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Ethylene Report

US can manage energy cost without 'punishing' industry
Meta evaluation helps model lost US gulf output
Economic analysis clarifies how Chad benefits from oil
Coiled tubing method deoils damaged US gulf pipeline

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July 28, 2008
Volume 106.28

ETHYLENE REPORT

REGULAR FEATURES

COVER

SABIC Europe BV's 1.275-million tonne/year (tpy) ethylene production plant, Geleen, The Netherlands, was one of the plants to show a capacity increase during 2007. The OGJ ethylene survey as of Jan. 1 showed a 2 million tpy increase in ethylene capacity worldwide compared with last year's survey. The global rise in capacity, which occurred mainly in Asia-Pacific and Western Europe, was a significant increase compared with the 2006 survey. An unprecedented amount of capacity is scheduled to come on stream in 2008, according to this week's special report, which starts on p. 46. The ethylene survey begins on p. 53. Photo from SABIC.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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July 28, 2008

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General Interest — Quick Takes

CGES: World needs more OPEC crude

The world needs more crude oil priced at a level that makes it economic to refine, said analysts at the Centre for Global Energy Studies (CGES), London.

CGES squarely places the blame for today's tight oil market on the Organization of Petroleum Exporting Countries. The organization continues to assert that the world is well supplied with crude and refuses to accept that production needs to rise, CGES said in its latest Monthly Oil Report.

The report refutes the assertion that the market has enough oil, pointing out that global oil inventories fell for six consecutive quarters between the fourth quarter of 2006 and the first quarter of this year.

OPEC shows no signs of being willing to increase its own production, as it continues to blame high oil prices on factors other than its own production policy, including the weak US dollar, geopolitics, and market speculators, CGES said.

While OPEC forecasts 2008 production growth outside the organization at 560,000 b/d, first-half production was down 330,000 b/d. This implies a surge in non-OPEC output of 1.45 million b/d in the second half.

CGES also said refinery runs will rise only if it becomes profitable to process the marginal barrel of supply without cracking it, since margins on straight-run processing are poor due to weak gasoline and fuel oil markets. Currently refineries are running at capacity of their upgrading units but not to capacity of their distillation units, according to the report.

"In the absence of additional supply, only a global recession, destroying enough demand to reduce the need for OPEC oil, can set prices on a downward path. It is a bleak picture and one that has OPEC's production policy among its key features," CGES said.

USGS: Arctic holds 90 billion bbl of undiscovered oil

The area north of the Arctic Circle contains an estimated 90 billion bbl of undiscovered, technically recoverable crude oil, reported the US Geological Survey July 23 as it released its first petroleum resource estimate of the region.

The Arctic, especially offshore, is essentially unexplored with respect to petroleum, it noted.

The region also contains an estimated 1,670 tcf of technically recoverable gas and 44 million bbl of technically recoverable natural gas liquids in 25 geologically defined areas thought to have petroleum potential, the US Department of the Interior agency said.

It said the resources represent about 22% of the world's undiscovered, technically recoverable petroleum resources (about 13% of the oil, 30% of the gas, and 20% of the gas liquids). About 84% of the estimated resources are offshore, USGS said.

USGS said the appraisal was part of a project to assess global petroleum basins using standardized and consistent methods and controls. USGS said it worked with a number of international agencies to geologically analyze the Arctic provinces.

"Before we can make decisions about our future use of oil and gas and related decisions about protecting endangered species, native communities, and the health of our planet, we need to know what's out there. With this assessment, we're providing the same information to everyone in the world so that the global community can make these difficult decisions," USGS Director Mark Myers said.

The assessment said more than half of the undiscovered oil resources are believed to be in just three provinces: Arctic Alaska, the Amerasia basin, and the East Greenland Rift basins. Gas is estimated to be three times more abundant than oil in the Arctic on an equivalency basis, with more than 70% of it occurring in the West Siberian basin, the East Barents basins, and Arctic Alaska, it indicated.

Brazil to update oil law in wake of discoveries

Brazil's ministry of mines and energy has created a new working group that will aim to update the country's existing oil law, according to a senior government official.

"This group is studying the legislation of several countries, especially those which have a monopoly, and we are going to make a proposal to change the current law," said Mines and Energy Minister Edison Lobao.

The minister said every country changes the rules whenever new discoveries are made and that "Brazil can't be different." However, he acknowledged that there are interests intent on maintaining "the status quo."

Lobao, who said the changes are in the interests of the Brazilian people, was apparently referring to criticism of the proposed changes voiced by Petroleo Brasileiro Chief Executive Jose Sergio Gabrielli.

Noting that 60% of Petrobras's capital is private, while only 40% is held by the government, Lobao said Gabrielli represents a private company and, as such, is fighting for Petrobras's interests.

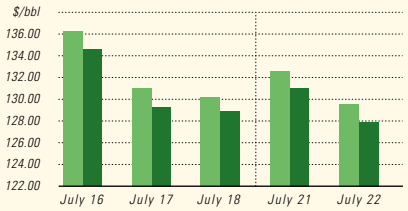
Lobao also gave assurances that the recently proposed creation of a new company to manage subsalt oil reserves will not result in a breach of existing contracts.

"This is an initial idea but, in my view, all contracts will have to be maintained," he said. "What we seek is a new formula."

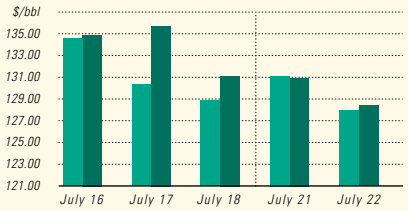
Earlier this week, it was reported that Lobao plans to propose to President Luiz Inacio Lula da Silva the creation of a new state-run firm that would manage oil discoveries made in recent months in the subsalt layer of the Santos basin (OGJ Online, June 30, 2008). ✦

Industry Scoreboard

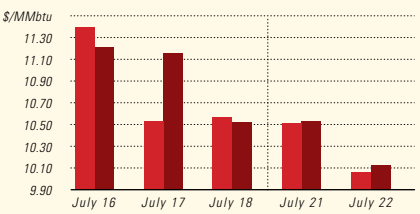
IPE BRENT / NYMEX LIGHT SWEET CRUDE



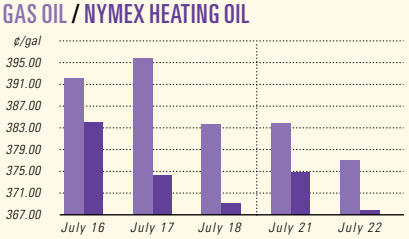
WTI CUSHING / BRENT SPOT



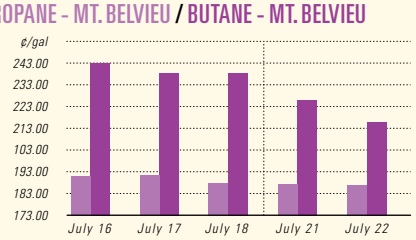
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



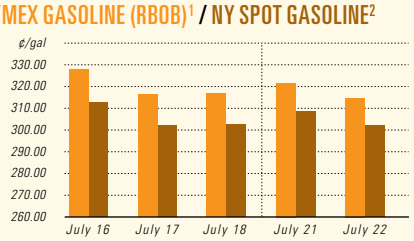
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Non-oxygenated regular unleaded.

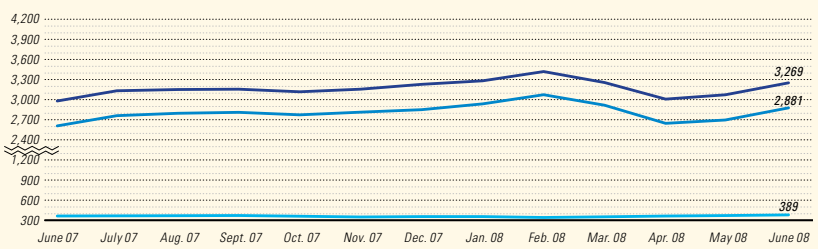
US INDUSTRY SCOREBOARD — 7/28

Latest week 7/11	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	9,346	9,550	–2.1	9,096	9,232	–1.5
Distillate	4,181	4,079	2.5	4,160	4,248	–2.1
Jet fuel	1,654	1,662	–0.5	1,578	1,623	–2.8
Residual	554	706	–21.5	622	768	–19.0
Other products	4,562	4,706	–3.1	4,806	4,825	–0.4
TOTAL DEMAND	20,297	20,703	–2.0	20,035	20,706	–3.2
Supply, 1,000 b/d						
Crude production	5,086	5,132	–0.9	5,118	5,184	–1.3
NGL production[2]	2,203	2,381	–7.5	2,226	2,356	–5.5
Crude imports	10,189	9,954	2.4	9,811	10,013	–2.0
Product imports	3,255	3,610	–9.8	3,219	3,552	–9.4
Other supply[3]	1,484	1,308	13.5	1,429	989	44.5
TOTAL SUPPLY	22,217	22,385	–0.8	21,803	22,094	–1.3
Refining, 1,000 b/d						
Crude runs to stills	14,887	15,313	–2.8	14,887	15,088	–1.3
Input to crude stills	15,103	15,627	–3.3	15,103	15,393	–1.9
% utilization	86.2	89.6	—	86.2	88.2	—

Latest week 7/11	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	296,888	293,936	2,952	352,131	–55,243	–15.7
Motor gasoline	214,238	211,766	2,472	203,341	10,897	5.4
Distillate	125,690	122,501	3,189	122,225	3,465	2.8
Jet fuel–kerosine	38,954	38,764	190	40,954	–2,000	–4.9
Residual	39,084	39,366	–282	36,899	2,185	5.9
Stock cover (days)[4]			Change, %		Change, %	
Crude	19.3	19.1	1.0	22.7	–15.0	
Motor gasoline	22.9	22.7	0.9	21.1	8.5	
Distillate	30.1	29.4	2.4	29.5	2.0	
Propane	48.8	45.9	6.3	48.3	1.0	
Futures prices[5] **7/18**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	135.34	140.04	–4.70	72.95	62.39	85.5
Natural gas, $/MMbtu	11.19	12.31	–1.12	6.57	4.61	70.2

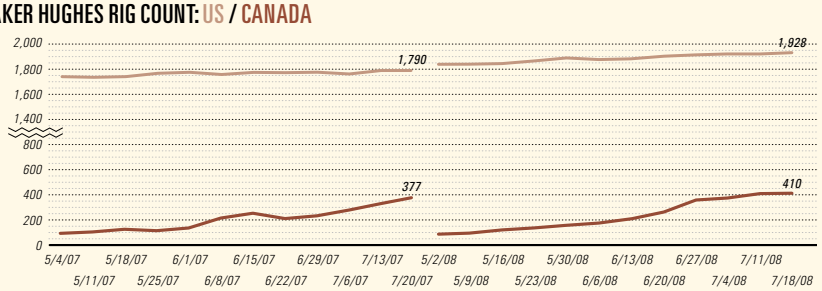
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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Exploration & Development — *Quick Takes*

China to Exxon: pull out of Vietnam exploration deal

The Chinese government has warned ExxonMobil Corp. to pull out of an exploration deal off Vietnam, describing the project as a breach of Chinese security, according to a Hong Kong newspaper.

The Sunday Morning Post, citing sources close to the firm, said Chinese diplomats in Washington, DC, have made repeated verbal protests to ExxonMobil executives in recent months, warning them that its future business interests on the mainland could be at risk.

The protests are said to involve a preliminary cooperation agreement between state oil firm Petrovietnam and ExxonMobil covering exploration in the South China Sea off Vietnam's south and central coasts.

ExxonMobil is confident of Vietnam's sovereign rights to the blocks it would be exploring, the paper's sources said—those off central Vietnam start at the coastline—but it could not dismiss China's warnings out of hand.

"If it was simply a legal question it would be easy," one of the sources said. "Vietnam would probably prevail in international mediation. But it's political, too. China's concerns make the situation much more complicated for a company like Exxon.... China is a very important player in the international oil industry."

The Chinese envoys based their protests on Beijing's historical claim to virtually all of the South China Sea, the source said. Both countries claim the entire Paracels and Spratlys archipelagos and much of the surrounding waters.

Vietnam bases its claims on its extensive continental shelf and the exclusive economic zone. This allows it to stake out according to the United Nations' International Law of the Sea. China's claim is legally vaguer, independent academics say.

An ExxonMobil spokesman refused to discuss any approaches from China, saying only that the firm is evaluating a "business opportunity, and sovereignty is a matter only governments can address."

Carl Thayer, a Vietnam-watcher at the Strategic and Defense Studies Centre of Australian National University, said Vietnam's sovereignty was "under threat" and that Hanoi was struggling to deal with the situation.

"Chinese hard power is once again part of the equation, as far as Vietnam is concerned," he said, adding that China may be trying to push Vietnam towards a joint exploitation deal like the one struck with Japan in the East China Sea.

Rift makes gas find in Papua New Guinea

Rift Oil PLC has discovered 48.5 m of net natural gas pay in its Puk Puk-1 wildcat in the forelands onshore Papua New Guinea.

The company reports that this result is 50% more than predicted and twice the thickness of the interval found in the Douglas-I wildcat drilled last year in the same permit, PPL235.

Puk Puk-1 was targeting an estimated predrill recoverable reserve of 226 bcf of gas.

The gas was found in the Toro, Upper Hedinia, and Lower Hedinia sands. Downhole sampling also recovered significant condensate, raising the possibility of an oil reservoir at depth in this structure, or at least potentially to be found in surrounding features.

Rift now plans to remap the Puk Puk structure and flow-test the well.

If the test is successful, the new find bodes well for the company's two gas development options for this area. Rift has signed an agreement with Flex LNG to use a floating LNG facility in the Papuan Gulf as one alternative.

It also has signed a nonbinding memorandum of intent with Alcan Australia to potentially supply Alcan's alumina plant at Gove in the Northern Territory of Australia with 40 bcf/year of gas for 20 years.

Key confirms Tanzanian find commercial

Key Petroleum Ltd.'s Kiliwani North-1 natural gas discovery in Tanzania has been declared a commercial development option.

Flow testing of the well confirms the earlier announcement of a flow of 40 MMcfd.

Perth-based Key adds that there was zero drawdown of bottom hole pressure during the test. This and other pressure data plus laboratory analysis satisfied Key that the well and the field are commercially viable.

The company has a 20% interest in the find.

Key says that the Nyuni block that surrounds the discovery has substantial upside potential including a number of untested leads and prospects in the vicinity.

The potential encompasses prospects in the range of up to 500 bcf of gas in place. Total undiscovered gas in the block could be more than 2 tcf.

Development plans for Kiliwani North-1 include construction of a pipeline to connect with the neighbouring Songo Songo gas field processing plant.

Key added that seismic and drilling data are still needed to assess further global growth prospects in the region. ✦

Drilling & Production — *Quick Takes*

Taiwan to invest in Canadian oil sands

Taiwan's state-owned CPC Corp. on July 17 signed a memorandum of understanding with Canadian-based Indian Oilsands Corp., paving the way for a possible partnership on oil sands development in Alberta. CPC Vice-Pres. Arthur Kung and Indian Oilsands representative Ken Thomas signed the MOU in Taipei.

CPC plans to budget $792 million for a 5-year exploration program. Company officials say the project is part of an effort to diversify energy sources and stabilize domestic energy supplies in face of the continued rise in global oil prices.

Formosa Petrochemical Corp., a member of the Formosa Plastics Group, also is studying a plan to tap Canada's oil sands and intends to send an inspection delegation to Alberta.

Pemex production rises after pipelines repaired

State-owned Petroleos Mexicanos (Pemex) said it increased production by 41,000 b/d in June to 2.84 million, a slight improvement over May but still below the company's target of 2.9 million b/d for 2008.

Pemex said the improvements came after it repaired an offshore pipeline in the Southeast marine region. The repairs enabled an 11.5% increase in June to 535,937 b/d.

Still, June production remains 11.5% lower than the same period a year ago, when Mexico produced 3.21 million b/d.

Earlier this week, Pemex said its average daily oil production in the first 6 months of 2008 fell 9.7% from the year-ago period, producing an average of 2.86 million b/d of crude oil in the first half of this year.

Pemex said output at Cantarell, its largest source of crude oil, was 1.15 million b/d, a decline of some 457,000 b/d from the same period in 2007. In June, it said, Cantarell production fell by 25,849 b/d to 1.05 million b/d.

Apart from the decline at Cantarell, Pemex production also has been hurt by the need to shut in wells that have started to produce large amounts of water. The company is said to be struggling to establish water separation facilities to enable continued production at such wells.

While crude production remains below target, natural gas output in the first half of the year rose 13.3% to 6.723 bcfd. Gas production also rose to a record 7.02 bcfd in June, up from 6.85 billion in May and 6.19 billion in June 2007.

Pemex said it is producing more gas at Cantarell, where gas is moving into wells that formerly produced oil. Gas output at Cantarell rose 4.9% in June to 1.67 bcf.

Karachaganak oil now subject to export tax

Kazakhstan, apparently reversing an earlier ruling, has announced that the consortium developing Karachaganak gas field must pay a new oil export duty.

"Karachaganak has become a payer of the export duty," said Deputy Finance Minister Daulet Yergozhin, referring to the consortium comprised of Eni SPA 32.5%, BG 32.5%, Chevron Corp. 20%, and Lukoil 15%.

Yergoshin also said the finance ministry soon plans to expand the list of 38 eligible companies announced in May when the government established the export duty.

The export tax, introduced on May 18, comes to $109.91/tonne of crude oil or $27.43/tonne for those who pay royalties for exported oil and gas condensate. The customs duty for heavy distillates, coke, and bitumen exports is $82.20/tonne.

At the time, the BG-Eni consortium and the Chevron-led Tengizchevroil joint venture both were excluded from the list due to their long-term contracts with the government under which they were considered exempt from any additional taxes.

The Karachaganak consortium's operations are regulated by a production-sharing agreement signed in 1997 by the Kazakh government and the group. The consortium has the right to continue operating the fields until 2038.

However, at the end of May, Kazakh Finance Minister Bolat Zhamishev said that all subsurface resource producers might have to pay the crude export duty.

The consortium faced threats of closure when the Kazakh customs control department in Atyrau would not sign off on an oil export declaration for June. It said the ministry of energy and mineral resources had not provided notification of whether the consortium had to pay the export duty.

One official had said at the time that if the issue were not resolved, Karachaganak might have to halt exports on the Caspian Pipeline Consortium (CPC) pipeline.

At that time the consortium faced a choice, he said: either it paid the duties for June in order to keep exports flowing, or it defended its position, in which case the CPC pipeline might be closed to it.

Chevron considers Big Foot development options

Chevron USA Inc. has hired Intec Engineering for a pre-FEED (front-end engineering and design) study concerning development options for the Big Foot project in the Gulf of Mexico.

Big Foot lies in more than 5,000 ft of water on Walker Ridge Block 29, 225 miles south of New Orleans and 180 miles offshore (OGJ, Feb. 11, 2008, Newsletter).

The development study, expected to be completed in the fourth quarter, will evaluate various types of subsea systems as potential alternatives.

Intec said a key aspect involves researching subsea boosting options.

Chevron owns 60% working interest in Big Foot. Partners are StatoilHydro AS 27.5% and Shell Gulf of Mexico Inc. 12.5%. ✦

Processing — *Quick Takes*

PetroVietnam lets Nghi Son refinery design contract

State-owned PetroVietnam has awarded Foster Wheeler a contract to design the 200,000 b/d Nghi Son refinery and petrochemical project, effective July 18.

Under the contract, Foster Wheeler will finish the designing in 16 months from the day the contract came into force. Scheduled for completion in 2013, the refinery is expected to meet 60% of Vietnam's domestic demand for gasoline and other products.

The Nghi Son project will import oil from Kuwait to produce high-quality products.

The award coincided with reports that Vietnamese Prime Minister Nguyen Tan Dung has asked contractors of the Dung Quat refinery project in central Quang Ngai province to speed up construction to ensure the planned February 2009 start up.

While visiting the construction site on July 19, Dung reminded lead contractor Technip and its subcontractors of the coming flood and storm season and asked them to keep a close eye on the progress of the project.

Meanwhile, Vietnam National Petroleum Corp. (Petrolimex) has recently received approval from central Khanh Hoa province to

build a $4.5 billion refinery in the region.

According to Petrolimex Chief Executive Vu Ngoc Hai, the plant will have a capacity to refine 10 million tonnes/year of oil.

Petrolimex has chosen Sinopec as a partner to carry out the project, and the two sides are said to have discussed setup of a joint venture as well as stake equity to be owned by each party.

Petrolimex also is working with PB Tankers Ltd. of Singapore and the Petrolimex Insurance Joint Stock Co. (PIJSC) to build Vietnam's first bonded warehouse for petroleum.

The depot is an investment of the Van Phong Warehouse Co. Ltd., a joint venture of Petrolimex, PIJSC, and PB Tankers.

Construction on the facility began in December 2007 in the Van Phong Economic Zone in Ninh Hoa district of central Khanh Hoa province.

Nguyen Van Que, director of Van Phong Warehouse, said the project has two phases, with the first phase costing $100 million over 18 months.

The depot will be capable of holding 500,000 cu m of petroleum in Phase 1 and a further 500,000 cu m on the completion of Phase 2. No date has been given for the completion of the second phase.

Van Que said the depot would be equipped with "the latest environmentally friendly technology and would be able to handle 150,000-dwt oil tankers."

PetroRabigh refinery upgrades near completion

Rabigh Refining & Petrochemical (PetroRabigh), a joint venture of Saudi Aramco and Sumitomo Chemicals, plans to complete the $10 billion upgrades to its 400,000 b/d refinery and petrochemical complex in Rabigh, Saudi Arabia, in the fourth quarter.

The project will raise output of transportation fuel and make the refinery the basis of a complex producing 2.4 million tonnes/year of petrochemical solids and liquids, along with large volumes of gasoline and other products (OGJ, Mar. 13, 2006, Newsletter).

Upgrades to the facility, originally built by the joint venture partners in 2005, will add a 60,000 b/d gasoline refining unit, a 200,000 b/d vacuum distillation unit, a 92,000 b/d catalytic cracking unit, and a 26,000 b/d alkylation unit.

The refinery also will see the addition of an ethane cracker capable of producing 1.25 million tonnes/year of ethylene as well as a gas processing plant that will produce 900,000 tonnes/year of propylene. ✦

Transportation — *Quick Takes*

Alaska Senate to consider natural gas pipeline

The Alaska House of Representatives approved a state license for TransCanada Corp. to pursue federal certification for a 1,715-mile natural gas pipeline. The Alaska Senate has yet to consider and vote on the measure.

The state's Senate must make its decision before Aug. 2 on Gov. Sarah Palin's Alaska Gasline Inducement Act. The AGIA established state requirements for companies interested in building a pipeline.

If the legislature grants a license to TransCanada, that still does not guarantee pipeline construction. A license would provide up to $500 million in state startup money for TransCanada to begin the lengthy, costly process toward federal certification for a pipeline.

Under AGIA, TransCanada was one of five companies that applied and the only one that satisfied the guidelines, Palin has said previously. The Alaska House passed HB 3001 with a vote of 23 to 16.

Meanwhile, BP PLC and ConocoPhillips are working on a pipeline proposal called Denali. They announced Apr. 8 plans to build a 4 bcfd gas pipeline that would extend from the Alaska North Slope to Canada and potentially on to the US (OGJ, Apr. 14, 2008, p. 30).

BP and ConocoPhillips called the proposed Alaskan gas line the "largest private-sector construction project ever built in North America." They plan to spend $600 million over the next 36 months on an open season, which is slated to begin before year-end 2010.

Holly, Centurion agree to W. Texas pipeline reversal

Holly Refining & Marketing Co., Dallas, has entered into a definitive agreement to ship crude oil on the Centurion pipeline, operated by a subsidiary of Occidental Petroleum Corp., to supply its Navajo Refining Co. LP refinery in New Mexico. Centurion has a 16-in. OD and is 375 miles long.

The agreement follows a 30-day open season held by Centurion starting Apr. 14 to determine interest in reversing the pipeline, which had been running from West Texas to Cushing, Okla. (OGJ Online, Apr. 25, 2008). The line to be reversed, known as the No. 1 Pipeline, is one of two 16-in. lines Centurion operates between Slaughter, Tex., and Cushing.

The No. 1 line will now deliver crude from Cushing to Slaughter, near the Texas-New Mexico border. Holly said it will build a 70-mile pipeline between Slaughter and Navajo and is considering both its physical properties and whether the line will be built by Holly Refining & Marketing or Holly Energy Partners. Holly has shipping commitments in place on TransCanada's Keystone and Enbridge's Spearhead pipeline to transport heavy crude from Canada to Cushing. Holly hopes to have both the reversed pipeline and the 70-mile line in service as early as fourth-quarter 2009, with a projected capacity of 60,000 b/sd.

Holly is implementing capital improvement projects on the Navajo refinery to increase its feedstock flexibility with an eye toward processing as much as 40,000 b/sd of heavier Canadian crudes. These projects are expected to be completed in fourth-quarter 2009. Holly is also expanding Navajo's overall capacity to 100,000 b/sd from 85,000 b/sd and expects this work to be mechanically complete by first-quarter 2009. ✦




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Minister of Oil & Gas Affairs, Chairman-National Oil & Gas Authority, Kingdom of Bahrain

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2008

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

International Petroleum Petrochemical Natural Gas Technology Equipment Exhibition, Shanghai, +86 21 55611008, +86 21 65282319 (fax), website: postmaster@aiexpo.com.cn, website: www.sippe.org.cn. 20-22.

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

Deep Water India Summit, New Delhi, +31 (0)26 3653 444, +31 (0)26 3653 446 (fax), e-mail: workshops@energywise.nl, website: www.energywise.nl. 26-27.

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SEPTEMBER

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

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

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

Rice Global Engineering & Construction Forum, Houston, (713) 552-1236, ext. 3, (713) 572-3089 (fax), website: www.forum.rice.edu. 9.

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

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

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

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

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

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

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

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

DGMK Future Feedstocks for Fuels & Chemicals Conference, Berlin, 040 639004 0. 040 639004 50 (fax), website: www.dgmk.de. Sept. 29-Oct. 1.

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

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

OCTOBER

GPA North Texas/NGS East Texas Red River Conference, Tyler, Tex., (713) 222-0852, (713) 222-0858 (fax), e-mail: tom.rommel@accessed.com, website: www.gasprocessors.com. 1-2.

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

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

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

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

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

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

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 13-17.

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

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

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Arab Oil & Gas Show, Dubai, +971 4 3355001, +971 4 3355141 (fax), e-mail: info@icedxb.com, website: www.ogsonline.com. 28-30.

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NOVEMBER

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

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LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current	Historical 1996–Current
Refinery	E1340	E1340C
Pipeline	E1342	E1342C
Petrochemical	E1341	E1341C
Gas Processing	E1344	E1344C

U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
PIPEMILL

OGJ 200/100 International Company Survey — Lists valuable financial and operating data for the largest 200 publicly traded oil and gas companies.
E1345 Current E1145C Historical 1989 to current

Oil Sands Projects — Planned Canadian projects in four Excel worksheets. Includes mining, upgrading, in situ projects, and historical table with wells drilled back to 1985.
OILSANDPRJ

Production Projects Worldwide — List of planned production mega-projects.
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CORE fights 'energy racism'

Sam Fletcher
Senior Writer

Roy Innis, chairman of the Congress of Racial Equality, has come out swinging against "elitist" environmentalists, politicians, and the nonprofit foundations that fund them for promoting "energy racism" by cutting off access to fossil fuels in the US and pushing up energy prices.

