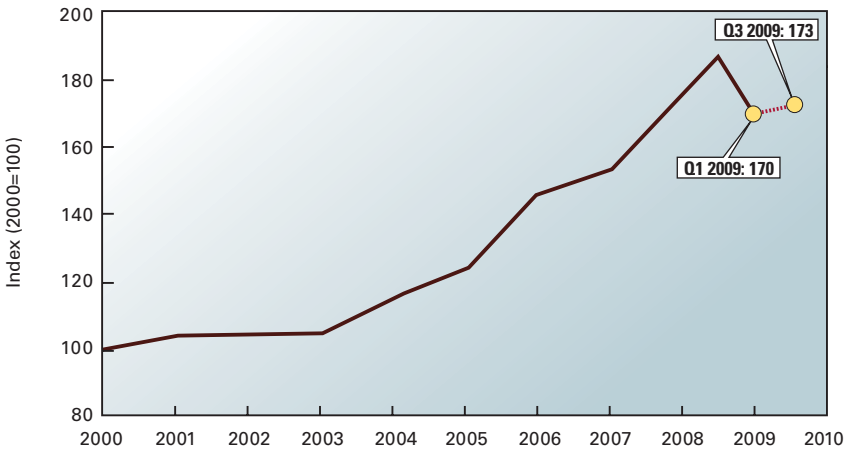
"Just as we saw the beginnings of a downturn cost trend after the third quarter of 2008, we are now seeing the beginnings of a turnaround as the return to economic growth in most regions of the world in 2010 increases the demand for commodities and materials for general construction," said IHS CERA Chairman Daniel Yergin. "But we are still a ways off from a return to the rapid price escalation that preceded the decline."

IHS CERA said the index turned up because of a 5% increase in construction labor costs, which resulted exclusively from conversion of local exchange rates into a weakened US dollar.

Without the currency translation, the downstream construction cost index would have fallen by 2% instead of rising by 1.5%.

The weak dollar also caused a "modest gain" in engineering and project management costs, IHS CERA said.

IHS CERA DOWNSTREAM CAPITAL COSTS INDEX



Source: IHS Cambridge Energy Research Associates

"The impact of the weak US dollar on engineering and project management costs is masking a very high level of competition in this market," said Jackie Forrest, lead researcher for the firm's Capital Costs Analysis Forum for Downstream. "These firms are slashing profit margins, overhead costs, and risk premiums to win new work."

Downstream projects remain hampered by caution about the economic recovery and low refining margins, IHS CERA said.

Matthew Konvicka, associate director for cost and technology, said companies are reassessing refinery investments.

"The current abundance of spare refining capacity, low refining margins, and the shrinking price differential between light and heavy crudes—as well as questions about biofuels and demand in some regions—have made the economics of new refining projects marginal," he said.

The firm expects most downstream construction projects planned in China and the Middle East eventually to proceed on the strength of demand growth and economic support from local governments. ✦

ExxonMobil: Global energy demand to rise 35% through 2030

Nick Snow
Washington Editor

Global energy demand will be about 35% higher in 2030 than it was in 2005, requiring trillions of dollars of investment and a commitment to innovation and technology, ExxonMobil Corp. said in its latest long-term energy outlook.

It also forecast a natural gas supply expansion, particularly in the US, where production from unconventional reservoirs is rising rapidly. The outlook includes an assessment of how potential carbon emission policies would affect future energy demand and the fuel mix.

ExxonMobil expects demand outside the Organization for Economic Co-operation and Development rapidly to increase during 2005-30. In OECD countries, energy demand will change little despite average economic expansion of 50%.

"By 2030, there will be more than 1 billion additional people on the earth–in total, close to 8 billion people all seeking better living standards," the forecast said. "Economic expansion will be key to reducing poverty and improving health and prosperity, and we expect developing countries to expand their economies to that end."

Meeting that demand while protecting the environment are "interlocking challenges" which will require accelerated gains in energy efficiency, expanded availability of reliable and affordable supplies, and development and deployment of technology to mitigate the growth of emissions associated with energy use, it said.

The forecast suggested that efficiency gains would accelerate from 2005 to 2030, curbing global energy demand growth by about 65%. "Oil remains the largest energy source through 2030, but natural gas will move into second place ahead of coal," it said. "In 2030, these three fuels will meet close to 80% of global energy needs."

Gas will be the fastest growing major fuel. "By 2030, demand for gas will be more than 55% higher than in 2005. Technologies that have unlocked 'unconventional' gas will help satisfy this demand," the forecast said.

The forecast also sees strong growth for nuclear and renewable fuels in generating electricity, with about 40% of the world's power coming from these sources by 2030. It expects a shift from coal to gas, nuclear, and renewables for producing power. "This will be driven by environmental policies, including ones that seek to reduce emissions by putting a cost on carbon emissions," it said.

Emissions and responses

Global carbon dioxide emissions will rise by an average 0.9%/year, "a significant increase but substantially slower than the pace of energy demand growth because of improved efficiency and a shift toward lower-carbon fuels." Progress on cutting carbon dioxide emissions beyond 2030 will require more aggressive gains in efficiency or

the use of less carbon-intensive fuels, the forecast said.

The company believes a revenue-neutral carbon tax would have advantages over a cap-and-trade system in curbing carbon emissions. It said a carbon tax would create "a clear and uniform cost for emissions in all economic decisions." Such an approach would avoid the costs and complexities of having to build a new emissions allowances market and the need for new regulators and administrators to manage it. It also would not create market manipulation opportunities or require complex and costly enforcement systems.

"Returning the tax revenue to consumers through reductions in other taxes–payroll taxes or a simple dividend–reduces the burden on the economy and ensures that government policy is specifically focused on reducing emissions, not on becoming a revenue stream for other purposes," the forecast said. "Because global participation is so important to controlling emissions, a carbon tax may be a more viable framework for engaging participation by other nations."

Transportation fuels

ExxonMobil expects the global vehicle fleet's composition to change through 2030. Although conventional gasoline vehicles will remain in the majority, followed by diesel-fueled vehicles, hybrids and other advanced vehicles will grow rapidly, reaching about 15% of the world's total personal vehicle fleet compared to about 1% currently.

"ExxonMobil believes that biofuels from photosynthetic algae could someday play an important role in meeting the world's growing need for transportation fuels, while also reducing CO_2 emissions," the forecast said. "Scientists already know that certain algae naturally produce oils similar to the petroleum products we use today. If commercial quantities of these algae-based oils could be developed, they could avoid the need to build the

Ethanol and gasoline

Two leading US House Republicans asked the Government Accountability Office to explore the impact of allowing more ethanol to be used in gasoline.

Joe Barton (Tex.), the Energy and Commerce Committee's ranking minority member, and Greg Walden (Ore.), who fills that post on the Oversight and Investigations Committee, made their request in a Dec. 9 letter to Gene Dodaro, the US Environmental Protection Agency's acting comptroller general.

EPA said on Dec. 1 that it expects, sometime in mid-2010, to finally determine whether to raise the allowable ethanol content in gasoline to 15% from 10% in response to a request from Growth Energy, a biofuels industry association.

Barton and Walden said an August GAO report, "Biofuels: Potential Effects and Challenges of Required Increases in Production and Use," identified many challenges already.

"Current automaker warranties on vehicles are voided if ethanol exceeds 10% of motor fuel," they told Dodaro. "There are also concerns that higher blends, or even E10, as the GAO noted, could damage non-auto engines...," they said.

Designed for 10%

Most gasoline distribution and storage systems are designed to dispense and store products with up to 10% ethanol, and not higher blends, the federal lawmakers continued. "Leak detection technologies used in underground storage tank systems have been developed for use for petroleum fuel and would need to be tested for performance with higher [ethanol content] fuel blends."

Barton and Walden said another strategy that GAO identified was greater use of vehicles running on fuels with 85% ethanol and the development of related infrastructure, such as dedicated ethanol pipelines to transport ethanol from the Midwest to the East and West coasts, dedicated tank system for storing E85, and specialized pumps and equipments to dispense it.

"As with increasing ethanol blend percentages, this strategy also may involve substantial costs and liabilities that have not yet been fully assessed or estimated," they said.

Study areas

They suggested that GAO investigate the extent of the federal government's risk and associated liability if it allowed the use of intermediate ethanol blends which damaged vehicles and other equipment and systems, the key components of the nation's motor vehicle and equipment fleets most at risk, durability and performance of vehicles and equipment with intermediate ethanol blends, and economic challenges to using dedicated ethanol pipelines.

The National Petrochemical & Refiners Association and 13 other organizations originally expressed concerns about possibly higher ethanol levels on Dec. 22, 2008.

"There has not been sufficient testing of motor vehicle and nonroad equipment engines" to determine that air quality, engine compatibility, and safety needs would be met, they said in a letter to then-EPA Administrator Stephen L. Johnson. ✦

extensive new delivery infrastructure that some other alternative transportation fuels might require."

ExxonMobil has entered a project with Synthetic Genomics Inc., a California biotech firm, to research and develop algae-based biofuels which would be commercially compatible with gasoline, diesel, and jet fuel. "Getting these algae fuels from the lab to broad commercial scale at the local gas station will be a tremendous undertaking and could require decades of work," the forecast said. The company expects to spend more than $600 million in the effort if research and development milestones are met. ✦

Prospects uncertain for US climate-change legislation

Nick Snow
Washington Editor

Prospects for US climate-change legislation in 2010 remain uncertain as 2009 enters its final weeks.

Proposals under discussion, including a bill already passed by the House, include a requirement that US refiners take responsibility for carbon dioxide emissions not only of their operations but also of consumers of their products. Producers argue that the proposals insufficiently emphasize use of natural gas.

Three US senators continue to work on legislation but report little progress. Two more had introduced their own proposal, while backers of bills which cleared the US House and the Senate Environment and Public Works Committee are pressing for their adoption.

Congress clearly feels pressure to act since the US Environmental Protection Agency issued a finding on Dec. 7 that greenhouse gas (GHG) emissions pose a danger to public health and should be regulated under the Clean Air Act. Lawmakers remain divided over whether adopting a domestic carbon cap-and-trade program is the best alternative, however.

Proponents argue that the program would establish a carbon price and a market for trading emissions credits. Critics warn that this new mechanism could encourage speculation and price manipulation without major safeguards.

Congress nevertheless has taken important steps, Senate Environment and Public Works Committee Chairwoman Barbara Boxer said on Dec. 14. Actions range from approval of billions of dollars in spending for clean-energy as part of the economic recovery bill in February to the Senate Energy and Natural Resources Committee's passage of the American Clean Energy Leadership Act in June and to her own committee and the House's similar, but separate, climate bills.

Attempts at consensus

Boxer said efforts by Sens. John F. Kerry (D-Mass.), Joseph I. Lieberman (I-Conn.), and Lindsay O. Graham (R-NC) to reach a bipartisan consensus also matter, while a new bill by Sens. Maria A. Cantwell (D-Wash.) and Susan F. Collins's (R-Me.) represents "a positive development because the more senators involved in discussing the issue, the better."

Most congressional Republicans remain wary.

"I think [we] have legitimate and serious concerns about this redirection of our energy policy, and we shouldn't be alone," said US Rep. Joe Barton (Tex.), ranking minority member of the Energy and Commerce Committee on Sept. 29.

Oil and gas industry association leaders have said the two cap-and-trade bills, HR 2454 and S 1733, pick winners and losers by providing carbon allowances to some businesses while penalizing others. Producers complain that they did not recognize natural gas's potential contribution in reducing GHG emissions, while refiners said they would drive domestic gasoline and diesel fuel production overseas.

"The fact is that both the House and Senate versions of cap-and-trade legislation would have devastating impacts on American businesses across the economic spectrum, specifically on the domestic refining and petrochemical companies that fuel our economy and power American ingenuity, to say nothing of the adverse effects on their hundreds of thousands of employees and families," National Petrochemical & Refiners Association Pres. Charles T. Drevna said on Nov. 11.

Kerry, Lieberman, and Graham released a framework for their compromise effort on Dec. 10 which includes provisions dealing with GHG emissions reduction goals, assistance to consumers and businesses in the transition to a lower-carbon economy, incentives for nuclear power and clean coal, and creation of nonfossil-energy jobs. It also contains an energy independence provision which addresses traditional energy producers as well as emerging technologies and processes.

Cantwell and Collins introduced

their bill on Dec. 12. It proposes setting up a climate auction to sell "carbon shares" and rebate 75% of the revenue directly to consumers (an estimated average $1,100/year for a family of four) from 2012 to 2030. The remaining 25% would be used exclusively for "clean-energy" research and development, regionally specific assistance for communities and workers making the transition to a "clean-energy" economy, energy efficiency programs, and reductions in non-CO_2 greenhouse gases, they said.

It also would establish GHG reduction goals of 20% by 2020 (compared to 17% in the Kerry-Lieberman-Graham framework and the other major climate change bills) and 83% by 2050. Several environmental leaders and organizations endorsed it immediately.

"Energy is a $6 trillion market opportunity, and green jobs can transform the US economy. But we need a signal so that this can happen," said Cantwell.

Meanwhile, Sen. Lisa Murkowski (R-Alas.), the Energy and Natural Resources Committee's ranking minority member, said on Dec. 14 that she plans to file a disapproval resolution to keep EPA from trying to regulate GHG emissions under the Clean Air Act. The administration announced the endangerment finding the week before US President Barack Obama headed for the United Nations climate change conference in Copenhagen instead of working with Congress to reach a bipartisan solution, she charged.

"EPA has taken these actions despite the fact that Congress is continuing to work on climate legislation. I find that highly counterproductive, especially as our nation struggles to regain its economic footing," Murkowski maintained.

She said she would file the resolution under provisions of the Congressional Review Act, which Congress incorporated into the 1996 Contract with America Advancement Act that was signed into law by President Bill Clinton. In this instance, a disapproval resolution would be referred to the Environment and Public Works Committee, which Barbara Boxer chairs. ✦

Salazar outlines onshore leasing schedule for 2010

Nick Snow
Washington Editor

As he announced that 38 onshore federal oil and gas lease sales have been scheduled for 2010, US Interior Secretary Ken Salazar said his department will continue to make constructive changes in the program.

"We believe our oil and gas leasing is robust, but it also is a program we are bringing back into balance. You wouldn't know it if you listened to some of the untruths coming out of some corners of the oil and gas industry," he told reporters during a Nov. 24 teleconference.

Salazar would not specifically identify sources of the criticism, but they apparently include the Independent Petroleum Association of Mountain States in Denver, which issued a 9-page position on paper on Nov. 18 strongly suggesting that federal onshore oil and gas leasing during fiscal 2009 was more anemic than robust (OGJ Online, Nov. 23, 2009).

"Trade groups for the oil and gas industry need to understand they don't own the nation's public lands. The public does," Salazar said. Producers also need to decide whether to support "trade associations, which behave more like the arm of a political party," or to engage constructively with US Department of the Interior agencies as they develop a more balanced leasing approach, he added.

Salazar disputed statements that the onshore leasing climate has grown significantly less certain because sold tracts have been canceled and proposed tracts have been withdrawn.

"The reason there's uncertainty is that short cuts were taken in the prior administration, where parcels were leased next to national parks without proper reviews," he maintained. "We're reforming the process to make sure the taxpayer gets fair returns from these leases, [and] to make certain we're leasing the public domain in the right places and avoiding the kind of litigation and protests [the leases] have attracted in the past."

'More certainty'

"We are looking at current land use plans to make sure they remain valid in light of changing policy," said US Bureau of Land Management Director Robert V. Abbey, who also participated in the teleconference. Noting that about 42% of the parcels BLM offered in 2008 and 50% in 2009 were protested, he said: "We're trying to reduce the protests and litigation to provide more certainty to the industry."

Salazar noted that the BLM director and Wilma A. Lewis, assistant Interior secretary for land and minerals management, have been thoroughly reviewing BLM leasing and other procedures, and he anticipates they will announce some changes in the future.

He said significant onshore and offshore acreage has been leased already that has not yet been developed. "Offshore, we have 7,735 active leases, of which only 5,211 are now producing. Onshore, we have 55,385 active leases, about 26,000 of which are not producing. Large parts of the public domain have been made available to the oil and gas industry, and large parts of that have not been developed," he said.

"We should look at economic factors, such as lower oil and gas prices," Abbey suggested. "That means that companies are idling wells on public

and private lands. It's simple economics at work. We intend to assure the industry that we take our responsibility seriously about including oil and gas as we diversify our resource portfolio."

Next year's scheduled onshore federal leases include one on Aug. 11—which would be the first in nearly 2 years within the National Petroleum Reserve-Alaska, Salazar said. The sale will offer available tracts in the northeast and a portion of the reserve's northwest areas, he said.

'Spurious argument'

Attacks on Salazar's onshore leasing record have no basis, a Wilderness Society official said following the teleconference. "According to DOI's own data for fiscal 2008, there were over 48 million onshore acres under lease, with less than 14 million acres actually in development. The industry has a stockpile of nearly 35 million acres which have been issued, but not developed," said Dave Albersworth, a senior advisor at the environmental organization and also a DOI official during the Clinton administration. "For it to complain that it's not getting enough acreage is a spurious argument. It has had lots of opportunities on federal lands."

Albersworth told OGJ that he appreciated Salazar's statement that the secretary intends to take control of BLM back from the oil and gas industry. "We haven't seen any proposals. There's a clear recognition of the problems of the previous administration's policies. I think they're committed to having a robust oil and gas program while protecting the nation's resources. That's what we're looking forward to," Albersworth said.

The American Petroleum Institute and IPAMS also issued statements following Salazar's press conference.

"While we appreciate the already anticipated lease sale announcement for 2010, the oil and natural gas industry, which supports 9.2 million American jobs, believes more can be done to expand the economy and create new jobs," API Pres. Jack N. Gerard said.

IPAMS said in a statement, "It's important to recognize that developing American clean energy requires a partnership with government and community stakeholders. We are all accountable to the American public to ensure that responsible development occurs. As such, we don't believe it's unreasonable to ask [DOI] to explain the rationale for its decisions and express concern when trends are not headed in the right direction."

Federal resource management has profound implications for the cost of energy, job creation, revenue growth, and economic activity, the statement continued. "We were very encouraged to hear that Secretary Salazar believes '…it is important for the oil and gas industry to have certainty.' We look forward to meeting with [DOI] to explore ideas about how America can more responsibly develop its federal energy resources," it said. ✦

API's Gerard: Staff cuts part of broader reorganization

Nick Snow
Washington Editor

A 15% reduction in its work force is only part of a major reorganization designed to modernize the American Petroleum Institute, API Pres. Jack N. Gerard said.

"We will achieve some savings, but the reorganization was not driven by budget issues. It was driven by our need to meet the demands of this century," Gerard told OGJ.

Effective advocacy remains API's primary mission, according to Gerard.

"The very art of advocacy has changed dramatically over the past decade. Today, through modern technology and social media, you can accomplish much more with much less," he said. "We have expanded our grassroots capability and developed the wherewithal to touch millions of people, educate them, and mobilize them as public policy is shaped."

"Today, we directly and indirectly employ 9.2 million people and provide 7.5% of the US gross domestic product. We are a significant component of the domestic economy."

—API Pres. Jack N. Gerard

He considers it essential to educate the industry's workers and be able to mobilize them in response to issues.

"Today, we directly and indirectly employ 9.2 million people and provide 7.5% of the US gross domestic product. We are a significant component of the domestic economy," he said.

API's standards and practices program will continue to be an essential part of its advocacy mission.

"The standards-setting and certification programs are about the industry and what it represents. When you take those standards and how they are implemented through the industry, that in itself is advocacy at multiple levels," Gerard told OGJ.

Becoming nimble

The trade association also plans to become more nimble and efficient, he said.

"There's a vast difference between the size and scope of the association and the industry generally. The association is more like a small business. The issues we face in being effective

and efficient can be different from what the companies face," Gerard said.

One aspect of API which hasn't changed is the challenge of developing a consensus from a wide range of opinions.

"I think we're doing much better developing consensus positions, and we continue to move forward. I think it's all about how you develop those positions. Since I've come here, we actually try to talk about the issues at board meetings and share ideas to fill opportunities we have in the current political climate," Gerard said.

"We're no different from any other industry. You're always going to have differing opinions. When they are shared, it helps us refine our thinking and come to a good resolution. So we welcome those views from the senior-most leaders of our member companies," he said.

Political issues can become opportunities, he noted.

"We see those opportunities today in discussions over climate. We've had a great opportunity to talk about the oil and gas industry as a major job creator in the US economy," the API president said. "People are starting to pay attention. Democrats and Republicans alike are saying they probably should look to oil and gas to help bring the US economy back to health."

API eliminated about 40 employee positions as part of the restructuring. ✦

CSB issues urgent recommendations in probe of Citgo refinery fire

Nick Snow
Washington Editor

The US Chemical Safety Board issued urgent safety recommendations to Citgo Petroleum Corp., calling on the refiner to immediately improve the emergency water system at its Corpus Christi, Tex., refinery and to perform third-party audits of hydrogen fluoride units there and at its Lemont, Ill., refinery.

Citgo said in a statement the same day that it appreciated CSB's "thorough and ongoing investigation" and that it has already taken action on the board's recommendations.

The federal agency took the action as it continued investigating a July 19 explosion and fire from hydrocarbons that were released along with potentially deadly HF vapor. CSB issues urgent recommendations before final investigations are completed in cases where board members determine an imminent hazard may be present and it has the potential to cause serious harm unless promptly rectified.

It noted that on the day of the accident, hydrocarbons and HF were suddenly released from the HF alkylation unit at Citgo's 163,000-b/d Corpus Christi plant. The hydrocarbons ignited, leading to a fire that burned for several days and critically injured one employee.

CSB said its investigators determined that a blockage of liquid caused by the sudden failure of a control valve led to violent shaking within the process recycle piping, which broke threaded pipe connections and released a hydrocarbons cloud. That cloud reached an adjacent unit and ignited, causing multiple additional fires and the release of about 42,000 lb of HF from equipment and piping within the unit.

CSB said the refinery used a water spray system to absorb the released HF, but added that at least 4,000 lb likely escaped into the atmosphere. Citgo said its own engineering calculations of how much HF was released were based on thousands of its own air monitoring samples as well as US Environmental Protection Agency data and a rigorous mass balance.