"They cause poor families to lose their homes. They make life tougher for families who've worked, struggled, and sacrificed to join the middle class. Then they throw out crumbs that make us beggars at the American banquet," Innis said in his book Energy Keepers-Energy Killers: The New Civil Rights Battle, published by Merril Press. "The fight over energy is the critical civil rights battle of our era," said Innis. "Simply put, energy transforms the civil rights enshrined in our Constitution into civil rights we enjoy in reality."

Federal lands belong to all US citizens and are supposed to be developed as well as preserved. However, Innis charges, "The reality is that these lands are held for affluent, highly educated, white, politically savvy environmentalists" who spend "enough money to support dozens of poor families for years, pressuring our government to post those resources into energy graveyards and turning thousands of hard-working blue collar families into beggars."

With the same passion that he once fought segregation, Innis said, "We have a right to sit at the energy lunch counter—to not be forced to sit at the back of the energy bus." He said, "We have to reframe the debate. It's not about the environment.... The real debate is over civil rights—yours and mine—and civil wrongs, the ones committed by energy killers."

Energy killers

People "who produce energy for everything we do, everything we buy, everything we dream of," Innis designates as energy providers. The "Bull Connor" energy killers, he said, "are people who try to stop them: activists and politicians against oil and gas drilling, against coal mining, against nuclear power, against all energy production, choking off the abundant, reliable, affordable American resources we need."

Opponents accuse oil companies of price gouging. But the "nearly 50¢ in taxes" on a gallon of gasoline is "government price gouging," Innis said. Stacks of "dubious environmental rules" that delay or prevent energy production is "regulatory price gouging." Placing off limits federal land "with years worth of oil, gas, coal, nuclear, and other energy resources" is "environmentalist price gouging." Legislation "that forces us to use politically correct 'renewable' energy like wind and solar that's expensive, unreliable, land-gobbling, and unable to produce enough fuel or electricity for a modern society" is "ideological price gouging," he said.

Independent oil companies are particularly vulnerable to activists' attacks. "These good, hard-working people are being marginalized, demonized, and destroyed by self-centered eco-bigots who look down on them as less deserving, less than human, in fact—as a despised minority, and I know what that's like," said Innis.

He faults Al Gore for his "mansion" that "consumes more electricity every month than the average American household uses in an entire year" and for the use of carbon offsets to buy his way into "climate heaven." He criticizes Hillary Clinton for campaigning in private jets that emit more carbon dioxide in 2 hours "than the average American family generates in a year." He knocks Barack Obama for claiming climate change is the biggest threat facing black American families today. "Not child welfare mothers 'raising' illegitimate children in fatherless families. Not substandard, incompetent schools ruled by incivility and violence, and turning out kids who can't read or do math. Not intolerable unemployment levels among black males. Not uneducated youths suited for gangs but not jobs. Climate change," Innis said.

Meanwhile, "rich white retirees, wealthy celebrities, and fancy-free heirs living on daddy's money" are locking up key energy resources in the US. "They can't stand seeing drilling rigs, oil and gas fields, mines, timber cutting, or even ranching operations, no matter how small, in 'their' backyards," he said.

"Sometimes I think environmentalists would rather see you jobless, homeless, or even dead than to support fossil fuel use, even the best, cleanest, and most abundant," said Innis. "The fear and loathing that some have for oil, natural gas, coal, and nuclear power is no excuse for us, our policy makers, or our courts to ignore energy reality and widen our energy gap by promoting renewable illusions and closing off access to the real energy we need." ✦

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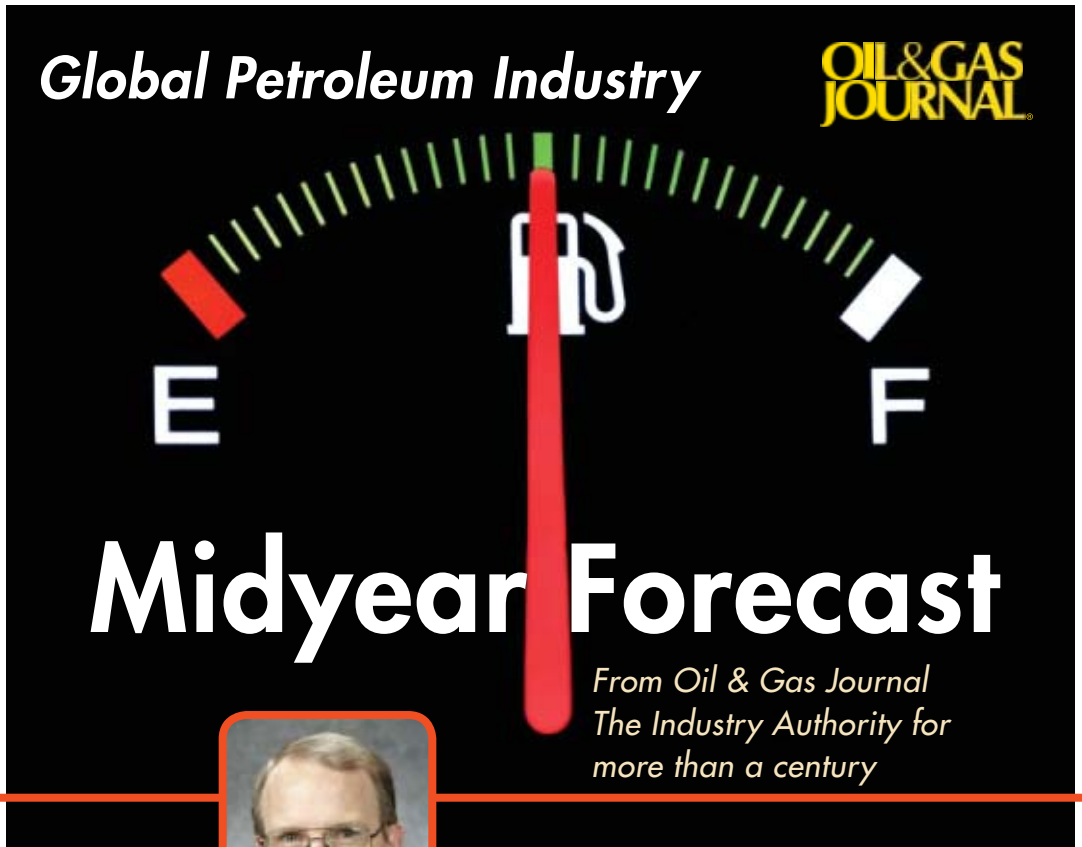

OGJ Editor, Bob Tippee

July 30, 2008

1:30 pm CST

Register free at:
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(webcast section)

The webcast will discuss highlights of Oil & Gas Journal's annual Midyear Forecast, a special report that appeared in the July 14 edition. The Midyear Forecast uses first-half data to update projections that appeared in OGJ's Annual Forecast and Review this past January. Both reports project oil and gas markets through the end of the year worldwide, analyze demand product by product in the US, and forecast drilling activity in the US and Canada.

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

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Editorial

Prices and energy plans

As they have throughout history, high oil prices are evoking calls for new patterns of energy supply and use. The response comes naturally to markets and politics, unleashing the creative potential those systems represent. If not held in check, though, it also gives way easily to costly excess.

High oil prices help new energy forms migrate from the economic margin into the market. Movement of this type is evident and, for a world with an energy appetite outgrowing its supply menu, beneficial.

Distortions and costs

Inevitably, however, some market participants turn to politics for competitive advantage while politicians turn to markets as tools of influence. Energy forms then advance not because they gain economic footing but because they win the enshrinement of policy. Distortions can result, fattening costs.

Plans central to this process articulate what "we" should do about energy now that high oil prices reveal the failure of whatever "we" did about energy beforehand. And they burrow into public consciousness encased in marketing packages that, even when proposals differ, bear common elements. Examples appear in two otherwise disparate proposals now swooping into the news.

Former Vice-Pres. Al Gore and oil and gas producer T. Boone Pickens both assert crisis. With stratospheric oil prices hurting people and economies, that's appropriate. But price pain alone isn't crisis enough when the appeal is for overhauling patterns of energy use and supply.

For Gore, who wants to end the use of fossil energy for power generation within 10 years, crisis stands on three legs: economic problems, global warming, and security threats, all linked by reliance on carbon-based energy. Pickens, who's promoting wind power to free up natural gas for use as vehicle fuel, heralds a similar three-fold crisis—economy, environment, and security—with US "addiction" to foreign oil as the centerpiece.

Like all efforts to overhaul energy patterns, those of Gore and Pickens deploy extravagant rhetoric. The former vice-president sees a country "awakening to the challenge of a present danger" at what he describes as a "generational moment." The oil producer hails the US as "the Saudi Arabia of wind power."

And, of course, both energy plans have dragons to slay. Gore's include oil companies and "defenders of the status quo," both of which come under incongruous assault with this delusion: "When people rightly complain about higher gasoline prices, we propose to give more money to the oil companies and pretend that they're going to bring prices down." Who's proposing to "give" oil companies anything? And how can grown-ups still believe oil companies control prices? Pickens is more subtle but nevertheless clear about the beasts he would vanquish: foreign sources of oil.

As do most energy plans born of high oil prices, the Gore and Pickens programs shout their promises but mumble their costs. Gore avers, "This goal is achievable, affordable, and transformative." In response to those daring to ask about the economics of replacing fossil energy with costlier substitutes, Gore says, "I ask them to consider whether the costs of oil and coal will ever stop increasing if we keep relying on quickly depleting energy sources to feed a rapidly growing demand all around the world." Pickens cites costs not of his program but of imported oil over 10 years at current oil prices, calling the result "the greatest transfer of wealth in the history of mankind."

Room to fall

Here, especially, both plans falter, as grand energy plans—not to mention investments—have before. To Gore's question whether prices of oil and coal will stop increasing, history, economic theory, and the past week's market news all answer loudly, Yes! The Pickens extrapolation assumes oil prices will stay at currently aberrant levels for 10 years. Prices never stay at any level that long. At present, they have lots of room to fall.

Plans to overhaul energy patterns appear when oil prices rise stressfully and disappear when prices fall—unless they become policy. Unlike today's prices, policies do tend to last. That's worth remembering in assessments of the Gore and Pickens plans and others sure to follow. ✦

COMMENT

US can manage energy cost without 'punishing' industry

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Driven by public outcry over $4/gal gasoline, the US energy policy debate is beginning to shift toward discussions for a return of punitive, self-defeating measures directed at companies that produce the nation's fuels. Congress is once again considering two previously tried "remedies" for controlling US energy prices—the imposition of "windfall profits" taxes on US oil and gas producers and the imposition of price controls on domestically produced oil, gasoline, and other petroleum products.

Lawmakers no longer are widely discussing governmental incentives for the oil, gas, and biofuels industries to facilitate development of additional supplies as a means of better controlling US energy prices.

This article revisits the 1970s and 1980s, an inflationary period in which the federal government intervened with price controls on oil and products and the imposition of a windfall profits tax on oil production. As a regulator during this period of maximum regulation, this author developed a unique perspective that may be missing in current energy policy debates.

Government can act beneficially by encouraging development of an adequate and affordable energy supply, including innovative Department of Energy (DOE) programs that support the growth of renewable fuels projects. These could be adapted to support large increases in the supply of all fuels.

What won't work

The first major attempt by the federal government to control inflation was undertaken during World War II under the Office of Price Stabilization (OPS), which imposed price ceilings and rationed a wide range of products and commodities needed for the war effort.

In order to curb what was believed to be widespread inflation in 1970, Congress passed the Economic Stabilization Act (ESA) giving the president broad powers to regulate prices and wages. In 1971 President Richard M. Nixon used the act to impose price and wage controls on all sections of the economy, using a newly formed Cost of Living Council, headed by John Dunlop. Wage and price controls were lifted after several months on all but the oil industry, and the newly formed Federal Energy Office (FEO) assumed responsibility for the administration of price controls on domestic oil and petroleum products. Shortly thereafter, the Federal Energy Administration (FEA) became a permanent agency, and DOE subsequently absorbed FEA's operations.

Nixon's price control program covered the period from November 1971 through December 1980, when Congress enacted the crude oil windfall profit tax with the support of President Jimmy Carter.

Nixon's price controls

Nixon first used the ESA of 1970 in August 1971. In Phase I, he instituted a price freeze, imposing price and wage ceilings on the products, services, and wages of most US businesses. In November 1971, a Phase II price control regimen allowed all firms—other than those in the oil and gas industry—to increase prices, based on average increases in their costs. Initially, Phase II ceilings had little impact on petroleum products prices because crude oil prices had remained stable. But during the winter of 1972-73, heating oil shortages arose, and price controls contributed to the shortages.

To encourage production of additional heating oil, Phase III price controls, instituted in January 1973, allowed oil companies to pass through their increased costs through price

increases. But by March 1973, large heating oil price increases put public pressure on the Nixon administration to reimpose stricter price controls on heating oil. As a result, Special Rule No. 1 was issued, which reestablished heating oil price ceilings for the 23 largest domestic oil companies.

Phase III remained in effect through August 1973, creating a number of unforeseen problems. Imported oil prices began to increase, but Phase III price controls did not allow the 23 refiners to pass through their increased costs to independent resellers or consumers. As a consequence, refiners began to reduce oil imports and cut back product sales to independent marketers.

Old vs. new oil

The ensuing shortages aroused public pressure on Congress and the administration and resulted in Congress's enacting the Emergency Petroleum Allocation Act (EPAA) in November 1973. This act froze existing buyer-seller relationships as they existed in 1972. It also created a two-tiered system of price controls on domestic oil, namely "old oil" and "new oil."

Old oil was determined by computing the average monthly amounts produced from each oil-producing property in 1972 (the base production control level or "BPCL"), and the "ceiling price" for each barrel of old oil was its posted price at the start of Phase III. New oil was any oil produced from that same property above the property's BPCL. New oil could then be valued and sold at the free market price.

In addition, price controls on products became more complex. Some products were decontrolled, while others, such as gasoline, diesel fuel, and heating oil, could be increased above their historical base prices through a complex set of allocations of unrecouped costs. This scheme was flexible and porous enough to allow most refiners to sell at market prices. It also created a regulatory nightmare for the FEO and FEA.

Because thousands of oil-producing properties in the US produced only marginal amounts of oil at a relatively high cost, many producers were unable to operate these properties at a profit if only old oil prices could be realized. Consequently, thousands of low-producing wells were shut in. To encourage producers to operate these properties, FEA instituted a stripper well exemption in November 1973.

A "stripper well" was defined as one that produced less than 10 b/d, and the exemption allowed operators to sell stripper well crude oil at market prices. However, the stripper well exemption created another set of complexities having to do with how to compute production from operating wells, shut-in wells, and wells used for waterflooding on unified properties. In addition, the creation by regulation of multiple tiers of domestic oil required a complex system of "certifications" and imposed a new set of enforcement responsibilities on FEO and FEA.

In addition, by imposing price controls only on old oil, an important allocation problem ensued that had not been foreseen. At the time, there were hundreds of refineries operating in the US, many of which did not have access to old oil, as integrated refiners kept this low-value oil for their own use. Many of these nonintegrated refineries then had to acquire imported oil and exchange it for domestic oil received by pipeline, paying the imported oil price. As a consequence, refiners who had access to old oil were able to make much larger profits on the sale of gasoline, as gasoline prices could be supported by reallocation of costs not recovered on the sale of other refined products.

"Attempts to ease market distortions [caused by price controls] created other distortions…and the US created a regulatory 'tar baby' instead of a remedy."

In order to address this disparity, in December 1974 FEA adopted an "Old Oil Entitlements Program." This program was an attempt to equalize the percentage of old oil used by each refiner, based on the industry average percentage of old oil being used each month. It required some refiners to buy entitlements and others to sell entitlements, based on excesses or deficiencies they had using the average price of old oil. In these programs, refiners with excess old oil actually wrote checks to refiners who had shortages of old oil.

Again, unintended consequences ensued.

Unintended consequences

The program was an attempt to equalize profits across refineries, but it really didn't work that way for very long. Refiners who were being forced to buy entitlements for old oil began to increase their oil imports rather than issue entitlement checks to their competitors. This had the effect of equalizing the entitlements differentials between imported and controlled oil. It also put small refiners at a disadvantage, as they could not compete even after receiving entitlements benefits.

To allay this distortion, FEA enacted a "Small Refiners Bias" granting small refiners additional old oil entitlements. This created still other distortions. Old oil began disappearing because refiners and traders began "foreignizing" old oil through complex tier trading schemes, many of which were illegal. In addition, many refiners having to make entitlements payments began filing claims of hardship to FEA in order to receive exemptions from making entitlements payments to other refiners. And to get such exemptions, claimants had to use an elaborate and costly FEA administered appeals process.

As the price of oil began to rise again in 1975, Congress passed the Energy

Policy and Conservation Act (EPCA) of 1975, which placed a price ceiling on new oil commencing in February 1976. This required adjustments to the entitlements program. The entitlements program was modified again in April 1976, giving entitlements to importers of residual fuel oil into the US East Coast. Middle distillate importers were then given partial entitlements to allay shortages of heating oil, diesel fuel, and jet fuel that occurred in February and March of 1977. Additional special entitlements were created for low-quality California crude oil, for Puerto Rican petrochemicals, and for purchase of crude oil for the Strategic Petroleum Reserve.

Finally, by May 1979, the Carter administration placed petroleum price controls on hold, and by the end of his term, most price controls on petroleum and petroleum products had been dismantled. President Ronald Reagan abolished all remaining controls by January 1981, and the EPCA formally expired in September 1981.

From all of these actions, the administration learned that price controls on energy really do not work except for very short periods of time. The EPAA and the EPCA came about in part as a response to the 1973 Arab oil embargo and the run-up in oil and petroleum product prices that ensued. But as is often the case, attempts to ease market distortions created other distortions that were unforeseen, and the US created a regulatory "tar baby" instead of a remedy. Even though the country is facing similar market pressures today, it should not repeat the mistakes made in the 1970s.

Market set prices

Worldwide market forces set oil prices. If domestic oil prices are subject to price controls, they will adversely impact domestic producers, create disparities between have and have-not refiners, require elaborate allocation schemes (such as the old oil entitlements program) to be instituted, foster creation of complex rules and regulations, and stimulate widespread circumvention efforts on the part of those regulated. An increased government enforcement effort would then be needed in order to achieve a modicum of compliance.

Further, controlling prices of some petroleum products and not others creates market distortions. These price distortions lead to shortages and ultimately to black market activity. And most importantly, as demonstrated by the 1970s price control program, such a program is unlikely to control prices to any measurable extent, as market forces always win out.

WPT won't work

After decontrolling oil prices in 1980, Carter reached a legislative compromise with Congress allowing for the passage of a windfall profits tax (WPT) on producers of crude oil, as he feared that decontrol would lead to steep price increases. However the WPT, which went into effect on Mar. 1, 1980, lasted through January 1988. It initially was to be phased out over a 33-month period ending in January 1991 but was repealed in 1988.

Price controls would require elaborate allocation schemes and complex regulations and would stimulate widespread circumvention efforts.

The WPT was not a tax on profits; it was an excise tax on domestic oil production. It was imposed on the differential between revenues received for sales of domestic crude oil at market prices and amounts that would have been received at designated base prices. Base prices were adjusted monthly to reflect inflation and state severance taxes applied at the point of first sale. Base prices were established for Tier 1, Tier 2, and Tier 3 oil, as previously defined under the EPCA, and exemptions given to small independent producers, to government entities, and to other preferred groups.

Over 1980-88, the WPT produced $227.3 billion in tax revenues, which the US Treasury collected but did not return to consumers. The WPT did not generate as much revenue as was predicted because oil prices did not increase as expected. And in 1986, the price of oil collapsed, and WPT collections were greatly reduced. The only real impact the WPT had was counterproductive; it contributed to the reduction of domestic oil production by 3-6% and to an increase in oil imports by 8-16%. As with price controls, this punitive measure provided no direct benefit to the consumer and may have contributed to higher energy prices.

One can easily be misled into believing that it is sound energy policy to set ceilings on oil company earnings and earmark the windfall profits tax revenues collected to support government-sponsored energy policy initiatives. But based on experience, such a WPT applied against oil company profits would more than likely prove to be counterproductive. It takes continued and substantial investment to find oil, to upgrade and expand refining capacity, to perfect energy alternatives, and to build distribution and marketing infrastructure.

To remain competitive, oil companies must reinvest today's profits in projects needed to meet future energy demand. Because these reinvestments are often high-risk, imposing a WPT on oil companies presumes that the government is in a better position to decide how to reinvest in the energy sector. It also presumes that if excess profits are left with oil companies they will not reinvest. These presumptions are wrong. Because it is in the best interests of oil companies and their shareholders to reinvest in projects they believe will be viable, most of them do.

Further, there is no evidence to suggest that in periods of higher profits, oil companies increase dividend distribu-

tions and curtail reinvestment. By imposing a WPT, the government would only undermine the ability of oil companies to provide investment needed to support energy development.

Positive government acts

The Energy Independence and Security Act of 2007 (EISA) recognizes the need for increasing production of biofuels, improving vehicle fuel economy, obtaining energy savings through improved lighting and building energy efficiency, increasing energy supply through alternative energy research, facilitating increased use of US-produced coal through development of carbon capture and sequestration systems, and improving energy efficiency in energy transportation and transmission infrastructure.

The Energy Policy Act (EPACT) of 2005 authorized DOE to offer loan guarantees for energy-related projects that offer innovative technologies. DOE backed 16 such projects with $8 billion in guarantees in 2007 and is about to provide $38 billion more in 2008.

Presidential candidates and congressional members debating energy policy have proposed a number of programs the government could promote to provide substantial added supplies of secure, affordable energy.

These include support for the development of nuclear power plants; sustainable supplies of clean, renewable energy; clean coal technology; hydrogen-powered vehicle development; drilling in the Arctic National Wildlife Refuge; passing new corporate average fuel economy (CAFE) standards for automobiles; and federal financing of energy projects through grants, low-cost loans, loan guarantees, tax rebates, and a strategic energy project fund.

Industry support

Another article recently published in Oil & Gas Journal discussed EISA at greater length (OGJ, Mar. 17, 2008, p. 24). Although some consider EISA a positive and constructive piece of energy legislation, it would fall short of its goal to increase the US's fuel supply substantially enough to reduce dependence on imported oil. EISA's key weakness is the fact that the renewable fuels standards contained in the legislation mandates the biofuels goals without providing incentives needed by the private sector. Hundreds of biofuels plants would be needed to generate the large volumes of biofuels mandated, and billions of dollars of investment capital must be raised.

The windfall profits tax's real impact was reducing domestic oil production by 3-6% and increasing foreign oil imports by 8-16%.

There are a number of recommendations the government could take to stimulate investment in biofuels plants and related infrastructure, including research and development grants, tariff protections, low-cost project financing, and loan guarantees.

It is also recommended that tax incentives be made available to biofuels plant operators during ramp-up and perhaps price subsidies or conventional fuel surtaxes employed to support the higher cost of distributing and marketing advanced biofuels.

If mandates are issued to meet certain energy goals, direct government funding may be needed by those in the private sector to lessen the risk of such undertakings. These funding mechanisms should include direct grants, direct investment from venture funds or trust funds underwritten by government in qualified projects.

This list should also include low-cost loans that could be obtained by qualified sponsors from the US Treasury's Federal Financing Bank coupled with DOE loan guarantees. DOE's loan guarantee program, established under Title XVII of EPACT 2005, already provides a set of rules for qualifying projects and project sponsors for such loans and loan guarantees. Currently the program is authorized to provide only $38 billion in new loan guarantees, but this authorization can easily be increased as the program does not create a drain on the US Treasury or the US taxpayer unless a default occurs.

The government also should consider tax holidays for an initial period of years, along with accelerated amortization of new technologies being used, to reflect recapture of investments in new technology with uncertain useful lives.

Another funding mechanism to consider would be public-private joint venture arrangements that involve a public entity or authority other than the federal government. Under this type of joint venture, the private partner finances the project and operates it until it is profitable or for a fixed period of time. The private partner is then bought out based on the project's going-concern value and the direct equity it has invested. This is often referred to as a build-operate-transfer (BOT) joint venture. BTO is another variation whereby the project developer is bought out early but operates the project for a fee.

The salient feature of all of these "positive" government measures is that they would only be made available to qualified sponsors of deserving projects that meet due diligence standards for commercially acceptable project risk.

No one solution

No one solution exists for achieving US energy policy objectives. It has been shown that finding organizations to blame and passing punitive measures against them is counterproductiive.

The ideas presented here illustrate ways that the US government can help the country produce more clean energy from secure sources. These measures emphasize using government backing to facilitate private sector initiatives that are based on sound business principals.

By backing viable projects, such government support should result in implementation of successful energy projects and would go a long way in helping the energy industry meet government mandates.

These measures alone will not be enough to control energy prices in the US, of course, but combined with reduction of energy demand through conservation, they can go a long way toward that goal. ✦

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Debate on commodities bill divides US Senate

Nick Snow
Washington Editor

Democrats and Republicans traded charges of obstructing debate as the US Senate began on July 22 to discuss Majority Leader Harry M. Reid's (D-Nev.) bill to reform energy commodity markets.

Democrats said that Republicans wanted to delay consideration of S. 3268 by weighing it down with amendments. Republicans responded that Democrats were not willing to consider more meaningful steps, such as opening more federal land to oil and gas leasing.

The Senate agreed to invoke cloture and limit debate on the bill in a 94-0 vote before recessing for lunch. But the two parties clearly stayed sharply divided over how to address near-record crude oil and gasoline prices and their impact on consumers.

"The American people watching these proceedings must think they've tuned in to an episode of The Twilight Zone. They see that members from both sides of the aisle are hearing complaints from their constituents about high [gasoline] prices. They're asking why we can't agree on a solution if we can agree on the problem," Reid observed just prior to the vote.

The bill, which he introduced July 15, would give the US Commodity Futures Trading Commission authorization to hire 100 more full-time employees to monitor and regulate commodities markets. It would change the definition of "legitimate hedge trading" to include only producers and purchasers of actual energy commodities, and would place limits on trading by others.

Additional provisions

S. 3268 also aims to make over-the-counter commodities transactions more transparent by making traders provide more detailed information to the CFTC. It also would require the CFTC to routinely collect detailed information from index traders and swaps dealers, and differentiate the two groups. The bill also would establish working groups to study long-term international and domestic energy market trends, including the impacts of institutional investing and speculative trading, and order the Federal Energy Regulatory Commission to study the role of financial institutions on the natural gas market.

Reid and other Senate Democrats indicated that the bill provided a starting point for a fuller effort to bring oil prices down by curbing excessive energy futures speculation. Republicans questioned Democrats' claims that speculation was largely responsible for soaring crude oil prices and suggested that increasing domestic supplies would be more effective.

Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) noted that his and several other Senate committees have held hearings to examine the impacts of speculative investments on energy markets. "We have heard testimony from industry analysts, traditional producers and consumers of petroleum products that the recent run-up in crude prices can be attributed, at least in part, to the rise of 'new fundamentals' in our energy markets. These new 'fundamental forces' include nontraditional investment flows into energy commodity markets as asset managers seek to hedge against inflationary risks and the decline of the value of the dollar," he said.

This investment flight into commodities is a symptom of an ailing general economy, he continued. It also poses questions from an energy market perspective, including whether and how the influx of billions of dollars in relatively passive investment is having an impact on the fundamental price discovery function that the markets were designed to perform, Bingaman said. "That is to say, to some pension fund managers and index investors taking positions in the oil markets, the price of a barrel of oil on any given day may be immaterial. Whether the price is $5 or $100/bbl, their oil market positions are designed to balance the risk in other parts of their investment portfolios," he explained.

Paper barrels

"The question for policymakers is whether this investment, this demand for paper barrels, has begun to swamp the price signals generated by the more traditional hedgers, the large producers and consumers of petroleum products

Supply, demand drove oil prices, says CFTC-led taskforce

Nick Snow
Washington Editor

Fundamental supply and demand forces provide the best explanation for recent crude oil price increases, concluded a staff report for the Interagency Task Force on Commodity Markets.

"If a group of market participants has systematically driven prices, detailed daily position data should show that [the] group's position changes preceded price changes. The taskforce's preliminary analysis, based on the evidence available to date, suggests that changes in futures market participation by speculators have not systematically preceded price changes," the report said in its executive summary.

"On the contrary, most speculative traders typically alter their positions following price changes, just as one would expect in an efficiently operating market," it added.

The US Commodity Futures Trading Commission formed the taskforce in June with representatives from the Departments of Agriculture, Energy, and the Treasury, the Federal Reserve's Board of Governors, the Federal Trade Commission, and the Securities and Exchange Commission. It issued a 45-page interim report limited to the crude oil market on July 22 because the issue of high oil prices is so important and timely, the CFTC said.

"The recent upward surge in the price of crude oil has significantly affected American consumers and businesses. This staff report reflects the collective knowledge of some of our governments' best economists," said the taskforce's chairman, CFTC Chief Economist Jeffrey Harris.

"Each of the participating agencies brings unique expertise to the taskforce, and this interim report, for the first time, attempts to compile the government's best available information and analysis into one report. We hope that it will serve as a useful resource concerning the crude oil market and will contribute to the public discussion of important energy issues," he said.

The taskforce will continue to evaluate commodity market conditions and will report on its additional work later this year, Harris said. ✦

in tune to the real-time dynamics of supply and demand," Bingaman said.

John Cornyn (R-Tex.) responded that Democrats have indicated that excessive energy commodities speculation represents only about 20% of the oil price problem. "Why aren't we addressing the other 80%? Republicans would like to solve 100% of the problem, assuming that's possible," he said.

He conceded that many Democrats are right when they argue that US oil and gas resources represent a relatively small portion of the world's remaining reserves. "It's important for Congress to realize that the one place we have the power to do something is on lifting the moratoriums on 85% of the Outer Continental Shelf and to authorize leasing within the 2,000-acre postage stamp within the huge Arctic National Wildlife Refuge. Yet every time Republicans try to bring up a bill to develop a new energy resource, Democrats block it," Cornyn said.

Byron L. Dorgan (D-ND) said Republicans simply were asking the Senate to make false choices. "It's fascinating to hear them come out and do this. Every 10 years or so, the same people come out and say find more and use less. We need something that's game-changing. You won't get that from those who say do the same thing, only drill deeper," he said.

Speculators have grown from 37% of the total oil futures market in 2000 to 71% in 2008, he added. "There's no other explanation for oil's price doubling within a year. Will the minority support this bill to address excessive speculation or simply insist on producing more? It's long past time for this country to change its energy mix. Drilling is not the only answer," Dorgan said.

Carl M. Levin (D-Mich.) said the Senate's Permanent Subcommittee on Investigations found in four separate inquiries that speculators are playing a bigger role on oil commodities markets, growing from 20% in 2000 to 40% in 2008. These estimates are an understatement since the CFTC classifies index funds as commercial traders, he said. "The need to control speculation is urgent. The president and chief executive officers of our major airlines have said so," Levin said.

'Message is clear'

But Pete V. Domenici (R-NM), the Energy and Natural Resources Committee's ranking minority member, said Republicans will insist that other issues be addressed. "In overwhelming majorities, the American people have said they want more energy production here at home. In response to this clarion call, it looks as if the majority will have to be dragged, kicking and screaming, into even discussing these issues. It seems content to hang its hat on commodities speculation and a so-called 'Use it or lose it' strategy," he said.

Acknowledging that Reid has said Republicans could offer their drilling amendment and Democrats would offer their own, Domenici said much more would be needed to pass substantive energy legislation. The 2005 Energy Policy Act was on the Senate floor for 10 days, had 23 total roll call votes (19 of which dealt with amendments) and contained 57 amendments of the 235 that were proposed when it was finally approved, he noted. The 2007 Energy Independent and Security Act was on the Senate floor for 15 days, had 22 roll call votes (16 of

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Cavaney raises important points

In a week that began with US President George W. Bush's rescinding the presidential Outer Continental Shelf oil and gas leasing withdrawal and ended with the US House defeating the latest bill incorporating "Use it or lose it" provisions, American Petroleum Institute President Red Cavaney raised some important points.

"In the ongoing energy debate, far too much time is being wasted in discussing what form of energy should be favored and which disadvantaged in meeting our country's needs," he said in a July 16 keynote address to the US Energy Association's Energy Supply Forum.

"Every respected energy study on future demand comes to a similar conclusion about the next several decades: We need all the energy that is economically viable to produce in an environmentally sensitive manner, as well as energy efficiency at levels heretofore unrealized," Cavaney observed.

Increasingly, what happens globally affects energy in general, and oil in particular, domestically. Current concerns about crude oil and gasoline prices underscore energy's link with the general economy, he said.

Demand requirements

Cavaney cited recent US Energy Information Administration estimates that sustaining 3% annual global economic growth will require a crude oil production increase equal to the US's and China's current combined consumption. Worldwide natural gas demand growth could be even larger, rising 53% by 2030, he added.

"Despite significant growth of alternatives and improvements in energy efficiency, more than half of the world's energy demand will be met by oil and natural gas in 2030, as is the case today," Cavaney said.

He cited often quoted US Minerals Management Service estimates of 18 billion bbl of oil and 76 tcf of gas believed to be waiting beneath the 85% of the Outer Continental Shelf that is still off-limits in the Lower 48 states.

But he also mentioned that only 17% of nonpark, nonwilderness lands that the federal government administers is open to energy development under standard lease terms. The US Bureau of Land Management has said the remaining land holds an estimated 19 billion bbl of oil and 94 tcf of gas, Cavaney said.

Growing recognition

"Several recent polls show that many Americans have a growing recognition that our nation must do more to find and develop the domestic oil and gas resources we need, both onshore and offshore," he continued.

A survey that Cable News Network and Opinion Research Corp. conducted in June found that 73% of those sampled favored increased drilling in US waters, he noted. "And a Fox News-Opinion Dynamics poll, also in June, found that 76% favored 'increased drilling for oil in the United States immediately,'" he said.

"We cannot afford to repeat the mistakes of the 1970s," Cavaney maintained. "We face far tougher energy competition today as a result. Price controls, allocation schemes, limitations on natural gas, picking winners and losers among fuels, and punitive taxes have all been tried by government—and none have worked to benefit the consumer." ✦

which involved amendments) and contained 49 amendments of 331 which were proposed when it was finally approved, Domenici said.

He also attacked the Democrats' "Use it or lose it" proposal, which he said originated with the Wilderness Society, an environmental organization that has sued to stop oil and gas development. "The tracts are already leased, and oil companies are trying to get the maximum return on their investments. In contrast, Congress currently continues to restrict access to 574 million acres of the OCS. It's clear who's sitting on domestic oil and gas resources," Domenici said.

Other Republicans suggested that Reid's bill could have harmful consequences. "It could limit investment opportunities for seniors' pension funds and drive US jobs overseas. All it does is delay other efforts that could make a difference," said John Ensign (Nev.). "Efforts to address market manipulation require a careful balance. Increased visibility should not translate into excessive regulation," said John Barrasso (Wyo.).

"Democrats have said from the start that curbing excessive speculation is not a panacea for high oil prices. But it's obviously an attempt to solve a major part of the problem. This kind of speculation wasn't even legal 8 years ago. Traders had to accept delivery of oil, something Wall Street investment banks weren't prepared to do. We're willing to give Republicans a vote on their drilling amendment to get this bill passed. But Democrats would like to vote on their drilling proposal too," Reid said. ✦

Another US House energy bill falls short of passage

Nick Snow
Washington Editor

The US House of Representatives rejected the Democratic leadership's latest energy bill in a 244-173 vote on July 17 when HR 6515—which came to the floor under a rules suspension—fell short of the necessary two-thirds vote for passage.

The bill, formally known as the Drill Responsibly in Leased Lands (DRILL) Act, included so-called "Use it or lose it" provisions from HR 6251, which Natural Resources Committee Chairman Nick J. Rahall (D-W.Va.) championed and the House rejected on June 26 by 223 to 195 votes. But HR 6515 also contained language aimed at producing crude oil quickly from the National Petroleum Reserve-Alaska while continuing existing leasing bans in the Arctic National Wildlife Refuge and on 85% of the US Outer Continental Shelf. It also would have reinstituted a ban on exporting Alaskan oil.

Oil and gas industry trade associations approved of the latest bill's defeat. "Congress was wise to listen to the American people and not move forward with this anticonsumer legislation," said the American Petroleum Institute in a statement. "Polls indicate that the majority of the American people see the need to expand access to domestic oil and natural gas resources. Americans would be better served if our elected leaders made responsible, long-term energy policy instead of promoting bad ideas that will fail to secure our energy future."

Brian T. Petty, the International Association of Drilling Contractors' senior vice-president of government affairs, commented: "We were delighted that the bill was defeated. It was completely wrong-headed. This was not about opening access and developing oil and gas resources, but about putting oil wine in a new bottle. It was the Rahall bill reconstituted with some troubling new features," Petty said on July 18.

'We're still nervous'

"Unfortunately, it was not defeated by the same margin as the earlier bill." Petty continued. "We lost some Blue Dog Democrats, who wanted to humor the speaker, and some Republicans. We're nervous about the speaker going back at it again. The majority leader has been coy and said they're studying possible further action. We're still nervous. We're ahead of the curve, but the deal is not done yet. It hasn't been put completely to bed so these people can go home for recess," he told OGJ.

Independent Petroleum Association of America President Barry Russell was critical of both the "Use it or lose it" provisions and HR 6515's NPR-A proposals, which he said are merely an attempt to draw attention away from areas of new production and other possible solutions. He said House Speaker Nancy Pelosi (D-Calif.) "and her inner circle continuously make feeble attempts to fleece the American public into thinking they are working to further production of American oil and natural gas, which they are not."

Rahall insisted otherwise. "As Democrats, we are pro-drilling. And we are for drilling now, in areas that can bring near-term relief to the American public. As others put forth bumper sticker energy policies, today House Democrats are bringing forth prudent legislation aimed at unleashing the vast potential of the National Petroleum Reserve in Alaska," he said as he opened floor debate on HR 6515.

"Part of what we must do to bring down the price of energy to the American people is to increase domestic supply," said Pelosi. "[That] means we must remove all doubt in the minds of those who wish to drill and those who want the drilling to take place that there are 68 million acres in the Lower 48 states where drilling is allowed," she said.

Majority Leader Steny H. Hoyer (D-Md.) said, "The DRILL Act speeds up the leasing process in the NPR-A. It ensures that Alaskan oil will fill American gas tanks. It calls on the president to speed up the completion of Alaskan oil and gas pipelines so the products will get to market sooner. And it tells the oil companies: 'Drill on the leases you have, or let somebody else do it, but don't just sit on them while Americans are paying $4/gal [for gasoline]. Use it or lose it.'" Hoyer insisted.

Bill 'a sham'

Republicans were equally adamant that the bill was a mistake. "This bill is a sham. It will not produce one drop of American-made oil or natural gas. In fact, there is more drilling in my dentist's office than in this bill," said Rep. Don Young (R-Alas.), the Natural Resources Committee's ranking minority member.

He said all lands within the NPR-A that are available to be leased under current US Bureau of Land Management planning documents have been offered in the past, are currently leased or are already available to be leased. Both the oil and gas industry and the DOI say that environmental lawsuits are the only impediment to more production from the NPR-A, "and the bill doesn't touch that. In fact, the 'Use it or lose it' parts of the bill create new litigation that will hold up leasing in the NPR-A," Young said.

Following the bill's defeat, House Minority Whip Roy Blount (R-Mo.) said that it was a slap in the face to millions of consumers trying to cope with record gasoline and diesel fuel prices. "But Democratic leaders didn't bring this bill to the floor with any illusions of passing it. Rather, what we saw today was a choreographed attempt to make it appear as if they're doing something to bring down the cost of [gasoline]

when in reality the situation is quite the opposite," he said.

Eleven Democrats joined 162 Republicans in voting against HR 6515, Blunt pointed out. He said that they included Rep. Jim Costa (D-Calif.), who chairs the Natural Resources Committee's Energy and Minerals Resources Subcommittee that would have jurisdiction of the DRILL Act. "The bill, of course, was never sent through committee," he said.

"You can run from bad energy policy: We saw that this afternoon on the House floor. But you can't hide. And every American who drives past a gas station this summer will see with his own eyes how bad energy policy in Washington leads to prohibitively high gas prices everywhere else," Blunt maintained. ✦

BLM releases proposed oil shale development regs

Nick Snow
Washington Editor

The US Bureau of Land Management on July 22 published proposed regulations to establish a commercial oil shale development program, which it said could add as much as 800 billion bbl of oil to US reserves.

The US Department of the Interior agency is proposing regulations—required under the 2005 Energy Policy Act (EPACT—that aim to provide critical information for investors considering financial commitments to prospective oil shale projects. But the regulations are only proposals because the fiscal 2008 DOI appropriation prohibits using funds to prepare or publish final regulations, BLM said.

"As Americans pay more than $4 for a gallon of gasoline and watch energy prices continue to climb higher and higher, we need to be doing more to develop our own energy here at home through resources such as oil shale. Instead, I find it ironic that we are asking countries halfway around the world to produce more for us," said US Interior Secretary Dirk A. Kempthorne.

US Sen. Ken Salazar (D-Colo.), Rep. Mark Udall (D-Colo.), Colorado Gov. Bill Ritter, and other state and local government officials have said that more time is needed to properly evaluate and find ways to mitigate economic and environmental impacts on communities near the deposits in that state. The largest known US oil shale deposits are in a 16,000-sq-mile area, the Green River Formation, in Colorado, Utah, and Wyoming.

BLM said that before any oil shale leases would be issued, a site-specific National Environmental Policy Act analysis would be conducted on a proposed development. A lessee would have to obtain all required permits from state and local authorities before operations could begin, the federal agency said.

It said the proposed leasing regulations incorporate provisions of EPACT and the Mineral Leasing Act relating to maximum oil shale lease size, maximum acreage limitations, and rental and lease diligence. The rule also will propose a range of royalty rate options and will ask for public input on the royalty provisions, BLM said.

The proposed regulations also would address the EPACT provision establishing work requirements and milestones to ensure diligent development of leases, it continued. Standard BLM leasing program components, including lease administration and operations, would be included along with additional NEPA documentation requirements for lease applicants, it said.

BLM will accept public comments on the proposed regulations for the next 60 days, it indicated.

The agency's announcement brings the US a step closer to developing an important energy resource, said the Institute for Energy Research on July 22. "The United States has more oil shale than the entire Middle East has crude, but we lack the governmental framework to lease those lands so the resource can be produced for our consumers. If politicians in Washington are looking for a way to revitalize our economy, they should look no further than oil shale," said Daniel Kish, IER's senior vice-president for policy. ✦

Pertamina import 'irregularities' examined

Eric Watkins
Senior Correspondent

Indonesia's state-owned PT Pertamina, already a candidate for government scrutiny over corruption in the upstream sector, is facing charges by legislators of "irregularities" in its importation of crude oil and products.

"Pertamina's imports of gasoline and diesel are always more expensive than those of...Singapore," said Tjatur Saptoedy, a member of the House of Representatives' inquiry committee.

Tjatur said that based on Pertamina's calculation, from January to May this year the company spent 1.18 trillion rupiah ($128 million) more than similar transactions would have cost in Singapore.

In 2007, he said, Pertamina imported 321,000 b/d of crude and 300,000-350,000 b/d of fuel to help meet domestic need of 1 million b/d in

fuel. The country's six refineries could produce only 652,000 b/d.

Several factors have been cited for the high cost of imports, including a lack of transparency in the import process and the company's partnership with oil brokers that have insufficient capacity.

While Pertamina claims to have 42 brokers for importing crude and 50 for fuel products, Tjatur said just 5-7 brokers regularly win tenders for the import procurements.

"I am really wondering why these companies frequently win the bidding. Some of them don't even have the products or the refineries," he said, adding that some bidders apparently have inside information, enabling them to bid on tenders more quickly than others.

"Only those who had obtained information beforehand would win the tenders,' said Tjatur, noting that one tender opened on July 14 and closed on July 18, leaving interested parties "next to no time" to prepare for the bid.

Pertamina Pres. Ari H. Soemarno defended his company's purchasing practices, saying, "We always take efficiency and reliability into consideration when carrying out procurements."

Tjatur's remarks came ahead of formal investigations into the country's oil and gas industry that are due to begin soon.

The House has set up an inquiry committee aimed primarily at investigating the causes of inefficiency in the country's energy sector. The committee's investigations are scheduled to start in mid-August.

In addition to the parliamentarians' investigation, recent reports say Indonesia's Corruption Eradication Commission as well as its upstream oil and gas supervisory agency, BPMigas, also are creating a team to evaluate the monitoring mechanisms in the upstream oil and gas industry. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Mixing oil and politics

Do any other oil and gas analysts feel that the 1950s are approaching again? I don't mean gasoline priced at 25 ¢/gal, either. No, I'm thinking more of the Cold War.

That's what came to mind last week as I saw stories involving belligerence—I'm sorry if that seems like a strong word to use—on the part of China and Russia.

The first story concerned China's warning to ExxonMobil over a bit of acreage off Vietnam.

Foreign ministry spokesman Liu Jianchao said China's position on the South China Sea matter is "clear and consistent" and that China has already stated "clearly" its position to relevant parties.

"China opposes any behavior that undermines China's sovereignty and jurisdiction in the South China Sea," he said.

Business deals at risk

Sources close to ExxonMobil said Beijing's envoys had protested several times in recent months, warning executives that they would put future business interests on the mainland at risk if they continued with the Vietnam deal.

The sources said ExxonMobil was confident of Vietnam's sovereign rights to the exploration blocks involved, but added that pressure from China added complications that could not easily be ignored "for business reasons."

If that is not enough to convince ExxonMobil, then it will be interesting to see what the Chinese do next. Perhaps they will launch the gun boats and call for a military "exercise" of some sort in the region.

That's the sort of diplomacy Russia looks to be exercising these days, too, especially in Latin America where it has signaled a new military alliance of sorts with Venezuelan President Hugo Chavez.

In fact, Russian President Dmitry Medvedev last week hailed closer ties with Chavez, overseeing energy deals bringing the two key oil producers and rivals of the US closer together.

Venezuela welcomes Russia

Not missing a beat, Chavez declared his country would readily allow Russia a military base if it asked for one. Said Chavez: "If Russia's armed forces want to be present in Venezuela, they will be given a warm welcome."

"We are considering issues linked to our strategic partnership, be it in the energy sector, industry, finance, science and technology, or military issues," Chavez said.

For his part, Medvedev also hailed the agreement.

"Venezuela is now the most important partner of the Russian Federation," said Medvedev, adding that "Our relations are a key factor of regional security...We have one common task—to make the surrounding world more democratic, fair and secure."

Chavez also said he would pursue fresh purchases of Russian arms, "because the North American empire... has plans to invade Venezuela, to disarm Venezuela."

"We are a peace-loving country, but we are threatened by the United States...because Venezuela's oil reserves are the world's largest," he told a news conference. "And we are forced to defend ourselves."

Yes, it seems like déjà vu for the Cold War. ✦

Markets ready for rise in Canadian oil sands production

Steven Poruban
Senior Editor

Production of Canadian oil sands bitumen will continue to rise in the coming decades but not without advances in processing technologies and the adoption by producers of varied strategies to market the resulting heavy crude blends.

These were some of the issues raised by speakers July 15 during the opening session of the second annual Oil Sands & Heavy Oil Technologies Conference & Exhibition in Calgary.

Tension was palpable at the opening session regarding one topic in particular: growing concerns in Canada about finicky talk in the US concerning the type of oil it allows to cross its borders.

This hot-button issue has its impetus in a resolution the US Conference of Mayors adopted last month that is modeled on a section in last year's Energy Independence and Security Act, which raised alarm about the potential environmental drawbacks of oil sands. The resolution calls for bans on purchases, for use in city vehicles, of any fuel with life-cycle emissions of greenhouse gases deemed excessive (OGJ, July 7, 2008, p. 21). Canadian oil sands producers' concerns hinge largely on such a resolution's gaining serious political steam during an already strongly polarized presidential election in the US.

Oil vs. 'dirty oil'

In a presentation that compared and contrasted conventional oil with oil sands and other heavy oil resources, Jim Hyne of Hyjay Research & Development stressed the need for different operational infrastructure for the two types of oil.

Hyne said the increased complexity of steps needed to extract and process oil sands sets the resource too far apart from conventional resources to fit old protocols. Differences include the number of steps, the amount of manpower, and the large capital resources required to extract and process oil sands. Transporting the finished products also is more complex for oil sands, and the environmental and social impact of its development is far greater than conventional resources, Hyne noted.

Regarding the changes and advancements needed to continue to process oil sands and heavy oil, Hyne said, "There are too many people in the business we are in who are still thinking 'inside the box.'" According to Hyne, there are vast new and different protocols that can be implemented that better meet the needs of responsible, profitable, and sustainable energy production from the oil sands.

Hyne pointed out that the features of the new and different operational infrastructure for oil sands include the amounts and toxicity of their emissions, getting the resource to the surface—and moving it once there—how and where to upgrade the resource, the certainty of the reserves, and fighting the image of "dirty oil."

Markets meet technology

Thomas Wise, vice-president of engineering consulting firm Purvin & Gertz, an engineering consulting firm with offices in Calgary, discussed the evolving oil sands and synthetic crude oil markets. He said oil sands production growth is expected to offset declines in conventional oil production, although recent project delays have reduced original production forecasts.

Wise said bitumen blends coming from Canada have been oversupplied in US Midwest markets, resulting in price discounts. New refinery coking projects should improve the balance, Wise noted.

Wise noted that the supply of light, sweet synthetic crude oil (SCO), without bottoms, continues to rise, but that the demand is limited to a minority of refineries without coking or asphalt production. Therefore, SCO price discounting can be expected. Also, refineries need more hydrocracking, and technology to reduce vacuum gas oil and leave some low-sulfur resid could enhance the marketability of SCO.

Wise said environmental issues will continue to impact the oil sands markets, adding that because greenhouse gas issues are so politically charged, clear government policies are needed. It is lack of this clarity that has delayed a number of upgrading projects, he said.

The value of oil sands

Robert Fryklund, vice-president of global exploration and production critical analysis for IHS, discussed the oil sands from the perspective of business developers. To date, more than 1 trillion bbl of oil has been produced globally, Fryklund said, which compares with the estimated 1.7 trillion bbl of original bitumen in place in the Canadian oil sands.

Fryklund noted that the oil sands landscape continues to change, even from a year ago. New entrants into the oil sands development projects include foreign companies such as Norway's StatoilHydro as well as additional Canadian domestic groups. Missing from the mix are certain European majors and US operators such as Hess Corp., Anadarko Petroleum Corp., and Apache Corp. Also, Petrobras, Petronas, and Pertamina have yet to enter.

Leasing activity has been on the rise, as has the number of merger and acquisition transactions, Fryklund noted. Capital cost creep, however, has begun to wear away at the number of players in the oil sands. With projects costing an average of $10 billion due to come on line in the next 5 years, it is not uncommon to discuss projects having a final price tag as high as $20 billion. ✦

Alberta keeps oil sands' environmental impacts in check

Steven Poruban
Senior Editor

The burgeoning development of Alberta's vast oil sands resources and its effect on the province's land, water, and air is being closely and carefully monitored by government officials as well as other environmental research agencies to ensure its sustainability.

This was the main message conveyed July 16 by several keynote speakers to delegates attending the Oil Sands & Heavy Oil Technologies Conference & Exhibition in Calgary.

"The theme for the conference sums it up very well—Stepping Up: Preparation for Growing Expansion," said Len Webber, parliamentary assistant, Alberta Energy. "Alberta is stepping up to our responsibility to ensure our energy resources are developed responsibly," he said.

Last year, Alberta exported about 1.35 million b/d of crude to the US, supplying 13% of American crude oil imports, Webber said, adding that while Alberta continues to garner more global attention, it has "become more important than ever for Alberta to maintain a stable environment for investors."

He added, "At the same time, it's vital that we ensure the environmentally responsible development of our oil sands."

Addressing climate change

Admitting that there was probably no bigger environmental issue currently than climate change, Webber reported that Alberta's oil sands compose only about 4% of Canada's overall greenhouse gas (GHG) emissions. "As an entire country, Canada is responsible for about 2% of global emissions," he said, adding, "Putting that in perspective, Alberta's oil sands contribute less than one tenth of 1% of all GHG emissions in the world."

Eddy Isaacs, executive director, Alberta Energy Research Institute (AERI), told conference attendees that in 2006, Alberta GHG emissions, by facility, broke down into power plants emitting 51.7 million tonnes, oil sands emitting 24 million tonnes, and heavy oil emitting 6.8 million tonnes.

Webber noted that Alberta is backing up words about climate change concerns with action, reminding attendees about the recent launch of two $2 billion initiatives: one designed to advance large-scale carbon capture and storage (CCS) projects and the other to propel public transit across the province.

Earlier this year, Alberta released a climate change plan of action designed to reduce its GHG emissions by 2050 by 50%, or 200 million tonnes/year. "CCS will be responsible for reducing 70% of our GHG emissions in 2050," Webber said.

Last year, Webber noted, Alberta became the first jurisdiction in North America to legislate GHG reductions of large industrial facilities. "By law, the largest industrial facilities, including oil sands facilities, must reduce their emissions intensity by 12%," he said.

Webber explained: "Facilities can choose to reduce emissions by making operating improvements that will result in reductions. They can buy Alberta-based credits from other large emitters who've reduced their emissions. Or they can contribute $15/tonne to a fund that will direct money towards strategic projects or technology aimed at reducing GHG emissions."

He said, "Results from the first year indicate that companies made 2.6 million tonnes of actual reductions. That's equivalent to taking 550,000 vehicles off the road in a year."

Land, water, and air

Webber said, "You might have heard that the oil sands lie beneath a region about the size of Florida—roughly 54,000 sq miles—over 140,000 sq km." However only about 162 sq miles, or about 500 sq km, have been disturbed by oil sands activity to date, he said, adding, "That's less than 1% of the total oil sands area."

Under Alberta's strict reclamation standards, Webber said, "every inch of land that is disturbed must be reclaimed so it can be productive again."

Alberta also places strict limits on industry water use, Webber said, adding, "Some might have you believe that oil sands projects are using nothing but fresh, drinkable water to extract bitumen."

In fact, Webber stated, "Oil sands developers have drastically reduced their need to draw fresh water. Some recycle more than 90% of the water used in their operations and use saline water instead of fresh water wherever possible."

Kate Rich, with the science and standards branch of Alberta Environment, a newly established division that focuses on policy development, told conference delegates that about 2-5 bbl of fresh water is being used for every 1 bbl of oil produced in mines and 0.5 bbl or less of fresh water being used for in situ production.

Several frameworks have been established, Rich said, noting as an example the Athabasca River Water Management Framework, which sets strict limits on how much water can be withdrawn. This amount of water is reduced, she said, during environmentally sensitive, or low-flow times.

Regarding air quality, Webber stated that it was important for people to know that it is being monitored 24 hr/day, 365 days/year. "It is tested for carbon monoxide, nitrogen dioxide, ozone, fine particulate matter, sulfur dioxide, and hydrogen sulfide," he said.

"In 2007, for example, air quality near Fort McMurray was rated good or better 98% of the time," Webber said.