Supply ran low

Investigators determined that during the first day of response, Citgo nearly exhausted the water mitigation system's stored supply and began pumping salt water from the ship channel into the refinery's water supply about 11½ hr after the initial release, according to CSB. It said that investigators found that multiple failures occurred during the saltwater transfer, including ruptures of the barge-to-shore transfer hoses and water pump engine failures.

"Investigators found that the Citgo water mitigation system serves as the last line of defense to protect the Corpus Christi community from an HF release," CSB Investigations Supervisor Robert Hall said.

CSB's urgent recommendations call on Citgo to develop and initiate plans within 30 days to ensure that the refinery's HF mitigation system has an adequate emergency water supply. They also ask the company to report planned or completed actions to the refinery terminal fire company and local emergency planning committee every 30 days until all planned activities are fully implemented.

An additional urgent recommendation called on Citgo to commission independent, third-party audits of its two HF alkylation units at the Corpus Christi refinery and its 167,000 b/d plant in Lemont. CSB said the audits should compare safety practices at the alkylation units to those recommended by the American Petroleum Institute. Investigators said Citgo has never conducted such an audit of the units despite an existing industry recommendation for audits every 3 years.

Video released

The federal agency also released video of the initial pipe failure, release, ignition, and fire as captured by two refinery surveillance cameras. "The camera footage shows the release and spread of the flammable vapor cloud

and the moment when the flammable vapor was ignited," said CSB Chairman John S. Bresland. "It shows just how severe the release and fire were during this incident."

He noted that the company objected, saying that releasing the information would raise substantial national security issues and sensationalize the accident. CSB subsequently received affirmation from the US Department of Homeland Security that the video did not fall under classifications requiring protection from disclosure. It is available online at CSB's web site, www.chemsafety.gov.

Bresland cited a law passed by Congress following secrecy claims by Bayer CropScience in Institute, W.Va. The American Communities' Right to Public Information Act, he said, "states that national security classifications may not be used to conceal corporate errors, prevent embarrassment, or improperly delay the release of information to the public." ✦

ExxonMobil to boost unconventional focus by acquiring XTO

ExxonMobil Corp. has agreed to buy XTO Energy Inc. in an all-stock deal valued at $41 billion that will be part of a strengthened focus by the energy giant on unconventional resources.

Since its founding in 1986, XTO has grown largely by acquiring mature producing properties and expanding reserves through the aggressive application of technology. It now holds large interests in major US shale, tight gas, and coalbed methane plays as well as the Bakken oil shale.

ExxonMobil said that after the transaction closes it will create an upstream organization to manage global development and production of unconventional resources. Outside the US, the company holds interests in unconventional resources in Canada, Germany, Poland, Hungary, and Argentina.

It estimated XTO's resource base at

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Japan cheers Iraq deal

Has Japan really succeeded in its long-term effort to secure a foothold in Iraq's oil and gas industry? Apparently so, especially after a consortium led by Japan Petroleum Exploration Co. (Japex) won the rights to develop Gharaf oil field.

In Japan, the news was met with elation. The Nikkei Business Daily (NBD) said the deal gives Japex the chance to become "a player to be reckoned with in an industry that has been dominated by Western energy giants."

NBD said the prize is a result of 10 years of effort led by Japex Chairman Yuji Tanahashi that may lay the foundation for the formation of a Japanese major and make Japex a driving force of industry consolidation.

"We have built strong ties based on mutual trust with Iraq," said Tanahashi, whose effort to win oil rights in Iraq started soon after he assumed the Japex presidency in 2001.

Tanahashi first visited Iraq to seek cooperation from the regime of Saddam Hussein. Then, following the end of the US-led war on Iraq, Tanahashi started contacting the new Iraqi government.

Developing ties

In 2005, Japex agreed with the Iraqi Oil Ministry over technological cooperation, conducted geological research of oil fields in the country, and provided training for 550 Iraqi oil and gas engineers.

As a result of such efforts, Japex got its reward: The deal on Gharaf field, which is expected to produce 230,000 b/d and, according to NBD, represents "a gigantic boost to Japex's stature in the industry."

Despite the estimated investment of about $7 billion needed to develop the field, the business will be adequately profitable, according to one Japex official. Under the 20-year service contract, up to 60% of produced oil will be used to recoup the investment.

Altogether, Japex and its partner Petronas will receive a fee of $1.49/bbl of produced oil, adding up to $2.5 billion of income for the two firms in 20 years—assuming no problems in the development.

Problems ahead?

But there could indeed be problems, as pointed out by Moody's Investors Service, which placed the A1 long-term issuer ratings of Japex under review for possible downgrade after the Gharraf announcement.

Compared to Japex's average production of 42,000 boe/d for the fiscal year ending March 2009, Moody's said, "the initial investment will have a significant impact on the company's financial metrics."

Moody's said its review will focus on the impact the total investment needed to develop Garraf field will have on the company's business and financial risk profile, the possible aid provided by the Japanese government and government entities, and Japex's financial and business strategy going forward.

Still, the cheers in Tokyo could not be denied.

"Japex has bet big on the country's massive and largely undeveloped oil reserves, and its first big success in its Iraq quest has made the firm a potentially powerful force," NBD concluded. ✦

45 tcf of gas equivalent.

XTO ranks No. 8 in this year's OGJ150 group of oil and gas producers with headquarters in the US, based on 2008 assets of $38.3 billion (OGJ, Sept. 21, 2009, p. 22). The ranking was one position below Chesapeake Energy Corp. and a position above Devon Energy Corp.

XTO's production

In this year's third quarter, XTO produced 2.42 bcfd of gas, 65,822 b/d of oil, and 22,010 b/d of natural gas liquids. It reported reserves on Dec. 31, 2008, of 13.86 tcf of gas equivalent, of which 85% was gas and 15% liquids, 64% proved developed producing and 36% proved undeveloped.

About 30% of XTO's gas production comes from shales. The company's net land positions in major shale plays are Barnett, 277,000 acres; Marcellus, 280,000 acres; Fayetteville, 380,000 acres; Woodford, 160,000 acres; and Haynesville, 100,000 acres.

Its Bakken oil shale position is 450,000 net acres.

About 45% of the company's gas production is from tight gas basins, including Williston, Green River, Uinta, Piceance, San Juan, Permian, Anadarko, Arkoma, East Texas, Arkla, Gulf Coast, and Appalachian.

One of the company's key plays is the Freestone trend of East Texas, where it holds 381,000 net acres and produced an average 816 MMcfd of gas, 598 MMcfd net to XTO, in the third quarter.

XTO's position there and elsewhere expanded with its September 2008 merger of Hunt Petroleum Co. in a cash and stock acquisition worth $4.2 billion.

The ExxonMobil acquisition remains subject to approvals by regulators and XTO shareholders. The boards of both companies have approved the deal. About $10 billion of the acquisition value represents assumption of XTO debt. ✦

GULF MARGINAL PRODUCTION—3

Model tracks structures' transition from marginal to abandonment

Mark J. Kaiser
Yunke Yu
Louisiana State University
Baton Rouge

In the final part of this series, we estimate the number of committed assets in the Gulf of Mexico that are expected to be marginal over a 60-year horizon.

Our sample set includes all producing structures in shallow water circa January 2007. Structures installed after January 2007, as well as deepwater structures, are not part of the assessment.

We compute the expected quantity and value of production and gross revenue streams using the probabilistic framework and model assumptions outlined in Part 2 (OGJ, Dec. 14, 2009, p. 33). The cumulative hydrocarbon production from the inventory of producing assets is estimated to be 1.056 billion bbl of oil and 13.3 tcf of gas.

Marginal production from the committed asset inventory is expected to contribute 4.1% of total oil production and 5.4% of gas production in the gulf. A meta-evaluation procedure is adopted to present the results of sensitivity analysis.

Structure assessment

Structure count trajectory

The total number of shallow water committed structures that are expected to produce over a 60-year horizon is depicted in Fig. 1 according to marginal and economic categorizations.

The trajectory depicted represents the average of several hundred simulations that sampled the model parameters (d, P^o, P^g, m, a, D) from their respective distributions described in Part 2 for each of the 2,364 producing structures in the gulf circa January 2007.

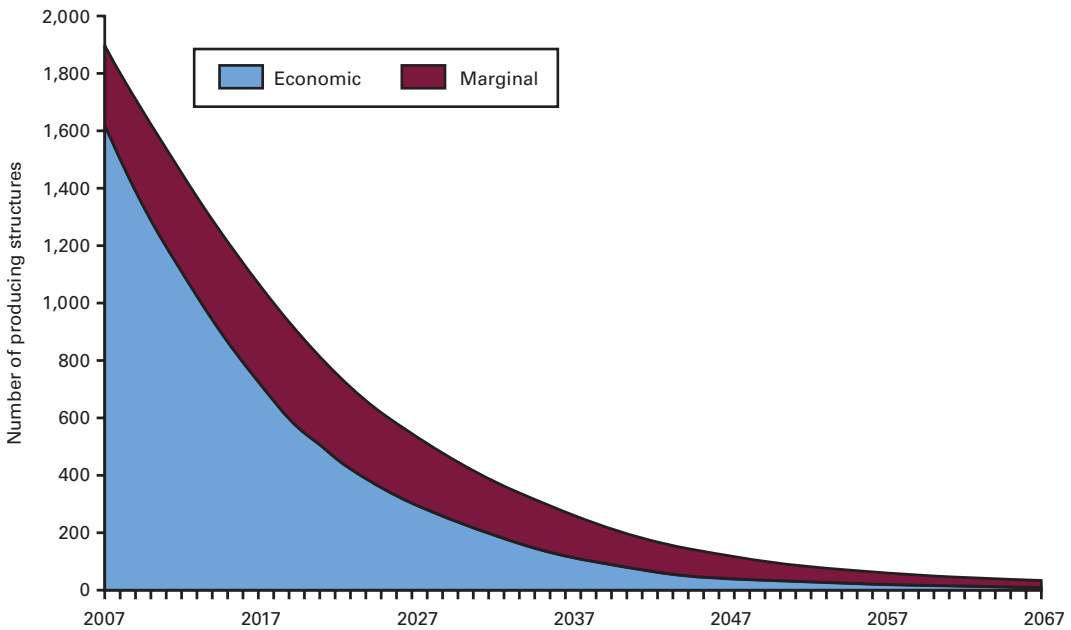
As shown in Fig. 1, the number of structures declines over time as production at individual assets decreases and transition from economic to marginal status, and eventually, to abandonment. When structures transition from economic to marginal status, and then again at a later time from marginal status to abandonment, the number of structures classified as economic and marginal will change.

All structures are removed at their economic limit regardless of the production status of the lease on which they reside.

The number of economic structures decreases monotonically over time, since once a structure is no longer economic, it will not return to economic

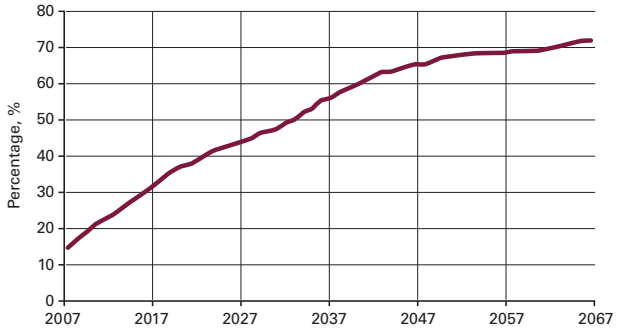
GULF SHALLOW WATER STRUCTURES BY MARGINAL AND ECONOMIC STATUS

Fig. 1



MARGINAL STRUCTURES SHARE OF COMMITTED ASSETS

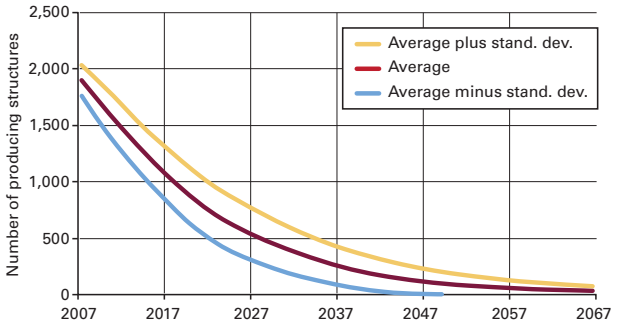
Fig. 2



Since committed asset inventory is fixed in this analysis, the percentage of marginal producers will increase over time.

AVERAGE PRODUCING STRUCTURE COUNT

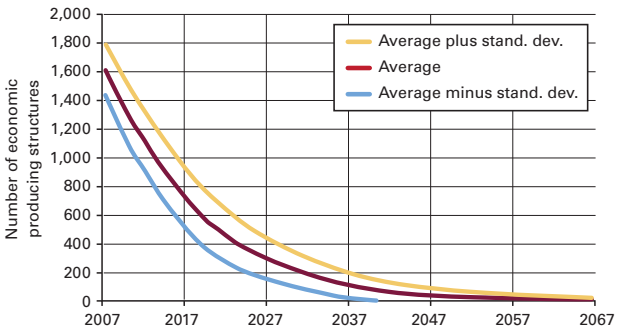
Fig. 3



Since committed assets inventory is fixed in this analysis, the percentage of marginal producers will increase over time.

AVERAGE ECONOMIC STRUCTURE COUNT

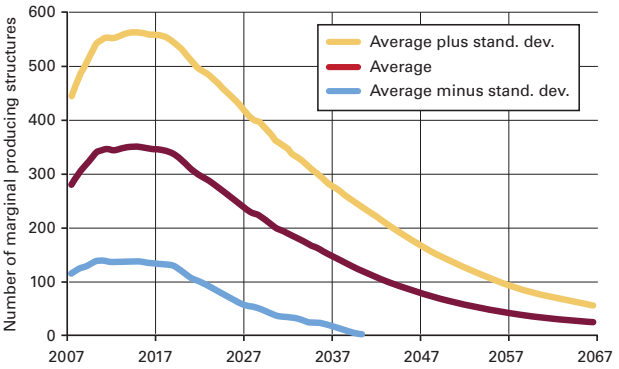
Fig. 4



Since committed assets inventory is fixed in this analysis, the percentage of marginal producers will increase over time.

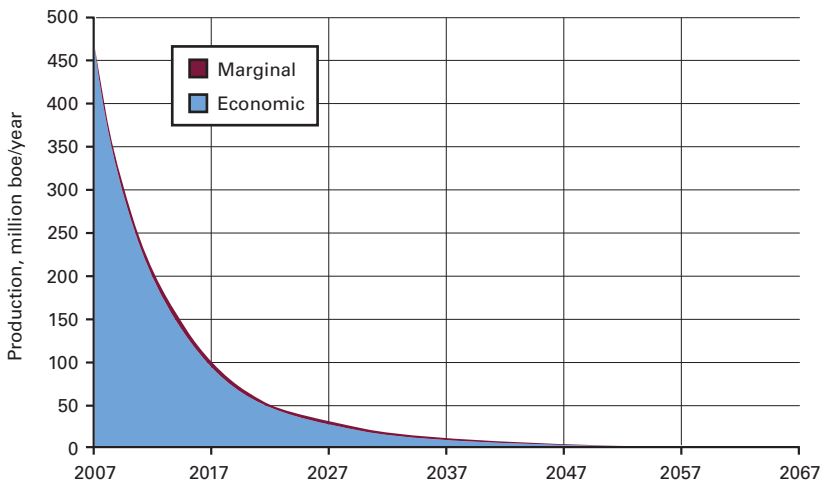
AVERAGE MARGINAL STRUCTURE COUNT

Fig. 5



PROFILE OF PRODUCTION STRUCTURES BY ECONOMIC AND MARGINAL CATEGORIES

Fig. 6



status since production is declining and price is fixed across the forecast period, and we assume that no investment to acquire additional reserves or slow decline will be made.

Our assessment only covers the existing inventory of structures, and new installations (via future developments) are not considered.

Economic structures transition through a marginal classification, and operate as marginal producers until revenue falls below their economic limit. The size of the marginal subcategory can therefore increase or decrease over time, depending upon the number of structures entering the class (as economic producers) and structures departing (to abandonment).

The absolute size of the marginal class is relatively constant over the first two decades of the forecast horizon. On a percent basis, as the number of economic structures declines, the inventory of marginal structures represents an increasing share of the committed asset inventory (Fig. 2).

Structure count envelopes

We count the number of economic and marginal structures each year for a given value of (d, P^o, P^g, m, a) where individual parameters are sampled from

their respective distributions. The total number of committed assets is denoted $\sigma(d, P^o, P^g, m, a)$, and the number of economic and marginal structures is denoted $\sigma_e(d, P^o, P^g, m, a)$ and $\sigma_m(d, P^o, P^g, m, a)$.

In Figs. 3-5, average counting functions are graphed with a one standard deviation envelope for the total number of structures and the number of economic and marginal producers. It is useful to consider the envelope as bounding the path trajectories that arise from selecting different points (d, P^o, P^g, m, a) in the design space.

Each point (d, P^o, P^g, m, a) is associated with one path trajectory, and as points are sampled within the design space, individual trajectories will change. If Normality conditions are assumed for the parameters, the actual path realized would be expected to be bound within the envelope about two thirds of the time.

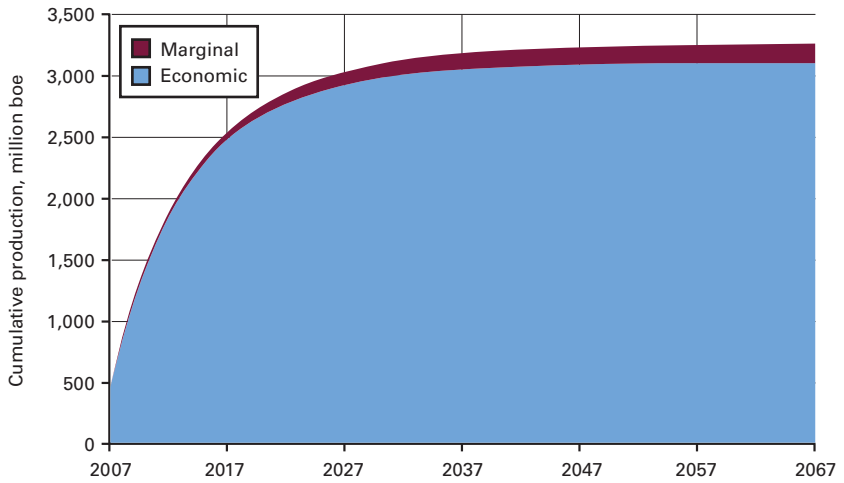
Structure counts are observed to be strictly decreasing functions for producing and economic structures (Figs. 3 and 4). Because the number of economic structures initially dominates the total structure count, the behavior of the composite trajectory (Fig. 3) is expected to closely follow the economic path (Fig. 4). The marginal structure count increases and plateaus for several years before declining (Fig. 5), and because the number of structures classified as marginal are small relative to the economic structure count, the total path trajectory is dominated by the economic class behavior.

During the period of time in which structure production is marginal, new structures enter the class (from economic producers) and marginal structures leave (for abandonment). The relative number of arrivals and departures impact the length of the plateau.