Alberta Environment's Rich explained that set objectives for Alberta's air management require the adoption of best-available technologies. "We do want to keep what's clean, clean," she said. ✦

MODELING GULF OF MEXICO LOST PRODUCTION—4 (Conclusion)

Meta evaluation helps model lost Gulf of Mexico output

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Valuing lost production from destroyed structures is an important measure in investment decision making, since if the value of future production is less than the expected redevelopment and cleanup cost, then the decision to redevelop the property will either be postponed or not undertaken.

In the final part of this series, we present a meta-model framework to quantify the quantity and value of lost production from the 2004-05 hurricane seasons.

Previously, in Part 3, we presented sensitivity graphs and similar charts to illustrate the manner in which system parameters impact the model output. In Part 4, we describe the use of a more sophisticated, and in many respects, more useful technique to explore sensitivity analysis and the complex interactions of assumptions on model output. We illustrate the technique with examples.

Model formulation

The meta-model methodology follows the basic development in Part 2 but with important structural differences (Fig. 1).

STEP 1: Initialization

The user selects the variables of interest and quantifies the manner in which they vary. This involves choosing the model variables, distribution functions and parameters.

The input set is user-defined and varies with the objectives of the analysis and the problem formulation. The distribution of each input variable is largely a design choice.

We employ the following variables: the price of oil and gas (P^o, P^g), the threshold multiplier a, and the discount rate D. The decline curve parameter d for structures that do not yield a best-fit curve is also a model input. The input parameters are denoted by the vector (d, P^o, P^g, a, D), although we also use the notation (X_1, X_2, …, X_n) to indicate the general nature of the model variables and the fact that their specification is both user-defined and problem specific.

Parameter X_i is governed by distribution function f_i, i = 1, …, n. The specification of the function may be determined by empirical analysis or by user preference.

For example, if the historic price of oil is determined to follow a lognormal distribution according to the parameters μ and σ^2, $P^o \sim LN(\mu, \sigma^2)$, the user may model future prices according to this distribution or may prefer to

Meta-modeling overview (Fig. 1)

Step 1 (Initialization). Sample the input parameters d, P^o, P^g, a, and D from their respective distribution functions.

Step 2. (A: Production and Revenue Forecast). For structure s, forecast future oil and gas production, $q^o(s)$ and $q^g(s)$, and revenue r(s) for the decline rate d and oil and gas price deck P^o, P^g.

(B: Economic Limit). Determine the first time when structure revenue falls below its estimated cost of operation, $r_t(s) \le a \cdot \tau_a(s)$, for a ≥ 0 and abandonment threshold $\tau_a(s)$.

(C: Cumulative Production and Value). Output cumulative oil and gas production, $Q^o(s)$ and $Q^g(s)$, and present value of the revenue stream, V(s), discounted at the rate D.

Step 3 (Aggregation). Aggregate oil and gas production, $Q^o(\Gamma)$ and $Q^g(\Gamma)$, and total discounted revenue, $V(\Gamma)$, across all structures in the sample set Γ.

Step 4 (Regression). Repeat Steps 1-3 and regress the model outputs $Q^o(\Gamma)$, $Q^g(\Gamma)$, and $V(\Gamma)$ against the system input variables (d, P^o, P^g, a, D).

Equations

$$T^a(s) = \min\{t \mid r_t(s) < a \cdot \tau_a(s)\} \quad (1)$$

$$Q^i(s) = \sum_{t=1}^{T_a(s)} q_t^i(s) \quad (2)$$

$$V(s) = \sum_{t=1}^{T_a(s)} \frac{r_t}{(1+D)^t} \quad (3)$$

$$Q^i(\Gamma) = \sum_s Q^i(s) \quad (4)$$

$$V(\Gamma) = \sum_s V(s) \quad (5)$$

$$f = \alpha_0 + \sum_{i=1}^{5} \alpha_i X_i \quad (6)$$

$$\Sigma = \{(d, P^o, P^g, a) \mid 0.05 \le d \le 1.2, \; 60 \le P^o \le 100, \; 6 \le P^g \le 10, \; 0 \le a \le 2.5\} \quad (7)$$

assume some other distribution type, such as the uniform distribution, $P^o \sim U(a, b)$.

Our preference is to maintain reasonable assumptions and bounds on the function parameters, recognizing that problem tasks and individual bias allows for a wide range of variation.

STEP 2a: Production and Revenue Forecast

The model curves for each structure are used to forecast future oil and gas production under the assumption of stable reservoir and investment conditions.

The production forecast for oil and gas begin in the year 2006 ($t = 1$) and continue into the future as $q^i(s) = (q_1^i, q_2^i, \ldots)$.

Revenue in year t for structure s is computed as $r_t(s) = q_t^o P_t^o + q_t^g P_t^g$, where P_t^o and P_t^g represent the average oil and gas price of the production sold during the year t. We assume a price deck that is constant throughout the life cycle of the structure.

The revenue forecast vector for structure s is denoted as $r(s) = (r_1, r_2, \ldots)$.

STEP 2b: Economic Limit

To terminate the production and cash flow vectors determined in Step 2a, we estimate the time the structure is no longer commercial by comparing the revenue each year, $r_t(s)$, to the economic limit of the structure, $\tau_a(s)$, and selecting the first year (earliest time) when revenue falls below the economic threshold given by Equation 1.

The value of a in Equation 1 is used to provide operational insight on the effect of changes in the threshold level. $T_a(s)$ denotes the time when production is no longer commercial. At time $t = T_a(s)$, the operator is assumed to stop producing, which will terminate the cash flow vector: $r(s) = (r_1, r_2, \cdots, r_{T_a(s)})$.

STEP 2c: Cumulative Production and Discounted Revenue

The cumulative lost production $Q^i(s)$ and discounted cash flow $V(s)$ associated with structure s is computed from 2006 ($t = 1$) through the time of abandonment, $t = T_a(s)$, as given by Equations 2 and 3.

The value of D used in the valuation computation denotes an industry-wide discount rate that is employed for each structure.

STEP 3: Aggregation

The model output for structure s is the forecast production profile, $q^i(s)$, cumulative production, $Q^i(s)$, and discounted cash flow, $V(s)$.

We perform the assessment for each structure and then aggregate across the collection of all hurricane-destroyed structures Γ, yielding Equations 4 and 5.

STEP 4: Regression Analysis

The model input are the parameters (d, P^o, P^g, a, D) and the model output includes $\{q^i(\Gamma), Q^i(\Gamma), V(\Gamma)\}$.

In the first loop of the process, each input parameter (d, P^o, P^g, a, D) is sampled from its respective distribution; intermediate calculations on production forecasting, abandonment, cumulative production and discounted revenue are performed for each structure; and then the structure results are aggregated to obtain $\{q^i(\Gamma), Q^i(\Gamma), V(\Gamma)\}$. We repeat

Design space geometry (Fig. 2)

The model input variables (X_1, X_2, ..., X_n) denote a "point" in n-dimensional space R^n. The specification of f^i for each parameter X_i, i = 1, ..., n, will generate an n-dimensional geometric body $\boldsymbol{B} \subset R^n$. The number of variables specified determines the dimension of $\boldsymbol{B}$. The size and shape of $\boldsymbol{B}$ is determined by the form of the distributions.

In the special case where each model variable is assumed to range over a uniform distribution, $X_i \sim U(a_i, b_i)$, X_i is bound between a_i and b_i, $a_i < b_i$, i = 1, ..., n, and the body $\boldsymbol{B}$ will transform into an n-dimensional hypercube Σ:

Σ: $\{(X_1, ..., X_n) \mid a_i \le X_i \le b_i, i = 1, ..., n\}$.

The end points of each interval determine the boundary of the hypercube, and since each variable is selected uniformly, the density of the resulting geometric body will be homogeneous.

The size, shape, and location of the geometric body $\boldsymbol{B}$ within Euclidean space R^n determines the range of the model variables and the space in which the model parameters inhabit. Using a hypercube Σ as our base shape, recall that the volume of Σ is the product of the length of each interval, $b_i - a_i$, i = 1, ..., n:

$$\text{Vol}(\Sigma) = \prod_{i=1}^{n} a_i - b_i$$

The volume of the design space and its position within R^n plays a role in the magnitude of the fit parameter and the values of the model coefficients. As the size of $\boldsymbol{B}$ increases, we would expect the model fits to decrease if the density of the sampling regime is not sufficient. The location of the body within R^n is determined by the specification of the distribution function and will influence the magnitude of the model coefficients.

Meta-model methodology summary (Fig. 3)

Step 0. Determine $q^o(s)$, $q^g(s)$, and $\tau_a(s)$ for each structure in the sample set Γ.

Step 1. Sample d, P^o, P^g, a, and D from the distribution functions selected as follows: $d \sim U(a_1, b_1)$, $P^o \sim N(\mu_1, \sigma_1^2)$, $P^g \sim N(\mu_2, \sigma_2^2)$, $a \sim U(a_2, b_2)$, $D \sim U(a_3, b_3)$, where $U(a_i, b_i)$ denotes a uniform distribution with end points (a_i, b_i), for i = 1, 2, 3, and $N(\mu_i, \sigma_i^2)$ represents a normal distribution with mean μ_i and variance σ_i^2, i = 1, 2.

Step 2. For structure s,

2.1. Compute future oil and gas production, $q_t^o(s)$ and $q_t^g(s)$, for t = 1, 2, ...

2.2. Compute future revenue $r_t(s) = q_t^o(s)P^o + q_t^g(s)P^g$, for t = 1, 2, ...

2.3. Compute the earliest time $T_a(s)$ when structure revenue falls below the economic limit $\tau_a(s)$, for a ≥0:

$T_a(s)$ min{t | $r_t(s) < a \cdot \tau_a(s)$}.

2.4. (a) Compute the annual oil and gas production profiles through abandonment:

$q^o(s) = (q_1^o, q_2^o, \cdots, q^o_{T_a(s)})$,

$q^g(s) = (q_1^g, q_2^g, \cdots, q^g_{T_a(s)})$.

(b) Compute the cumulative oil and gas production through abandonment:

$$Q^o(s) = \sum_{t=1}^{T_a(s)} q_t^o(s), \quad Q^g(s) = \sum_{t=1}^{T_a(s)} q_t^g(s)$$

(c) Compute the present value of the revenue stream discounted at the rate D:

$$V(s) = \sum_{t=1}^{T_a(s)} \frac{r_t(s)}{(1+D)^t}$$

Step 3. For each structure $s \in \Gamma$, repeat Step 2 for the input parameters (d, P^o, P^g, a, D) and compute the aggregate model output $\{q^i(\Gamma), Q^i(\Gamma), V(\Gamma)\}$, i = o, g.

3.1. Compute the aggregate annual oil and gas production profiles:

$q^o(\Gamma) = (q_1^o(\Gamma), q_2^o(\Gamma), \cdots)$,

$q^g(\Gamma) = (q_1^g(\Gamma), q_2^g(\Gamma), \cdots)$

where

$$q_j^o(\Gamma) = \sum_s q_j^o(s) \text{ and}$$

$$q_j^g(\Gamma) = \sum_s q_j^g(s), \; j = 1, 2, \ldots$$

3.2. Compute the aggregate cumulative oil and gas production:

$$Q^o(\Gamma) = \sum_s Q^o(s), \; Q^g(\Gamma) = \sum_s Q^g(s)$$

3.3. Compute the discounted cash flow stream:

$$V(\Gamma) = \sum_s V(s)$$

Step 4. Repeat Steps 1-3 and perform regression analysis on the output measures $\{Q^i(\Gamma), V(\Gamma)\}$ using the input variables (d, P^o, P^g, a, D) as descriptive factors:

4.1. Compute $Q^o(\Gamma) = \alpha_0^o + \alpha_1^o d + \alpha_2^o P^o + \alpha_3^o P^g + \alpha_4^o a$, $R^2_{Q^o(\Gamma)}$.

4.2. Compute $Q^g(\Gamma) = \alpha_0^g + \alpha_1^g d + \alpha_2^g P^o + \alpha_3^g P^g + \alpha_4^g a$, $R^2_{Q^g(\Gamma)}$.

4.3. Compute $V(\Gamma) = \beta_0^o + \beta_1 d + \beta_2 P^o + \beta_3 P^g + \beta_4 a + \beta_5 D$, $R^2_{V(\Gamma)}$.

Model parameters and distribution functions

Table 1

Parameter	Notation (unit)	Distribution*
Decline rate	d (%)	U(0.05, 1.2)
Oil price	P^o ($/bbl)	N(80, 10)
Gas price	P^g ($/Mcf)	N(8, 1)
Economic limit multiplier	a	U(0.5, 2.5)
Discount rate	D (%)	U(0.06, 0.18)

*U(a, b) denotes the uniform distribution with end point (a, b). $N(\mu, \sigma^2)$ represents the normal distribution with mean μ and standard deviation σ^2.

Model results for cumulative lost production

Table 2

Coefficient	$Q^i = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 a$, i = o, g, BOE: Q^g, Mcf	Q^o, bbl	Q^{BOE}, BOE
α_1	–1.7 E8 (24.7)	–2.7 E7 (–25.0)	–5.6 E7 (–25.3)
α_2	1.23 E6 (7.5)	3.31 E5 (13.0)	5.6 E5 (10.2)
α_3	13.82 E6 (8.3)	2.84 E6 (11.1)	5.14 E6 (9.6)
α_4	–7.29 E6 (–1.9)	–1.52 E6 (–2.5)	–2.73 E5 (–2.2)
R^2	0.69	0.89	0.82

this process p times, each time resampling from the parameter distributions, performing the intermediary calculations, and compiling the aggregate results.

The final step of the analysis is to regress the model output $\{Q^i(\Gamma), V(\Gamma)\}$ against the input parameters (d, P^o, P^g, a, D) and derive linear relations of the form shown in Equation 6, for $f \in \{Q^i(\Gamma), V(\Gamma)\}$ and $(X_i, X_2, X_3, X_4, X_5) = (d, P^o, P^g, a, D)$.

The model coefficients α_i, i = 0, …, 5, are determined from the regression analysis and determine the magnitude and direction of the function relative to changes in the parameter set (d, P^o, P^g, a, D). The coefficients α_i, i = 0, …, 5, vary with the choice of output metric f, distribution function f_i, and sample size p.

Model results for present value

Table 3

Coefficient	$PV = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 a + \alpha_5 D$: PV_A ($1,000)[1]	PV_B ($1,000)[1]	PV_{A+B} ($1,000)[1]
α_1	—	–2.6 E6 (–36.6)	–2.9 E6 (–31)
α_2	7.35 E3 (98.6)	2.6 E4 (12.4)	2.14 E4 (9.4)
α_3	3.27 E4 (43.8)	2.45 E4(8.7)	1.56 E5 (6.8)
α_4	–8.27 E4 (–48.2)	–960 (*)[2]	4.8 E4 (*)[2]
α_5	–2.07 E6 (–74.9)	–1.20 E6 (–3.5)	– 9.10 E5 (2.1)
R^2	0.76	0.82	0.79

[1][A]—class structures are normal structures. [B]—class structures combine young and chaotic structures within the same category. [2]t-statistic <1.

Model structure

Model specification

The linear model specified in Equation 6 relates the cumulative production and present value to the model input variables.

The "proper" sign of the function coefficients α_i, i = 0, …, 5 are suggested by economic theory and the model framework and provide an initial check on the veracity of the model structure.

Expected signs

The coefficient α_0 represents the

Example 1 (Fig. 4)

To illustrate application of the model output, consider the lost oil production functional $Q^o(\Gamma)$. The model output for total lost oil production in the GOM yields

$Q^o(\Gamma) = -2.7E7d + 3.31E5P^o + 2.84E6P^g - 1.52E6a$.

The coefficients of the regression model are all of the expected sign and statistically significant.

If we evaluate the lost oil functional for any parameter vector within the design space; i.e., (d, P^o, P^g, a) $\in\Sigma$, we will obtain the average value for lost oil production for the parameter input selected.

For example, for (d, P^o, P^g, a) = (0.10, 120, 8, 1.5), we obtain $Q^o(\Gamma)$ = –2.7E6 + 39.72E6 + 22.72E6 – 2.34 E6 = 57.4 million bbl. In this case, we see that if the average future price of oil and gas are $120/bbl and $8/Mcf, then at a 10% decline rate, lost oil production is estimated at 57 million bbl.

The price of oil and gas are the most significant factors, being about an order-of-magnitude larger than the contribution from the decline parameter d and a multiplier. If future oil prices average $60/bbl, cumulative lost oil production is estimated at 37.5 million bbl.

Example 2 (Fig. 5)

The present value for [A], [B], and [A]+[B] class structures are determined as

$PV_A = 7.35E3P^o + 3.27E4P^g - 8.24E4a - 2.07E6D$,

$PV_B = -2.6E6d + 2.6E4P^o + 2.45E4P^g - 960a - 1.20E6D$,

$PV_{A+B} = -2.9E6d + 2.14E4P^o + 1.56E4P^g + 4.84E4a - 9.1E5D$.

The signs of the coefficients are consistent with expectations, and the relative contribution of terms is easily ascertained. The present value of lost oil and gas production provided by [A] class structures is computed at PV_A = $623.7 million if ($P^o$, P^g, a, D) = (100, 8, 0.75, 0.15), For [B]-class structures, PV_B(d, P^o, P^g, a, D) = PV_B(0.15, 70, 6, 1.25, 0.1) = $1.46 billion.

fixed term (intercept) of the functional and there are no expectations on its sign. Depending upon the model type and user preference, the fixed term coefficient may be excluded from the formulation.

The coefficient α_1 is associated with model parameter d, which defines the rate of decline of production for those structures that have less than 7 years production history or did not yield a best-fit decline curve. The value of d will therefore "control" only that portion of annual production associated with young structures or where curve fitting was not successful.

As d increases, production at each structure will decline faster and reach its economic limit sooner, and so the quantity of reserves and their value will also decline. We would expect $\alpha_1 < 0$ for the Q^o, Q^g, and V functionals because increasing d will lead to declining cumulative production and value.

The coefficients α_2 and α_3 are associated with the price of oil and gas, respectively. As P^o and P^g increase, revenue will increase, delaying the onset of the economic limit of each asset.

This in turn promotes the production of additional reserves, which at an elevated price level, will lead to a greater discounted cash flow. Thus, increasing (decreasing) P^o and-or P^g will lead to increases (decreases) across all the outputs Q^o, Q^g, and V, and so we would expect α_2, $\alpha_3 > 0$.

The coefficient α_4 is associated with the multiplier a which is used to vary the economic threshold τ_a. The variable a ranges over a positive interval, and as a increases, the value of $a \cdot \tau_a(s)$ will increase, forcing production out of profitability at an earlier time. This will reduce cumulative production, Q^o and Q^g, and the value of production, V. The coefficient α_4 is expected to be negative for Q^o, Q^g, and V.

The coefficient α_5 is associated with the discount rate D that is used to compute present value, and thus, will only influence the valuation estimate V. The behavior of discount rate with present value is well known: as D increases, the value of future cash flow declines, and so we expect the sign of the coefficient α_5 to be negative. Coefficient α_5 is not included in the model specification for cumulative production.

Function interpretation

The functional construct is used to compute the expected value of the output for any parameters that fall within the design space, as well as to investigate the impact of one or more changes in the input parameters on the model output. The functional represents the average relation between the input variables and model output for the input parameters specified, and thus the model coefficients must be interpreted with respect to the geometry of the design space (Fig. 2).

Model summary

A summary of the model structure is provided in Fig. 3.

Model results

Design space

The parameters and distribution functions that serve as model input are shown in Table 1.

These parameters lead to a four-dimensional hypercube design space, shown in Equation 7, where the oil and gas price distributions are truncated at two standard deviations.

Cumulative lost production

Following the modeling steps described above, regression models for cumulative lost oil, gas, and BOE production are constructed as shown in Table 2. In Fig. 4, an illustrative example is provided.

Valuing lost production

Present value functionals for the oil and gas stream forecast is shown in Table 3 for [A] and [B] class structures, where [A]-class structures denote normal assets and [B]-class structures denote young and chaotic producers. Fig. 5 provides an example.

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Biographies for coauthors Mark Kaiser and Yunke Yu were published in part 1 of the series (OGJ, July 7, 2008, p. 42).

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Central Wilmington pipeline ends oil trucking

Oil production is increasing and trucking oil has been eliminated from the central part of Wilmington field in Long Beach, Calif.

A new 10-in., 20,000 b/d oil pipeline placed in service Mar. 14 now transports crude to the ConocoPhillips refinery at Carson, just north of Wilmington field. The pipeline eliminates 50 trips/day by tanker trucks, said Warren Resources Inc., New York, which operates the Wilmington Townlot and North Wilmington units.

The company's two units are in the central part of giant Wilmington field, an 18½-mile long structure that ranks as the third largest oil field in the US in terms of cumulative production after Prudhoe Bay in Alaska and East Texas field.

Production from the two units averaged 3,500-3,700 b/d in mid-June. The units produced 243,000 bbl in the quarter ended Mar. 31, up 51% on the year. The company had booked 34 million bbl of net proved reserves in WTU and 19 million bbl in NWU at the end of 2007. The figures for WTU don't include further secondary recovery or alkaline-surfactant-polymer flood potential. Warren Resources has also taken steps to consume more associated gas and may eventually be able to sell gas from the units.

Oil operations

The WTU was producing 375 b/d when Warren assumed operation in 2005.

The City of Los Angeles in 2006 approved the drilling of as many 540 directional oil and water injection wells from as many as five cellars in the WTU (see map, OGJ, Feb. 19, 2007, p. 36). Warren Resources has completed construction of two cellars on one city block in Long Beach, and about 100 wells are producing.

The 2008 capital budget for the WTU is $42 million to drill or recomplete 30 producing wells and six water injection wells and $16 million for cellar construction and other facilities improvements.

A soundproofed electric rig is to replace the unit's conventional rig in the third quarter of 2008. The cellars allow drilling to take place below ground surface. Most of the newer wells will be horizontal or high angle penetrations.

The company drilled three producing and four injection wells in the first quarter to the Upper Terminal reservoir at 3,600 ft. Recoverable oil also remains in the shallower Tar and Ranger formations, and one of the wells helped confirm the company's expectation of a meaningful oil resource in the Tar formation, said Ken Gobble, chief operating officer.

Warren Resources has identified 10 more Tar well locations, but it deferred drilling the higher-rate Tar horizontal wells in the first quarter due to oil and gas handling constraints.

Ultimately the company plans to evaluate the deeper Union Pacific, Ford, and basement Schist formations. Another $17 million is budgeted for the NWU, where 55 wells are producing.

Gas potential

Warren Resources is also making greater use of gas from the WTU.

The company has a permit to flare as much as 93 Mcfd from the unit, and in October 2007 it began operating six microturbines that convert part of the produced gas to electricity for field use.

The company also applied to the South Coast Air Quality Management District for a permit to install a high-efficiency, low-emission enclosed burner to replace the existing flare. The microturbines will burn 140 Mcfd, and field heater-treaters take 25 Mcfd.

Even though the current gas-oil ratio is very low, continued Upper Terminal and Ranger waterflood development will boost gas output, and the company is applying for short-term reinjection permits, Gobble said.

Terminal/Ranger drilling and future development of the deeper Ford formation, if successful, could eventually boost gas volumes to salable levels. The field's underexplored basement Schist zone also contains oil and gas. ✦

Economic analysis clarifies how Chad benefits from oil

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Anthony Rogers
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Contrary to previously published reports, Chad's take (share of profits) from oil development is average by world standard.

The oil-producing consortium in Chad operates under a progressive fiscal system in that the government share of profits increases as profitability increases. It is unclear, however, if the royalty would have protected the government if oil prices stayed at or below $15/bbl. With low oil prices, Chad may not have received a royalty in the early years of production. But with higher oil prices, Chad's fiscal system appears to provide good returns for the government.

Chad today receives about 70% of the profits from the oil development. This certainly is much higher than previously published expectations.

The producing consortium has strong incentives to keep costs down. It keeps about $0.40 of every $1.00 saved. Costs have been a controversial issue for the oil development.

Our analysis assumes that the consortium recovered sunk costs. Some feel that the consortium should not have recovered all of the sunk costs, thereby increasing by $1.1 billion the profit split between the government and consortium. Another complaint has been that the consortium is deducting exploration costs in other areas from the Doba basin production. We do not know if this is the case because ring fence terms (what exploration costs can and cannot be deducted from production) are not publically available.

The biggest overall complaint with the deal is the lack of transparency. This has caused problems for the consortium and Chad. One explanation for confidentiality provisions being included in these contracts is that governments often offer better terms for early contracts to entice investment. They would prefer that those terms not be made public because it could hamper subsequent negotiations.

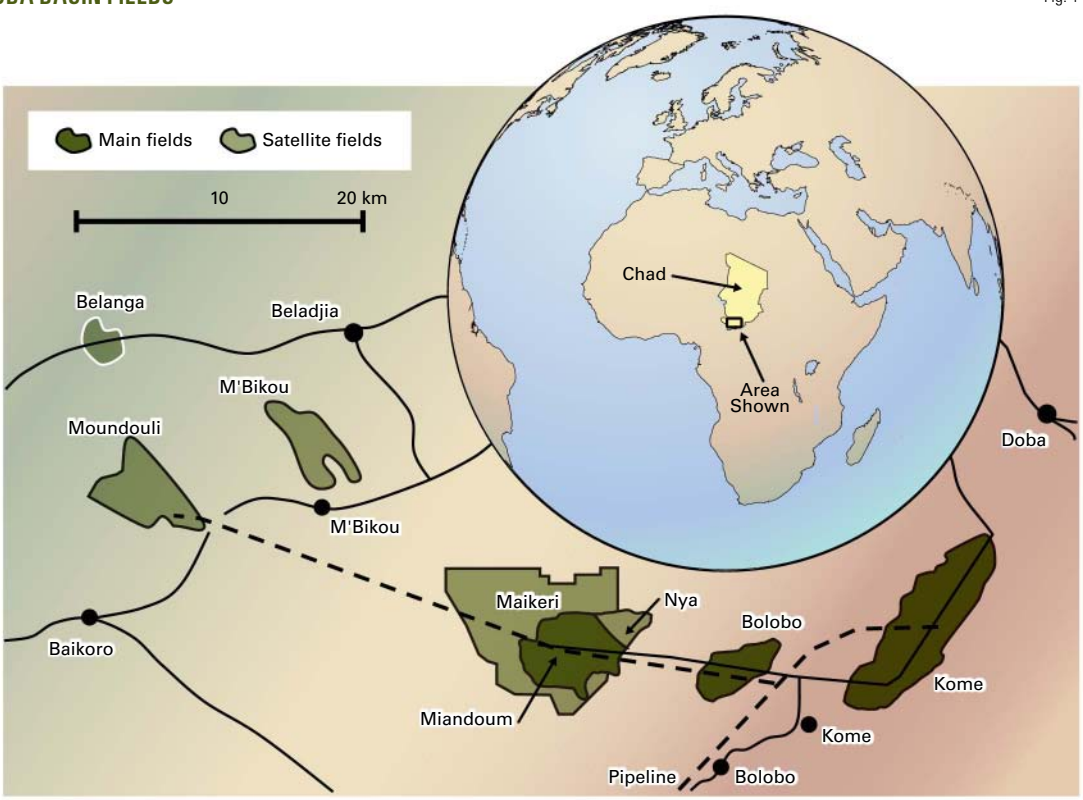
A unit of ExxonMobil Corp. is the operator of the consortium with a 40% interest. The other consortium members currently are Petronas, 35%, and Chevron Corp., 25%.