The shape of the marginal trajectory would be expected to play a dominant role when the number of economic structures decline, but at this time, since the shape of the two trajectories are similar and the counts are of similar magnitude, the influence of the

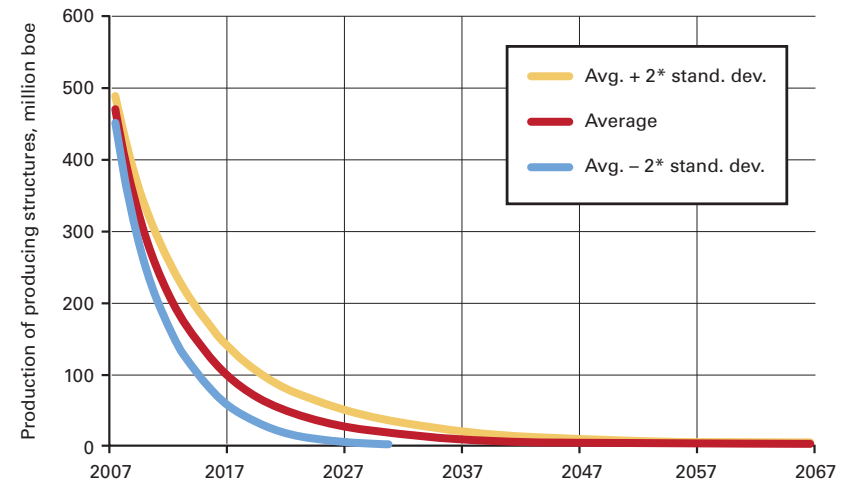
Cumulative production of producing structures

Fig. 7



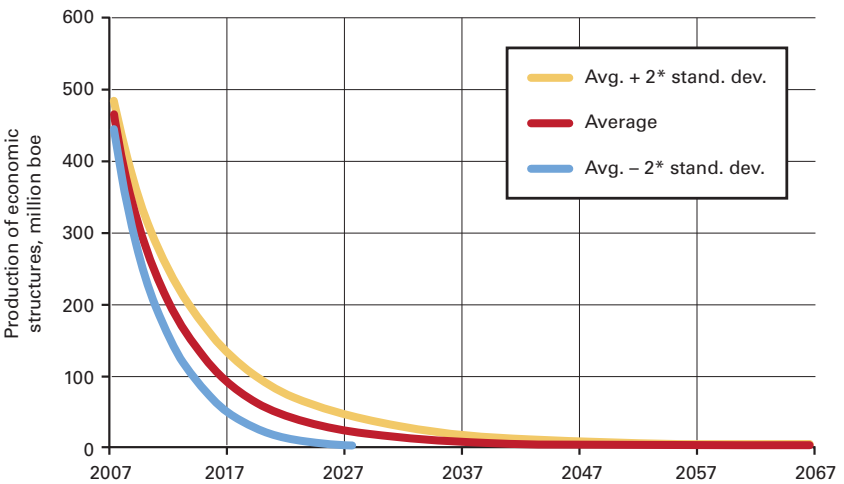
Production envelopes of producing structures

Fig. 8



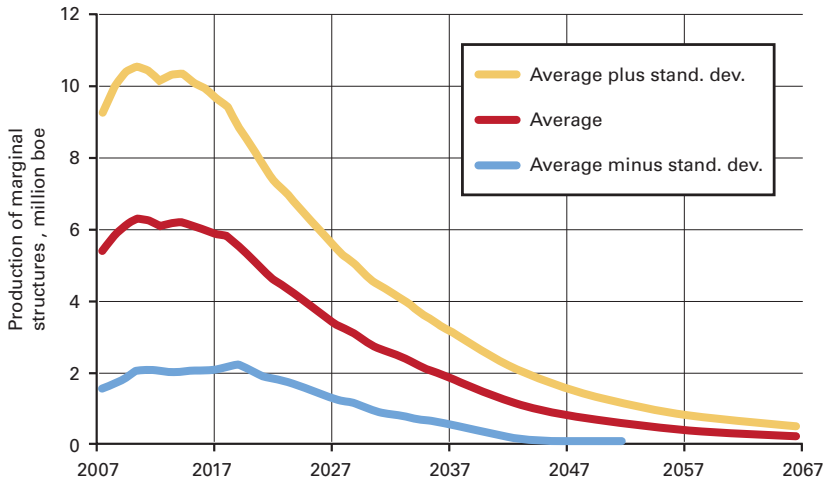
Production envelopes of economic structures

Fig. 9



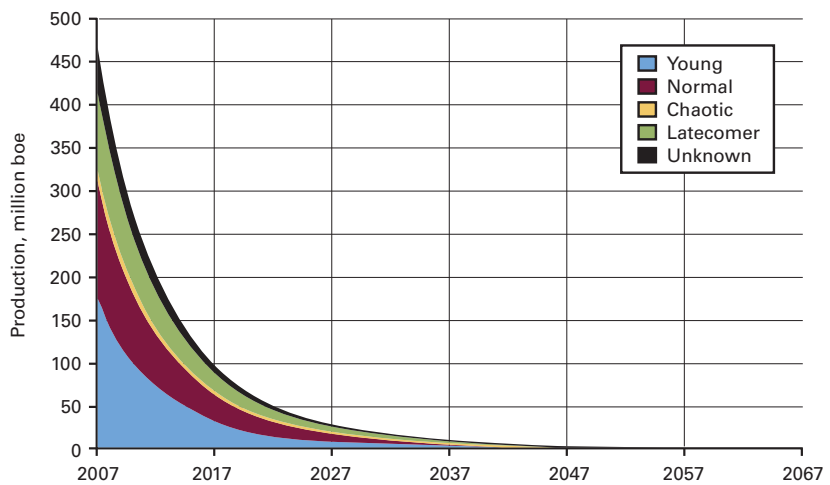
PRODUCTION ENVELOPES OF MARGINAL STRUCTURES

Fig. 10



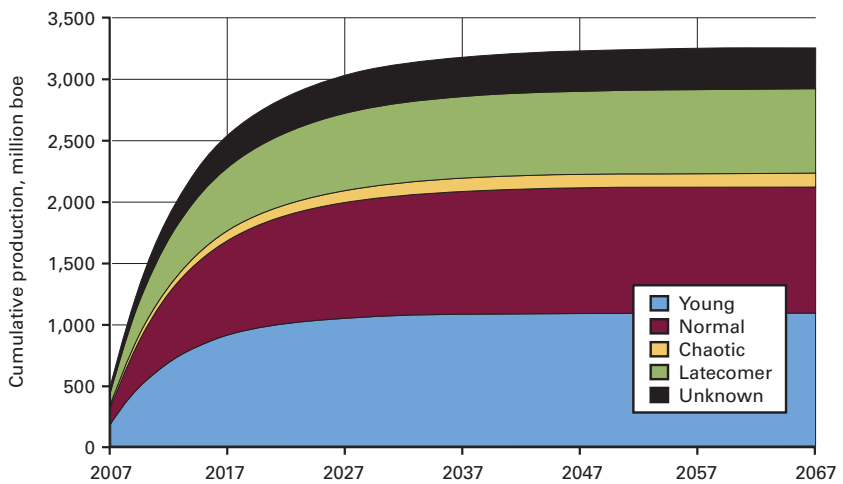
PRODUCTION CONTRIBUTION PER ASSET CATEGORY

Fig. 11



CUMULATIVE PRODUCTION CONTRIBUTION PER ASSET CATEGORY

Fig. 12



marginal trajectory on the composite trajectory is diminished.

Production profiles

Aggregate production

The average annual production from economic and marginal structures is shown in Fig. 6.

The production profile parallels the general shape of the structure count and illustrates the relative contribution provided by economic and marginal assets for each year of the forecast.

Marginal assets produce a fraction of the total production, although over time its relative contribution increases (Fig. 7), as dictated by the model framework (since the committed asset inventory is fixed). In total, production from shallow water marginal structures is expected to contribute less than 5% of the total shallow water production from the structure set.

Production envelopes

Production envelopes for economic and marginal structures are shown in Figs. 8-10. In Figs. 8 and 9, the average production profile for all producing and economic structures is depicted with a two standard deviation envelope. Near the beginning and end of the production forecast for these asset classes the envelopes tend to be very tight, due in part to the relative insensitivity of the total production to parameter variation at these points in time.

As structures age and production transfers to the marginal categorization, the impact of changes in input variables becomes more pronounced. The production envelope of marginal structures maintains a wide interval at the start of the horizon but converges near the end of the forecast (Fig. 10).

Production by asset category

In Fig. 11, the average production is decomposed according to the production classes young, normal, chaotic, latecomer, and unknown defined in Part 2.

Summary of Gulf Assets, 2006

Table 1

Production, unit	Economic	Marginal	Total
Oil, million bbl	1,013	44	1,056
Gas, bcf	12,622	717	13,338
BOE, million boe	3,116	163	3,279
Discounted revenue, $ billion	147.7	1.7	149.4

Model Results for Cumulative Gas Output

Table 3

$Q^g = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$

Coefficient	Economic	Marginal	Total
	Mcf		
α_1	–2.0E10 (–7.8)*	–8.4E8 (–5.1)	–2.1E10 (–7.7)
α_2	5.9E7 (6.7)	2.4E6 (4.2)	6.4E7 (6.8)
α_3	6.9E8 (7.8)	8.0E5 (0.1)	7.0E8 (7.5)
α_4	8.6E7 (0.7)	3.4E8 (36.9)	—
α_5	—	–4.0E8 (–23.5)	2.9E8 (1.1)
R^2	0.97	0.97	0.97

*t-statistics denoted in parenthesis.

Model Results for Cumulative Oil-Equivalent Output

Table 2

$Q^{boe} = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$

Coefficient	Economic	Marginal	Total
	Boe		
α_1	–5.3E9 (–8.2)*	–1.8E8 (–5.1)	–5.6E9 (–8.2)
α_2	1.5E7 (6.7)	4.2E5 (3.4)	1.6E7 (6.8)
α_3	1.7E8 (7.5)	1.1E6 (0.9)	1.7E8 (7.3)
α_4	2.9E7 (0.9)	7.7E7 (38.2)	—
α_5	—	–9.1E7 (–24.1)	8.3E7 (1.3)
R^2	0.89	0.69	0.82

*t-statistics denoted in parenthesis.

Model Results for Cumulative Oil Output

Table 4

$Q^o = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$

Coefficient	Economic	Marginal	Total
	Bbl		
α_1	–2.0E9 (–9.1)*	–4.3E7 (–4.7)	–2.1E9 (–9.0)
α_2	5.3E6 (6.7)	2.0E4 (0.6)	5.5E6 (6.8)
α_3	5.4E7 (6.9)	9.4E5 (3.0)	5.6E7 (6.9)
α_4	1.5E7 (1.3)	2.1E7 (41.1)	—
α_5	—	–2.4E7 (–25.0)	3.5E7 (1.6)
R^2	0.97	0.97	0.97

*t-statistics denoted in parenthesis.

In Fig. 12, the cumulative production profiles depict the relative contribution of each asset class. The collection of young and normal producers contributes nearly two thirds of total gulf production; with latecomer assets, 80% of total production is captured.

Summary statistics

Composite statistics for oil, gas, and production from shallow water committed assets in the gulf circa early 2007 are summarized in Table 1.

Production quantity and discounted gross revenue per product stream are decomposed in terms of economic, marginal, and composite classes. The expected amount of hydrocarbon production is estimated at 1,056.4 million bbl of oil and 13.3 tcf of gas, or 3,279 million boe.

The expected discounted gross revenue is calculated as $149.4 billion. Marginal production is expected to contribute 4.1% of the total oil production and 5.4% of the total gas production. We estimate that 1.2% of the total value of future committed production is due to marginal assets.

Regression models

Cumulative production functions

Regression models for the cumula-

Model Results for Present Value of Cumulative Oil and Gas Output

Table 5

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$

Coefficient	Economic $\alpha_0 = 0$	Economic $\alpha_0 \neq 0$	Marginal $\alpha_0 = 0$	Marginal $\alpha_0 \neq 0$	Total $\alpha_0 = 0$	Total $\alpha_0 \neq 0$
	$1,000					
α_0	—	8.86E7 (13.3)*	—	1.69E6 (2.2)	—	9.64E7 (19.4)
α_1	–1.90E8 (–14.8)	–1.86E8 (–24.5)	4.45E5 (0.5)	5.58E5 (0.6)	–1.86E8 (–14.3)	–1.79E8 (–30.6)
α_2	8.06E5 (17.4)	5.87E5 (18.4)	2.21E3 (0.7)	–2.01E3 (–0.5)	8.12E5 (17.4)	5.61E5 (22.7)
α_3	9.64E6 (21.2)	7.29E6 (22.7)	7.91E4 (2.5)	3.55E4 (1.0)	1.00E7 (22.0)	7.36E6 (29.8)
α_4	–2.64E5 (–0.4)	–2.11E6 (–5.2)	1.28E6 (26.2)	1.25E6 (25.2)	—	—
α_5	—	—	–1.82E6 (19.8)	–1.85E6 (–20.4)	–3.67E6 (–3.0)	–6.59E6 (–11.5)
α_6	–3.20E8 (–7.6)	–5.62E8 (–18.2)	–1.07E7 (–3.7)	–1.52E7 (–4.3)	–3.08E8 (–7.2)	–5.70E8 (–24.2)
R_2	0.99	0.96	0.93	0.90	0.99	0.98

*t-statistics denoted in parenthesis.

Model Results for Present Value of Gas Output

Table 6

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$

Coefficient	Economic $\alpha_0 = 0$	Economic $\alpha_0 \neq 0$	Marginal $\alpha_0 = 0$	Marginal $\alpha_0 \neq 0$	Total $\alpha_0 = 0$	Total $\alpha_0 \neq 0$
	$1,000					
α_0	—	4.4E7 (8.9)*	—	5.4E5 (0.7)	—	5.1E7 (19.0)
α_1	–9.8E7 (12.7)	–9.6E7 (–16.8)	3.6E5 (0.4)	4.0E5 (0.5)	–9.3E7 (13.5)	–8.9E7 (28.3)
α_2	1.2E5 (4.4)	1.3E4 (0.5)	–3.9E3 (–1.3)	–5.2E3 (–1.5)	1.2E5 (4.7)	–1.7E4 (–1.3)
α_3	8.4E6 (30.9)	7.2E6 (29.9)	8.8E4 (3.0)	7.4E4 (2.1)	8.7E6 (36.1)	7.3E6 (55.2)
α_4	–5.1E5 (–1.3)	–1.4E6 (–4.7)	5.6E5 (12.4)	5.5E5 (11.7)	—	—
α_5	—	—	–1.2E6 (–14.6)	–1.3E6 (14.5)	–4.5E6 (–6.9)	–6.0E6 (19.6))
α_6	–1.8E8 (–7.1)	–3.0E8 (–13.0)	–1.6E6 (–0.6)	–3.0E6 (–0.9)	–1.6E8 (–6.9)	–3.0E8 (23.4)
R_2	0.94	0.99	0.73	0.75	0.98	0.99

*t-statistics denoted in parenthesis.

tive economic, marginal, and total production are given by Equations 1-3.

The coefficients of the regression models are of the expected sign and statistically significant for most of the variables, and the model fits are relatively high (Tables 2-4). For any input parameters selected within the design space, the output for cumulative BOE production will vary in accord with the regression models shown.

In Table 2, model results for total (cumulative) production are depicted. In Tables 3 and 4, regression results for gas and oil streams are depicted. The model fits in Tables 3 and 4 are improved somewhat over their BOE counterpart due in part to the more homogeneous nature of the production stream. An example is illustrated in the following box.

Regression functions are useful to estimate total hydrocarbon production for user-defined variables and to investigate parameter sensitivities. From Table 2, selecting the point (d, P^o, P^g, m, α) = (0.10, 120, 10, 4, 1) in the design space yields the cumulative production from marginal assets as Q_m (0.10, 120, 10, 4, 1) = –1.8E7 + 5.04E7 + 1.1E7 + 3.08E8 – 9.1E7 = 2.60E8 boe = 260 million boe. Similarly, Q_e (0.10, 120, 10, 4) = 3.09 billion boe and Q_T (0.10, 120, 10, 1) = 3.14 billion boe. Cumulative oil and gas production estimates are computed similarly using the results in Tables 3 and 4.

Valuation functions

The discounted gross revenue of future hydrocarbon production is obtained by monetizing the oil and gas streams at assumed future prices, discount rates, and economic and marginal thresholds. We do not consider capital or operating expenditures, or the impact of tax, royalty, or depreciation schedules in the assessment.

The model results for total boe, gas, and oil production for the economic, marginal, and combined asset classes are shown in Tables 5-7. Equations for the total hydrocarbon production stream are described in $1,000 and given by Equations 4-6.

The use of a fixed-term coefficient is optional and the model results are presented with and without this term. The coefficients of the regression models are of the expected sign and statistically significant for most of the variables, and the model fits are reasonably high.

The most important components of marginal production are the values of m, a, and D; the decline parameter and hydrocarbon prices are less significant. This is not surprising considering the nature of the producing assets. The decline parameter only contributes to the portion of total production due to latecomer structures and is not expected to be a significant model driver. If latecomer structures contributed a larger portion of total GOM production, the significance of the decline parameter would increase. An example of the revenue models is illustrated in the box below.

EQUATIONS

(1) Q_e (d, P^o, P^g, m) = –5.3E9d + 1.5E7P^o + 1.7E8P^g + 2.9E7m

(2) Q_m (d, P^o, P^g, m, a) = –1.8E8d + 4.2E5P^o + 1.1E6P^g + 7.7E7m – 9.1E7a

(3) Q_T (d, P^o, P^g, a) = –5.6E9d + 1.6E7P^o + 1.7E8P^g + 8.3E7a

(4) PV_e (d, P^o, P^g, m, D) = –1.9E8d + 8.1E5P^o + 9.6E6P^g – 2.6E5m – 3.2E8D

(5) PV_m (d, P^o, P^g, m, α, D) = 4.4E5d + 2.2E3P^o + 7.9E4P^g + 1.3E6m – 1.8E6a – 1.0E7D

(6) PV_T (d, P^o, P^g, α, D) = –1.9E8d + 8.1E5P^o + 10.0E6P^g – 3.66E6a – 3.1E8D

The present value of economic production for a 10% decline rate, $100/bbl oil, $10/Mcf gas, and a 15% discount rate is computed to be PV_e (0.1, 100, 10, 4, 0.15) = $147 billion. For economic assets, the abandonment threshold does not play a role in determining value, and thus a term for the parameter a is not included in the model. The discounted value and gross revenue for marginal producing assets is computed to be PV_m (0 0.1, 100, 10, 4, 1, 0.15) = $3 billion.

Summary

When the revenue from an offshore structure's production stream approaches its cost of operations, the structure is said to be marginal and its production is classified as marginal.

We operationalized the definition of marginal production based on revenue threshold and classified and forecast economic and marginal production in the shallow water gulf. The number of marginal structures from the current inventory of committed assets and the amount and value of marginal production was forecast for a 60-year time horizon.

A simulation strategy was employed that combined scenario analysis defined through a probabilistic design space and a meta framework to investigate the impact and sensitivity of input variables on model output. Count and produc-

MODEL RESULTS FOR PRESENT VALUE OF OIL OUTPUT

Table 7

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$

Coefficient	Economic		Marginal		Total	
	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
	$1,000					
α_0	—	4.4E7 (14.8)*	—	1.2E6 (6.6)	—	4.5E7 (15.6)
α_1	–9.2E7 (14.9)	–9.0E7 (–26.5)	8.1E4 (0.3)	1.6E5 (0.8)	–9.3E7 (–14.5)	–9.0E7 (–26.3)
α_2	6.8E5 (30.6)	5.7E5 (40.1)	6.1E3 (7.1)	3.2E3 (3.9)	7.0E5 (30.2)	5.8E5 (40.1)
α_3	1.2E6 (5.6)	6.1E4 (0.4)	–8.4E3 (–1.0)	–3.8E4 (–4.6)	1.3E6 (5.6)	2.3E4 (0.2)
α_4	2.4E5 (0.8)	–6.8E5 (–3.7)	7.1E5 (54.4)	6.9E5 (61.6)	—	—
α_5	—	—	–5.7E5 (23.2)	–5.9E5 (28.7)	8.3E5 (1.4)	–5.5E5 (–1.6)
α_6	–1.4E8 (–6.9)	–2.6E8 (–18.9)	–9.2E6 (11.7)	–1.2E7 (15.3)	–1.5E8 (–7.1)	–2.7E8 (–19.9)
R_2	0.99	0.97	0.98	0.98	0.99	0.97

*t-statistics denoted in parenthesis.

tion trajectories were presented for economic and marginal structures for oil, gas, and boe forecasts.

Regression models were used to simplify and synthesize results on the impact of variability in the design parameters. We forecast both numeric and vector quantities. Numeric quantities are easier to configure and compute, while vector quantities require more advanced techniques to handle.

Acknowledgment

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The authors

Mark J. Kaiser (mkaiser@lsu.edu) is professor and director, research and development, at the Center for Energy Studies at Louisiana State University. His primary research interests are related to policy issues, modeling, and econometric studies in the energy industry. Before joining LSU in 2001, he held appointments at Auburn University, American University of Armenia, and Wichita State University. Kaiser has a PhD in industrial engineering and operations research from Purdue University.

Yunke Yu is a research associate at the LSU Center for Energy Studies since 2007. His research interests are related to modeling and economic evaluation. He earned a bachelor of engineering in oil and gas transportation and storage from China University of Petroleum and a master of finance from Tulane University.

Australia

Beach Petroleum Ltd., Adelaide, and ATCO Ltd., Toronto, signed a memorandum of understanding to investigate opportunities to develop and commercialize Beach's unconventional shale gas and liquids resource in Australia's Cooper basin.

Beach and ATCO will focus on the gas gathering, processing, transportation, and distribution requirements of the unconventional gas development program. The parties may also consider the feasibility of using commercialized discoveries of unconventional gas to fuel a gas-fired power plant.

Beach has a dominant shale gas acreage position in the Nappamerri Trough in the Cooper basin through its acquisition of interests in PEL 218, where it has a 90% interest in Permian strata and 23.33% in post-Permian strata, and ATP 855, where it holds up to a 40% working interest.

The Nappamerri Trough straddles the South Australian-Queensland border at the heart of the Cooper basin and is considered the source kitchen for the oil and gas fields on the margins of the trough.

Initial work by Beach in this area suggests the potential for a world class shale gas resource of tens of trillions of cubic feet, Beach said.

China

Far East Energy Corp., Houston, let contracts for five rigs that are to begin drilling coalbed methane development wells starting in mid-December 2009 on the Shouyang block in China's Shanxi Province.

Gas production on the block has surpassed 500 Mcfd as earlier wells dewater. Far East plans to drill and frac nine new wells by mid-February 2010 and frac its existing P4 well.

Eight of the new wells will continue the westward expansion of the high permeability field, and one will be a new parameter well several kilometers west to test extent of the high permeability-high gas content area.

Two pipelines and one local distribution-compressed natural gas company have indicated a desire to purchase the gas produced from the Shouyang Block.

Indonesia

Tap Oil Ltd., Perth, plans to earn a 24% interest in the 3,977 sq km Rangkas block onshore West Java, Indonesia, from Lundin Petroleum AB, Stockholm, the operator.

Previous exploration seismic and drilling in the block, along with the presence of surface oil seeps, indicates the presence of an active petroleum system. Recent reviews of the block, including seismic reprocessing, resulted in Tap and its proposed joint venture partners concluding that the previous wells were not valid tests of the prospectivity.

Leads identified on 2D seismic data will be the target of a new seismic survey of up to 500 line-km in the first half of 2010. Depending on results, the joint venture may commit to additional seismic and drilling in 2011-2012.

Block interests are Lundin Rangkas BV 51%, Carnarvon Petroleum (Indonesia) Pty. Ltd. 25%, and Tap Oil 24%.

Alabama

Venture Oil & Gas Inc., Laurel, Miss., gauged an exploratory well off the southeast flank of Huxford (Smackover) field in Escambia County, Ala.

The 1 Mason 36-14, in 36-2n-6e, 22 miles west of Brewton, flowed at the rate of 457 b/d of 43° gravity oil and 538 Mcfd of gas on a $^{10}/_{64}$-in. choke with 2,627 psi flowing tubing pressure from Smackover perforations at 14,902-936 ft. Gas is 1,500 ppm hydrogen sulfide.

Oklahoma

Red Fork Energy Ltd., Perth, said a well east of Vinita, Okla., logged 52 ft of Devonian Woodford shale above TD of 485 ft with excellent log characteristics and gas shows across the entire section.

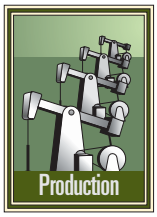
The well is the Wattenbarger 1-22, in 22-25n-21e, Craig County, 5 miles east of Vinita. Top of Woodford shale is at 385 ft.