Project controversy

The Chad-Cameroon pipeline project is one of Africa's largest infrastructure

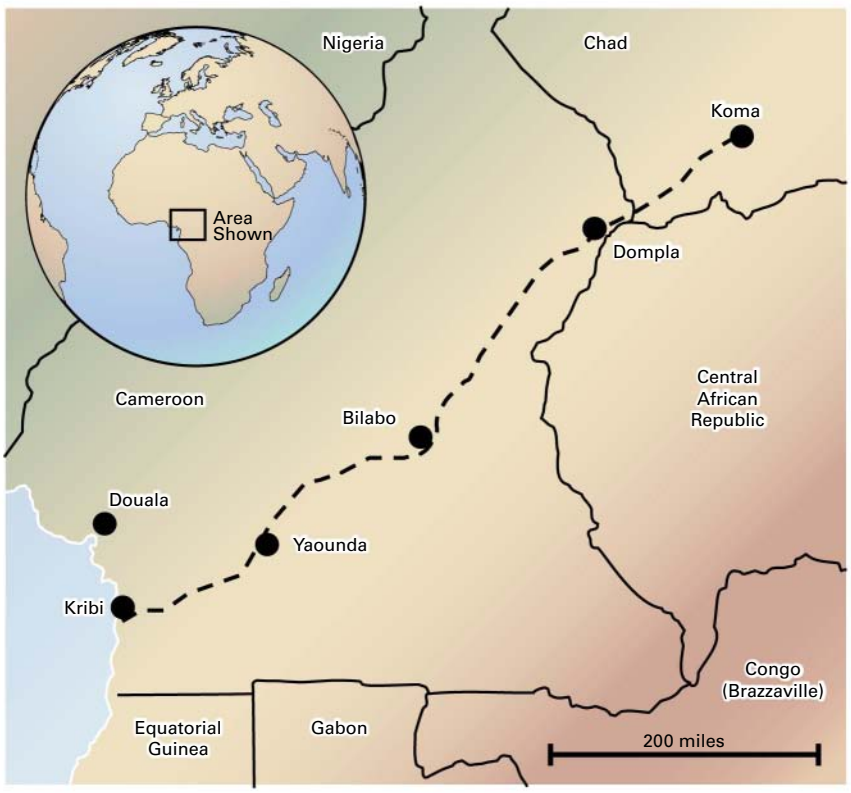
Doba basin fields

Fig. 1



CHAD-CAMEROON PIPELINE

Fig. 2



projects and probably was destined to be controversial. Developing oil in one of the world's poorest countries during a time of war, civil war, and coups carries huge risks. But when the World Bank Group became involved, controversy was assured. The World Bank acknowledges the project is the most scrutinized project in the bank's history.

Among the many controversies, some dire and some perceived, is the notion that Chad received a bad deal. The assumption is that Chad simply did not have the negotiating experience of the oil companies. And, that inexperience or incompetence resulted in a disproportionately large share of profits or revenues going to the oil company consortium.

This article addresses this controversy associated with the impression that Chad received a bad deal, when in fact it did not.

Project overview

The first oil discovered in Southern Chad's Doba basin (Fig. 1) was in the early 1970s, but civil war and other reasons delayed its development for several decades. In 1992, during a relative lull in the civil war, the oil company consortium approached the World Bank with development plans.

The plans anticipated producing nearly 1 billion bbl of oil and transporting the oil via pipeline across Cameroon to the Gulf of Guinea for export. The consortium approached the World Bank because it expected the bank's involvement would mitigate political risk and ease the fears of institutional lenders. The World Bank saw an opportunity to design a standardized loan program that would serve as a model for aleviating poverty in Chad and other developing countries. Others saw a recipe for disaster.

Original development plans for the Doba basin's three primary fields included about 290 producing wells and 25 injection wells with two-thirds of them for Kome, the largest field. The operations center and central treating facility also are at Kome.

The development cost estimate for the fields was about $1.5 billion.

Production started up when Miandoum came on stream in July, 2003. Kome and Bolobo production followed in 2004. Satellite fields Nya, Moundouli, and Maikeri went into production in 2005, 2006, and 2007, respectively.

In late 2007, the consortium submitted a development plan for Timbre field.

Completion of the Chad-Cameroon pipeline (Fig. 2) was in 2003 when Miandoum field was brought on stream. The onshore portion of the pipeline, buried at 1 m, is nearly 670 miles long. An additional 7 miles of submarine pipe terminate at a floating storage and offloading (FSO) vessel in the Gulf of Guinea near Kribi, Cameroon.

The 30-in. pipeline is designed to handle up to 225,000 b/d and has three pumping stations. Estimated pipeline cost was $2.2 billion or $109,000/in.-mile.

The fields reached a peak production at yearend 2004 of 212,000 bo/d. Production since then has declined rapidly at about 20%/year. New exploration activity and satellite field development, however, is expected to use the pipeline infrastructure for years to come.

Two companies operate the pipeline system: Tchad Oil Transportation Co. (TOTCO) in Chad, and Cameroon Oil Transportation Co. SA (COTCO) in Cameroon.

Cameroon owns slightly more than 5% of COTCO. Chad owns nearly 3% of COTCO, and more than 8% of TOTCO. The consortium member companies own the rest of the two pipeline operating companies.

Chad and Cameroon investments in the project as well as World Bank loans secured the government's working interest shares.

Criticism of Chad take

One source criticizing the deal Chad received from the oil consortium is

the book published by the Catholic Relief Services and Bank Information Center in February 2005.[1] Although it thoroughly evaluates the project, it also provides a flawed comparison of Chad's take to other African oil producers.

Fig. 3 is from this report and shows Chad's take to be less than half the take of other West African countries. The message is compelling; however, the analysis is flawed.

The industry defines take as the division of profits from a project over its full life or full cycle, whereas Fig. 3 only focuses on 8 years, 2002-10. Chad's oil did not start flowing until late 2003.

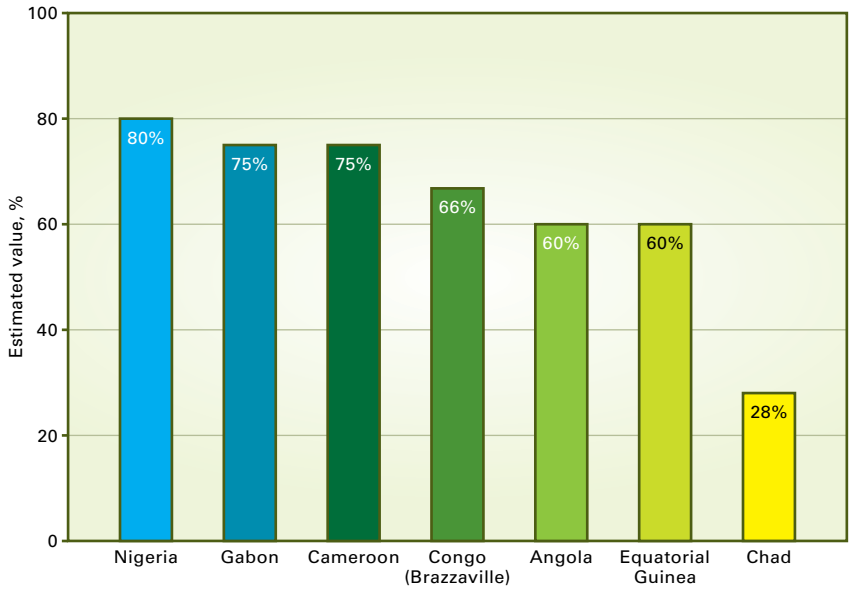
Most of the 8 years in Fig. 3 span the early production in the Doba basin, not full cycle. Early production years represent the capital cost recovery phase of a project. During this time it is common for the governments to receive only their royalty while oil companies recoup their investment.

With slow production and high costs, the investing companies could be in a non-tax-paying position for several years. Because the comparison in Fig. 3 does not cover the full life of the project, it does not represent a true division of profits or take for Chad but most likely does for the other countries shown.

Other statements from articles that imply Chad received a much worst deal include:

- "The World Bank's own internal report estimates that most of the $9 billion revenue from the project over the next 28 years will accrue to the corporations and banks; the Chad government will receive only $1.7 billion (19%), with $505 million (6%) going to Cameroon."[2]
- "Chad currently gets 12.5% of the royalties from its production of some 160,000 b/d, compared with the 80% of oil production that Nigeria enjoys."[3]
- "Revenue split: 1. Cameroon = 7%, 2. Chad = 22%, 3. Oil Consortium = 71%,"[4]
- "Observe, for example, the difference in the mere 7% of revenues that accrued to Chad in its earliest contracts compared to the approximately 90% of revenues going to the more experienced and capable petrostates."[5]

FLAWED TAKE COMPARISON Fig. 3



Source: "Chad's Oil: Miracle or Mirage," CRS & BiC-PFC Energy, West Africa Sector: Oil Value Forecast and Distribution, December 2003

Four reasons why there is so much confusion, particularly with the range of values of Chad's share of revenue or take from these sources include:

1. *Lack of transparency.* A confidentiality provision in the contract has kept important contractual details out of reach of analysts.
2. *Industry terminology.* The World Bank's Project Appraisal Document (PAD) added to the confusion with the introduction of distributable returns, which appears to represent a distribution of profits but certainly does not.
3. *Chad royalty.* The Chad royalty is not a percentage of gross revenue, but rather a percentage of gross revenue less transportation costs.
4. *Inexperience.* There seems to be a general misunderstanding of how petroleum fiscal systems work.

The following analysis uses information from three sources—the World Bank's Project Appraisal Document (PAD) Report N. 19343 published prior to construction, the World Bank's Implementation Completion Report No. 36560-TD (ICR) dated Dec. 15, 2006, and EssoChad Quarterly Reports.

Table 1 summarizes data from the two World Bank reports.

Anticipated production

The PAD anticipated Chad producing (exporting) 883 million bbl between 2004 and 2027, with peak years of production at 81 million bbl or about 225,000 bo/d (Fig. 4). The ICR lowered production expectations to 748 million bbl and peak production of only 170,000 bo/d. These figures do not agree necessarily with other sources.

There were also natural expectations of increased investment, exploration, and satellite field development once the pipeline system was in place.

Crude quality

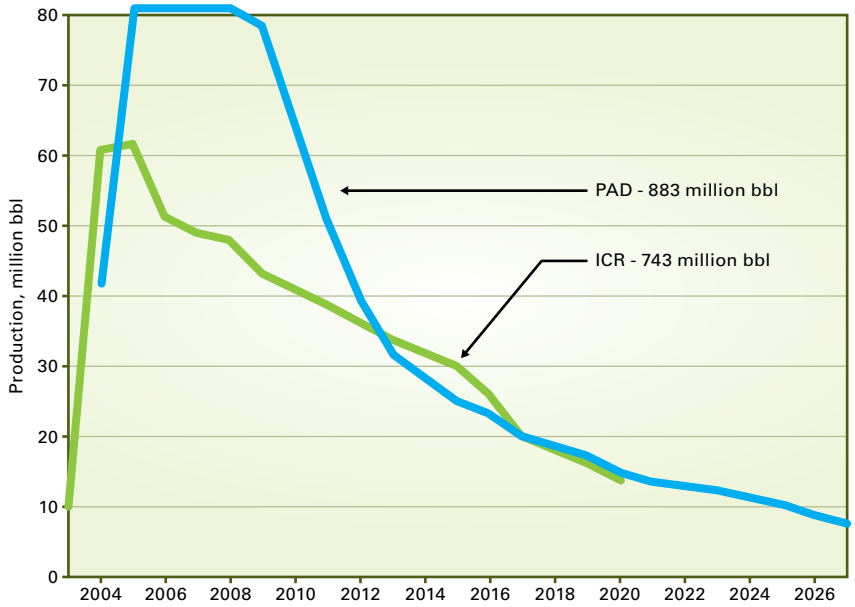
The oil from Kome, Miandoum, and Bolobo fields constitutes the Doba Blend, which has a heavy oil 18.8-20.5° API gravity.

The Doba Blend wellhead price has a discount from the price of Brent Blend, with a 38.8° API gravity, to accommodate the quality differential and distance to market.

The discount was expected to be about 20% off the Brent price in the

PRODUCTION PROFILES

Fig. 4



Sources: World Bank PAD and ICR reports

WORLD BANK PAD, ICR REPORTS

Table 1

PAD Project appraisal document Report No: 19343 AFR submitted: Apr. 13, 2000	ICR Implementation completion report Report No: 36560 TD Submitted: Dec. 15, 2006
Purpose: Assess project viability and establish development objectives.	Purpose: Assess development objectives and design, and quality of entry.
Oil price projections average $15.50/bbl	Oil price projections average $32.30/bbl
Starts at $14/bbl in 2004 and escalates 1%/year reaching $18/bbl in 2027	Starts at $26/bbl in 2003 rising to $46/bbl in 2006 and declines to $26/bbl by 2020
Production total, 883 million bbl	Production total, 748 million bbl
Production start, 2004	Production start, 2003
Peak production, 81 million bbl	Peak production, 62 million bbl
Chad royalties, $1,017	Chad royalties, $2,402
Percent of gross revenue, 7.4	Percent of gross revenue, 9.9
Royalties start, 2004	Royalties start, 2006
Chad upstream taxes, $553	Chad upstream taxes, $3,933
Taxes start, 2014	Taxes start, 2010

World Bank's ICR. With increasing worldwide demand for transportation fuels, which are difficult to extract from the Doba Blend, the discount could be greater than the anticipated 20%.

Distributable returns

As identified in the two studies, Table 2 shows the distributions to the governments of Chad and Cameroon and the consortium. It is likely that this part of the World Bank data provided the foundation for the varied reports that Chad received a bad deal.

Upon first glance, distributable returns appear to represent a distribution of profits (take) or revenues. Unfortunately, the analyses in the two World Bank studies provide little insight into the actual meaning or function of distributable returns. Ultimately, sunk costs, in addition to some percentages of capital and operating expenditures must still be recovered from distributable returns to obtain a true distribution of economic profits for the project.

Table 3 shows the true economic profits (gross revenues less costs). Our analysis includes sunk costs of $1.102 billion mentioned in the PAD report but not used in its cash flow model.

A huge difference obviously exits between distributable returns and economic profits, but many published sources seem oblivious to this distinction.

Analysis focus

Our analysis focuses on five points:

1. Overall division of profits or the government's and consortium's take.
2. Effective royalty rate. What is the minimum revenue Chad can expect each accounting period once production starts?
3. Savings index. What is the contractor's incentive to keep costs down?
4. Price and cost assumptions.
5. Timing.

The analysis uses these industry standard definitions:

- Gross revenue, which is the total revenue generated over the full life of the project (full cycle).
- Costs, which include capital costs, operating costs (opex), transportation costs, and reclamation and refurbishment costs or abandonment costs.
- Economic profits, which is gross revenue less costs (full cycle).
- Government take, which is the government share of economic profits during the full life of the project full cycle).
- Effective royalty rate (ERR), which is the government share of revenue in any given accounting period (not full cycle). During the typical worst-case accounting periods, the costs are high and production is low. In a royalty-tax system, the royalty is the only guarantee the government will receive any revenue in those worst-case accounting periods for most systems.
- Savings index, which is the share of savings the contractor, or consortium, keeps if there is a reduction in costs. It represents their incentive to keep costs down.

Chad's fiscal terms

Chad has a royalty-tax based fiscal system.

In 2000, Chad received a $25 million signature bonus when Chevron and Petronas joined the consortium. It received two additional $15 million signature bonuses related to explora-

tion agreements in 2003 and 2004.

Bonuses are not unusual, and the bonuses Chad received were not particularly large, about $0.05/bbl based on the PAD reserves expectations.

The bonus has no substantial impact on the economics because oil companies typically do not recover bonuses but it is not unusual for bonuses to be tax deductible.

Chad's royalty is 12.5% of gross revenue less transportation costs. The industry refers to this as netbacking. Although it can be controversial, it is not unusual. The controversies associated with netbacking stem from:

- Abuse of deductions that result in lower royalties to the royalty owner.
- Lack of information or transparency that makes it difficult for royalty owners to verify royalty determination.

We have no evidence of the consortium inflating deductions for royalty determination; however, the royalty determination method and definition do lack transparency.

Chad's transportation costs have four parts: Cameroon transit fee, opex (pipeline), debt service, and throughput payments.

The Cameroon transit fee is a fixed $0.41/bbl paid by COTCO to Cameroon for passage of crude oil through its territory.

Opex includes both operation and maintenance costs associated with the pipeline.

The debt service is not defined in the report but assumed to be a mechanism for recovery of pipeline loans and interest charges.

The throughput payments are complex calculations for recovering pipeline investments. No additional information on this component is available.

It is quite possible that this method of royalty determination drove the design of the World Bank cash flow model, resulting in distributable returns that became a major source of confusion.

Chad taxes are based on an R factor or payout formula and range from 40% to 65%. The R factor equals cumulative receipts divided by cumulative expenditures.

Exactly how the Chad R factor works is unavailable; however if it behaves like most R factors, it would resemble the hypothetical sliding scale shown in the accompanying calculation box.

As the consortium recovers its investment, the R factor and tax rate increase. When cumulative receipts equal cumulative expenditures, the consortium will have reached payout and R will equal 1. The subsequent tax rate will equal 50% in the hypothetical sliding scale.

According to some sources, the current tax rate has already progressed to 60%. In other words, if these reports are true, Chad is receiving 60% of the profits through the tax mechanism in addition to royalties.

What is not clear, and adds to the confusion, is what costs are recoverable and or tax deductible and how they are handled. PAD recognizes sunk costs but does not use them in calculating distributable returns. In all likelihood, the consortium is recovering and tax deducting sunk costs, but that is not certain.

The World Bank PAD estimated project capital costs of $3.7 billion, and total operating costs of $3.8 billion. The ICR estimated costs are greater, but as a percentage of gross revenue, they are much lower. Table 4 shows the costs details from the two reports and presents them as a percentage of gross revenue.

The calculation in the box follows the World Bank PAD cash flow model as far as distributable returns, after which we account for additional costs incurred in the project to obtain the division of profits or take.

In the PAD base case, with oil prices averaging $15.50/bbl, Chad and Cameroon government's share of profits or take is 52%.

The World Bank's ICR cash flow appears to follow the netbacking scheme more to closely, the calculated royalty after transportation costs has been deducted from gross revenue. Gross revenue less transportation costs equates to distributable returns out of which the royalty is taken.

The calculation in the box follows the ICR cash flow up to the royalty calculation then includes unrecovered costs to determine true division of profits.

Distributable returns

Table 2

	PAD 2000		ICR 2005	
	Distributable returns, million $	Percent of distribution	Distributable returns, million $	Percent of distribution
Chad	1,817	22	6,560	36
Cameroon	548	7	546	3
Consortium	5,759	71	11,157	61
Total	**8,125**	**100**	**18,394**	**100**

True economic profits

Table 3

	PAD 2000		ICR 2005	
Gross revenue less costs	**Million $**	**Percent of gross revenue**	**Million $**	**Percent of gross revenue**
Gross revenue	13,721	100	24,182	100
Costs				
Capex	3,737	27	7,301	30
Sunk costs	1,102	8	1,102	5
Debt service	509	4	158	1
Opex	3,812	28	4,293	18
Total costs	9,159	67	12,854	53
Economic profits	**4,562**	**33**	**11,328**	**47**

Note: Percentages may be off slightly due to rounding.

Effective royalty rate

The notion of ERR is 11 years old now and should be considered a normal or essential part of the analysis (OGJ, Dec. 1, 1997, pp. 49-51).[6] The ERR calculates what government revenue would be in a worst-case accounting period, such as early production when contractors could be in a nontax paying position, which is not uncommon.

With a royalty-tax based system, the royalty is typically the only guar-

ANALYSIS CALCULATIONS

Hypothetical sliding scale

R factor	Tax rate, %
0-0.5	40
0.5-1.0	45
1.0-1.5	50
1.5-2.0	55
2.0-2.5	60
>2.5	65

Calculations based on PAD and oil price of $15.50/bbl

		Million $	%
A	Gross revenue (100%)	13,721	100
B	Operating costs	–3,813	–28
C	Debt service	–1,909	–14
D	Distributable returns (A+B+C)	8,000	58
E	Royalty (12.5%)	–1,017	–7
F	(D+E)	6,983	51
G	Capex (less debt)	–2,337	–17
H	Sunk cost	–1,102	–8
I	Taxable income (F+G+H)	3,544	26
J	Taxes and fees (~38%)	–1,348	–10
K	Consortium cash flow	2,196	16

Consortium take = K/(A – B – C – G – H) = 16/(100 – 67) = 48%
Government take = (E + J)/(A – B – C – G – H) = (7 + 10)/(100-67) = 52%

Note:
- PAD total costs = $9,161 (67% of gross revenue).
- Taxes and fees as a percentage of gross revenue (10%) equate to an imputed tax rate shown in parenthesis of about 38%.
- Government take includes both Chad and Cameroon.

Calculations based on ICR and oil price of $32.30/bbl

		Million $	%
A	Gross Revenue (100%)	24,182	100
B	Pipeline capex	–2,157	–9
C	Debt Service	–758	–3
D	Pipeline opex and maintenance	–1,837	–8
E	Cameroon transit fee	–352	–1
F	Distributed returns (A+B+C+D+E)	19,078	79
G	Royalty (12.5%)	–2,402	–10
H	(F+G)	16,676	69
I	Capex (less debt)	–4,545	–19
J	Sunk Cost	–1,102	–4
K	Field opex	–2,456	–10
L	Taxable income (H+I+J+K)	8,573	36
M	Taxes and fees (~55%)	–4,704	–20
N	Consortium cash flow (L+M)	3,799	16

Consortium take = N/(A – B – C – E – I – J – K) = 16/(100 – 54) = 35%
Government take = (G + M)/ (A – B – C – E – I – J – K) = (10 + 19)/(100 – 54) = 65%

Note:
- Total costs = $13,207 (54% of gross revenue, see Table 3), the difference in the total costs in Table 3 and those calculated above is due to the Cameroon transit fee included above but not in Table 3.
- Government take includes both Chad and Cameroon.

Savings index calculation

	PAD ($15/bbl), $	ICR ($32.30/bbl), $
Taxable income	1.00	1.00
Taxes and fees	–0.38	–0.55
Consortium share	0.62	0.45
Government share	0.38	0.55

antee a government will receive some revenue in any given accounting period. In the Chad agreement, the royalty is determined after transportation costs are recovered. But due to confidentiality provisions in the contract, it is impossible to evaluate how those costs are recovered, so that it is not possible to quantify the amount (if any) that the royalty guarantees Chad will receive some revenue in the early years of production.

From the cash flows of the World Bank's documents, the PAD shows royalty payments starting in the first year of production, 2004, while the ICR does not show royalty payments to Chad until 2006, 3 years after the 2003 production start. We do know that Chad did receive royalties prior to 2006, most likely due to the higher oil prices.

It is likely the Chad royalty offered no guarantee that the government would receive revenue during early production.

Savings index

The savings index is a measure of the incentive a contractor and a government have to keep costs down. If $1.00 is saved, how is that $1.00 shared between the contractor and government? In the previous examples the tax rates when oil prices were $15.50 and $32,30 were about 40% and 50% respectively. A $1.00 saved increases taxable income by $1.00.

The savings index is a function of the tax rate as shown in the calculation box. ✦

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PUT RIVER—Conclusion

BP's modeling simplifies Prudhoe reservoir analysis

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BP is using a highly automated workflow to evaluate the PUT River formation, an early Cretaceous sandstone reservoir on Alaska's North Slope.

This sandstone has four discrete lobes forming separate reservoirs, with different fluids and pressures. BP focused on the southern lobe, with an estimated original oil in place (OOIP) of 12.6-19.2 million stock tank bbl (MMstb). Part 1 of this article discussed the geology, rock properties evaluation, fluid properties, geostatistical modeling, and reservoir development options for the southern lobe (OGJ, July 14, 2008, p. 55).

A key step was flow simulation work to design a pattern flood for the PUT River reservoir. This concluding article describes top-down reservoir modeling (TDRM) that the team used to assess the effect of reservoir uncertainty on ultimate oil recovery.[1] It describes the field implementation of the pattern flood along with field observations.

Uncertainty estimation

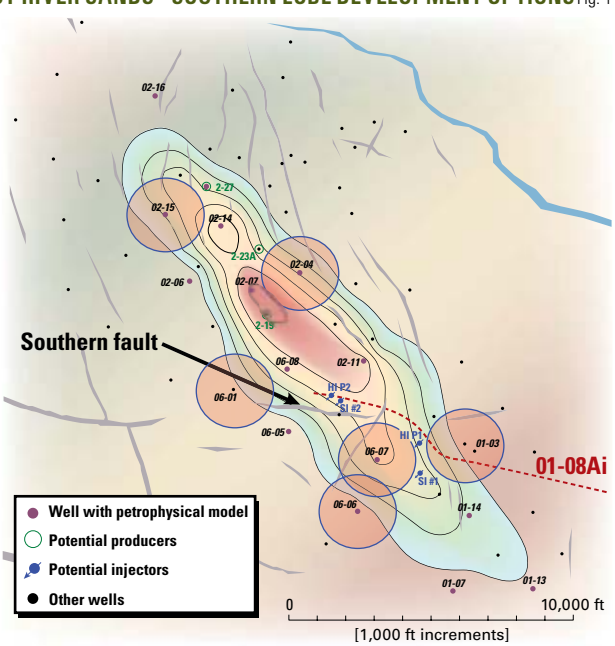
One of the main objectives of the PUT River study was to estimate the effect of uncertainty of various reservoir parameters on the success of PUT River development because any unexpected downside outcome could diminish its economic viability.

Fig. 1 is a guide for understanding the development options available. Many existing penetrations could become producing or injector wells by recompleting them in the PUT River sand. The quality of the reservoir rock decreases from northeast to southwest.

Overall development uncertainties are:

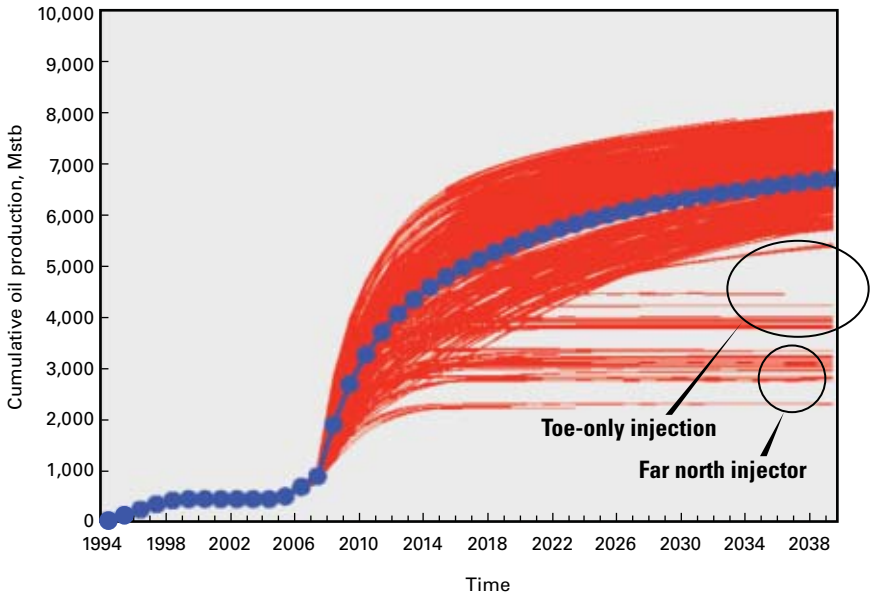
- Fault transmissibility. How transmissive is the fault near the southwest edge of the lobe? A sealing fault could make the injection less effective.
- Rock quality, connectivity between the injector and producers? The correlation length of permeability in both depositional and transverse directions is unknown.
- Number of producers needed to optimize ultimate recovery?