Continuous well-flow estimates improve production allocation

Ron Cramer
Dave Schotanus
Shell Global Solutions (US) Inc.
Houston

Kolin Ibrahim
Brunei Shell Petroleum Co.
Seria, Brunei

Nick Colbeck
Shell Petroleum Development Co. of Nigeria Ltd.
Abuja, Nigeria



Evidence from several Shell operating units confirms that daily allocation based on continuous well flow estimates can be more accurate than the more traditional approach based on well testing.

The key point is that continuous allocation on a well-by-well basis, using a software application such as Shell's FieldWare Production Universe (FW PU) assigns the right production to the right wells, unlike the traditional monthly, batch approach that erroneously allocates the difference between fiscal and well test measurement across all wells.

Reference 1 reports similar findings or increased accuracy of daily allocation when compared with monthly.

Several Shell operating units have adopted the continuous-allocation approach and automatic daily production key-performance-indicator reporting based on real-time well flow estimates.

Allocation

The oil industry reconciles fiscally measured hydrocarbon production with estimated production from associated wells. This process, known as allocation, is important for several reasons including accounting for field production to owners and governments, field surveillance, and volumetric input to reservoir simulators.

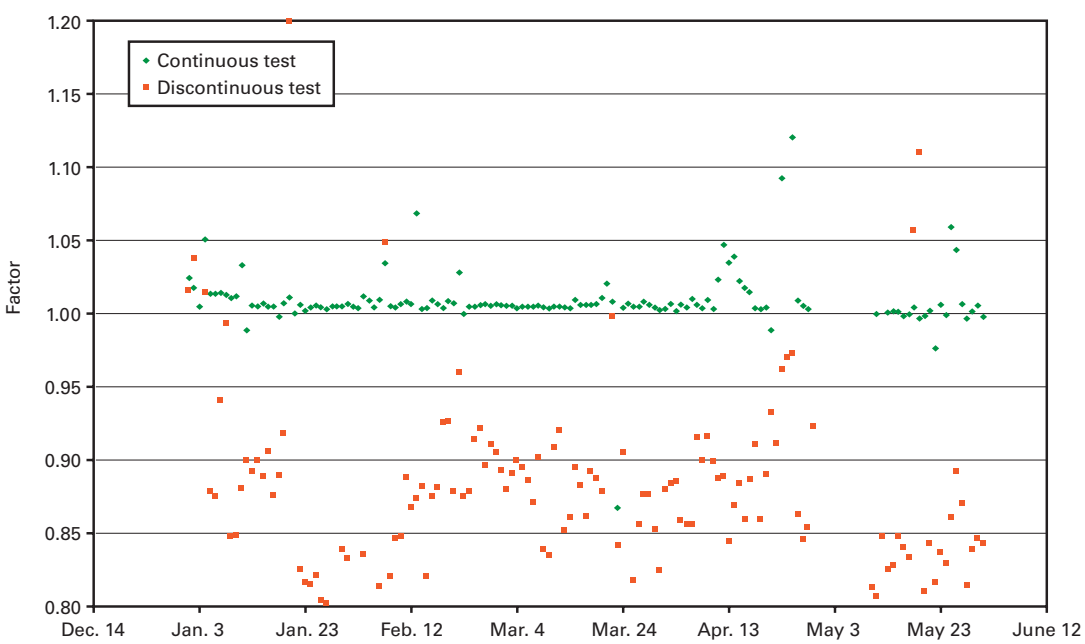
Traditionally companies perform allocation monthly, reconciling the less accurate sum of the well tests adjusted by well uptimes with the more accurate fiscal measurements. This process has several inherent inaccuracies including less-than-perfect well tests, lack of precisely knowing when wells were off production, unknown well flow changes, and the methods for allocating the difference between fiscal and well test measurements.

Ineffective allocation can lead to financial consequences because of inaccuracies in volumes allocated between multiple owners and various tax regimes.

Inaccuracies can also feed through

PLATFORM EXAMPLE

Fig. 1



to reservoir simulators that assist in decision making such as where to drill the next well. These inaccuracies often compound with time, as monthly allocation occurs during the field's life cycle.

Hydrocarbon accounting

Hydrocarbon accounting systems prepare and store reconciled production and injection data on a well at the conduit, reservoir, block, and zone level with the following objectives to:

- Account for fluid volumes transported in production systems from the source (reservoir) to the point of sale.
- Differentiate the ownership of hydrocarbon fluids.
- Assist production planners regarding hydrocarbon offtake schedules.
- Inform operations and petroleum engineering staff regarding reservoir, well, and production facility behavior.
- Maximize the validity and integrity of hydrocarbon accounting data for report, audit, and review purposes.

Hydrocarbon accounting culminates in a monthly report of producing wells. The MRPW is the official production record used for fiscal, audit, and reporting purposes.

MRPW data provide volumetric input to reservoir simulators that in turn help make decisions regarding future field developments. The data also provide a way to track and record reservoir reserves.

Shell calls the concept of adjusting individual conduit volumes such that their sum equals the related fiscal measurements as reconciliation. The term allocation is the calculation whereby the official conduit volumes (produced or injected) are assigned to the related reservoir units.

A flaw in the traditional hydrocarbon accounting process is the assumption that the flow during a well test (about 1% of the time) equals the flow of when the well is not on test (about 99% of the time). This assumption is questionable because:

- Well rates can vary unpredictably between well tests due to natural decline, especially during later stages of the life cycle.
- Well stream composition can suddenly change, for example from increasing water cut or increasing GOR.
- Production rates of artificially lifted wells can vary between well tests due to the effects of variables such as backpressure (gas lift) and pump speed and efficiency (electric submersible pumps, progressing cavity pumps, beam pumps, and hydraulic lift).
- Production from wells in enhanced oil recovery can change unpredictably due to changes in gas, water, steam, or polymer flows in the reservoir.
- Variable periodic production in wells that are on intermittent gas lift and gas wells subject to periodic liquid loading;
- Produced wax, ashphaltines, or scale that foul production lines, which need to be cleaned often.

All of the above unpredictable instabilities are aggravated by flaws in the basic well test process such as:[2]

- Wrong well put on test.
- Wrong instrumentation used, such as improperly sized or damaged orifice plate.
- Inaccuracies in well test instrumentation due to improper calibration or lack of maintenance.
- Improperly ranged well test instrumentation such as testing a well producing at low rates with instrumentation sized for wells producing at high rates.
- Testing wells at flow and pressure conditions that differ from normal flow conditions, especially for wells with high backpressure such as step outs and subsea wells with long flowlines.
- Commingled subsea wells without a dedicated test line, forcing testing by difference at test conditions that may vary from normal flowing conditions.

Operators can mitigate the effects of these flaws with techniques that continuously estimate well flow rates.

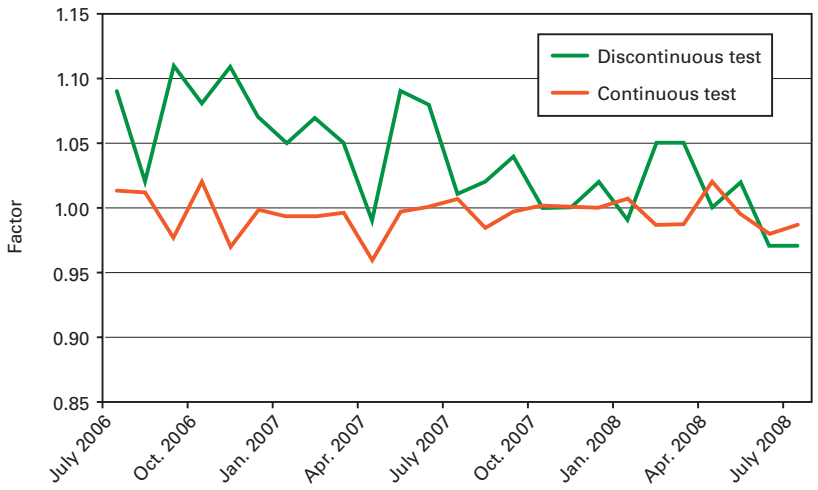
They can also use continuous estimation of well flow rates to produce automatic daily reports of key performance indicators such as daily well oil, gas, and water production and deferment rates.

Shell's estimation technique

Shell developed the FieldWare Production Universe data-driven modeling application for continuously estimating well production. References 3-7 describe the development background and Shell's early operational experiences with the application.

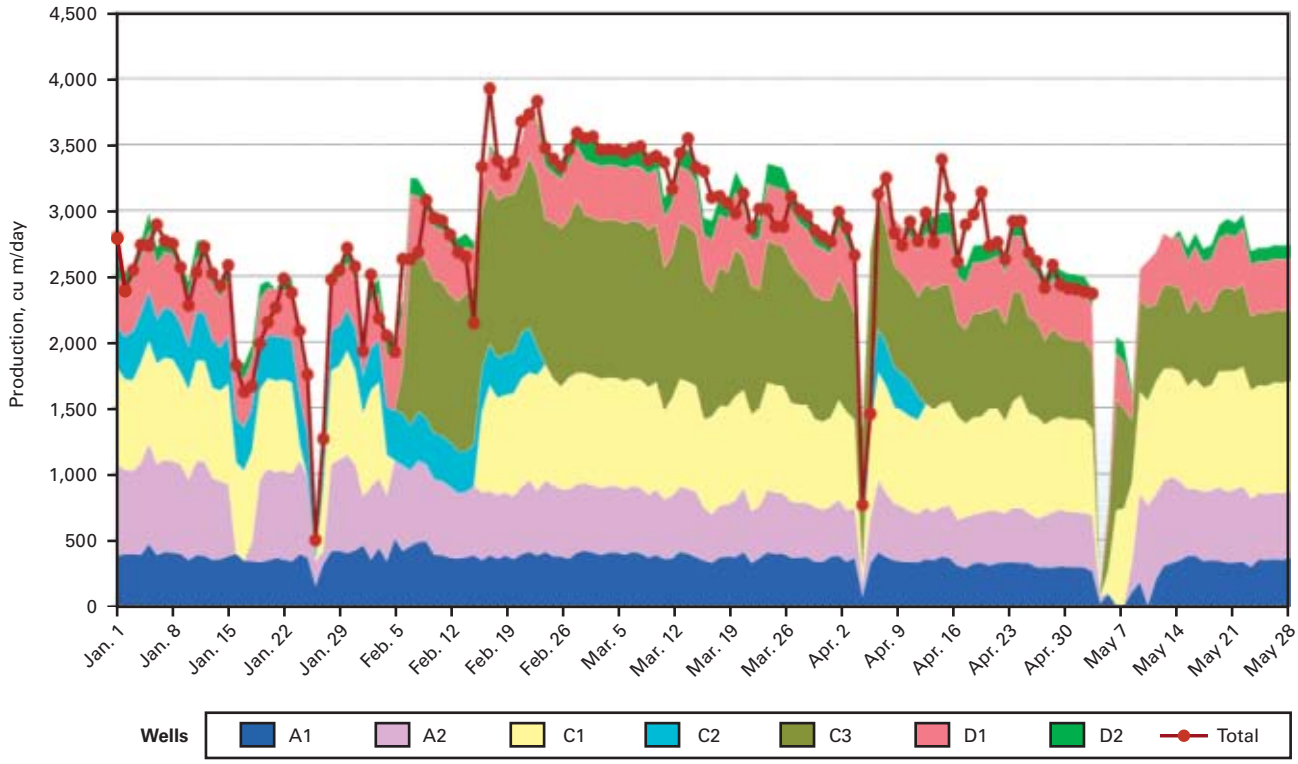
Data-driven models provide a virtual continuous three-phase meter for all wells.

FPSO EXAMPLE Fig. 2



LONG TIEBACK EXAMPLE

Fig. 3



The data-driven approach takes full advantage of the well test and available real-time production metering in conventional production operations, particularly with regard to changing well conditions and instrumentation uncertainty.

The technique requires an abbreviated multirate well test along with historic well-test results as input for the modeling process that generates data-driven well models. These models relate the three-phase flow from the well on test with signals from the wellhead instrumentation, such as tubinghead pressures and temperatures, lift-gas injection rates, and production choke openings.

The software application automatically retrieves well test and instrumentation signals from associated production data systems such as supervisory control and data acquisition systems, distributed control systems, or historian systems.

After completing the construction of a model for each well, the software application uses the model to automatically compute oil, gas, and water rates for each well. The application also retrieves bulk, fiscal station oil, gas, and water signals from production data systems and then performs a continuous material balance in which the well flow's estimates provide the flow in and the bulk measurement gives the flow out.

The ratio of total well-flow estimate to total measured bulk/fiscal flow equals the allocation factor.

The software application has an intuitive graphical user interface for operator data load/display and well-model configuration and validation. The process automatically uploads subsequent well tests into the application for model validation or updating. Algorithms within the application automatically indicate when a model requires updating (retesting).

The use of data-driven models for well production surveillance provides a number of advantages, such as simplicity of the approach and how it incorporates and extends the conventional well testing process. The process requires no numerical assumptions about the underlying physics of the well.

In an operational environment with limited engineering resources, the process does not require frequent wellhead instrumentation calibration. The application only requires repeatable well measurements; within limits. Absolute measurement accuracy is not critical.

To ensure robustness, the application creates several independent data driven models for each well using different inputs such as multiple fallback models based on some or all of the following parameters: wellhead pressure, wellhead temperature, manifold pressure, bottomhole pressure. This allows well estimates to continue should an individual instrument fail. This also allows the model to identify and report malfunctioning instrumentation.

The net effect is that FW PU real-

time well flow estimates, comparison with bulk measurements, fallback models, and easy-to-use graphical user interface provide:

- Automatic daily production and deferment totals for individual and collective wells.
- Real-time crosscheck on the quality of the estimates indicating when wells need retesting and pinpointing instrumentation problems;
- Estimated well flows (when the wells are not on test) by streaming real-time well data to the models. The process also automatically compares the sum of the estimated well production with real-time, single-phase flows as physically measured by export or bulk meters.
- Daily allocation factors.
- Applicable to all well types such as naturally flowing, artificially lifted, unstable, onshore, offshore, deep water, shallow water.
- Applicable to all well sizes.
- Fast, easy to sustain and cost effective implementations.

Four case studies compare continuous allocation using Shell's software and discontinuous allocation using the traditional well test approach.

Offshore platform

Fig. 1 compares continuous well-flow estimation vs. flow derived from discontinuous well tests for an offshore platform producing 50,000 boe/d from 33 platform wells and 2 subsea tiebacks. All wells are on gas lift and have water cuts ranging between 10% and 95% with an overall GOR of 78 scf/scf.

In the facility, operators used to measure three-phase flow by periodically routing the wells to a test separator, with well production interpolated from test to test.

They also tried physical models in combination with real-time wellhead pressure and temperature to estimate three-phase flow from the wells, but they found this method difficult to sustain in an operational environment.

Consequently, the operators tried the FW PU application for estimating three-phase flow continuously for each well.

They used these data for daily well allocation in which the sum of the well estimates divided by the overall platform oil production rate derived a daily allocation factor.

They also calculated allocation factors daily from well tests, adjusted by well uptime and then summed across all wells and divided by overall platform oil production rate.

Fig. 1 compares the two methods. As can be seen, the FW PU method provides a fairly stable allocation factor in the range of 1.0, whereas the well-test method has a relatively unstable factor that averages about 0.88 on the low side.

The field operator subsequently has adopted continuous allocation FW PU well-flow estimates.

FPSO

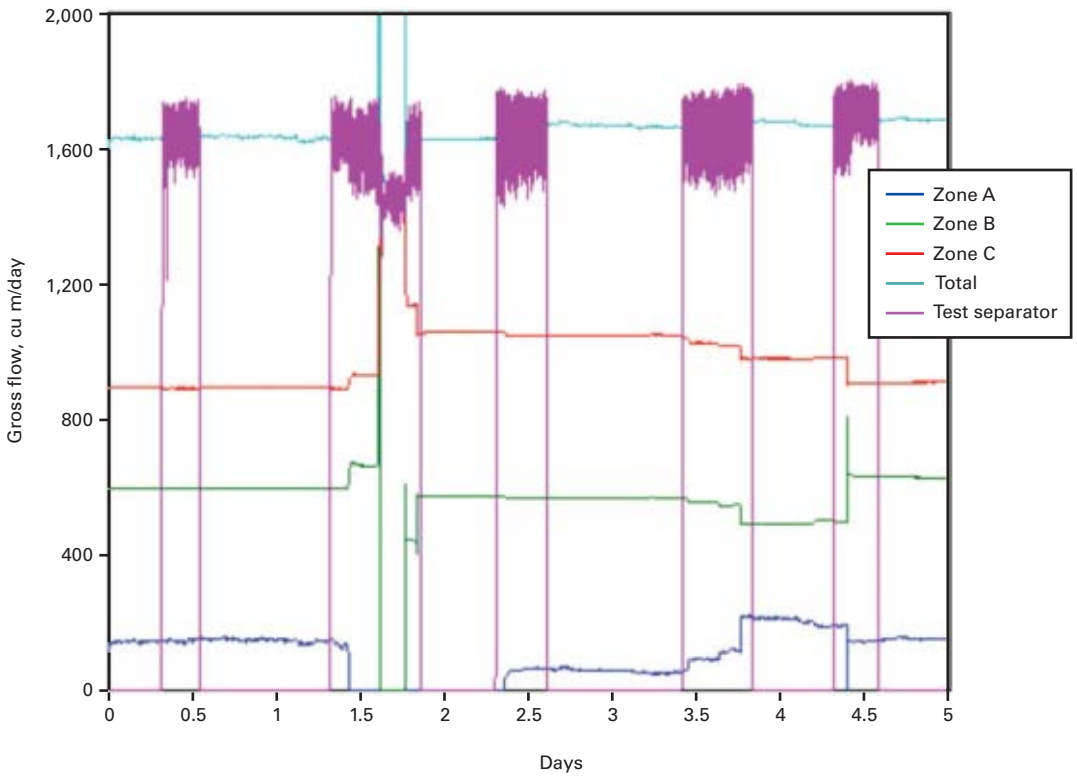
Another illustration on the use of the application is from a spread-moored floating production, storage, and offloading (FPSO) vessel with 2 million bbl of oil storage, off West Africa. The facility is in a 3,200-3,700 ft water depth and handles about 200,000 bo/d of production and about 300,000 b/d of water injection.

The FPSO ties in 13 subsea production wells and 13 subsea water injectors.

The well with the highest produc-

MULTIZONE EXAMPLE

Fig. 4



tion capacity can produce 50,000 bo/d and the well with the highest injection capacity can inject 70,000 b/d.

The wells are on five subsea manifolds each with two flowlines to the FPSO. The production risers, connecting the flowlines to the FPSO, include an option for gas lift if required.

The operation initially used the traditional hydrocarbon accounting and allocation approach. In this case, the operators obtained well-interrupt times from real-time pressure readings at the subsea and FPSO DCS control systems and hence these times were accurate within reason.

Fig. 2 compares the traditional allocation approach with the continuous flow estimation of oil, gas, and water. As can be seen in this case, the old method gave allocation factors which erred 4% on the high side, whereas the new method averaged 0.05% on the low side.

The field operator subsequently adopted continuous allocation.

Long subsea tieback[5]

A third example is a subsea cluster consisting of eight wells tied back to a remote platform via a 60-km flowline with no separate test line due to the length of the tieback.

The operation measured total production on the remote receiving platform. Initially each well had three downhole pressure (BHP) gauges and a downhole venturi meter. The combined measurements of pressure drop over the venturi and density in the wellbore allowed for the estimation of production rates. In addition to these downhole flowmeters, the subsea flowlines from each wellhead to the drill center also had venturis installed.

Although seemingly robust, the operation overestimated the reliability of the subsea and downhole metering equipment. One downhole flowmeter failed at start-up. Initially, production estimates from the other wells proved sufficiently accurate for allocating by difference the production of the well with the failed equipment.

During the second and third years of production, however, signals from the other downhole flowmeters stopped or became unreliable. The subsea venturis also proved unreliable due to blocked impulse lines, inadequate density measurement, and faulty associated instrumentation (tubinghead pressure and temperature).

The combination of no data with inaccurate data affected the understanding of the production from the field and impeded allocating and optimizing production.

Consequently the operator deployed the FW PU to estimate continually the highly variable production behavior of each well's oil, gas, and water flow.

Although the application had previous successes in subsea fields, this subsea cluster required a new approach. The 60-km long flowline resulted in a time delay between the changes in bulk meter and well variations, making it difficult to effectively test wells.

As such, the challenge was to use the available continuous real time and historical well measurement and commingled production data optimally, with an end target of providing an operationally sustainable real-time application for continuously estimating well-by-well production.

This involved the building of initial data-driven models using total commingled production data during the preceding time period and then calculating production rates from the downhole flowmeters during the periods that this data was available.

Validation and calibration of the downhole flowmeter data used testing by difference data for allocating some of the total production to individual wells. The resulting FW PU models provided real-time well production estimates, which tracked the steady-state production metering values (Fig. 3).

After a period of observation, analysis of the estimates against operations expectations, actual production events and total production values, found a fairly good fit.

This led to a recommendation to use FW PU as a basis for production reporting and allocation for the field.

Multizonal smart wells.

The last example is from multizonal smart wells. In this case, the application uses the mechanical configuration, annulus and tubing downhole pressures, and the associated inflow control valve openings, for generating data-driven models for individual zones in the wells.

The zonal models then provide production estimates for the individual zones in real time, working from the real-time downhole pressure gauge readings and inflow-control-valve settings.

These zonal flow estimates are the basis for the continuous allocation. The software continuously compares the sum of the allocation flows with the total well production that may be measured with a multiphase flowmeter.

If a MFM is not installed, the operation assumes that total well flow is the sum of the individual zonal flows and then the process continuously compares this sum along with FW PU-derived flows for all other wells in a given field with the measured total flows for that field.

The building of the FW PU data-driven models for the zones requires a series of specifically designed tests in which test flows of individual zones and combinations of zones of the smart well flow to a surface test separator or MFM. The test includes varying the zonal ICV settings and recording the downhole and surface pressures and temperatures.

In general, well tests of zones flowing one zone at a time are inadequate because the pressure regimes will be different when all zones flow together. The zones also interact with one another. It is therefore desirable to have the zones flow together for at least part of the test.

From the tests, the application can derive models for estimating individual zonal production for oil, gas, and water

based on, for example, ICV position and differential pressure across the ICVs.

On completion of the well testing and modeling, the models are put online. Based on real-time data on ICV positions as well as downhole pressures, the zonal models estimate production from each zone in real time and report and allocate produced volumes daily.

Fig. 4 illustrates the individual zonal liquid flow continuously estimated by the application. The figure shows well flow estimate as the numeric sum of the individual zonal estimate and the total well flow periodically measured by the test separator. As can be seen, the FW PU estimated total of the zonal flows matches well with the test separator measured flow. ✦

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The authors

Ron Cramer (Ronald.Cramer@shell.com) is a senior advisor with Shell Global Solutions (US) Inc., Houston, in oil field automation and production systems. Cramer has 30 years' experience with Shell International in upstream oil field operations and production systems. He also worked for 10 years as a chemical engineer for Union Carbide and Polysar in downstream research and process areas. Cramer holds a BS in chemical engineering from Strathclyde University, Glasgow, and an MS in chemical engineering from Waterloo University, Ontario.

Dave Schotanus, (Dave.Schotanus@shell.com) is currently FieldWare operational support leader for Shell Global Solutions (US) Inc. in Houston. He has worked for Shell in a variety of functions in several operating units and was one of the first programmers to use the Shell-developed Production Universe. Schotanus has a BSc in mechanical engineering from LeTourneau University, Longview, Tex.

Kolin Ibrahim is the lead production programmer for Brunei Shell Petroleum's east asset. He has 11 years of experience in operations, safety, and business improvement activities. Ibrahim has a bachelor of engineering and is a chartered engineer member of the Institution of Engineering and Technology.

Nick Colbeck previously worked for Shell E&P in various operations around the world. While head of production programming and allocation for Shell's Nigerian deepwater asset, one of his responsibilities was working with the Fieldware Production Universe. He currently works as petroleum engineering team lead with Hess Corp. in Indonesia. Colbeck is a graduate of the University of Glasgow.

Global crude distillation capacity in 2009 shot ahead of capacity for 2008, according to the latest OGJ survey of the world's refineries, extending in a big way the growth evident in recent years. Worldwide refining capacity set a record for the eighth year in a row.

Global refining capacity advances; US industry faces uncertain future

Warren R. True
Chief Technology Editor-LNG/Gas Processing

Leena Koottungal
Survey Editor/News Writer

For 2009, OGJ's survey shows a total capacity of 87.2 million b/cd for 661 refineries, an increase of more than 1.6 million b/cd over 2008. Last year's refinery survey, as of Jan. 1, 2009, listed a global capacity of 85.6 million b/cd in 655 refineries.

The 2009 capacity growth far surpasses the total growth for the previous 3 years: 2008 (300,000 b/cd), 2007 (130,000 b/cd), and 2006 (52,000 b/cd). And the number of refineries reversed what had been a steady contraction, adding a net of six new plants during 2009 and reversing a 10-year contraction that saw more than 100 refineries closed, mostly smaller, less-efficient ones.

Fig. 1 shows the trend in operable refineries and worldwide capacity.

Five new refineries started up in 2009, all in the burgeoning oil-product markets of the Middle East and Asia. Net Asian refining capacity in fact leaped more than 1 million b/cd for 2009, followed by North America with more than 393,000 b/cd, and the Middle East with more than 200,000 b/cd.

Other regions experienced little or no net gain or loss in stated capacity.

New crude capacity

This year's survey lists five new refineries, adding more than 1 million b/cd of crude capacity.

In the Middle East, the Kar Group opened the 40,000-b/cd plant in Abril in Iraq's Kurdistan region (OGJ, July 27, 2009, p. 10), while Laffan Refinery Co. Ltd. at midyear opened a 138,700-b/cd refinery at Ras Laffan City, Qatar.

Qatargas Operating Co. Ltd. is operating the plant for a consortium of Qatar Petroleum (51%), ExxonMobil (10%), Total (10%), Cosmo Oil Co. (10%), Mitsui (4.5%), and Marubeni (4.5%; OGJ, Apr. 20, 2009, p. 9).

In Asia, Reliance Industries Ltd. started up a 580,000-b/cd plant in the state of Gujarat; PetroVietnam started up the first refinery in Vietnam, at Dung Quat, 148,000 b/cd; and China National Petroleum Corp. started up a new refinery at Dushanzi in far western Xinjiang region, 200,000 b/cd.

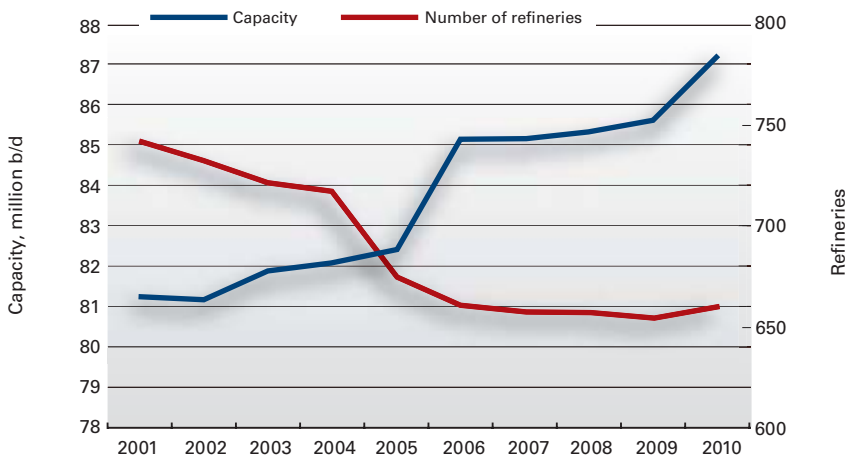
All other increases in refining capacity occurred in existing facilities:

- For North America, OGJ's survey for US refineries reveals a total capac-

Laffan Refinery Co. Ltd. this year started up a new refinery at Ras Laffan City operated by Qatargas Operating Co. Ltd. (photograph from Qatargas).

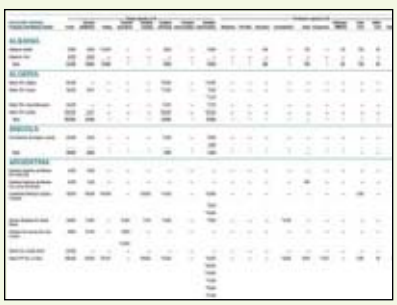
WORLDWIDE REFINING*

Fig. 1



*As of Jan. 1 of each year.

OGJ subscribers can now download, free of charge, the text version of the OGJ Worldwide Refining Report 2009 tables from www.ogjonline.com. Scroll down to "Additional Information," click "OGJ Subscriber Surveys," then "Worldwide Refining." This link also features the previous editions of this report as well as a collection of other OGJ surveys from previous years. Subscribers and nonsubscribers may purchase Excel spreadsheets of the survey data by sending an email to orcinfo@pennwell.com or calling (800) 752-9764. For further information, please email lkoottungal@pennwell.com, or call Leena Koottungal, OGJ Survey Editor/News Writer (713) 963-6239.



ity increase of 383,837 b/cd. Much of that results from new data received for Valero Energy's Norco, La., refinery that now peg its crude capacity at 310,000 b/cd.

The other large increase is for Marathon Oil's 436,000-b/cd Garyville, La., refinery that in late 2009 has started up a 180,000-b/cd expansion.

More capacity is on the horizon for South America. Last month, Petroleo Brazileiro SA (Petrobras) and the Rio Grande do Norte state government agreed on details for expanding the Refiniaria Potiguar Clara Camarao to boost its installed capacity and deploy a gasoline production unit (OGJ Online, Nov. 19, 2009).

The 30,000-b/d refinery, which already produces LPG, diesel fuel, and aviation kerosine, will also produce petrochemical naphtha and other products, along with enough gasoline to make Rio Grande do Norte self-sufficient.

The upgrade will allow the refinery to produce 21,000 cu m/month of gasoline, 45,000 cu m/month of diesel, 7,500 cu m/month of aviation kerosine, 11,700 cu m/month of LPG, and 3,000 cu m/month of chemical naphtha.

- In the Middle East, Kuwait reported an increase in capacity at its three refineries, to 936,000 b/cd for 2009, up by 46,800 b/cd over 2008. That increase also represents the total net increase for the Middle East.
- In Asia, new data for two refineries in South Korea—Yeosu and Onsan—and Taiwan, at Mailiao, added a net increase for the region of 115,000 b/cd.

And more Asian capacity is in the works.

Climate change efforts to hit US industry hard

Trends noted in this report—recently falling US capacity and utilization and rising Asian and Middle Eastern capacity—come at a difficult time for US refiners, as the US Congress prepares to craft climate-change legislation for debate in 2010.

A recent analysis by industry consultancy Wood Mackenzie, Edinburgh, compared the impact on the US refining industry of the US House of Representatives' HR2454 (Waxman-Markey) with the impact starting in 2013 of Phase III of the European Union's Emissions Trading Scheme (OGJ, Nov. 2, 2009, p. 30).

Key conclusions of the study are the following:

- The US allocation of free credits is much less generous than its European counterpart, which is the primary driver for the US industry being "materially disadvantaged."
- Higher fuel costs (projected for the near term) will not materially affect oil-product demand; other legislative measures (auto fleet efficiency and low-carbon fuels standards) will be much more significant.
- Waxman-Markey threatens to disrupt the US refining industry through its provisions on intrastate trade. This could offer significant advantages to long-haul gasoline exporters and thus prompt rationalization in the US refining industry. "That would be contrary to US interests of improving its security of supply," said the report.

Even if this intrastate provision in the bill is removed, said Wood Mackenzie, the "costs of carbon increase overall operating costs and thus significantly reduce future cash flows and hence enterprise value" of the US refining industry.

Allocation effects

The analysis further noted that the proposed Waxman-Markey bill allocates the refining industry 2% of total emission credits for the entire US economy. The refining allocation thus equates to "about 100 million tons in 2015, less than 5% of carbon emissions from the production and consumption of transportation fuels" in the US.

The legislation makes the refiner responsible for buying the additional credits associated with the stationary (refinery) sources and also "the emissions associated with consumption of the various transportation and commercial fuels by end-users (vehicle drivers, residential consumers, industry, etc.)."

Moreover, emissions allocated to US refining only provide around 30% of its stationary emissions, if the additional burden of credits on transportation fuels is entirely passed to the end-user.

Wood Mackenzie concluded, therefore, that US refiners will need to purchase more than 2 billion tonnes of credits in 2015, based on expectations of US oil-product demand and refinery utilization.

The report correctly cautions that US climate legislation has a long road ahead of it and will be taken up only after contentious health-care and financial regulations debates. Nonetheless, the report also correctly notes the US Environmental Protection Agency is moving ahead with regulations governing CO_2 emissions from mobile sources, soon to be followed by rules for stationary sources.

How the world's largest refiners rank

Table 1

Rank		Company	Crude capacity, b/cd[1]
Jan. 1, 2010	Jan. 1, 2009		
1	1	ExxonMobil Corp.	5,797,000
2	2	Royal Dutch Shell PLC	4,630,239
3	3	Sinopec	3,971,000
4	4	BP PLC	3,328,390
5	5	ConocoPhillips	2,778,200
6	8	Valero Energy Corp.	2,704,660
7	6	Petroleos de Venezuela SA	2,678,000
8	9	China National Petroleum Corp.	2,615,000
9	7	Total SA	2,594,608
10	12	Chevron Corp.[2]	2,492,000
11	10	Saudi Aramco	2,433,000
12	11	Petroleo Brasileiro SA	1,997,000
13	13	Petroleos Mexicanos	1,703,000
14	14	National Iranian Oil Co.	1,451,000
15	15	Nippon Oil Co. Ltd.	1,317,000
16	16	Rosneft	1,293,000
17	17	OAO Lukoil	1,217,000
18	20	Marathon Oil Corp.	1,196,000
19	18	Repsol YPF SA	1,105,000
20	19	Kuwait National Petroleum Co.	1,085,000
21	21	Pertamina	993,000
22	22	Agip Petroli SPA	904,000
23	23	Sunoco Inc.	825,000
24	25	SK Corp.	817,000
25	24	Flint Hills Resources	816,525

[1]Includes partial interests in refineries not wholly owned by the company. [2]Includes holdings in Caltex Oil and GS Caltex.

Last month, Pakistan Minister for Petroleum and Natural Resources Naveed Qamar told the country's National Assembly that three refineries with a total capacity of 465,000 b/d "are in the pipeline" (OGJ, Nov. 16, 2009, p. 12).

Included are the 250,000-b/d Khalifa Coastal refinery and the 115,000-b/d Bosicor Oil Pakistan Ltd. plant, both in Hub, Balochistan Province; and the 100,000-b/d Trans-Asia Refinery Ltd. plant at Port Qasim in Karachi.

Refinery closures, delistings

As the global recession took hold during 2009, oil demand fell and crude inventories expanded. With the year winding to its end, refinery curtailments and shutdowns became more and more likely.

COMPANIES WITH 200,000+ B/CD REFINING CAPACITY IN ASIA, THE US, WESTERN EUROPE

Table 2

Rank	Company	No. of refineries	Crude capacity, b/cd[1]
Asia[2]			
1	Sinopec	27	3,971,000
2	China National Petroleum Corp.	25	2,615,000
3	ExxonMobil Corp.	10	1,937,500
4	Royal Dutch Shell PLC	13	1,324,875
5	Nippon Oil Co. Ltd.	7	1,317,000
6	Reliance Petroleum Ltd.	2	1,240,000
7	Pertamina	8	1,011,825
8	SK Corp.	1	817,000
9	Indian Oil Co. Ltd.	10	787,290
10	Chinese Petroleum Corp.	3	770,000
11	GS Caltex Corp.	1	[3]730,000
12	Tonen/General Sekiyu Seisei KK	4	[4]628,250
13	Idemitsu Kosan Co. Ltd.	4	608,000
14	Hyundai Oil Refinery Co.	3	589,500
15	Cosmo Oil Co. Ltd.	4	565,250
16	S-Oil Corp.	1	[5]565,000
17	Formosa Petrochemical Co.	1	540,000
18	Chevron Corp.	6	523,667
19	BP PLC	4	345,864
20	Saudi Aramco	6	327,652
21	Hindustan Petroleum Corp. Ltd.	2	296,250
US			
1	ConocoPhillips	13	2,226,200
2	Valero Energy Corp.	13	2,209,660
3	ExxonMobil Corp.	7	2,065,000
4	BP PLC	6	1,477,525
5	Marathon Oil Corp.	7	1,196,000
6	Royal Dutch Shell PLC	8	[6]959,350
7	Chevron Corp.	5	941,000
8	Petroleos de Venezuela SA	4	[7]849,400
9	Sunoco Inc.	4	825,000
10	Flint Hills Resources (Koch Industries)	3	816,525
11	Motiva Enterprises LLC[8]	3	732,000
12	Tesoro Corp.	7	658,000
13	Saudi Aramco	3	[9]370,000
14	LyondellBasell	1	268,000
15	Alon USA	3	241,000
16	Husky Energy Inc.	2	237,500
17	EnCana Corp.	2	226,000
Western Europe[10]			
1	Total SA	15	2,264,587
2	ExxonMobil Corp.	9	1,665,500
3	Royal Dutch Shell PLC	11	1,549,940
4	AgipPetroli SPA	10	876,117
5	BP PLC	8	868,954
6	Petroplus International NV	7	796,000
7	Repsol YPF SA	5	709,200
8	Turkish Petroleum Refineries Corp.	4	613,275
9	ConocoPhillips	4	610,125
10	Compania Espanola de Petroles SA (CEPSA)	3	427,000
11	Ineos Group Holdings Inc.	2	402,800
12	OMV AG	3	398,635
13	ERG Group	4	396,214
14	Preem Raffinaderi AB	2	316,000
15	Hellenic Petroleum SA	3	313,000
16	Neste Oil	6	[11]309,000
17	Statoil AS	3	304,210
18	Galp Energia SA	2	304,172
19	Saras SPA	1	300,000
20	Petroleos de Venezuela SA	8	294,550
21	Chevron Corp.	1	210,000

[1]Includes partial interest in refineries not wholly owned by the company. [2]Asia includes Australia, Bangladesh, Brunei, China (and Taiwan), India, Indonesia, Japan, Malaysia, Myanmar, New Zealand, North Korea, Pakistan, Papua New Guinea, the Philippines, Singapore, South Korea, Sri Lanka, and Thailand. [3]Includes Caltex's 50% stake. [4]Includes ExxonMobil Corp.'s 50% stake. [5]Includes Saudi Aramco's 35% stake. [6]Includes Shell's stakes in Motiva and its 50% stake in the Deer Park, Tex., refinery. [7]Consists of PDVSA's ownership of Citgo and its 50% stake in the ExxonMobil Chalmette, La., refinery. [8]50/50 joint venture between Shell and Saudi Aramco. [9]Consists of 50% stake in Motiva. [10]Western Europe includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the UK. [11]Includes 50% stake in AB Nynas refineries.

The only shutdown OGJ's survey reflects this year was in March by Nihonkai Oil Co. Ltd. at its 57,000-b/cd Toyama, Japan, refinery. The company plans to convert the plant to an oil terminal. It was the smallest refinery owned by the Nippon Oil group (OGJ, Aug. 3, 2009, p. 44).

Several refiners, mainly among hard-hit US operators, have announced reduced utilization, periodic idling of units, planned temporary shutdowns, and one permanent closing.

In March of this year, Motiva Enterprises LLC announced it was delaying for more than 2 years the completion target for addition of a single-train crude distillation unit that will add 325,000 b/cd of capacity to its Port Arthur, Tex., refinery. Added to its current capacity of 285,000 b/d, the project will make the refinery the largest in the US.

A joint venture of Shell Oil Co. and Saudi Refining Inc., Motiva originally planned to complete the $7 billion expansion late next year.

In June, Valero Energy Corp. announced suspension of plans to add hydrocrackers at its 250,000-b/d Port Arthur refinery and its 310,000-b/d St. Charles, La., refinery. At Port Arthur, plans were to add a 50,000-b/d hydrocracker for an estimated $1.7 billion. At St. Charles, Valero planned a new 50,000-b/d hydrocracker to cost $1.25 billion (OGJ Online, June 4, 2009).

In September, the company also announced it was shutting down the coker and gasifier complex at the 210,000-b/cd refinery at Delaware City, Del., operated by its Premcor Refining Group Inc. subsidiary. This step followed an earlier shut down of the coker and fluid catalytic cracking unit at its 315,000-b/d Corpus Christi, Tex., refinery (OGJ Online, Sept. 9, 2009).

But the moves at the Delaware City refinery proved insufficient, and last month Valero Energy permanently closed the plant, citing financial losses caused by "very poor economic conditions, significant capital spending requirements, and high operating costs" (OGJ Online, Nov. 20, 2009). The closure will be reflected in OGJ's 2010 survey results.

In fourth-quarter 2009, the company said, it will report a pretax charge of $1.7-1.8 billion, related primarily to

"asset impairment," employee severance, and other shutdown costs.

Valero estimates the shutdown will reduce pretax operating expenses by about $450 million in 2010, including $125 million of noncash costs, and will reduce capital spending and turnaround costs by about $200 million through 2010.

Shutting down the refinery's gasifier and coking operations to improve reliability and financial performance did not sufficiently improve profitability, said Valero Chairman and CEO Bill Klesse last month.

In October, Sunoco Inc., Philadelphia, announced it was idling its 150,000-b/d Eagle Point refinery at Westville, NJ. The refinery is interconnected with Sunoco's refineries at Philadelphia and Marcus Hook, Pa., which form a complex capable of processing 655,000 b/d of crude oil (OGJ Online, Oct. 6, 2009).

Last month, Western Refining Inc., El Paso, announced plans to consolidate two small refineries in New Mexico to reduce operating costs. At Gallup, Western will consolidate the 23,000-b/d refinery there and the 17,000-b/d facility at Bloomfield, which will be idled.

Elsewhere, earlier this year, Kuwait canceled plans to build a 630,000-b/d fourth refinery at Al Jour on the Persian Gulf coast near the Saudi Arabia border. The refinery, earlier expected to cost $10 billion but later raised to $15 billion and rebid, had been scheduled to start in 2013 (OGJ, Nov. 12, 2007, p. 32; OGJ Online, Mar. 23, 2009).

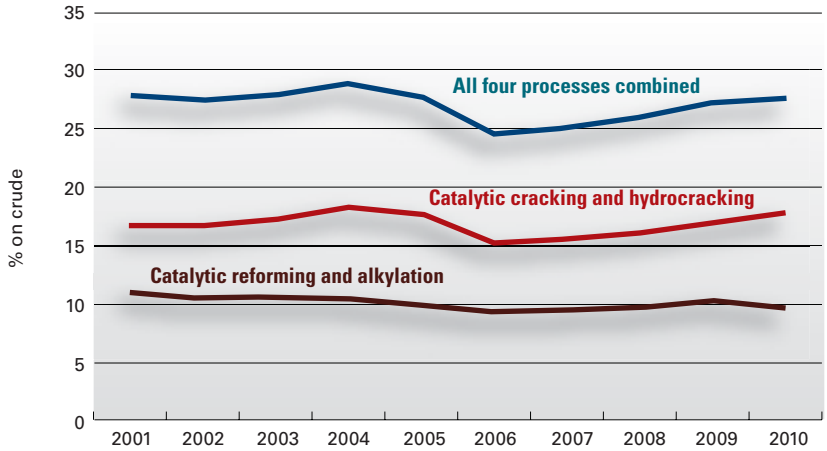
And last month, in Germany, ConocoPhillips confirmed plans to delay an upgrade at its 260,000-b/d Wilhelmshaven refinery. The company had planned to add a coker, hydrocracker, and hydrogen units to the refinery, which it acquired in 2006 from Louis Dreyfus Refining & Marketing Ltd. (OGJ Online, Nov. 18, 2009).