PUT RIVER SANDS—SOUTHERN LOBE DEVELOPMENT OPTIONS Fig. 1



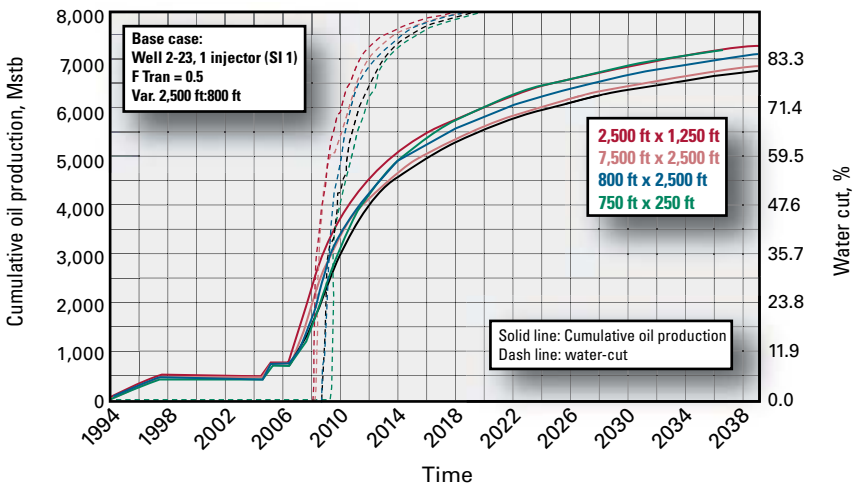
PUT RIVER TDRM RESULTS

Fig. 2



EFFECT OF PERMEABILITY VARIOGRAM

Fig. 3



• Injector location and type? Choose either vertical or horizontal injectors to get adequate injection into the rock.

All combinations of the options had to be evaluated for us to choose the optimal development plan.

Well options

Options for producing the PUT River include:

• One production well (Well 2-23A).

• Two producers (2-23A and 2-27).

• Three producers (2-23A, 2-27, 2-19).

• Two producers (2-23A and 2-19).

• Four producers (2-23A, 2-27, 2-19, and 2-20).

Options to place the injector wells for the pattern flood include:

• One injection point, south of the fault (SI 1).

• One injection point, north of the fault (SI 2).

• Two injection points (SI and SI 2) with:

• Continuous injection.

• Toe injection, followed by heel injection only.

• One injection point, far north end of the lobe.

Fault transmissibility is one of the uncertainties, and was modeled at 0%, 25%, 50%, and 100%.

Rock quality

Geologic uncertainty hinges on the rock quality. We estimated the effect of rock quality uncertainty using these combinations of correlation length of the permeability field when generating the geostatistical models:

• 7,500 ft (NW-SE): 2,500 ft (NE-SW).

• 2,500 ft: 800 ft.

• 2,500 ft: 1,250 ft.

• 800 ft: 2,500 ft.

• 750 ft: 250 ft.

TDRM background

To evaluate the effect of various combinations of all the options, BP implemented a TDRM approach. TDRM is a philosophy for simplifying uncertainty analysis that can provide the simplest appropriate model for an optimal business decision.[1] The workflow is highly automated and enables customized decision-making. BP's assisted depletion planning process, top-down depletion planning (TDDP), was not used for this study.[2]

Using TDRM to evaluate the effect of the previously mentioned parameter uncertainties generated 960 simulation runs. Fig. 2, which compares the potential cumulative oil produced from all the simulation runs, summarizes the simulation results. The options that involve injection only at the toe of the southern injector and a single vertical northern injector are clearly suboptimal, yielding low ultimate recovery because of quick water breakthrough and water cycling.

The base case run has these parameters:

• Fault transmissibility: 0.5.

- One production well: 2-23A.
- One injection well: SI 1 (south of fault).
- Variogram parameters: correlation length of 2,500 ft in the NW-SE direction, 800 ft in the NE-SW direction, and 4 ft vertically.

TDRM results

The TDRM gave insight into the relative impacts of rock heterogeneity, production well location, injection well location, and transmissibility across the southern fault.

We captured the effect of uncertainty in rock property or heterogeneity by varying the correlation length of the permeability field of the geostatistical model.

Fig. 3 summarizes the effect of rock heterogeneity; it presents the cumulative oil produced and water cut as a function of time. Ultimate oil recovery is insensitive to the correlation length of the permeability field.

Fig. 4 summarizes estimated cumulative oil production with the various producer options. The base case with production well 2-23A provides about 5 MMstb. Adding well 2-27 and well 2-20 adds another 1 MMstb to the ultimate oil production. Well 2-19 has a marginal impact on oil recovery.

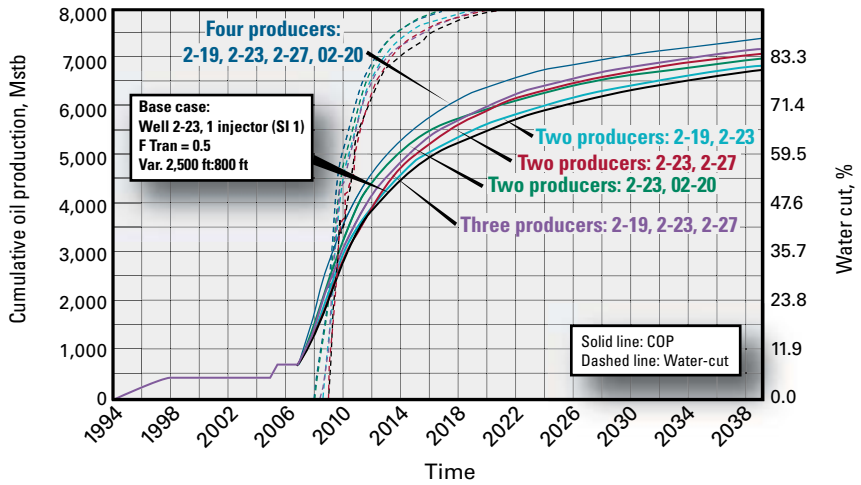
Fig. 5 summarizes the projected effect of various injection options on ultimate oil production. Any combination of injection at the far north side leads to early breakthrough and water cycling, thereby yielding a low ultimate oil recovery.

Based on the modeling, we expect maximum oil recovery with slow growth in the water cut with a single (heel region of a high angle injector or a vertical injector) injector on the south of the fault or a horizontal injector (with the heel to the south of the fault and toe crossing to the north side of it).

We recommend the horizontal injector option because this mitigates the risk of low oil recovery due to the uncertainty of location and throw of the existing fault. A horizontal injector can also provide a higher injection rate

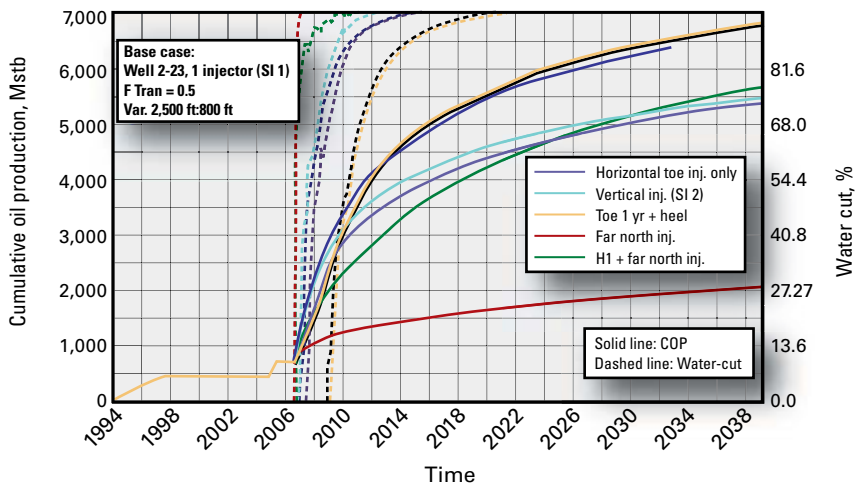
Impact of production well options

Fig. 4



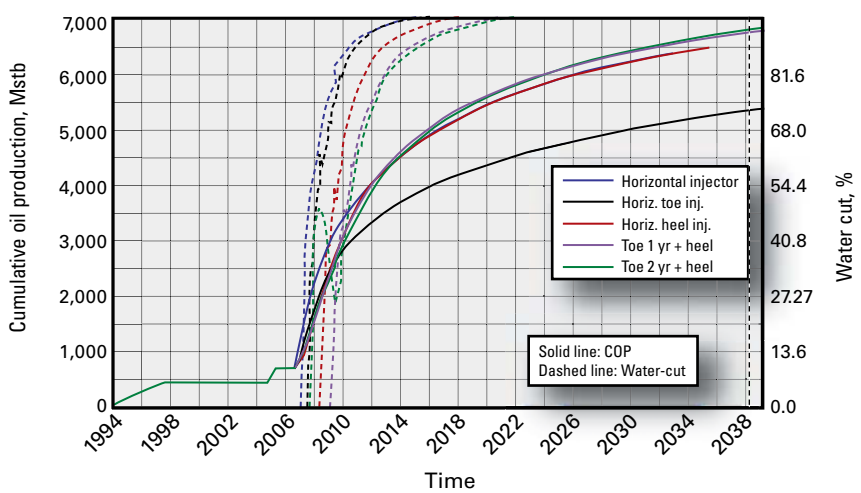
Impact of injection well options

Fig. 5



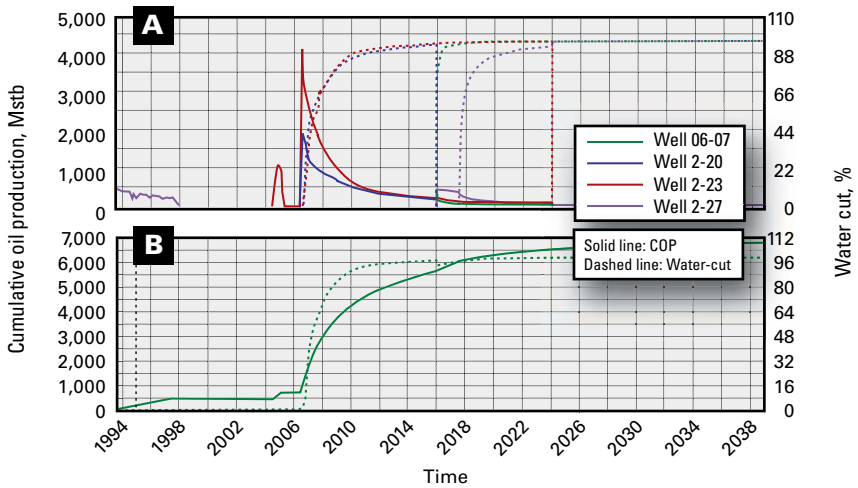
Impact of horizontal injection options

Fig. 6



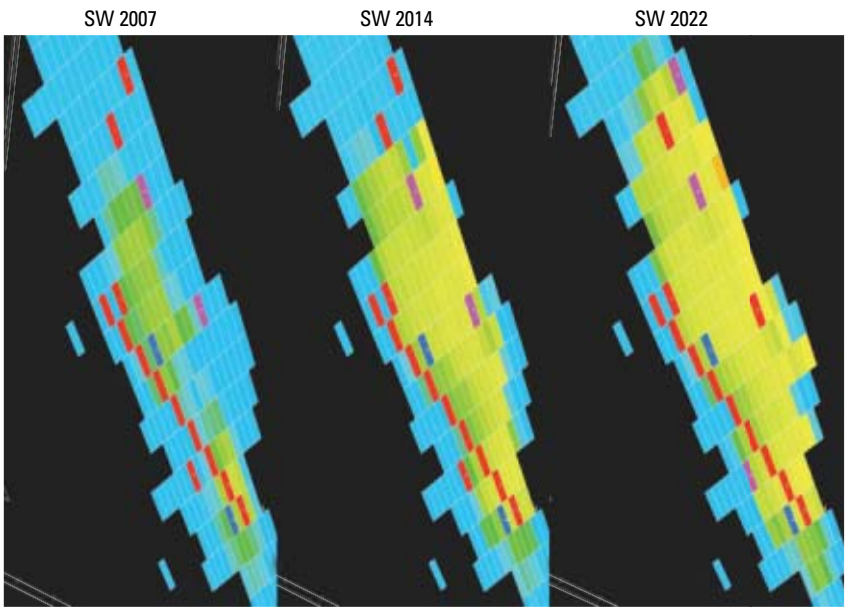
PLAN OF DEVELOPMENT, CASE 2

Fig. 7



POD CASE 2, WATER SATURATION

Fig. 8



compared to a vertical injector.

Varying the potential fault transmissibility from 0-100% indicates that the southern fault has minimal influence on reservoir performance.

Refining individual cases

In addition to examining the effect of parameter uncertainty, TDRM can also be used to further refine the effect of individual parameters. This section examines the influence of injector and producer selection in further detail. The effects from reservoir heterogeneity and fault transmissibility are minimal.

A horizontal injector that has the heel on the south side of the southern fault and toe to the north-west side of the fault is optimal for PUT River development. We studied five injection scenarios (Fig. 6). Injection into the toe (only) yields a poor ultimate recovery because of early breakthrough and water cycling.

All other cases yield more or less the same ultimate oil recovery. We chose the case that injects for about 1 year into the toe region followed by injection into the heel region as the optimal injection option for PUT River development. This option increases the reservoir pressure sufficiently above the bubble point pressure during the first year, assuring no release of solution gas in the reservoir, allowing optimal oil recovery.

Development cases

We simulated several development cases based on the TDRM analysis, and present three cases that yield high cumulative oil recovery. The horizontal injector near the fault is treated as combination of two segments: SI 1, the heel section to the south of the fault and SI 2, the toe region to the northwest of the fault (Fig. 1).

Case 1. Inject in injector SI 1 (south of the fault) only; produce from wells 02-23A and 2-20 until the water cut is 96%, then shut in 02-23A and 2-20 and produce from 2-27 and 6-07. We reviewed the simulation data by plotting the postulated oil production rate, water cut, and cumulative oil production as a function of time. We also plotted water saturation in the middle layer as a function of time, showing the expected areal sweep by water flood for 2007, 2013, and 2024.

Case 2. Inject in the toe part (SI 2) of the horizontal injector for about 1 year, then inject in the heel region (SI 1). Produce from 02-23A and 2-20 until the water cut reaches 96%, then shut in 02-23A and 2-20 and produce from 2-27 and 6-07. Fig. 7 presents the results from the simulation run.

The dotted curves represent the water cut and the solid lines represent the oil rate for various producers in Fig. 7a; Fig. 7b shows the cumulative oil production. Fig. 8 presents water saturation in the middle layer as a function of time, which shows the progress of areal sweep.

Case 3. Inject into SI 1 only. Produce from 2-20 until the water cut is 96%, then shut in 2-20. Produce from 02-23A until the water cut is 96%, then shut in 02-23A and produce from 2-27 and 6-07.

Comparing the data, we found that Case 1 and Case 2 yield higher ultimate oil recovery than Case 3. As described earlier, however, Case 2 is preferred to Case 1 because the horizontal injector provides an option to mitigate oil recovery risks due to the uncertainty related to the location of the fault and its throw. It can also provide a higher injection rate compared to a vertical injector.

We also found that the sweep is better in Case 2, which provides accelerated oil production compared with Case 1. In Fig. 8, the brighter color represents higher water saturation.

As a result of this analysis, we chose Case 2 as the preferred development option for the southern lobe of the PUT River reservoir.

Implementation

Based on the TDRM results, BP initially developed the reservoir with one injection well and one production well, to be followed by a second producer. The injection well was completed in early 2006 and production commenced from a single well in October 2006. Initial production was 2,000 bo/d.

Injection and production rates are managed to maintain the reservoir pressure above the bubble-point pressure.

Designing an optimal development plan for a minor reservoir is a complicated process. This is especially true when the field has poor quality and heterogeneous reservoir rock, such as the PUT River sands of Alaska's North Slope.

A number of existing well penetrations provided attractive options for recompletion but restrict the optimal placement of wells. Designing a successful flood process for a complex case like the PUT River can benefit from a TDRM process that can determine the effect of various reservoir parameter uncertainties.

This article shows this process through practical examples. Detailed numerical simulations led to the design of the optimal development case for the southern lobe of the PUT River sands:

1. Optimal producer option. Produce from wells 2-23A and 2-20 with an option to produce from 06-07 and 2-27 in future.
2. Optimal injector option. Horizontal injector or southern vertical injector. Using a horizontal injector mitigates geological and fault uncertainty.
3. Inject in the middle 10-15 ft.
4. Upside potential for off take in the far north and southwest.

Acknowledgments

We thank the owners of the Prudhoe Bay Unit for their permission to publish this work. The conclusions presented are those of the operator and may not reflect those of the other working interest owners. ✦

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Worldwide ethylene capacity increases 2 million tpy in 2007

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Refining/Petrochemical Editor

Ethylene producers added a net 2 million tonnes/year (tpy) of capacity in 2007, according to the latest ethylene survey. This is a significant increase from the 2006 addition rate of 245,000 tpy.

Capacity as of Jan. 1, 2008, was 119.6 million tpy, an increase from 117.6 million tpy of capacity reported in last year's survey (OGJ, July 16, 2007, p. 46). The 2-million-tpy addition is a rise of 1.7%.

The latest survey showed that one new train with a capacity of 1.2 million tpy in an existing plant started up in 2007. None of the ethylene producers surveyed reported any shutdown capacity. The net additional 800,000-tpy of capacity resulted from expansions and debottlenecking at existing sites.

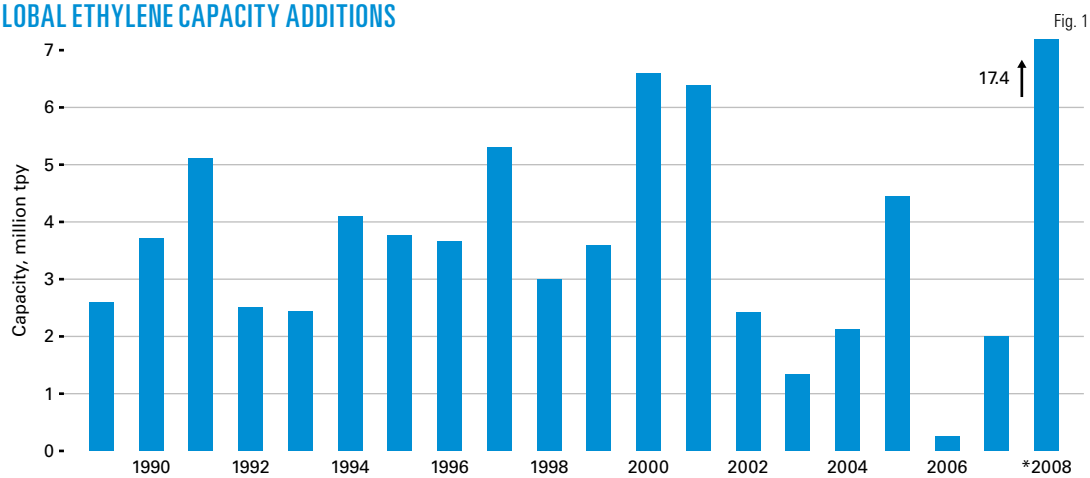
Fig. 1 shows that the capacity additions recovered from last year's low addition rate, which was the lowest in at least 20 years. In 2007, capacity additions should be at their highest level in more than 20 years.

According to the latest OGJ Construction Survey, more than 17 million tpy of capacity is slated for start-up in 2008, mostly in the Middle East. Most of the projects, which have been delayed numerous times, are in Iran and are scheduled to start up in 2008.

Fig. 2 shows that global operating rose slightly in 2007, but are still lower than the peak of about 93% in 2004. Due to large amounts of capacity coming online in 2008-12,

GLOBAL ETHYLENE CAPACITY ADDITIONS

Fig. 1



*Estimate.
Sources: ChemSystems, White Plains, NY (1988-99 data). OGJ Energy Database (2000-08 data)

operating rates will decrease to the low levels seen in 2001-03.

Fig. 2 also shows that demand for ethylene will not keep pace with rapidly expanding capacity.

New units

One new ethylene unit appears in this year's survey. Formosa Petrochemical Corp. started up a new 1.2-million-tpy cracker in May 2007. The ethylene plant at Formosa's Mailiao, Taiwan, plant is the largest in Asia.

Formosa's Mialiao complex now has three trains with a total plant production capacity of 2.5 million tpy. It is now the largest ethylene production complex in Asia and second largest worldwide.

All the additional capacity is due to expansions at existing plants.

Regional review

Table 1 shows rankings of the 10 largest ethylene production complexes in the world. Nova Chemical Corp.'s 2.8-million-tpy Joffre plant retains the top spot on the list.

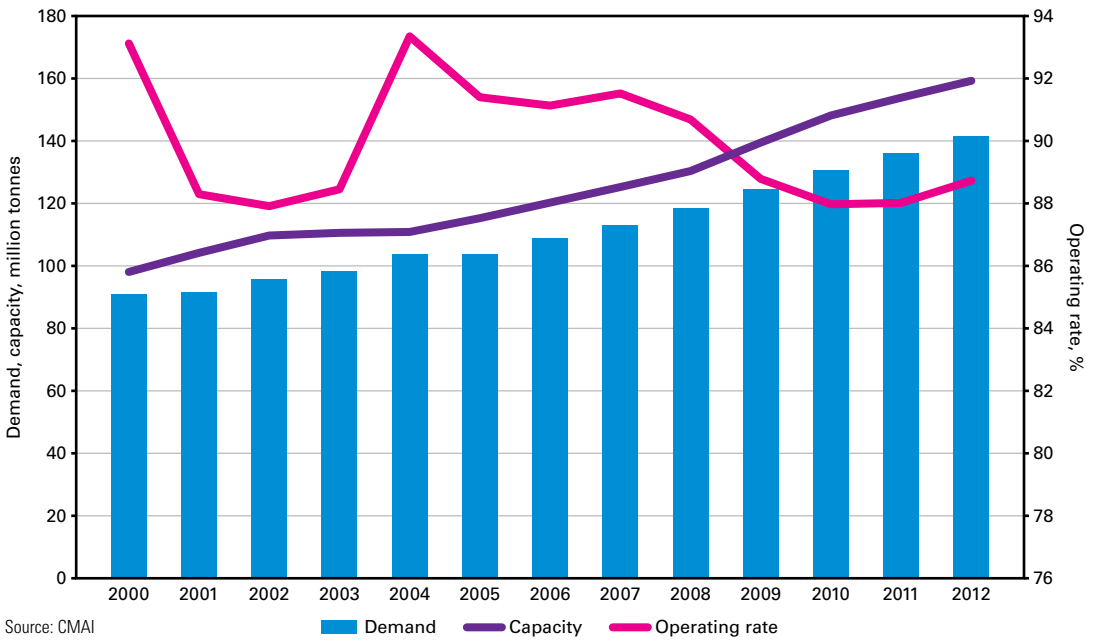
Formosa is a new listing in Table 1 due to the new unit at its Mailiao plant. The Mailiao complex was previously 14th largest in the world. It is now the second largest ethylene production complex in the world.

All the other listings in Table 1 fell a spot from last year's report. Shell Chemical's 1.5-million-tpy Norco, La., plant fell off the list.

Table 2 ranks ethylene production capacity by region. The biggest gainers were Asia-Pacific, which added 1.4 million tpy of capacity, and Western Europe, which added 490,000 tpy. Other regions showed incremental gains, except for the Middle East, which

ETHYLENE OPERATING RATE

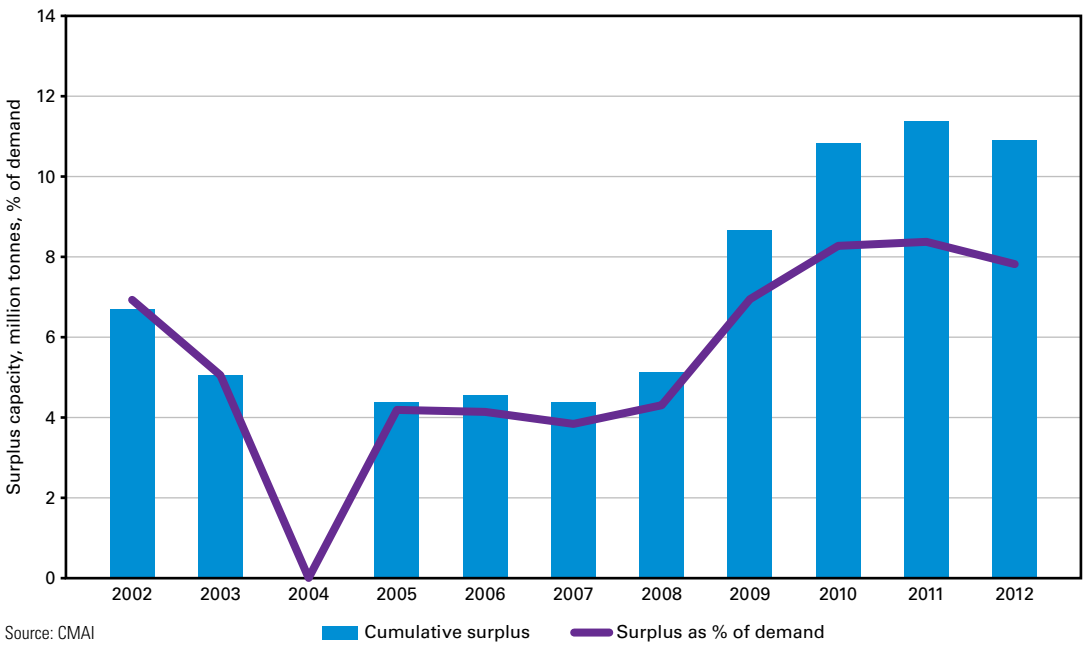
Fig. 2



Source: CMAI

SURPLUS ETHYLENE CAPACITY

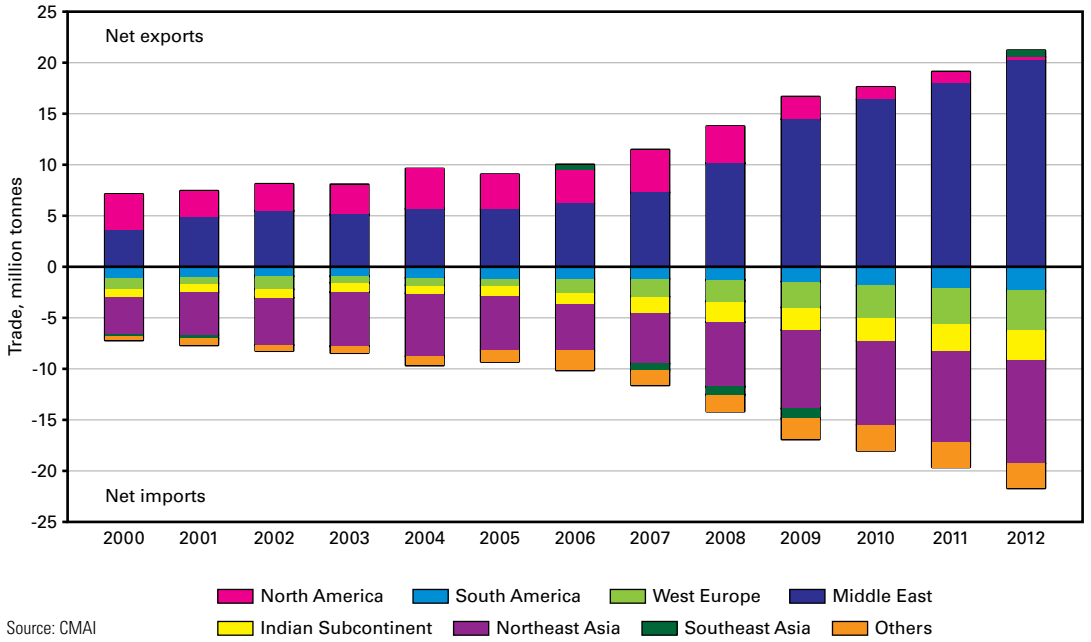
Fig. 3



Source: CMAI

ETHYLENE TRADE

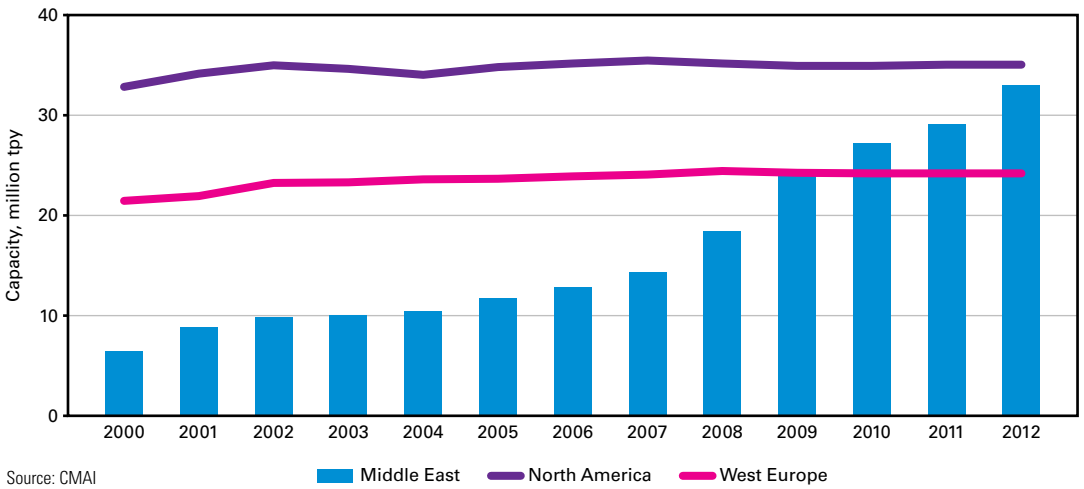
Fig. 4



Source: CMAI

REGIONAL CAPACITY

Fig. 5



Source: CMAI

showed a slight decrease.

In addition to Formosa's Mailiao plant start-up, two other plants in Asia-Pacific showed significant expansions of ethylene production capacity. Samsung-Total Petrochemicals increased the capacity of its Daesan, South Korea, naphtha cracker to 820,000 tpy from 600,000 tpy.

The company is a 50/50 joint venture of Samsung and Total Petrochemicals. Total announced that the expansion construction was completed in May 2007 and the unit was brought online in early June.

On Mar. 23, 2007, ExxonMobil Chemical announced the successful completion of an expansion in its Singapore steam cracker. The plant can now produce 900,000 tpy of ethylene, up from a previous capacity of 860,000 tpy as listed in last year's survey.

In Western Europe, two major expansions occurred. BASF increased the capacity of its Antwerp, Belgium, plant to 1.08 million tpy from 800,000 tpy. BASF reported in its annual report that the expansion was completed in late 2007.

OMV AG completed an expansion of its Burghausen, Bavaria, Germany, petrochemical plant (OGJ, Nov. 13, 2006, p. 10). The ethylene production capacity increased to 450,000 tpy from 340,000 tpy.

Table 3 ranks ethylene production capacity by country. Taiwan showed the largest increase, followed by Belgium, Germany, and South Korea, for the reasons previously mentioned.

Russia showed a loss of 180,000 tpy of capacity and Ukraine showed a 180,000-tpy gain because the ethylene survey corrected the location of the Oriana ethylene plant.

Smaller increases occurred in Brazil, Egypt, Hungary, Netherlands, Slovakia, and the US.

Closed, idled plants

Table 3 also shows that only two countries showed a net decrease in capacity: Australia and Saudi Arabia. The

total decrease in these two countries was 85,000 tpy.

No plant announced a complete shutdown; therefore, the capacity decreases were due to partial shutdowns or companies restating ethylene capacity.

The most significant decline occurred in Saudi Arabia. Saudi Petrochemical Co. reported to OGJ that the production capacity of its Jubail plant is 1.045 million tpy. Last year's survey lists the capacity at 1.1 million tpy.

Ownership, name changes

There were two significant ownership changes in 2007.

LyondellBasell Industries (then Basell) purchased the ethylene plant in Munchsmuntser, Germany, from Ruhr Oel GMBH, a joint venture of BP PLC and Petroleos de Venezuela SA. The plant has a listed production capacity of 320,000 tpy of ethylene.

On Dec. 20, 2007, Basell and Lyondell Chemical Co. completed a merger that created LyondellBasell Industries.

TOP 10 ETHYLENE COMPLEXES*

Table 1

	Company	Location	Capacity, tpy
1	Nova Chemicals Corp.	Joffre, Alta.	2,812,000
2	Formosa Petrochemical Corp.	Mailiao, Taiwan, China	2,550,000
3	Arabian Petrochemical Co.	Jubail, Saudi Arabia	2,250,000
4	ExxonMobil Chemical Co.	Baytown, Tex.	2,197,000
5	ChevronPhillips Chemical Co.	Sweeny, Tex.	1,868,000
6	Dow Chemical Co.	Terneuzen, Netherlands	1,800,000
7	Ineos Olefins & Polymers	Chocolate Bayou, Tex.	1,752,000
8	Equistar Chemicals LP	Channelview, Tex.	1,750,000
9	Yanbu Petrochemical Co.	Yanbu, Saudi Arabia	1,705,000
10	Dow Chemical Co.	Freeport, Tex.	1,640,000

*As of Jan. 1, 2008.

The $20 billion deal included the Lyondell subsidiary Equistar Chemicals LP, which has six ethylene production plants in the US.

Table 4 lists the top 10 owners of ethylene capacity worldwide. There were two changes in the company order. The LyondellBasell acquisition moved it up to fifth on the list. Formosa's new unit allowed the company to move up to seventh. The company was not included in Table 4 in last year's report.

Construction

Last year, OGJ forecast that 3.0 million tpy of new capacity would come online in 2007, based on responses to construction surveys. The 2 million tpy of capacity that started up in 2007 did not include two plants in Iran that were listed in Table 5 last year.

The plants in Iran again experienced project delays. At least two of these will start up in 2008, including the Arya Sasol Polymer Co. and Jam Petrochemical

REGIONAL CAPACITY BREAKDOWN

Table 2

	Ethylene capacity, tpy		Change	
	Jan. 1, 2008	Jan. 1, 2007	tpy	%
Asia-Pacific	33,002,000	31,602,000	1,400,000	4.43
Eastern Europe	8,512,000	8,462,000	50,000	0.59
Middle East, Africa	12,342,000	12,367,000	–25,000	–0.20
North America	35,707,700	35,687,700	20,000	0.06
South America	5,083,500	5,018,500	65,000	1.30
Western Europe	24,928,000	24,438,000	490,000	2.01
Total capacity	**119,575,200**	**117,575,200**	**2,000,000**	**1.70**

NATIONAL ETHYLENE CAPACITIES

Table 3

Country	Jan. 1, 2008 Ethylene capacity, tpy	Jan. 1, 2007 Ethylene capacity, tpy	Change, tpy
Algeria	133,000	133,000	0
Argentina	838,500	838,500	0
Australia	502,000	532,000	–30,000
Austria	500,000	500,000	0
Azerbaijan	330,000	330,000	0
Belarus	193,000	193,000	0
Belgium	2,460,000	2,180,000	280,000
Brazil	3,500,000	3,435,000	65,000
Bulgaria	400,000	400,000	0
Canada	5,531,000	5,531,000	0
Chile	45,000	45,000	0
China	6,988,000	6,988,000	0
China, Taiwan	3,621,000	2,421,000	1,200,000
Colombia	100,000	100,000	0
Croatia	90,000	90,000	0
Czech Republic	485,000	485,000	0
Egypt	330,000	300,000	30,000
Finland	330,000	330,000	0
France	3,373,000	3,373,000	0
Germany	5,757,000	5,557,000	200,000
Greece	20,000	20,000	0
Hungary	660,000	620,000	40,000
India	2,515,000	2,515,000	0
Indonesia	520,000	520,000	0
Iran	1,214,000	1,214,000	0
Israel	200,000	200,000	0
Italy	2,170,000	2,170,000	0
Japan	7,265,000	7,265,000	0
Kazakhstan	130,000	130,000	0
Kuwait	800,000	800,000	0
Libya	350,000	350,000	0
Malaysia	1,649,000	1,649,000	0
Mexico	1,384,000	1,384,000	0
Netherlands	3,975,000	3,965,000	10,000
Nigeria	300,000	300,000	0
North Korea	60,000	60,000	0
Norway	550,000	550,000	0
Poland	700,000	700,000	0
Portugal	330,000	330,000	0
Qatar	1,030,000	1,030,000	0
Romania	844,000	844,000	0
Russia	3,490,000	3,670,000	–180,000
Saudi Arabia	6,800,000	6,855,000	–55,000
Serbia and Montenegro	200,000	200,000	0
Singapore	1,980,000	1,940,000	40,000
Slovakia	220,000	210,000	10,000
South Africa	585,000	585,000	0
South Korea	5,630,000	5,440,000	190,000
Spain	1,430,000	1,430,000	0
Sweden	625,000	625,000	0
Switzerland	33,000	33,000	0
Thailand	2,272,000	2,272,000	0
Turkey	520,000	520,000	0
Ukraine	630,000	450,000	180,000
UAE	600,000	600,000	0
United Kingdom	2,855,000	2,855,000	0
United States	28,792,700	28,772,700	20,000
Uzbekistan	140,000	140,000	0
Venezuela	600,000	600,000	0
Total	**119,575,200**	**117,575,200**	**2,000,000**

TOP 10 ETHYLENE PRODUCERS[1]

Table 4

	Company	No. of sites	Capacity, tpy: Of entire complexes	Capacity, tpy: With only company partial interests
1	Dow Chemical Co.	14	13,155,000	10,369,500
2	ExxonMobil Corp.	15	11,470,000	8,352,000
3	Saudi Basic Industries Corp.	7	8,940,000	7,165,000
4	Royal Dutch Shell PLC	10	8,965,000	6,841,000
5	LyondellBasell[2]	7	5,200,000	5,200,000
6	Ineos	4	4,656,000	4,286,000
7	Formosa Petrochemical Corp.	2	4,091,000	4,091,000
8	Sinopec	9	4,375,000	4,075,000
9	Chevron Phillips Chemical Co. LP[3]	4	3,956,000	3,701,000
10	Total AS	9	5,713,000	3,421,800

[1]As of Jan. 1, 2008. [2]Includes subsidiary Equistar Chemicals LP. [3]Ownership: ChevronTexaco Corp. 50%, ConocoPhillips 50%.

Co. plants in Assaluyeh Bushehr.

According to the latest OGJ construction data, an unprecedented 17.4 million tpy of new capacity is slated to come on stream in 2008 (Table 5).

The vast majority of this capacity is in the Middle East. Twelve of the projects list capacities of more than 1 million tpy each. All are in the Middle East except for one in China and one in Venezuela.

Global market

Ethylene markets experienced strong

ETHYLENE EXPANSIONS, 2008-12

Table 5

Location	Company	2008	2009	2010	2011	2012
		Ethylene capacity, tpy				
Arzew, Algeria	Total/Sonatrach					1,100,000
Santo Andre, Sao Paulo, Brazil	Petroquimica Uniao SA	200,000				
Nanjing, China	BASF-YPC Co. Ltd.		750,000			
Heilongjian Province, China	Daqing Petroleum & Chemical Co.					600,000
Fujian Province, China	Fujian Petrochemical Co. Ltd.	800,000				
Lanzhou, China	Lanzhou Petrochemical Co.	360,000				
Ningbo, China	PetroChina				1,200,000	
Dushanzi, Xinjang, China	PetroChina Dushanzi Petrochemical Co.	1,000,000				
Maoming, Guangdong, China	Sinopec			320,000		
Quanzhou City, China	Sinopec				800,000	
Ningbo, Zhejiang, China	Zhenhai Refining & Chemical Co. Ltd.			1,000,000		
Koln, Germany	Ineos	100,000				
Dibrugarh, Assam, India	GAIL India Ltd.				220,000	
Panipat, India	Indian Oil Co. Ltd.		800,000			
Dahej, India	Oil & Natural Gas Corp.			1,100,000		
Bandar Imam, Iran	Arvand Petrochemical Co.				1,000,000	
Assaluyeh Bushehr, Iran	Arya Sasol Polymer Co.	1,000,000				
Assaluyeh Bushehr, Iran	Jam Petrochemical Co.	1,320,000				
Kharg Island, Iran	Kharg Petrochemical Co.	500,000				
Bandar Assaluyeh, Iran	Marun Petrochemical Co.	1,200,000				
Bandar Assaluyeh, Iran	Petrochemical Industries Dev. Mgmt. Co.		1,200,000			
Shuaiba, Kuwait	Petrochemical Industries Co., Dow Chemical Co.	850,000				
Sohar, Oman	Dow Chemical Co.		850,000			
Ras Laffan, Qatar	Qatar Chemical Co. Ltd., ChevronTexaco Corp., Total AS	1,300,000				
Ras Laffan, Qatar	Qatar Petroleum Co., ExxonMobil Corp.	1,600,000				
Mesaieed, Qatar	Qatar Petroleum Co., Honam Petrochemical Co.		900,000			
Al-Jubail, Saudi Arabia	Eastern Petrochemical Co.	1,300,000				
Al-Jubail, Saudi Arabia	National Petrochemical Industrialization	1,008,000				
Rabigh, Saudi Arabia	Saudi Aramco, Sumitomo Chemical Co.	1,500,000				
Yanbu, Saudi Arabia	Saudi Basic Industries Corp.	1,300,000				
Al-Jubail, Saudi Arabia	Tasnee Petrochemicals	1,000,000				
Singapore	ExxonMobil Chemical Corp.				1,000,000	
Singapore	Shell Eastern Petroleum Ltd.			800,000		
Kaoshiung Linyuan, Taiwan	Chinese Petroleum Corp.				1,000,000	
Map Ta Phut, Thailand	PTT Polyethylene Co. Ltd.		1,000,000			
Rayong, Thailand	Siam Cement PLC, Dow Chemical Co.			900,000		
Trinidad & Tobago	Westlake Chemical Corp.			570,000		
Ruwais, Abu Dhabi, UAE	Abu Dhabi Polymers Co. Ltd.			1,500,000		
El Tablazo, Venezuela	Polinter					1,000,000
Jose, Anzoategui, Venezuela	Pequiven	1,050,000				
Total		**17,388,000**	**5,500,000**	**6,190,000**	**5,220,000**	**2,700,000**

Source: Oil & Gas Journal construction survey

supply-demand conditions again in 2007, a trend that started in late 2004. Fig. 2 shows that worldwide operating rates were nearly 92%, a slight increase from 2006. Operating rates were high in 2004 when incremental demand surpassed capacity increases.

According to Mark Eramo, executive vice-president for CMAI, Houston, "the regional markets are experiencing some moderation in the supply-demand balance as the US economy beings to slow. By the end of 2008, the industry will begin to feel the impact of the next wave of Middle East new steam cracker start-ups."

Fig. 3 shows surplus ethylene capacity. Eramo told OGJ, "by 2009-10, the acceleration in capacity additions compared to the forecast for annual demand growth will prove to be too much in a short period of time and surplus capacity is expected to rise once again."

CMAI predicts that surplus capacity will peak at nearly 11 million tpy, or 8% of total demand. This level of surplus capacity could sustain through 2012; therefore, the next market downturn could be prolonged.

Fig. 4 shows that Middle East producers will dominate the net equivalent ethylene trade (net trade flows of ethylene derivatives).

"The Middle East low-cost position will ensure that their product will be supplied to those areas that offer the most profitable net backs; this will be Asia, Europe, India, South America, and North America in that order," Eramo said. "This period will prove to be a significant challenge as the Middle East producers are sure to take market share, leaving a very competitive environment for the other producers."

CMAI forecasts that Middle East ethylene capacity will increase to more than 30 million tpy by 2012 (Fig. 5). By 2010, Middle East capacity will surpass that of Western Europe, and by 2012, it will nearly match capacity in North America. ✦

INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008

Leena Koottungal
Survey Editor

Capacities as of Jan. 1, 2008

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, % Ethane	Propane	Butane	Naphtha	Gas oil	Other
ALGERIA								
Sonatrach	Skikda	133,000						
Total Algeria		**133,000**						
ARGENTINA								
Dow Chemical Co.	Bahia Blanca (BB1)	275,000	100					
Dow Chemical Co.	Bahia Blanca (BB2)	490,000	100					
Huntsman Corp.	San Lorenzo	21,000		25		75		
Petrobras Energia	Puerto San Martin	32,500		100				
Petrobras Energia	San Lorenzo	20,000		100				
Total Argentina		**838,500**						
AUSTRALIA								
Huntsman Chemical Co. Australia Ltd.	Melbourne, Vic.	32,000	100					
Qenos Pty. Ltd.	Altona, Vic.	180,000	75	15	10			
Qenos Pty. Ltd.	Botany, NSW	290,000	80			20		
Total Australia		**502,000**						
AUSTRIA								
OMV AG	Schwechat	500,000	15		23	62		
Total Austria		**500,000**						
AZERBAIJAN								
Azerichimia	Sumgait	30,000						
Azerichimia	Sumgait	300,000						
Total Azerbaijan		**330,000**						
BELARUS								
Production Association Polymir	Novopolotsk	73,000						
Production Association Polymir	Novopolotsk	120,000						
Total Belarus		**193,000**						
BELGIUM								
BASF Antwerpen NV	Antwerp	1,080,000		5		95		
Benelux FAO	Antwerp	230,000	16	16	18	50		
Benelux FAO	Antwerp	580,000	16	16	18	50		
Benelux FAO	Antwerp	570,000	16	16	18	50		
Total Belgium		**2,460,000**						
BRAZIL								
Braskem SA	Camacari, Bahia	600,000	5			95		
Braskem SA	Camacari, Bahia	680,000				100		
Copesul	Triunfo, RS	700,000				100		
Copesul	Triunfo, RS	500,000				100		
Petroquimica Uniao SA	Santo Andre, Sao Paulo	500,000				100		
Rio Polimeros	Duque de Caxias	520,000						
Total Brazil		**3,500,000**						
BULGARIA								
Lukoil Neftochim Bourgas JSC	Bourgas	250,000	3.4		10	86.6		
Lukoil Neftochim Bourgas JSC	Bourgas	150,000				100		
Total Bulgaria		**400,000**						
CANADA								
Dow Chemical Co.	Ft. Sask., Alta.	1,285,000	100					
Imperial Oil Products & Chemicals	Sarnia, Ont.	300,000	33	33	34			
Nova Chemicals Corp.	Corunna, Ont.	839,002	10	20	20	40	10	
Nova Chemicals Corp.	Joffre, Alta. (E1)	725,624	95	5				
Nova Chemicals Corp.	Joffre, Alta. (E2)	816,327	100					
Nova Chemicals Corp.	Joffre, Alta. (E3)	1,269,841	100					
Petromont	Varennes, Que.	295,000		10	25	50	15	
Total Canada		**5,530,794**						
CHILE								
Petrox SA	Concepcion	45,000	8		16	76		
Total Chile		**45,000**						
CHINA								
BASF-YPC Co. Ltd.	Nanjing	600,000						
China National Offshore Oil Co.	Daya Bay, Guangdong	800,000						
China National Offshore Oil Co.	Dushanzi	140,000						
China Petrochemical Industrial Corp.	Daqing	320,000						
Dalian Petrochemical Co.	Dalian	4,000						
Fushun Petrochemical Complex	Fushun	115,000						
Gaoqiao Petrochemical Co.	Gaoqiao	14,000						
Guangzhou Petrochemical Co.	Guangzhou	150,000						
Jilin Chemical Industrial Co. Ltd.	Jilin	700,000						
Lanzhou Chemical Industrial Co.	Lanzhou	240,000						

INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008 (CONTINUED)

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, % Ethane	Propane	Butane	Naphtha	Gas oil	Other
Panjin Gas Processing Plant	Panjin	130,000						
Sinopec	Beijing	660,000				30	70	
Sinopec	Caojing, Shanghai	145,000				30	70	
Sinopec	Caojing, Shanghai	700,000				60	40	
Sinopec	Guangzhou, Guandong	140,000				100		
Sinopec	Maoming, Guangdong	380,000				100		
Sinopec	Neijing	650,000				60	40	
Sinopec	Puyang, Henan	180,000				100		
Sinopec	Qilu	720,000				80	20	
Sinopec	Tianjin	200,000				100		
Total China		**6,988,000**						
CHINA, TAIWAN								
Chinese Petroleum Corp.	Kaohsiung Linyuan	422,000	100					
Chinese Petroleum Corp.	Linyuan	230,000	100					
Chinese Petroleum Corp.	Linyuan	419,000	100					
Formosa Petrochemical Corp.	Mailiao	450,000				100		
Formosa Petrochemical Corp.	Mailiao	900,000						
Formosa Petrochemical Corp.	Mailiao	1,200,000						
Total China, Taiwan		**3,621,000**						
COLOMBIA								
Empresa Colombiana de Petroleos	Barrancabermeja	100,000	80	20				
Total Colombia		**100,000**						
CROATIA								
Polimeri	Zagreb	90,000	100					
Total Croatia		**90,000**						
CZECH REPUBLIC								
Chemopetrol AS	Litvinov	485,000		2	6	50	2	Hydrowax-40
Total Czech Republic		**485,000**						
EGYPT								
Sidi Kerir Petrochemicals Co.	Alexandria	330,000						
Total Egypt		**330,000**						
FINLAND								
Borealis OY	Porvoo	330,000				100		
Total Finland		**330,000**						
FRANCE								
A.P. Feyzin	Feyzin	250,000				100		
ExxonMobil Corp.	Notre Dame de Gravenchon	400,000				100		
Naphthachimie	Lavera	740,000			50	50		
Polimeri Europa France SNC	Dunkerque	370,000	0.5	1.5	8	90		
Societe du Craqueur de L' Aubette SCA	Berre l'Etang	450,000			12	75	13	
Total Petrochemicals	Carling-St. Avold-Marienau	568,000				100		
Total Petrochemicals	Gonfreville l'Orcher	520,000				100		
Total Petrochemicals	Lacq (Snea plant)	75,000	100					
Total France		**3,373,000**						
GERMANY								
Basell Polyfine GMBH	Wesseling	738,000			10	90		
Basell Polyfine GMBH	Wesseling	305,000					100	
BASF AG	Ludwigshafen	620,000		5	5	90		
BP Gelsenkirchen	Gelsenkirchen	580,000		1	9	75	15	
BP Gelsenkirchen	Gelsenkirchen	480,000			4	78	18	
INEOS	Dormagen	550,000				100		
INEOS	Dormagen	544,000				100		
LyondellBasell	Munchsmunster	320,000	13	17	17	53		
Dow Chemical Co.	Bohlen	560,000				100		
OMV Deutschland GMBH	Burghausen, Bavaria	450,000	2.5	6	6	84	1.5	
Shell & DEA Oil GMBH	Heide	110,000						
Shell & DEA Oil GMBH	Wesseling	500,000						
Total Germany		**5,757,000**						
GREECE								
EKO Chemicals Co. AE	Thessaloniki	20,000				65		Ref. gas-35
Total Greece		**20,000**						
HUNGARY								
Tiszai Vegyi Kombinat Ltd.	Tiszaujvaros	370,000		0-5	0-5	85-90	0-10	
Tiszai Vegyi Kombinat Ltd.	Tiszaujvaros	290,000		5-8	5-8	70-80	10-20	
Total Hungary		**660,000**						

INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008 (CONTINUED)

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, % Ethane	Propane	Butane	Naphtha	Gas oil	Other
INDIA								
Gas Authority of India Ltd.	Pata, Uttar Pradesh	300,000						
Haldia Petrochemicals Ltd.	Haldia, West Bengal	520,000				100		
Indian Petrochemicals Corp. Ltd.	Baroda, Gujarat	130,000				100		
Indian Petrochemicals Corp. Ltd.	Gandhar, Gujarat	300,000	35-50	50-65				
Indian Petrochemicals Corp. Ltd.	Nagothane, Maharashtra	400,000	35-50	50-65				
National Organic Chemical Industries Ltd.	Thane, Maharashtra	75,000				100		
Reliance Industries Ltd.	Hazira, Gujarat	790,000				100		
Total India		**2,515,000**						
INDONESIA								
PT Chandra Asri	Cilegon, West Java	520,000						
Total Indonesia		**520,000**						
IRAN								
Amir Kabir Petrochemical Co.	Amir Kabir	520,000	24	4	12	58		2
Arak Petrochemical	Arak	247,000				100		
Bandar Imam Petrochemical Co.	Bandar Imam	311,000	20	3	10			67
Tabriz Petrochemical Co.	Tabriz	136,000	4	8	8	80		
Total Iran		**1,214,000**						
IRAQ								
Present status unknown		—						
Total Iraq		**—**						
ISRAEL								
Carmel Olefins Ltd.	Haifa	200,000		10	10	80		
Total Israel		**200,000**						
ITALY								
Polimeri Europa	Brindisi	440,000				100		
Polimeri Europa	Gela	245,000	25	5		70		
Polimeri Europa	Porto Marghera	490,000				100		
Polimeri Europa	Priolo	745,000	2		1	65	32	
Syndial	Porto Torres	250,000				70	30	
Total Italy		**2,170,000**						
JAPAN								
Asahikasei Chemicals Corp.	Kurasiki, Okayama	484,000				100		
Idemitsu Petrochemical Co. Ltd.	Chiba	374,000			2	98		
Idemitsu Petrochemical Co. Ltd.	Tokuyama	450,000				100		
Keiyo Ethylene	Ichihara, Chiba	768,000						
Maruzen Petrochemicals	Chiba	480,000						
Mitsubishi Chemical Corp.	Kashima (Unit 1)	375,000		10	20	55		NGL-15
Mitsubishi Chemical Corp.	Kashima (Unit 2)	453,000		10	20	55		NGL-15
Mitsubishi Chemical Corp.	Mizushima	450,000		5	5	80		NGL-10
Mitsui Chemicals Inc.	Ichihara, Chiba	553,000			10	90		
Mitsui Chemicals Inc.	Takaishi City, Osaka	450,000						
Nippon Petrochemical	Kawasaki	450,000						
Showa Denko KK	Oita	600,000				100		
Sumitomo Chemical Co. Ltd.	Chiba	380,000						
Tonen Chemical Corp.	Kawasaki	505,000				100		
Tosoh Corp.	Yokkaichi	493,000				100		
Total Japan		**7,265,000**						
KAZAKHSTAN								
Akpo	Aktau	100,000						
Government	Atyrau	30,000						
Total Kazakhstan		**130,000**						
KUWAIT								
Equate Petrochemical Co.	Shuaiba	800,000	100					
Total Kuwait		**800,000**						
LIBYA								
National Oil Co.	Ras Lanuf	350,000						
Total Libya		**350,000**						
MALAYSIA								
Ethylene Malaysia Sdn. Bhd.	Kertih	400,000	100					
Optimal Olefins Sdn. Bhd.	Kertih	600,000	100					
Titan Petrochemicals Sdn. Bhd.	Johor	400,000				100		
Titan Petrochemicals Sdn. Bhd.	Pasir Gudang	249,000				100		
Total Malaysia		**1,649,000**						
MEXICO								
Petroleos Mexicanos	La Cangrejera, Veracruz	600,000	100					
Petroleos Mexicanos	Morelos, Veracruz	600,000	100					

INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008 (CONTINUED)

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, % Ethane	Propane	Butane	Naphtha	Gas oil	Other
Petroleos Mexicanos	Pajaritos, Veracruz	184,000	100					
Total Mexico		**1,384,000**						
NETHERLANDS								
Dow Chemical Co.	Terneuzen (No. 1)	580,000		15		85		
Dow Chemical Co.	Terneuzen (No. 2)	585,000		15		85		
Dow Chemical Co.	Terneuzen (No. 3)	635,000				100		
SABIC Europe	Geleen (No. 3)	600,000				100		
SABIC Europe	Geleen (No. 4)	675,000				100		
Shell Nederland Chemie BV	Moerdijk	900,000						
Total Netherlands		**3,975,000**						
NIGERIA								
Eleme Petrochemical Co. Ltd.	Eleme River	300,000						NGL
Total Nigeria		**300,000**						
NORTH KOREA								
Namhung Youth Chemical Complex	Anju, South P'yong'an Province	60,000						
Total North Korea		**60,000**						
NORWAY								
Noretyl AS	Rafnes, Bamble	550,000	30	45	25			
Total Norway		**550,000**						
POLAND								
PKN Orlen SA	Plock	700,000		5	5	90		
Total Poland		**700,000**						
PORTUGAL								
Repsol YPF SA	Sines	330,000				100		
Total Portugal		**330,000**						
QATAR								
Qatar Petrochemical Co.	Mesaieed	530,000	100					
Q-Chem I	Mesaieed	500,000	80	20				
Total Qatar		**1,030,000**						
ROMANIA								
Petrom SA	Pitesti	200,000	19.5	8.5	23.7	48.4		
Petromidia SA	Navodari	200,000						
Petromidia SA	Constanta	224,000		10.7	5.0	54.7		Kero.-29.6
Petrotel SA	Teleajen	220,000						
Total Romania		**844,000**						
RUSSIA								
Angarskneftorgsintez	Angarsk, Siberia	60,000			5.2	89.2	5.6	
Angarskneftorgsintez	Angarsk, Siberia	240,000			5.2	89.2	5.6	
Nizhnekamskneftekhim	Nizhnekamsk	450,000						
Norsy		300,000				100		
Omskykauchuyk	Omsk, Siberia	90,000						
Orgsintez	Kazan	140,000						
Orgsintez	Kazan	100,000						
Orgsintez	Kazan	100,000						
Oxosyntez	Orsk	45,000						
Polimir		150,000				100		
Salavatneftorgsintez	Salavat	300,000						
Sibur Himprom		30,000						
Sibur-Neftechim	Nizhny Novgorod	300,000			20	80		
Sintezkauchuk		300,000						
Stavrapolpolymer	Prikumsk	350,000						
Tomsk PCC	Tomsk	300,000						
Uraorgsintes	Ufa	235,000						
Total Russia		**3,490,000**						
SAUDI ARABIA								
Al Jubail Petrochemical Co.	Jubail	800,000	50	50				
Arabian Petrochemical Co.	Jubail	800,000				100		
Arabian Petrochemical Co.	Jubail	800,000	50	50				
Arabian Petrochemical Co.	Jubail	650,000	100					
Jubail United Petrochemical Co.	Jubail	1,000,000						
Saudi Petrochemical Co.	Jubail	1,045,000	100					
Yanbu Petrochemical Co.	Yanbu	875,000	100					
Yanbu Petrochemical Co.	Yanbu	830,000	16	16	18	50		
Total Saudi Arabia		**6,800,000**						

Practical solutions to slow global warming

Whilst the world discusses the climate change and its consequences, Linde has been developing concepts to significantly reduce energy consumption and greenhouse gas emission in existing ethylene plants.