Largest refining companies

Table 1 lists the top 25 refining companies that own most worldwide capacity. Table 2 lists companies whose

ASIA PROCESSING CAPABILITY*

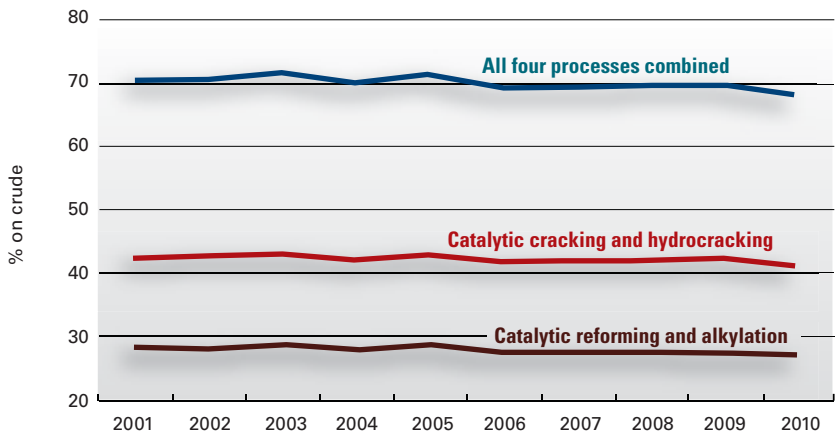
Fig. 2



*As of Jan. 1 of each year.

US PROCESSING CAPABILITY*

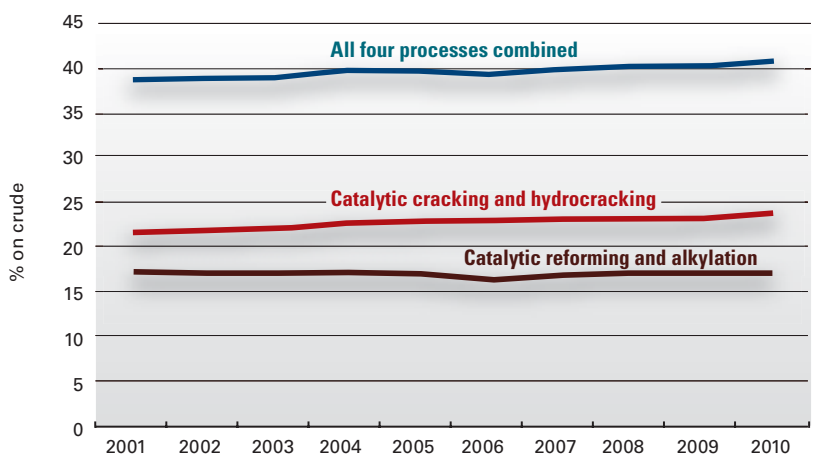
Fig. 3



*As of Jan. 1 of each year.

EU PROCESSING CAPABILITY*

Fig. 4



*As of Jan. 1 of each year.

Moves earlier in the year by Valero Energy to improve margins at its 210,000-b/d Delaware City, Del., refinery proved futile in November as the company permanently closed the plant (photograph from Valero Energy).

plants total more than 200,000 b/cd of capacity in Asia, the US, and Western Europe. Capacities from Tables 1 and 2 include partial interests in refineries that the companies do not wholly own.

Major changes of positions in Table 1 since Jan. 1, 2009, involve Valero, Chevron, Total, and Marathon. Other refiners moving up or down the list by only one rank are Petroleos de Venezuela SA, China National Petroleum Corp., Petroleo Brasileiro SA, Kuwait National Petroleum Co., SK Corp., and Flint Hills Resources.

Netting an annual gain of only slightly more than 100,000 b/d in capacity, Valero nonetheless managed to move past Total and PDVSA in this year's rankings, after new data for Total redefined its holdings.

And, as has already been noted, Marathon added 180,000 b/d at Garyville, La., moving it up the ranking to eighteenth from twentieth.

In Asia, India's Reliance Industries Ltd. moved up to sixth position from twelfth following start-up in late 2008 at its 580,000-b/d refinery at Jamnagar in western India, as also noted previously. Combined with Reliance's neighboring 660,000-b/d refinery, total refining capacity at the site is 1.24 million b/d.

Chevron's position for Asia fell to eighteenth from eleventh after a downward adjustment of 145,000 b/d of capacity at Thailand's Ma Ta Phut, in whose operator, Alliance Refining Co. Ltd., Chevron has an interest.

Other changes in capacity that appear in Tables 1 and 2 are due to adjustments in declared capacity. In Table 2, several companies moved one position up or one position down.

These include, for Asia, nearly all companies between the fourth and seventeenth positions. Gone from the list this year is Showa Yokkaichi Sekiyu Co., whose refinery capacity dropped to less than 200,000 b/d.

For the US, ConocoPhillips and Valero switched positions, Royal Dutch Shell moved up two spots to fourth, and Total dropped off the list when adjusted capacity for its Port Arthur refinery dropped to less than 200,000 b/cd.

WORLD'S LARGEST REFINERIES

Table 3

	Company	Location	Crude capacity, b/cd
1	Paraguana Refining Center	Cardon/Judibana, Falcon, Venezuela	940,000
2	SK Corp.	Ulsan, South Korea	817,000
3	GS Caltex Corp.	Yeosu, South Korea	730,000
4	Reliance Industries Ltd.	Jamnagar, India	660,000
5	ExxonMobil Refining & Supply Co.	Jurong/Pulau Ayer Chawan, Singapore	605,000
6	Reliance Industries Ltd.	Jamnagar, India	580,000
7	ExxonMobil Refining & Supply Co.	Baytown, Tex.	576,000
8	S-Oil Corp.	Onsan, South Korea	565,000
9	Saudi Arabian Oil Co. (Saudi Aramco)	Ras Tanura, Saudi Arabia	550,000
10	Formosa Petrochemical Co.	Mailiao, Taiwan	540,000
11	ExxonMobil Refining & Supply Co.	Baton Rouge, La.	504,500
12	Hovensa LLC	St. Croix, Virgin Islands	500,000
13	Kuwait National Petroleum Co.	Mina Al-Ahmadi, Kuwait	466,000
14	Shell Eastern Petroleum (Pte.) Ltd.	Pulau Bukom, Singapore	462,000
15	BP PLC	Texas City, Tex.	451,250
16	Citgo Petroleum Corp.	Lake Charles, La.	440,000
17	Marathon Petroleumn Co. LLC	Garyville, La.	436,000
18	Shell Nederland Raffinaderij BV	Pernis, Netherlands	404,000
19	Sinopec	Zhenhai, China	403,000
20	Saudi Arabian Oil Co. (Saudi Aramco)	Rabigh, Saudi Arabia	400,000
21	Saudi Aramco-Mobil	Yanbu, Saudi Arabia	400,000

REGIONAL LOOK AT WORLDWIDE REFINING OPERATIONS

Table 4

Region	No. of refineries	Crude distillation	Vacuum distillation	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Coke, tonnes/day
		b/cd						
Africa	45	3,278,382	507,904	205,765	458,427	61,754	830,876	1,841
Asia	161	23,527,629	4,686,771	3,019,525	2,114,856	1,180,755	9,721,163	20,410
Eastern Europe	89	10,343,580	3,903,261	877,089	1,474,382	330,392	4,273,893	12,570
Middle East	44	7,245,365	1,982,275	357,550	654,397	596,891	2,038,063	3,300
North America	154	21,342,753	9,279,757	6,546,834	4,230,491	1,897,133	16,249,568	132,074
South America	66	6,571,153	2,846,885	1,309,507	402,095	132,400	1,904,061	24,640
Western Europe	102	14,914,517	5,817,689	2,255,960	2,186,185	1,179,706	9,977,420	12,709
Total	**661**	**87,223,380**	**29,024,542**	**14,572,230**	**11,520,833**	**5,379,031**	**44,995,044**	**207,544**

For Western Europe, single-position changes are evident for Royal Dutch Shell, ExxonMobil, AgipPetroli, and BP PLC.

Largest refineries

Table 3 lists the world's largest refineries with a minimum capacity of 400,000 b/cd.

Two new refineries joined the list this year, both previously mentioned:

- Reliance Industries' new 580,000-b/d refinery adjacent its older 660,000-b/d refinery at Jamnagar, India.
- Marathon Oil's Garyville, La., plant that boosted its capacity to 436,000 b/d from 256,000 b/d.

Several plants added capacity and, in a few cases, changed positions as a result. Among those are GS Caltex, which reported an additional 50,000 b/d at its Yeosu, South Korea, refinery; S-Oil added 45,000 b/d at Onsan, South Korea; Kuwait National Petroleum, 23,300 b/d at in Mina Al-Ahmadi plant; Formosa Petrochemical Co., 20,000 b/d at Mailiao, Taiwan; and Shell Eastern Petroleum, 13,000 b/d at Pulau Bukom, Singapore.

Other plants changed positions as they added or reduced smaller capacities.

Regional crude capacities

Table 4 lists regional process capabilities as of Jan. 1, 2010. As previously mentioned, the largest increase in crude capacity occurred in Asia, thanks to the start-up of more than 900,000 b/d at three new refineries in India, Vietnam, and China.

China's apparent petroleum demand in October jumped 10.2% from a year earlier, according to a report last month from Platts, as the world's second largest oil consumer ramped up crude processing rates.

For October, Chinese oil demand reached an estimated 33.886 million tonnes (about 248 million bbl) compared with 30.75 million tonnes in October 2008, analysis of official data showed.

October was the second consecutive month Chinese oil demand had posted double-digit growth year over year. The country's oil demand climbed by 12.6% in September from a year earlier. October demand, however, was only slightly higher than September's 33.8 million tonnes, said Platts.

Chinese refineries processed 33.29 million tonnes (7.87 million b/d) of crude in October, surpassing the previous all-time high of 33.11 million tonnes set in July of this year.

Citing official Chinese data, the analysis went on to say that Chinese industrial production and retail sales had risen by more than 16%/year in October, but Chinese growth "continues to be driven by domestic demand rather than a recovery in the country's export markets."

It said higher crude throughput at refineries in October coincided with a 12.3% spike in crude imports during the month, compared with September, and an 11.6% slide in refined-products imports.

October crude imports of 19.33 million tonnes represented a 19.6% increase from a year earlier and were the second highest monthly purchase by China historically, said Platts's analysis.

Elsewhere, the Middle East added 178,700 b/d of new capacity at new refineries in Iraq and Qatar.

North America and Western Europe also increased crude distillation capacity.

Processing capabilities

Figs. 2-4 show the processing capabilities of Asia, the European Union, and the US for the past 10 years. Processing capabilities are defined as conversion capacity (catalytic cracking and hydrocracking) and fuels-producing processes (catalytic reforming and alkylation) divided by crude distillation capacity (% on crude).

Countries in the EU include Belgium, Denmark, France, Germany, Greece, Ireland, Italy, the Netherlands, Portugal, Spain, and the UK. ✦

Method provides welders new technique for avoiding arc blow

Jose Hiram Espina Hernandez
Francisco Caleyo
Gabriela Lourdes Rueda Morales
Jose Manuel Hallen
CIDIM, Instituto Politecnico Nacional
Mexico City

Abraham Lopez Montenegro
Eloy Perez Baruch
Pemex PEP
Mexico City

A new method allows welders with little background in magnetism to reduce arc blow during DC welding of pipelines.

Arc blow most commonly occurs after an in-line magnetic-flux-leakage inspection tool magnetizes a pipe wall during an inspection run.

DC arc welding is one of the most popular techniques in the oil and gas industry because of its versatility and relatively low cost. Interaction between the magnetic field associated with the current flowing through the electrode and the residual magnetic field in the pipeline under repair can produce arc blow.

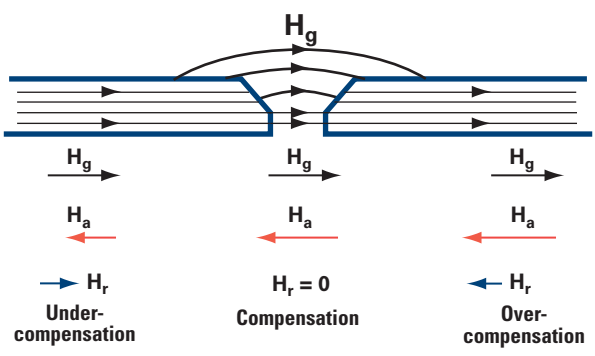
This article describes a simple method to reduce arc blow during DC arc welding of pipelines. In contrast to methods so far available in the literature,[1,2] the method proposed here provides simple rules for welders with little background in magnetism.

Technicians measured residual magnetic field levels of different pipelines in southern Mexico in the gap following girth-cut of damaged sections and in the V-groove following insertion of the new sections. FEMM[3] performed magnetic finite element simulations for residual magnetic field compensation using real-life pipeline dimensions and field parameters. Simulations used variables such as residual magnetic field in the groove, number of coil turns required for the residual magnetic field compensation, DC current flowing through the coil and the electrode, position of the coil relative to the groove, and pipeline WT and OD. Results allowed development of an empirical predictive equation for the magnetic field required to compensate for the residual magnetic field in the weld groove.

Most of the procedures developed in the past adjusted current in order to compensate for the magnetic field in the groove, a disadvantage during DC arc welding since the electrodes' specifications do not cover a wide range of current values. The method proposed here supersedes this disadvantage by making it possible to properly select the number of coil turns and the position of the coil relative to the groove to compensate for residual magnetic field in the groove.

COMPENSATION SCENARIOS

Fig. 1



Arc blow

Residual magnetization of the parts to be soldered often affects DC arc welding of pipelines during repair causing the arc to deviate, a phenomenon known as arc blow. Steel pipelines are huge ferromagnetic structures and can be magnetized by the earth's magnetic field if they extend from north to south. Arc blow becomes a concern when a pipeline has been subject to a strong magnetic field. MFL in-line inspection tools ("pigs") can induce residual magnetization in operating pipelines. MFL pigs use strong permanent magnets to saturate the pipe wall magnetically.

DC arc welding is a manual process establishing an electric circuit between

the welding power supply, the electrode, the welding arc, the parts to be soldered, and the ground connection. The current flowing through a conductor produces a magnetic field according to Ampere's law. The interaction between this magnetic field and the residual magnetic field of the parts causes a displacement of the arc relative to the joint. The continuing displacement of the arc can cause weld defects.

Arc blow depends on the direction and magnitude of the residual magnetic field of the parts. The magnitude of the residual magnetic field in the welding zone should measure less than 30 Gauss to ensure a high-quality weld.[4] Measuring the magnitude and polarity of the residual magnetic field in the groove with a gaussmeter is mandatory. Once the magnitude and polarity of the residual magnetic field are known, a coil wrapped around the pipeline close to the groove reduces its residual magnetic field.

Fig. 1 schematically shows a V-groove and the three possible compensation scenarios. The ideal case occurs when the applied magnetic field (H_a) opposes the residual magnetic field (H_g) in the groove and the resultant magnetic field (H_r) is zero. In the second case, H_a is not high enough, resulting in an undercompensation with $H_r = H_g - H_a$. In the overcompensation case, H_a is strong enough to reverse the polarity of the resultant magnetic field. These last two cases create the risk of arc blow.

Kildishev et al. proposed a deperming technology for large ferromagnetic pipes based on compensating for the axial field in the groove by remagnetizing the pipe near the joint.[2] The procedure is scientifically correct but assumes a solid background in magnetism.

Proctor proposed a practical and simple procedure for reducing the magnetic field at pipeline tie-ins, well known in the oil and gas industry,[1] observing variation of current flowing through the coil-electrode to compensate for the residual magnetic field in the groove. Required current magnitude changes, however, could lie outside the range of current valid values specified for the electrode in DC arc welding procedures. Proctor's procedure requires, as a general rule, wrapping the welding ground lead with four to six-turns coil at about one-half OD from the groove and modifying the electrode current to compensate for the residual magnetic field in the groove.

Technicians took manual measurements at four different points along the pipeline's circumference, starting at 12:00 and ending at 9:00 hr. The residual magnetic field measurement shown is taking place in the gap created by cutting the pipeline (Fig. 2).

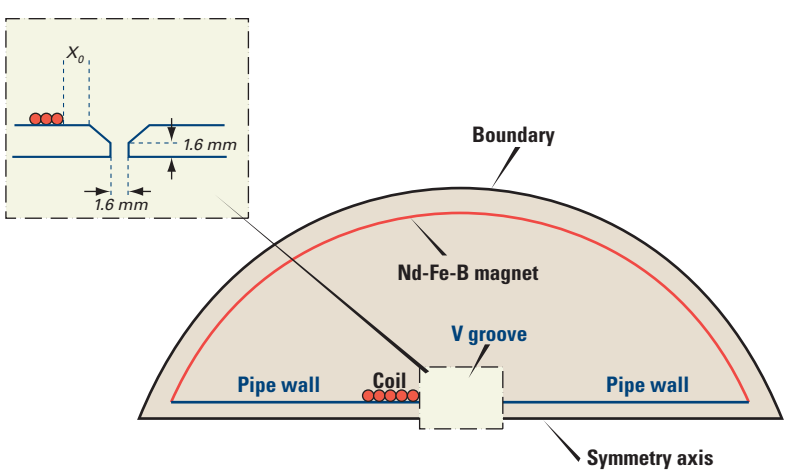
The American Welding Society classifies welding electrodes according to size (in.) and current range (amp). An E6010 electrode of ⅛ in., for instance, has a current range of 75-130 amp. Galvery and Marlow recommend the use of the lower current to obtain a smooth arc.[4] Welders adjust the current through the electrode at the beginning of the welding procedure to obtain a correct arc length and good stability but cannot guarantee a proper compensation of the residual magnetic field in the groove with the variation of the electrode current when the number of turns and position of the coil from the groove are fixed.

Experimental investigation

Technicians took several measurements of the residual magnetic field of pipelines in southern Mexico (Fig. 2). A Magnet-Physik FH-51 Gaussmeter took magnetic flux density measurements of 8, 10, and 30-in. OD pipelines.[6]

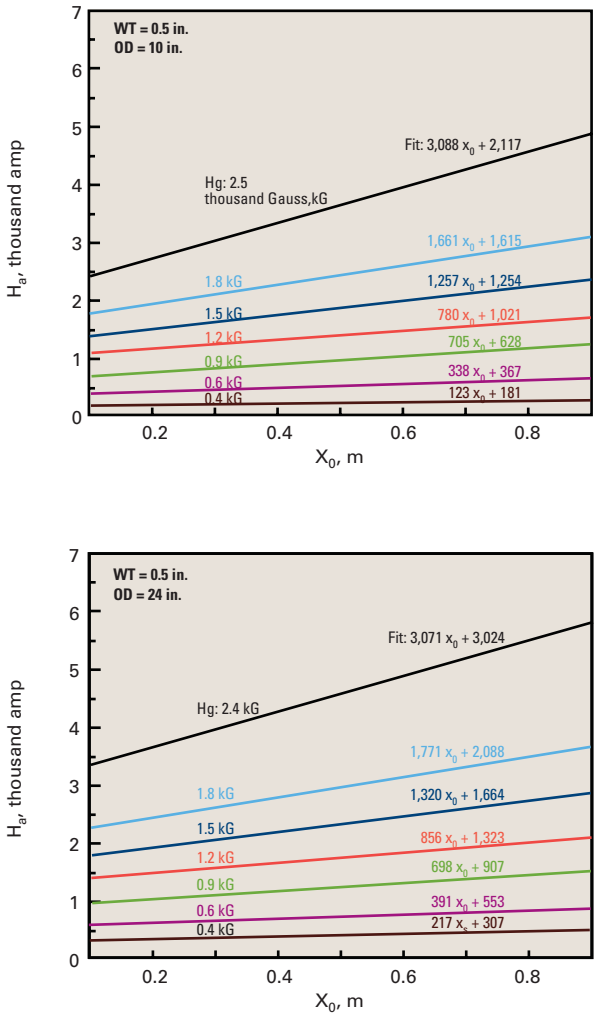
Removed pipeline sections measured 34 m, 6.2 m, and 24.3 m. Table 1 shows the average values of the residual

FEMM MODEL Fig. 3



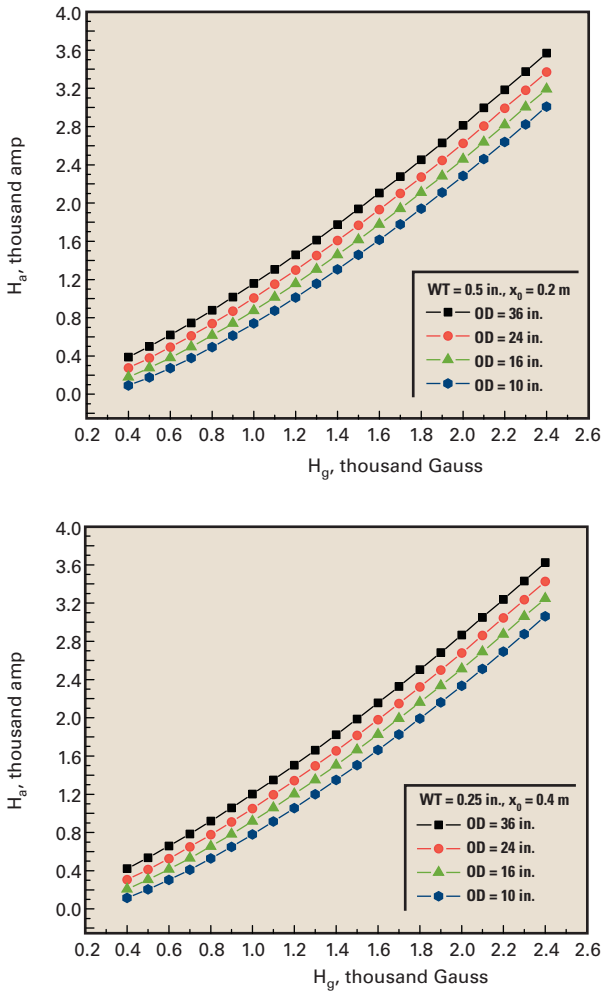
Relationship between H_a, X_0

Fig. 4



Compensation curves

Fig. 5



magnetic field in three different scenarios. Measurements occurred at four different points along the pipeline's circumference, starting at 12:00 and ending at 9:00 hr. These measurements took place:

- In the gap after the pipeline was cut (MB in Table 1, Fig. 2).
- At the edge of the new section before its insertion between the pipeline segments (MC).
- In the welding groove after the new section was inserted and lined up with the other pipeline segments (MA).

The edges of the pipeline were roughly flat in the first two cases. The V groove had already machined according to API-1104 standard in the last instance.[7]

The average values marked as MA, underlined in Table 1, correspond to the values needing to be compensated for to avoid arc blow during welding.

Residual magnetic field values

Table 1

OD, in.	Average MB	Average MC	Average MA
	Gauss		
8	30	20	40
10	1,000	25	400
30	500	25	350

The pipelines with 10 and 30-in OD have values more than 10 times higher than the maximum permissible value of 30 Gauss needed to avoid arc blow.

Modeling, simulation

FEMM helped develop an axisymmetric model of the pipeline with a coil of n-turns.[3] FEMM is a freeware program for electrostatic and magnetic finite-element simulations in two dimensions. Fig. 3 represents the model used to simulate the residual magnetic field in the groove and the compensation

process by selecting different current values flowing through the coil.

The simulation process used 16-m pipe sections with a groove consistent with dimensions dictated by API-1104.[7] An Nd-Fe-B magnet in the form of a ring produced the residual magnetic field in the groove. Changing the coercivity (HC) of the Nd-Fe-B material produced the different values of the residual magnetic field.

The simulation used variables:

- t = WT.
- n = number of coil turns.
- I = soldering current flowing through the coil and the electrode.
- x_0 = coil position relative to the groove.
- D = OD.
- H_g = residual magnetic field intensity in the groove.

Table 2 presents the variables of the simulation runs and their respective values. Considering all possible combinations yielded 3,584 simulation runs.

Results

FEMM simulation software estimated the values of the applied magnetic field necessary to compensate for the residual magnetic field levels in the groove, producing a total of 3,584 values of the resultant magnetic field, H_r. These values cover all possible stages during the compensation process: undercompensation, compensation, and overcompensation.

Fig. 4 shows examples of the relationship between H_a (proportional to nI) and the position of the coil relative to groove x_0 for seven intensities of the residual magnetic field H_g on two pipelines of 0.5-in. WT and 10 and 24 in. OD.

Fig. 4 shows the applied magnetic field H_a required to compensate for the given residual magnetic field H_g in the groove as a function of the position of the coil x_0. The amount of energy H_a (proportional to nI) to achieve compensation depends directly on the position of the coil relative to the groove, OD, and WT. Fig. 4 supports the assumption that the coil must be placed in the immediate vicinity of the groove to achieve compensation with a minimum amount of energy.

As a general rule, therefore, operators should wrap the coil as closely as possible to the groove. The coil position, however, will ultimately depend on the residual magnetic field being compensated for and the optimum current necessary to obtain the appropriate arc length for the given electrode.

Compensating for the residual magnetic field in the groove could be a complex task for operators without a clear and simple step-by-step procedure. Equation 1 is a general expression of the resultant magnetic field H_r as a function of the selected simulation variables obtained with the results of the 3,584 simulation runs performed with FEMM. Introducing the whole dataset into the SPSS multivariate statistical software allowed proposal of a mathematical function best fitting the data with the polynomial expression 1, obtaining a correlation coefficient R^2 = 0.93.

Closer examination of Equation 1 explains the influence of each variable in the compensation process. The applied magnetic field H_a (nI) necessary for compensation is inversely proportional to WT (t) and OD (D) of the pipeline and directly proportional to the position of the coil x_0.

Equation 1 reduces to a simple expression when real-life conditions are taken into account. The compensation procedure aims to apply a magnetic field (H_a) counteracting the residual magnetic field (H_g) to obtain a resultant magnetic field (H_r) below 30 G, including a best case of H_r = 0 (Fig. 1).

WT and OD are known fixed parameters for each particular case. Operators generally intend to optimize system performance by wrapping the coil as closely as possible to the groove. Bearing these parameters and intents in mind, Equation 1 turns into Equation 2, where A (Equation 3) is a constant dependent on actual field parameters. Equation 2 is a simple relationship between the residual magnetic field (H_g) in the groove and the amount of energy (nI) required to avoid arc blow.

Equation 2 yields graphs with sets of curves for the compensation of any value of the residual magnetic field in the groove. Fig. 5, for example, shows two sets of curves obtained for different pipeline WT, OD, and compensation coil position. Applying Equation 1 to all possible ranges of the variables considered in the model would yield a complete set of such graphs making graphs similar to those shown in Fig. 5 for different combinations of the field parameters (t, D, I) and variables (n, x_0) available to operators and providing

Equations

$$H_r = H_g^{1.04} + 712 \cdot D^{0.23} + 1{,}148 \cdot t - 6.3 \cdot nI^{0.76} - 1{,}387 \cdot x_0^{0.25} \quad (1)$$

Making $H_r = 0$:

$$6.3 \cdot nI^{0.76} = H_g^{1.04} + A \quad (2)$$

being:

$$A = 712 \cdot D^{0.23} + 1{,}148 \cdot t - 1{,}387 \cdot x_0^{0.25} \quad (3)$$

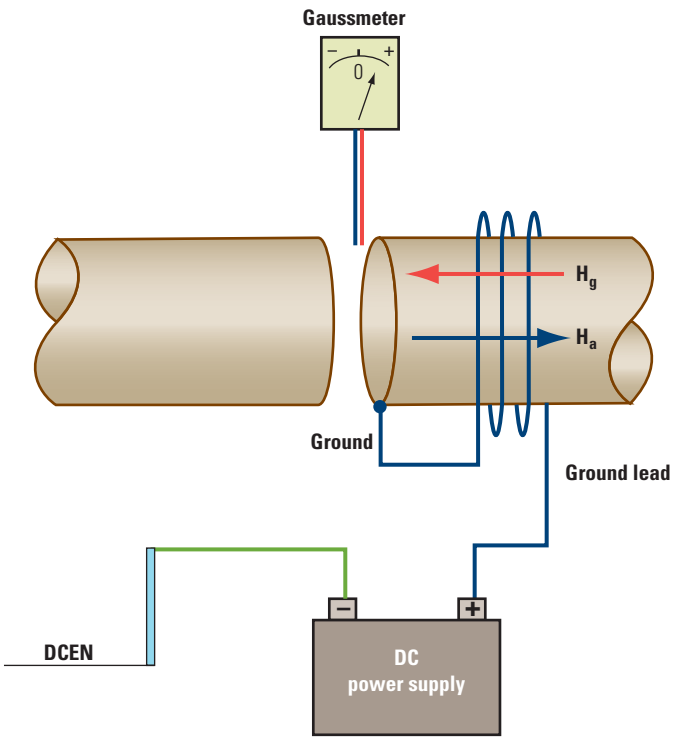
Simulation variable values

Table 2

Variable							
WT, in.	0.25	0.50	—	—	—	—	—
Coil turns	8	10	12	16	—	—	—
Soldering current, amp	100	120	150	200	—	—	—
Coil position, relative to groove, m	0.2	0.4	0.6	0.8	—	—	—
OD, in.	10	16	24	36	—	—	—
In-groove residual magnetic field intensity, kg	0.4	0.6	0.9	1.2	1.5	1.8	2.4

RIGHT-HAND RULE APPLICATION

Fig. 6



a straightforward tool for avoiding arc blow.

Proposed procedure

The first step of the welding process is to adjust the current through the electrode to obtain the optimum arc length. Electrode selection itself depends on many factors, including welder skill and base metal properties. The operator will always know in advance the range of current to be used for a specific welding task according to the electrode selection. Applying Equation 1 can reduce and optimize each case's compensation curves.

A step-by-step compensation procedure follows:

1. Measure the strength (magnitude) and polarity (direction) of the residual magnetic field in the groove with a gaussmeter.
2. With the magnitude of the residual magnetic field (H_g) known, and knowing the characteristics of the pipeline under repair, select the appropriate set of graphs. The position of the compensation coil is important during this selection. It should lay as close as possible to the groove. The value H_g allows the necessary Ampere-turns (nI) to be estimated with the proper compensation curve (Fig. 5).
3. Divide nI by the selected value of current I flowing through the electrode. This provides the number of coil turns.
4. Wrap the welding ground lead around the pipe, according to the selected parameters, in such a way as to produce a magnetic field opposing the residual magnetic field in the groove.
5. Put the gaussmeter probe inside the groove to verify compensation. The welder should use an extra work piece for welding and at the same time perform the magnetic measurement in the groove. This guarantees the electrical circuit is closed, maintaining operator safety.
6. If the residual magnetic field is compensated for (<30 G), remove the gaussmeter probe and start the welding process.

DC arc welding can use two different electric circuits according to electrode type: Direct Current Electrode Positive (DCEP) or Direct Current Electrode Negative (DCEN). Step 4 should be performed carefully to avoid delays and consequent reduction in productivity.

Fig. 6 can help operators set a circuit for compensation. It assumes a working electrode of DCEN type, meaning the DC power supply has a positive ground terminal. All gaussmeters give the polarity of the measured magnetic field, either sign or pole-type, based on the orientation of the measurement probe. If residual magnetic field H_g has the polarity shown by the red arrow line, the gaussmeter reading will be positive, or will mark a north pole. In this case, the coil should be wrapped as shown in Fig. 6 to produce a magnetic field H_a (marked with the blue arrow) counteracting the residual magnetic field.

With a DCEP electrode the DC power supply has a negative ground terminal. If the residual magnetic field has the same polarity as shown in Fig. 6 the coil should be wrapped in the opposite direction to achieve compensation. ✦

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The authors

Jose Hiram Espina Hernandez (jhespina@gmail.com) is a professor at the Instituto Politecnico Nacional (IPN). He is a researcher at the Convenio de Investigacion y Desarrollo de Integridad Mecanica (CIDIM) of the IPN. He holds a BS in electrical engineering, an MS in automation, and a PhD in technical sciences from the Instituto Superior Politecnico Jose Antonio Echeverria of Havana.

Francisco Caleyo (fcaleyo@gmail.com) is a professor at the IPN. He is a senior researcher at the CIDIM of the IPN. He holds a BS in physics and an MS in materials science from Universidad de La Habana and a PhD in materials science from Universidad Autonoma del Estado de Mexico.

Gabriela Lourdes Rueda Morales (gruedamorales@yahoo.com.mx) is a professor at the IPN. She is researcher at the CIDIM of the IPN. She holds a BS, an MS, and a PhD in physics from IPN.

Jose Manuel Hallen (j_hallen@yahoo.com) is a professor at the IPN and heads the CIDIM, which has service contracts with Pemex to conduct mechanical integrity and risk analyses of onshore and offshore pipelines. He holds a BS and MS in physical metallurgy from IPN and a PhD in physical metallurgy from the University of Montreal.

Abraham Lopez Montenegro (alopezmon@pemex.pep.com) is a superintendent of pipeline reliability at the Gerencia de Transporte y Distribucion de Hidrocarburos, Pemex Exploracion y Produccion. He holds a BS in industrial chemistry engineering from IPN and an MS in project management engineering from the Universidad de las Americas, Mexico.

Eloy Perez Baruch (eperezb@pemex.pep.com) is maintenance vice-manager at the Gerencia de la Coordinacion Tecnica Operativa Region Sur, Pemex Exploracion y Produccion. He holds a BS in industrial chemistry engineering from IPN and an MS in pipeline management engineering from the Universidad de las Americas, Mexico.

Equipment/Software/Literature

New natural gas engine for pumping use

The new AJAX E-565 natural gas engine is a rugged one cylinder, two-cycle version that's suited for pumping applications in a variety of different operating conditions.

The company says the engine can operate efficiently using a range of fuel gas including H_2S warranted up to 2.5%. The E-565 meets all current federal US emissions standards, the firm points out.

This 40 hp unit is rated at 56 braked mean effective pressure at 525 rpm with a 6:1 compression ratio. It comes with an automotive starter, a Ringfeder Corp. flywheel to crankshaft locking device, which the firm says provides an easier, safer way to remove the flywheel during maintenance, an Altronic Inc. I ignition system, and a standard "dry" type air filter.

Source: **Cameron,** 2101 S.E. 18th St., Oklahoma City, OK 73129.

New software aids oil company planning

Newly released of Merak enterprise planning (MEP) software is a next-generation technology that enables dynamic oil and gas business planning, including event-driven or evergreen plans.

The firm says, "With MEP, oil and gas companies can get fast answers to complex business questions for improved decision making. This software helps clients to proactively respond to changing market and operational conditions to achieve growth objectives."

In a preliminary field test with a large integrated, independent oil and gas company, MEP demonstrated 50% reduction in project processing time, increased confidence in results, and 75% reduction in analysis time, the firm noted.

MEP uses an oil and gas data management cube to align strategy with plans and budgets—simultaneously integrating reserves, production, and financial data—to reveal business insights for timely decisions based on continually updated business plans.

MEP leverages Microsoft Corp. technologies to provide a collaborative platform for oil and gas business applications to generate valuable information in context using a calculation engine. Its data aggregation and mining capabilities deliver business intelligence and performance analytics in the context of an oil and gas enterprise.

Source: **Schlumberger,** 300 Schlumberger Drive, Sugar Land, TX 77478.

Software update aids reservoir estimates

EnABLE 2.3 estimation software promises to provide a better understanding and measurement of uncertainty in reservoir production performance estimates.

Using an advanced statistical framework and proxy model, based on conventional reservoir simulations, EnABLE provides E&P companies with a rapid understanding of production behavior and the creation of uncertainty forecasts, the company says.

Source: **Roxar AS,** Gamle Forusvei 17, Box 112, 4065 Stavanger, Norway.

Services/Suppliers

Fluor Corp.,

Irving, Tex., has elected David T. Seaton to its newly created COO position. All five of the company's operating groups will report to Seaton, along with project operations, a unit formed earlier this year to bring greater efficiency and support to the company's projects. Seaton joined Fluor in 1984. He most recently served as senior group president with responsibility for the company's energy and chemicals, power, and government groups, as well as for Fluor's activities in China and the Middle East. Prior to that, he was group president, energy and chemicals, and has held sales and operations roles in the US, Europe, and the Middle East. He also served as managing director of Fluor Arabia Ltd. and led the company's global sales function. Seaton has a bachelor's degree from the University of South Carolina and has completed advanced management programs at the Wharton School of Business and Thunderbird University.


Seaton

Fluor provides engineering, procurement, construction, commissioning, operations, maintenance, and project management services to the oil and gas and other industries.

Blueback Reservoir AS,

Stavanger, has named Rod Hall manager, Americas, to head the company's new Houston office. Plans call for recruiting staff to expand the Houston office to offer geological and geophysical consulting, software development, and software sales and support in concert with the company's Norway and UK teams. Hall will offer 3D geologic model building and custom Petrel software development services. He previously was vice-president of sales and marketing with GrailQuest Corp. in Houston.


Hall

Blueback provides geomodeling consulting services and software solutions for the global exploration and production industry. It is the leading commercial developer of Petrel Ocean plug-ins.

Red Wing Shoe Co.,

Red Wing, Minn., has opened its third global operations hub, in Houston, to serve as its North American operations headquarters supporting global contracts for oil and gas personal protection equipment (PPE). The Houston hub will join the Dubai hub, supporting Middle East operations, and the Denmark hub, supporting European operations. Each facility will provide specialized product, sales, and distribution support for Red Wing industrial workwear and work boots, in conjunction with Red Wing's oil and gas distribution partners in more than 100 countries. The Houston hub will be led by Lenny Moore, who has nearly 30 years of industry experience, including a stint as president of Wenaas USA.

Red Wing supplies industrial workwear, workboots, and PPE to oil and gas operating and service and supply companies worldwide.

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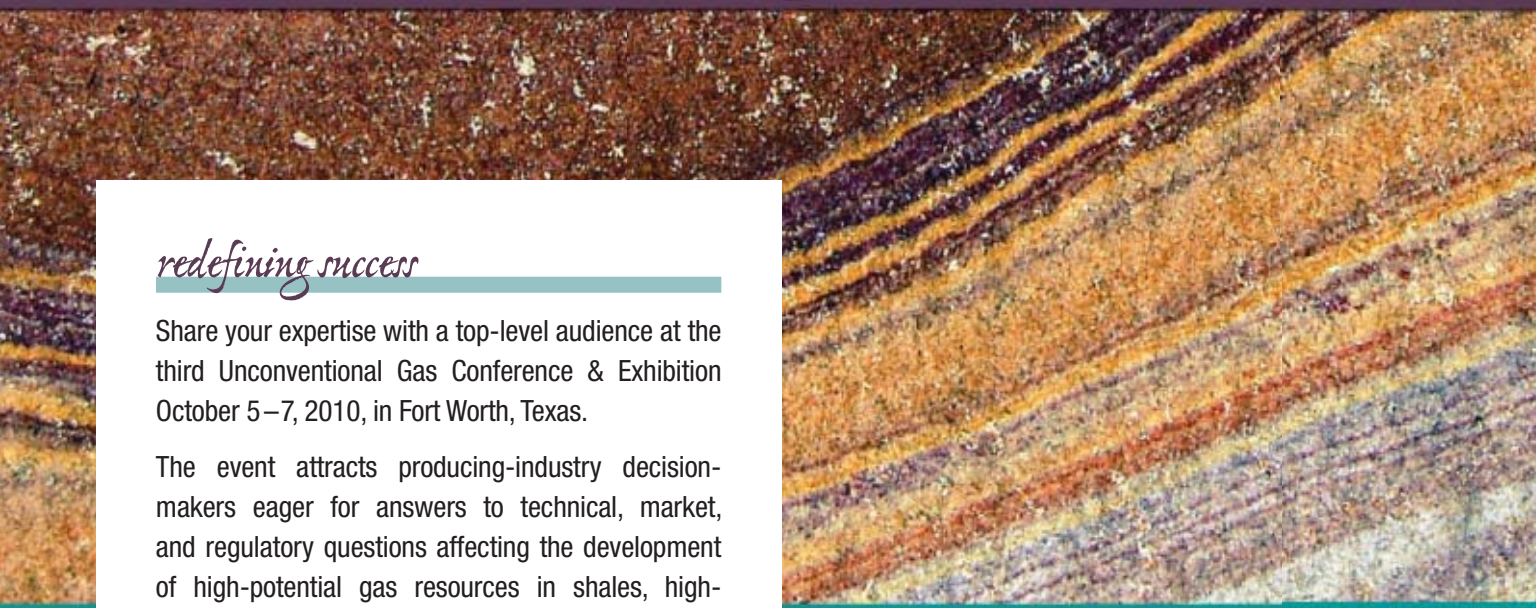

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Imports of crude and products

	Districts 1-4		District 5		Total US		
	12-4 2009	11-27 2009	12-4 2009	11-27 2009	12-4 2009	11-27 2009	*12-5 2008
	1,000 b/d						
Total motor gasoline	700	1,035	50	65	750	1,100	1,106
Mo. gas. blending comp.	596	831	50	65	646	896	940
Distillate	185	136	0	0	185	136	103
Residual	188	359	39	18	227	377	312
Jet fuel-kerosine	37	54	59	9	96	63	26
Propane-propylene	135	239	8	8	143	247	207
Other	453	358	10	(22)	463	336	120
Total products	**2,294**	**3,012**	**216**	**143**	**2,510**	**3,155**	**2,814**
Total crude	**7,139**	**7,534**	**998**	**867**	**8,137**	**8,401**	**9,959**
Total imports	**9,433**	**10,546**	**1,214**	**1,010**	**10,647**	**11,556**	**12,773**

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

Purvin & Gertz LNG netbacks—Dec. 11, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.71	4.52	5.80	4.41	5.11	5.72
Everett	4.31	2.19	3.94	2.27	2.75	4.61
Isle of Grain	4.02	1.91	3.39	1.81	2.47	3.42
Lake Charles	2.42	0.55	2.19	0.71	0.93	3.04
Sodegaura	5.18	7.47	5.43	7.16	6.42	4.48
Zeebrugge	6.24	3.98	5.56	3.88	4.61	5.62

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	12,344	57,876	40,809	11,728	76,576	13,339	5,421
PADD 2	87,446	51,753	25,105	7,548	29,718	1,102	23,520
PADD 3	164,790	70,252	40,618	13,478	45,623	18,310	30,284
PADD 4	15,744	6,675	2,233	569	3,255	220	[1]2,138
PADD 5	55,752	29,778	26,072	9,223	12,145	3,251	—
Dec. 4, 2009	**336,076**	**216,334**	**134,837**	**42,546**	**167,317**	**36,222**	**61,363**
Nov. 27, 2009	**339,899**	**214,081**	**133,343**	**41,820**	**165,698**	**38,056**	**62,711**
Dec. 5, 2008[2]	**320,764**	**202,664**	**109,174**	**39,315**	**130,587**	**38,037**	**61,144**

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

Refinery report—Dec. 4, 2009

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,048	1,020	2,516	62	339	63	53
PADD 2	3,206	3,192	2,215	195	940	67	222
PADD 3	7,209	6,963	2,688	710	2,034	330	692
PADD 4	508	498	325	23	187	8	[1]178
PADD 5	2,359	2,248	1,419	398	494	106	—
Dec. 4, 2009	**14,330**	**13,921**	**9,163**	**1,388**	**3,994**	**574**	**1,145**
Nov. 27, 2009	**14,077**	**13,844**	**9,025**	**1,334**	**3,904**	**725**	**996**
Dec. 5, 2008[2]	**15,398**	**14,967**	**8,999**	**1,391**	**4,654**	**573**	**1,202**
	17,681 Operable capacity		**81.1% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*12-11-09	*12-12-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	78.92	48.57	30.35	62.5
Brent crude	73.14	42.10	31.04	73.7
Crack spread	5.78	6.48	–0.70	–10.7
FUTURES MARKET PRICES				
One month				
Product value	80.04	49.95	30.09	60.2
Light sweet crude	71.53	44.71	26.82	60.0
Crack spread	8.51	5.23	3.28	62.6
Six month				
Product value	86.38	59.77	26.61	44.5
Light sweet crude	77.51	53.35	24.16	45.3
Crack spread	8.87	6.41	2.45	38.2

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

OGJ GASOLINE PRICES

	Price ex tax 12-9-09	Pump price* 12-9-09	Pump price 12-10-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	225.5	256.9	177.6
Baltimore	217.5	259.4	167.8
Boston	217.5	259.4	172.6
Buffalo	207.7	270.9	173.2
Miami	223.0	275.9	176.6
Newark	218.5	251.4	178.2
New York	207.7	270.9	183.3
Norfolk	211.7	249.4	173.2
Philadelphia	216.2	266.9	182.3
Pittsburgh	214.7	265.4	187.3
Wash., DC	227.0	268.9	192.3
PAD I avg	217.0	263.3	178.6
Chicago	228.9	284.0	179.1
Cleveland	226.0	272.4	159.5
Des Moines	208.0	248.4	163.7
Detroit	223.8	275.4	170.9
Indianapolis	220.3	270.4	169.1
Kansas City	199.0	234.7	157.9
Louisville	217.8	258.7	164.9
Memphis	200.6	240.4	158.8
Milwaukee	214.4	265.7	164.2
Minn.-St. Paul	213.4	259.0	163.1
Oklahoma City	186.3	221.7	154.8
Omaha	199.7	245.4	156.5
St. Louis	198.7	234.4	169.2
Tulsa	184.0	219.4	158.1
Wichita	193.0	236.4	159.3
PAD II avg	207.6	251.1	163.3
Albuquerque	212.2	249.4	173.9
Birmingham	214.7	254.0	168.6
Dallas-Fort Worth	208.0	246.4	164.6
Houston	210.0	248.4	155.8
Little Rock	203.2	243.4	165.8
New Orleans	216.1	254.5	172.0
San Antonio	212.6	251.0	174.9
PAD III avg	211.0	249.6	167.9
Cheyenne	222.0	254.4	160.8
Denver	219.0	259.4	172.3
Salt Lake City	211.0	253.9	164.8
PAD IV avg	217.3	255.9	165.9
Los Angeles	231.1	296.9	185.9
Phoenix	219.8	257.2	176.5
Portland	235.8	279.2	191.5
San Diego	231.4	297.2	196.5
San Francisco	237.4	303.2	192.3
Seattle	237.7	293.6	186.5
PAD V avg	232.2	287.9	188.2
Week's avg.	**214.8**	**259.6**	**171.8**
Nov. avg.	**218.8**	**263.6**	**215.5**
Oct. avg.	**208.4**	**253.6**	**317.6**
2009 to date	**185.9**	**231.4**	—
2008 to date	**288.3**	**332.6**	—

*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

	12-4-09 ¢/gal		12-4-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	196.46	New York Harbor	199.30
Gulf Coast	193.21	Gulf Coast	197.55
Los Angeles	192.60	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	193.34	ARA	197.05
Singapore	198.57	Singapore	197.98
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	194.96	New York Harbor	174.57
Gulf Coast	191.35	Gulf Coast	174.12
Los Angeles	198.60	Los Angeles	190.34
		ARA	173.98
		Singapore	179.67

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

BAKER HUGHES RIG COUNT

	12-11-09	12-12-08
Alabama	5	4
Alaska	9	13
Arkansas	38	52
California	26	38
Land	25	38
Offshore	1	0
Colorado	38	103
Florida	0	1
Illinois	0	0
Indiana	3	2
Kansas	19	15
Kentucky	12	10
Louisiana	181	169
N. Land	120	86
S. Inland waters	15	21
S. Land	11	9
Offshore	35	53
Maryland	0	0
Michigan	0	0
Mississippi	5	20
Montana	7	11
Nebraska	0	0
New Mexico	48	68
New York	2	5
North Dakota	60	83
Ohio	8	12
Oklahoma	93	168
Pennsylvania	63	24
South Dakota	0	1
Texas	458	828
Offshore	2	7
Inland waters	0	0
Dist. 1	22	20
Dist. 2	12	36
Dist. 3	33	63
Dist. 4	31	77
Dist. 5	65	167
Dist. 6	53	125
Dist. 7B	12	25
Dist. 7C	42	61
Dist. 8	85	108
Dist. 8A	21	29
Dist. 9	36	45
Dist. 10	44	65
Utah	13	38
West Virginia	22	30
Wyoming	41	78
Others—HI-1; NV-4; OR-1; TN-1; VA-3	10	17
Total US	**1,161**	**1,790**
Total Canada	**354**	**390**
Grand total	**1,515**	**2,180**
US Oil rigs	393	401
US Gas rigs	757	1,379
Total US offshore	38	65
Total US cum. avg. YTD	**1,084**	**1,885**

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	Rig count	12-11-09 Percent footage*	Rig count	12-12-08 Percent footage*
0-2,500	77	1.2	95	3.1
2,501-5,000	64	71.8	127	50.3
5,001-7,500	131	29.7	244	12.2
7,501-10,000	237	8.0	424	2.5
10,001-12,500	255	12.5	409	1.9
12,501-15,000	160	2.5	343	0.2
15,001-17,500	163	--	160	--
17,501-20,000	61	--	78	--
20,001-over	33	--	31	--
Total	**1,181**	**11.9**	**1,911**	**6.1**
INLAND	16		27	
LAND	1,129		1,838	
OFFSHORE	36		46	

*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]12-11-09	[2]12-12-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	22	21
Alaska	718	715
California	643	648
Colorado	70	67
Florida	6	5
Illinois	26	25
Kansas	115	109
Louisiana	1,434	1,114
Michigan	18	17
Mississippi	64	62
Montana	87	84
New Mexico	172	160
North Dakota	224	210
Oklahoma	186	181
Texas	1,409	1,343
Utah	67	63
Wyoming	153	145
All others	67	73
Total	**5,481**	**5,042**

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

US CRUDE PRICES

	12-11-09 $/bbl*
Alaska-North Slope 27°	64.51
South Louisiana Sweet	70.25
California-Midway Sunset 13°	60.90
Lost Hills 30°	69.00
Wyoming Sweet	60.37
East Texas Sweet	65.75
West Texas Sour 34°	61.25
West Texas Intermediate	66.25
Oklahoma Sweet	66.25
Texas Upper Gulf Coast	59.25
Michigan Sour	58.25
Kansas Common	65.25
North Dakota Sweet	57.00

*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]	12-4-09
United Kingdom-Brent 38°	77.24
Russia-Urals 32°	76.19
Saudi Light 34°	75.97
Dubai Fateh 32°	78.31
Algeria Saharan 44°	77.90
Nigeria-Bonny Light 37°	78.90
Indonesia-Minas 34°	80.33
Venezuela-Tia Juana Light 31°	76.23
Mexico-Isthmus 33°	76.12
OPEC basket	77.46
Total OPEC[2]	76.91
Total non-OPEC[2]	75.24
Total world[2]	76.18
US imports[3]	73.52

[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]

	12-4-09	11-27-09	12-4-08	Change, %
	bcf			
Producing region	1,195	1,219	956	25.0
Consuming region east	2,061	2,092	1,879	9.7
Consuming region west	517	526	465	11.2
Total US	**3,773**	**3,837**	**3,300**	**14.3**
	Sept. 09	**Sept. 08**	**Change, %**	
Total US[2]	**3,643**	**3,163**	**15.2**	

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

International rig count

Region	Nov. 2009 Land	Nov. 2009 Off.	Nov. 2009 Total	Nov. 08 Total
WESTERN HEMISPHERE				
Argentina	56	—	56	78
Bolivia	4	—	4	3
Brazil	32	34	66	59
Canada	277	—	277	417
Chile	3	—	3	4
Colombia	28	—	28	42
Ecuador	9	—	9	12
Mexico	99	28	127	107
Peru	7	3	10	8
Trinidad	0	2	2	3
United States	1,071	36	1,107	1,935
Venezuela	45	10	55	80
Other	1	—	1	1
Subtotal	**1,632**	**113**	**1,745**	**2,749**
ASIA-PACIFIC				
Australia	7	9	16	28
Brunei	1	2	3	4
China-offshore	0	27	27	22
India	65	33	98	82
Indonesia	46	12	58	61
Japan	3	—	3	3
Malaysia	—	12	12	16
Myanmar	3	1	4	6
New Zealand	3	—	3	4
Papua New Guinea	2	—	2	3
Philippines	7	—	7	3
Taiwan	—	—	—	—
Thailand	5	10	15	13
Vietnam	—	9	9	6
Other	—	—	—	2
Subtotal	**142**	**115**	**257**	**253**
AFRICA				
Algeria	28	—	28	25
Angola	—	4	4	6
Congo	1	—	1	2
Gabon	1	—	1	1
Kenya	—	—	—	—
Libya	15	1	16	15
Nigeria	3	5	8	4
South Africa	—	—	—	—
Tunisia	3	2	5	3
Other	3	2	5	3
Subtotal	**54**	**14**	**68**	**59**
MIDDLE EAST				
Abu Dhabi	8	3	11	11
Dubai	—	1	1	1
Egypt	38	7	45	55
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	—
Kuwait	14	—	14	13
Oman	48	1	49	54
Pakistan	18	—	18	22
Qatar	1	8	9	13
Saudi Arabia	54	12	66	76
Sudan	—	—	—	—
Syria	24	—	24	20
Yemen	13	—	13	14
Other	2	—	2	—
Subtotal	**220**	**32**	**252**	**279**
EUROPE				
Croatia	—	—	—	—
Denmark	1	2	3	2
France	1	—	1	1
Germany	4	1	5	12
Hungary	2	—	2	5
Italy	3	1	4	4
Netherlands	2	3	5	2
Norway	—	22	22	21
Poland	3	—	3	3
Romania	9	—	9	20
Turkey	8	—	8	6
UK	—	14	14	25
Other	7	3	10	6
Subtotal	**40**	**46**	**86**	**107**
Total	**2,088**	**320**	**2,408**	**3,447**

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	—	—
Caribbean	Houston	Resid.	380	76	0.98
Caribbean	Houston	Resid.	500	89	1.15
N. Europe	New York	Dist.	200	112	2.08
N. Europe	Houston	Crude	400	90	2.43
W. Africa	Houston	Crude	910	77	2.38
Persian Gulf	Houston	Crude	1,900	30	1.71
W. Africa	N. Europe	Crude	910	82	1.86
Persian Gulf	N. Europe	Crude	1,900	33	1.36
Persian Gulf	Japan	Crude	1,750	49	1.63

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

Waterborne Energy Inc. US LNG imports

Country	Oct. 2009	Sept. 2009	Oct. 2008	Change from a year ago, %
	MMcf			
Algeria	—	—	2,980	—
Egypt	14,470	17,540	—	—
Equatorial Guinea	—	—	—	—
Nigeria	2,980	2,500	—	—
Norway	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	16,920	16,890	24,280	–30.3
Total	**34,370**	**36,930**	**27,260**	**26.1**

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

Propane prices

	Oct. 2009	Nov. 2009	Oct. 2008	Nov. 2008
	¢/gal			
Mont Belvieu	100.84	107.60	104.47	73.79
Conway	99.13	108.68	103.83	79.93
Northwest Europe	113.59	122.49	108.89	71.47

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					
Nov. 2009						
Product revenues	84.11	81.79	81.99	84.00	86.13	80.78
Feedstock costs	–80.49	–79.19	–75.65	–74.18	–78.23	–80.48
Gross margin	3.62	2.60	6.34	9.82	7.90	0.30
Fixed costs	–2.15	–2.49	–2.42	–2.82	–2.42	–1.88
Variable costs	–1.41	–1.06	–1.28	–2.15	–3.45	–1.01
Cash operating margin	**0.06**	**–0.95**	**2.64**	**4.85**	**2.03**	**–2.59**
Oct. 2009	1.56	0.32	4.94	6.36	0.60	–2.36
YTD avg.	3.47	1.46	6.27	11.06	1.61	–0.39
2008 avg.	9.09	3.04	11.53	12.96	6.77	3.13
2007 avg.	12.60	6.65	18.66	20.41	6.05	2.32
2006 avg.	12.54	6.38	14.97	23.64	6.10	0.93

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

Muse, Stancil & Co. gasoline marketing margins

Oct. 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	264.55	236.88	302.87	267.40
Taxes	54.37	38.40	59.74	49.92
Wholesale price	202.31	197.01	225.34	200.69
Spot price	194.28	186.66	201.90	189.89
Retail margin	7.82	1.47	17.79	16.79
Wholesale margin	8.03	10.35	23.44	10.80
Gross marketing margin	**15.85**	**11.82**	**41.23**	**27.59**
Sept. 2009	29.76	33.60	44.45	46.98
YTD avg.	22.87	22.34	24.66	29.61
2008 avg.	33.11	32.15	27.22	41.81
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	19.94	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		
Nov. 2009			
Product revenues	46.58	79.21	99.09
Feedstock costs	–28.80	–61.16	–102.61
Gross margin	17.78	18.05	–3.52
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–3.52	–4.10	–5.41
Cash operating margin	**8.88**	**7.59**	**–16.12**
Oct. 2009	10.83	6.71	–16.10
YTD avg.	13.41	10.26	–13.54
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

Nov. 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	3.36	3.17
Liquids	1.18	3.23
Gas purchase cost	3.74	4.25
Operating costs	0.07	0.15
Cash operating margin	**0.73**	**2.00**
Oct. 2009	0.58	1.53
YTD avg.	0.39	1.09
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	35%	37%

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

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POSITION ANNOUNCEMENT

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY (Missouri S&T; Formerly University of Missouri-Rolla "UMR") invites applications or nominations for the ***Wayne and Gayle Laufer Endowed Chair in Energy***. We seek an individual with a sustained record of professional achievement as indicated by outstanding teaching, significant sponsored research and publications, and/or major leadership activities. This endowed Chair position is a sign of the commitment of the University to enhance its national prominence at both undergraduate and graduate levels in education and research in the energy-related disciplines. The Laufer Chair will actively participate in expanding the campus strengths in education and research in the traditional sources of energy that have historically contributed to the global energy supply. Candidates must have a Ph.D. or equivalent and have the qualifications and standing to be appointed as a tenured full professor. The successful candidate is anticipated to play a campus/national role in developing new energy research and policy initiatives. The Laufer Chair will be appointed in one of the several academic disciplines supporting energy production, consistent with the interests and background of the successful appointee. The Laufer Chair will become a part of an active community of faculty at Missouri S&T engaged in energy-related research and teaching and will be expected to provide leadership that will enhance the productivity, stature, and capabilities of the energy policy and research activities at the University.

The start date for this endowed appointment is September 2010, and candidates will be expected to demonstrate capabilities in the areas of energy policy and research that involve traditional, high capacity sources of energy. Candidates are preferred who possess an earned PhD in fields closely related to high capacity energy generation, including, but not limited to, chemical engineering, geology and geological engineering, mining engineering, nuclear engineering, and petroleum engineering. The successful Chair will be expected to teach at both undergraduate and graduate levels, as well as provide leadership in interdisciplinary and interdepartmental research. Superior communication and interpersonal skills, demonstrated leadership capabilities, the ability to engage in collaborative research, and the ability to motivate and inspire students and colleagues are required attributes. The successful candidate will strengthen, and capitalize on, Missouri S&T's strong ties with industry, educational institutions, and federal and state agencies and build relationships with each.

Missouri S&T is the technological campus of the University of Missouri system. There are approximately 6800 students (5200 undergraduates, 1600 grad students) in 37 different degree programs. Missouri S&T was ranked 45th overall and 12th among public universities by American high school counselors in the US News and World Report "America's Best Colleges 2009," and a "Top 20 STEM Research University" by Academic Analytics (January 2008). The Missouri S&T campus also has related research centers: the Energy Research and Development Center, Materials Research Center, Missouri S&T University Transportation Center (one of the 10 existing national UTC centers), the Rock Mechanics and Explosives Research Center, the Environmental Research Center, and the Center for Infrastructure Engineering Studies.

Questions regarding the position can be sent to Dr. Richard K. Brow, Search Committee Chairman, ***brow@mst.edu***; (573) 341-6812 or to Greenwood/Asher & Associates, Inc. The Committee will continue to accept applications and nominations until the position is filled. Screening of candidates will begin immediately. For best consideration, applications should be provided by January 15, 2010. An application should reference "the Laufer Chair Position #00050304," and include a letter describing relevant experiences and interest in the position; academic curriculum vitae, a vision statement for what the applicant would like to accomplish in this position, and complete contact information for at least five references. Electronic submission of materials is strongly encouraged. Individuals wishing to place names in nomination should electronically submit a letter of nomination to include the name, position, address and telephone number of the nominee. Greenwood/Asher & Associates is assisting the University in the search.

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Iranian political mood swings back toward the brink

Since the revolution of 1979, Iran's political mood has cycled several times toward and away from upheaval. Now, the Islamic republic finds itself yet again on the brink.

Pressure on the mullahs who run the country comes from several directions.

Increasingly alarmed by Iranian efforts to develop nuclear weapons, external powers threaten to tighten trade sanctions

The Editor's Perspective

by Bob Tippee, Editor

against the defiant theocracy. France, in particular, has hardened its position.

"There is no longer any reason to wait," the country's ambassador to the United Nations, Gerard Araud, told the Security Council this month.

His country, the US, and Great Britain have met resistance to toughened sanctions from the other permanent Security Council members, Russia and China, which say they want to persuade Iran by other means to quit enriching uranium.

Inside Iran, meanwhile, protests have spread and intensified—along with reprisals from the government and the thugs who enforce its oppression.

The Iranian citizenry is clearly tired of tyranny, rigged elections, and economic hardship. Protests have begun to target the supreme leader, Ayatollah Ali Khamenei, rather than political figures.

Iranians also seem to have had enough of President Mahmoud Ahmadinejad and his claims to be preparing for return of the 12th Imam, a messianic figure of Shi'ite Islam. For doubters, those preparations too frequently involve violent encounters with the Revolutionary Guard and "basij" militia, sometimes ending in notoriously cruel prisons.

Fractures, meanwhile, have widened in the power structure. No less a figure than former President Ali Akbar Hashemi Rafsanjani, who backed a challenger to Ahmadinejad in disputed June elections, has spoken against the regime of which he remains an important part, lately declaring it to be in crisis. For that, he provoked an ominous rebuke from Intelligence Minister Heydar Moslehi, who said this week, "Those who themselves are in crisis think the country is in crisis." He went on to declare, as "an informed official," that "there is no crisis in the country."

Such heavy-handedness probably plays well among the powerful mullahs in Qom. Other citizens of Iran, where oil production averaged 3.7 million b/d in November, probably see things differently.

(Online Dec. 11, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Iraq, Nigeria oil output increasing

After years of losses because of war and revolution, oil production in Iraq and Nigeria is starting to increase. "Although we see the potential for the sharpest near-term gains in Nigeria, Iraq is making significant progress on deals with international oil companies that could double production there over the next 5 years," said Adam Sieminski, chief energy economist, Deutsche Bank AG, Washington, DC.

"Geologists have long believed that Iraq's reserves could rival those of Saudi Arabia (where production could easily go to 11 million b/d from today's 8.5 million b/d)," Sieminski said. "We believe Iraq could be producing 2.5 million b/d in 2010, but it could be more than twice that by 2016. Fields in Iraq like West Qurna and Majnoon are world-class, and they are undeveloped. As [analysts at Wood Mackenzie Ltd., Edinburgh,] observed, Iraq remains among the most challenging places in the world to do business—logistically, operationally, legally, and politically. But the potential returns are huge, if the companies can manage the risks."

Iraq has not yet regained its production level previous to the US-led invasion in 2003. In June, however, BP PLC teamed with China National Petroleum Corp. in a successful bid for Rumaila oil field with 17.8 billion bbl in oil reserves and the potential to hike Iraqi production past 4 million b/d within a few years, WoodMac analysts said.

Earlier this month, Royal Dutch Shell PLC joined with Malaysia's Petronas to secure rights to Manjoon field in the Basra region, one of the largest oil fields in the world, beating out a consortium of France's Total SA and CNPC. However, a consortium of CNPC, Total, and Petronas won a deal to develop Iraq's giant Halfaya oil field in the country's second bidding round since 2003.

In April, the Centre for Global Energy Studies in London said Iraq would need to invest $28-43 billion in order to raise its oil production capacity to 6 million b/d.

Nigeria rebounds

The International Energy Agency earlier reported Nigerian production fell to 1.68 million b/d in July, its lowest level in 2 decades and well below its hypothetical capacity of 3 million b/d.

By the end of summer, however, the Movement for the Emancipation of the Niger Delta agreed to a cease-fire under the Nigerian government's amnesty offer to militants. Production responded quickly, with November output estimated at 2 million b/d. "With natural gas liquids output at close to 400,000 b/d and also growing, Nigeria seems set for a period of relatively strong growth," Sieminski said.

"Total Nigerian oil production could come in at 2.5 million b/d in 2010 in our view," he said. "Although we harbor some concerns about the ability of the government and MEND to stick to maintaining the cease-fire, the agreement is already beating skeptics' estimates for duration." WoodMac, a former Deutsche Bank subsidiary, assumes there will be some easing of funding constraints but operational delays on certain projects will continue. "Furthermore, it seems likely that Shell's shut-in fields in the Forcados region will only reach around two thirds of its previous output. Nevertheless, WoodMac believes that total oil, condensate, and LPG production could reach circa 3 million b/d in 2016," said Sieminski.

Biofuel expansion

Meanwhile, the US government's strategic decision to increase the role of biofuels—"specifically ethanol"—in the country's energy mix has had "a powerful effect on demand side fundamentals" in corn and soybean markets, said Deutsche Bank analysts. According to the US Department of Agriculture, the US ethanol industry will be responsible for just over 50% of global corn consumption growth in 2009. "Today more than 30% of the US corn harvest is used for ethanol production. Given US Federal government targets, this could rise to as high as 40% by 2015, or 5.5 billion bushels," analysts said.

To achieve the targets for US ethanol production, they said, "We expect the US Environmental Protection Agency will increase the current 10% blend of ethanol in gasoline use by 5 percentage points from the middle of next year. This would not only increase ethanol consumption by approximately 7 billion gal, but it would also avert the US ethanol industry from hitting the 'blend wall'...when ethanol production and use is equal to 10% of the country's gasoline supply. We believe the increasing use of corn for ethanol production will sustain corn inventories at critically low levels and consequently sustain the price spike risk in this market."

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