One of Linde's innovative solutions is to replace the furnace section of a cracker during a turnaround and thus install state-of-the-art technology in an existing plant without any production loss.

This new Linde furnace technology reduces greenhouse gas emissions while increasing yields and substantially improving reliability and economic efficiency.

Other innovative concepts customized to individual plant requirements are available from Linde, the leading ethylene technology contractor.

Designing Processes – Constructing Plants.

Linde AG
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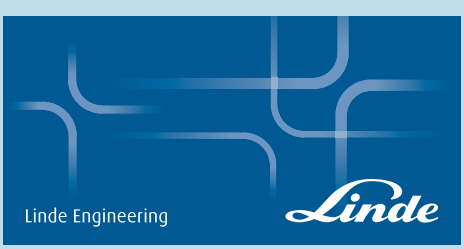
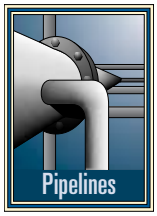


INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008 (CONTINUED)

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, % Ethane	Propane	Butane	Naphtha	Gas oil	Other
SERBIA AND MONTENEGRO								
Chemi Industria	Pancevo	200,000						
Total Serbia and Montenegro		**200,000**						
SINGAPORE								
ExxonMobil Chemical Co.	Jurong Island	900,000				33	33	34
Petrochemical Corp. of Singapore Pte. Ltd.	Pulau Ayer Merbau	465,000				100		
Petrochemical Corp. of Singapore Pte. Ltd.	Pulau Ayer Merbau	615,000				100		
Total Singapore		**1,980,000**						
SLOVAKIA								
Slovnaft Petrochemicals	Bratislava	220,000	0-5	5-15	5-15	75-85		
Total Slovakia		**220,000**						
SOUTH AFRICA								
Sasol Polymers	Sasolburg	110,000	80	20				
Sasol Polymers	Secunda	475,000	75	5		20		
Total South Africa		**585,000**						
SOUTH KOREA								
Honam Petrochemical	Yeochun	700,000				100		
Korea Petrochemical Industries Co. Ltd.	Ulsan	320,000				100		
LG Daesan Petrochemical	Daesan	450,000				100		
LG Petrochemical Co. Ltd.	Yeosu City	760,000				100		
Lotte Daesan Petrochemical	Daesan	600,000				100		
Samsung General Chemicals	Daesan	820,000				100		
SK Corp.	Ulsan	545,000				100		
SK Corp.	Ulsan	185,000				100		
Yeochon	Yeochun	480,000				100		
Yeochon	Yeochun	420,000				100		
Yeochon	Yeochun	350,000				100		
Total South Korea		**5,630,000**						
SPAIN								
Dow Chemical Co.	Tarragona	580,000				100		
Repsol YPF SA	Puertollano	250,000						Ref. streams
Repsol YPF SA	Tarragona	600,000						
Total Spain		**1,430,000**						
SWEDEN								
Borealis AB	Stenungsund	625,000	40	20		40		
Total Sweden		**625,000**						
SWITZERLAND								
Lonza Ltd.	Visp	33,000		24	56	20		
Total Switzerland		**33,000**						
THAILAND								
PTT Chemical	Map Ta Phut, Rayong	437,000	80	6				LPG-14
PTT Chemical	Map Ta Phut, Rayong	385,000	5	18	28	49		
PTT Chemical	Map Ta Phut, Rayong	350,000						
PTT Chemical	Map Ta Phut, Rayong	300,000	100					
Rayong Olefins Ltd.	Map Ta Phut, Rayong	800,000						LPG-60, NGL-40
Total Thailand		**2,272,000**						
TURKEY								
Petkim Petrochemicals Holding Co.	Aliaga, Izmir	520,000				100		
Total Turkey		**520,000**						
UKRAINE								
Chlorvinyl	Kalush	250,000					100	
Oriana		180,000						
TNK-BP	Lisichansk	200,000				100		
Total Ukraine		**630,000**						
UNITED ARAB EMIRATES								
Borouge Abu Dhabi Polymers Co. Ltd.	Ruwais, Abu Dhabi	600,000	100					
Total UAE		**600,000**						
UNITED KINGDOM								
INEOS	Grangemouth	730,000				100		
INEOS	Grangemouth	340,000				100		
ExxonMobil Chemical Co.	Fawley	120,000	9	8	8	25	25	25
ExxonMobil Chemical Co.	Mossmorran Fife	800,000	100					

INTERNATIONAL SURVEY OF ETHYLENE FROM STEAM CRACKERS—2008 (CONTINUED)

Company	Location	Total nameplate capacity, tonnes/year	Typical feedstock or feedstock mixture on which listed capacity is based, %					
			Ethane	Propane	Butane	Naphtha	Gas oil	Other
SABIC Europe	Wilton	865,000		20	10	70		
Total United Kingdom		**2,855,000**						
UNITED STATES								
BASF Fina Petrochemicals	Port Arthur	830,000				100		
Chevron Phillips Chemical Co. LP	Cedar Bayou	794,000	30	20	25	25		
Chevron Phillips Chemical Co. LP	Port Arthur	794,000	70	25	5			
Chevron Phillips Chemical Co. LP	Sweeny	923,000	38	37	25			
Chevron Phillips Chemical Co. LP	Sweeny	673,000	75	25				
Chevron Phillips Chemical Co. LP	Sweeny	272,000	85	15				
Dow Chemical Co.	Freeport (LHC 7)	630,000	50	50				
Dow Chemical Co.	Freeport (LHC 8)	1,010,000	10	20		70		
Dow Chemical Co.	Plaquemine (LHC 2)	520,000	75	25				
Dow Chemical Co.	Plaquemine (LHC 3)	740,000		70	10	20		
Dow Chemical Co.	Taft 1	590,000	20	40		40		
Dow Chemical Co.	Taft 2	410,000	20	40		40		
DuPont	Orange	680,000	100					
Eastman Chemical Co.	Longview	781,000	25	67	7	1		
Equistar Chemicals LP (LyondellBasell)	Channelview	875,000	5			95		
Equistar Chemicals LP (LyondellBasell)	Channelview	875,000	5			95		
Equistar Chemicals LP (LyondellBasell)	Chocolate Bayou	544,000				100		
Equistar Chemicals LP (LyondellBasell)	Clinton	476,000	80	20				
Equistar Chemicals LP (LyondellBasell)	Corpus Christi	771,000	10	30		60		
Equistar Chemicals LP (LyondellBasell)	LaPorte	789,000	60	20		20		
Equistar Chemicals LP (LyondellBasell)	Morris	550,000	80	20				
ExxonMobil Chemical Co.	Baton Rouge	975,000	9	8	8	25	25	25
ExxonMobil Chemical Co.	Baytown	2,197,000	58	8	9	25		
ExxonMobil Chemical Co.	Beaumont	816,000	8	8	9	75		
ExxonMobil Chemical Co.	Houston	102,000						100
Formosa Plastics Corp. USA	Point Comfort	816,000	45	15		40		
Formosa Plastics Corp. USA	Point Comfort	725,000	45	15		40		
Huntsman Corp.	Odessa	360,000						
Huntsman Corp.	Port Arthur	635,000				60		LPG-40
Huntsman Corp.	Port Neches	180,000						
INEOS Olefins and Polymers USA	Chocolate Bayou	1,752,000	50	35		15		
Javelina Co.	Corpus Christi	151,000						Ref. Gas-100
Sasol North America Inc.	Lake Charles	453,515	100					
Shell Chemicals Ltd.	Deer Park	1,426,000						
Shell Chemicals Ltd.	Norco	900,000	5			35	60	
Shell Chemicals Ltd.	Norco	656,000	45	5	5	45		
Sunoco Inc.	Marcus Hook	225,000	100					
Westlake Petrochemicals Corp.	Calvert City	195,000		100				
Westlake Petrochemicals Corp.	Sulphur #1	567,000	100					
Westlake Petrochemicals Corp.	Sulphur #2	522,000	70	30				
Williams Olefins	Geismar	612,245	90	10				
Total United States		**28,792,760**						
UZBEKISTAN								
Uzbekneftegaz	Shurtan	140,000						
Total Uzbekistan		**140,000**						
VENEZUELA								
Pequiven-Petroquimica de Venezuela SA	El Tablazo, Zulia	250,000	30	70				
Pequiven-Petroquimica de Venezuela SA	El Tablazo, Zulia	350,000	100					
Total Venezuela		**600,000**						
TOTAL WORLD		**119,575,053**						



Coiled-tubing method deoils damaged US gulf pipeline

Ignacio Quintero III
Chevron Pipeline Co.
Bellaire, Tex.

Bob Murphy
Joe Maddox
Weatherford International
Houston

John Noddin
Critical Path Consulting
Beaumont, Tex.

A unique coiled-tubing method can serve as a model for several offshore pipeline repairs the US Mines and Minerals Service has mandated occur by 2010. The method successfully deoiled a total of 4,190 ft of a buried pipeline length of 7,500 ft and isolated the balance between two plugs, in compliance with MMS requirements.

This article reviews the pipeline damage to which this CT method was first applied and discusses the various options considered to ensure the line's safety and prevent future leakage and environmental damage. It then describes in detail the preparation for and successful performance of the CT deployment.

Background

The West Delta 109A platform stands in 250 ft of water at the mouth of the Mississippi River. Crude oil production runs 39,000 ft through an 8-in. pipeline to a 12-in. tie-in at WD 125. In July 2005, tropical storm Cindy separated the pressure-balance safety joint on the 8-in. crude riser. Surveys followed passage of the storm and in accordance with approved MMS procedures, several steps were taken to assess damage.

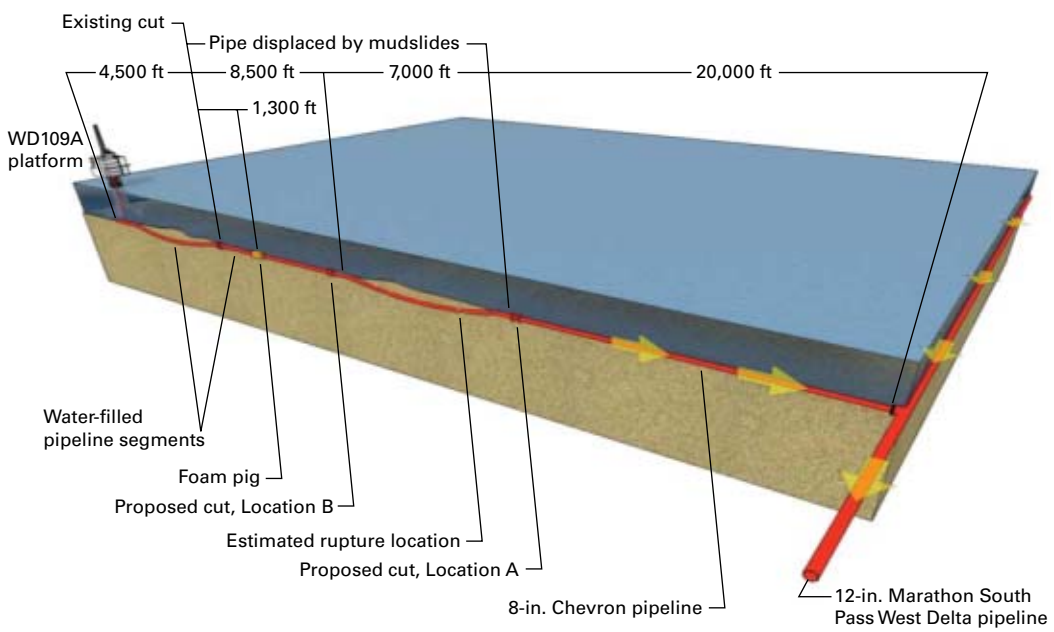
A lock out at the platform and blind flange installed at the base of the riser deoiled and isolated it. Divers found the separated end of the pipeline 300 ft to the southwest. Reconnecting the riser required a total of 300 bbl sea water pumped into the line behind a soluble ball and a soft foam pipeline pig, displacing oil from a 5,000-ft section of line. Before displacement of the line was completed, however, Hurricane Katrina entered the Gulf of Mexico, forcing suspension of operations.

Sidescan sonar and magnetometer equipment surveyed the pipeline after Katrina and a dive-support vessel with excavation equipment and divers mobilized to search for it. Both the survey results and physical inspection by divers showed the pipeline had undergone

Based on presentation to the SPE/ICoTA Coiled Tubing and Well Intervention Conference, The Woodlands, Tex., Apr. 1-2, 2008.

POST-KATRINA PIPELINE CONDITION

Fig. 1



major additional movement during Katrina.

When pressure testing the pipeline revealed a leak, the dive support vessel was mobilized to its rough location after multiple days of digging and probing, however, the DSV could not locate the pipeline in the area where there was believed to be a leak. The DSV demobilized and further planning was initiated to come up with a procedure to locate the pipeline.

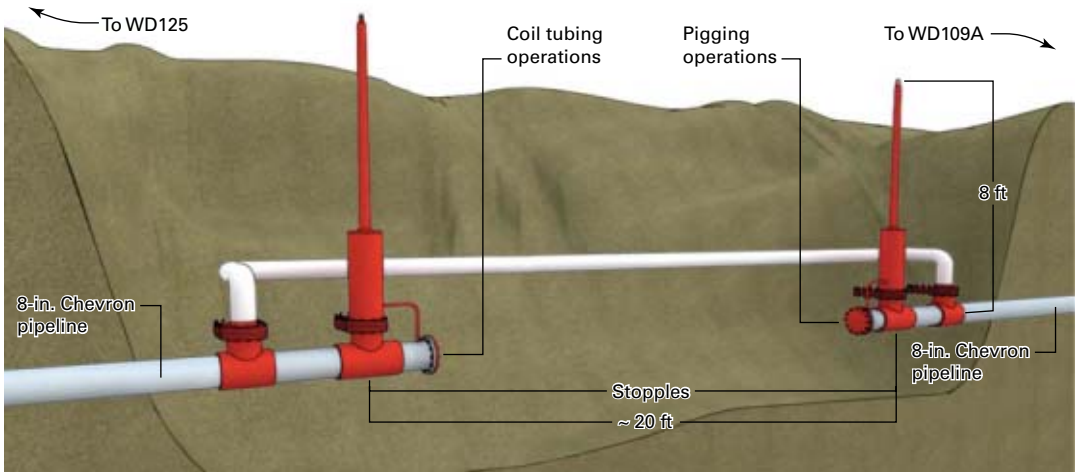
A new technique located the leak in the pipeline using a mass spectrometer to detect the highest product concentration on the seafloor. The highest concentration would hopefully coincide with the location of the pipeline leak. A second mobilization occurred and a 200 × 200 ft hole was excavated to a depth of 26 ft.

The divers, however, failed to find the damaged pipeline, showing it was buried deeper than 236 ft.; the 26 ft. already exposed and 10 more surveyed by magnetometer.

Subsequent plans to deoil the pipeline divided it into four sections; two pipeline segments on each side of the damaged leaking pipe, one section from the riser to the damaged pipeline, and the final section between the main line tie-in and the other side of the damaged pipeline.

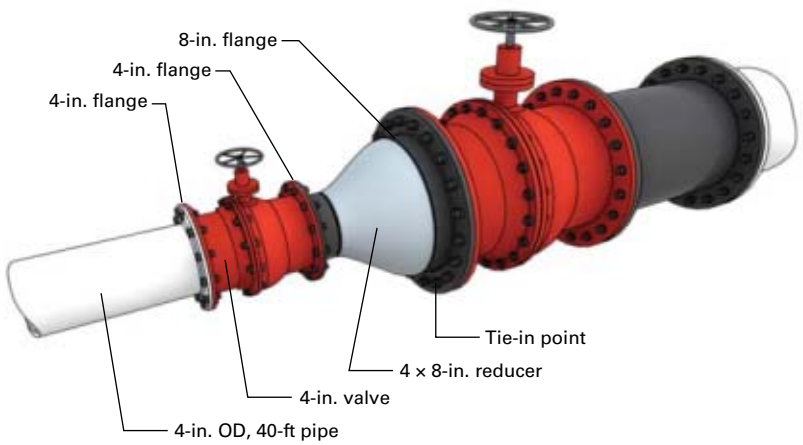
Location B pipeline configuration

Fig. 2



Riser-to-pipeline connection

Fig. 3



Deoiling plans

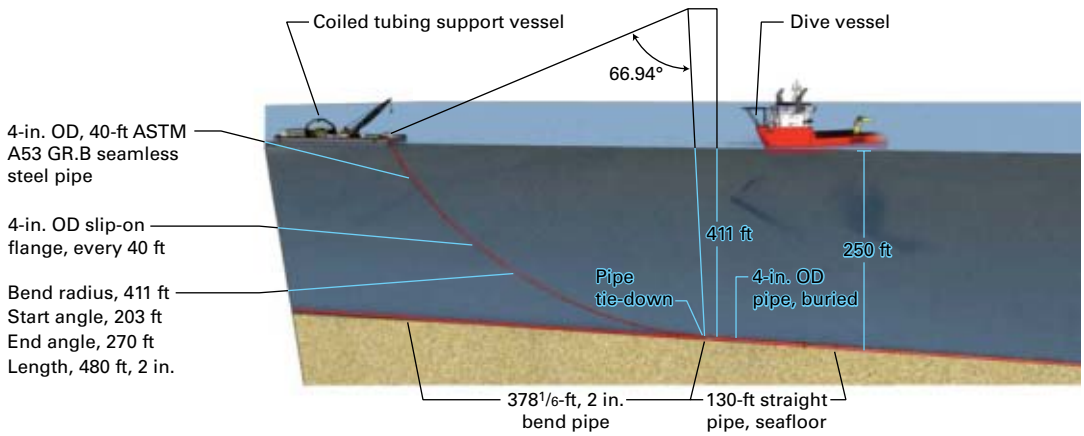
Fig. 1 shows the complexity of the problem faced on the remainder of the pipeline. The roughly 6,500-ft section from the cut towards the pipe line tie-in was partially filled with water as far as the foam pig, and the balance filled with oil to the point labeled Location B, before disappearing into the mud slide area for a total of 7,500 ft. Somewhere in this section lay a rupture or perhaps several, until the line became accessible again at Location A, with the balance of 20,000 ft to the tie-in unaffected and no additional leak or rupturing detected.

Three distinct sections therefore required attention, two of them were readily accessible to divers while the third, containing the rupture(s), was totally buried. Each section would require different treatment: The section from Location A to the tie-in could be pumped out; the section from the cut to Location B would lend itself to a pump and pig receiver approach using the pig already in place; but the buried segment presented problems in terms of deoiling while retaining the contents.

Chevron, in consultation with contractors, decided the buried section could most easily be accessed via CT working from a service barge by way of a custom-built riser attached to the line by divers. A 4-in. riser system designed to be made up to the buried line at Locations A and B separately and attached to the barge at 15° to vertical provided for attachment of the CT injector head. A final meeting held in July 2007 re-

Riser configuration

Fig. 4



viewed and refined the plans, with the operation scheduled for August 2007.

Operation

The first stage prepared the pipeline to allow access for CT operations. This involved plugging the line at Locations A and B, cutting into it, and installing block valves to isolate the buried section. A diving support vessel (DSV) provided the base for the following steps:

- Divers installed stopples (pipeline plugs inserted into the line through a hot tap and valve fixture) at Location B some 20 ft apart (Fig. 2) to provide space for the custom riser.
- A hose was then attached from a pump on the service barge at Location B to one of the stopple flushing ports and a return hose connected to the other leading to tanks on the vessel and allowing the line between the stopples to be flushed clean.
- Placing a pollution dome around the section between the stopples allowed the line to be cut in two places 4 ft from each stopple, the 12-ft section to be removed, and flanges and ball valves installed and closed.
- The stopples were then retracted, the hot tap valve closed and plugged, and the stopple housings removed from both fittings.
- The process was repeated at Location A.

In the meantime the two 4-in. risers arrived on the DSV as 32 40-ft flanged sections and were assembled into three joint sections; the lower end of the riser being equipped with a 4-in. ball valve and a transition to an 8-in. flange for installation onto the cut end of the buried pipeline section (Fig. 3), the upper end with a 4-in. flange. Divers connected the separate sections of the riser to the cut end of the line at Location B after they'd been lowered to the seabed, with the final section being attached to a recovery wire and buoy on surface.

The DSV moved to Location A, while the coiled-tubing support vessel (CTSV) was mobilized to Location B and, with the recovery wire and vessel crane, lifted the end of the riser to the surface while the vessel maneuvered to maintain the required riser curvature and place the top of the riser at the vessel deck at 15° to vertical (Fig. 4).

Rigidly attaching the riser to the CTSV preceded pressure testing to 250 psi to verify its integrity. The first test failed and the entire riser had to be laid down, the CTSV moved, and the riser gaskets replaced by divers before a good test could be obtained. Reattaching the riser to the CTSV preceded cutting it to length, welding another flange in place, and again pressure testing the riser to 250 psi.

Testing followed makeup of the injector head, and the bottomhole assembly (BHA), consisting of the following components, was picked up and run first into the riser and then into the pipeline:

- Bull plug.
- Inflatable retrievable production packer with 2.875-in. OD.
- Pressure-activated relief assembly.
- Pressure-actuated disconnect.
- Coiled-tubing connector.

The BHA became hung up at a depth of 2,022 ft, equivalent to 1,371 ft inside the buried pipeline and, despite efforts to continue its progress, it would go no farther. Pressure applied to the CT to 500 psi and then to 1,250 psi set the packer and increased to 2,000 psi to shear open the pressure relief assembly. Set down and pickup weight applied to the packer verified its setting, a ⅝-in. ball was dropped and circulated to its seat, and 5,000 psi of pressure applied to the CT to shear the disconnect loose.

After raising of the CT a short distance, seawater circulated the riser and pipeline to the CTSV tanks until returns were clean, after which the CT was retrieved, the unit disengaged, the riser detached and lowered back to the seabed, and the 8-in. ball-valve closed.

The entire process led to substantial deoiling of the upstream end of the damaged section of line, with a permanent plug put in place to retain the balance of the pipeline contents.

A similar operation at Location A prepared the other end of the buried section for isolation and, following relocation of the CTSV, the same basic deoiling steps were repeated. In this case the BHA stopped at a depth of 3,459 ft equivalent to 2,819 ft inside the pipeline, where the packer was set, the relief valve sheared open to establish circulation, and the ⅝-in. ball dropped

and pumped to seat to release from the packer.

Seawater then circulated the pipeline clean as before, taking returns into the CTSV tanks before the riser was lowered to the seabed. ✦

The authors

Ignacio Quintero III (iquintero@chevron.com) serves as project manager at Chevron Pipe Line Co. in Bellaire, Tex. He has also served as project engineer at Shell Oil Co. and senior facility engineer at Delphi Automotive. He holds a bachelors degree in mechanical engineering (1997) from the University of Texas at El Paso. He is also a licensed professional engineer in the state of Michigan.

Bob Murphy (bob.murphy@weatherford.com) is global product line manager, thru-tubing packers with Weatherford International Ltd, based in Houston. He has 29 years of experience running packers and bridge plugs in completion and remedial applications. Murphy has spent the last 10 years working exclusively with coiled tubing conveyed packers, including thru tubing inflatables. He is a member of the Society of Petroleum Engineers (SPE) and the Intervention & Coiled Tubing Association (ICoTA).

Joe Bob Maddox (joe.maddox@weatherford.com) is a thru-tubing specialist at Weatherford International in Broussard, La. He has also served as downhole tool specialist for Techline Oil Tools and Elder Oil Tools.

John M. Noddin (jnoddin@sbcglobal.net) is president at Critical Path Consulting, Beaumont, Tex., and specializes in project management for the oil and gas industry. He has also served as senior project manager for both manufacturing and service companies. He holds a degree in mechanical engineering from Texas A&M University, College Station. He is a member of ASME and SME.

New gas detection tool

Here's the UltraRAE 3000, a new photoionization detector for compound-specific gas monitoring.

It makes use of proprietary prefilter tubes to measure specific gases such as benzene and butadiene. The unit is wirelessly enabled, making it compatible with the industry-standard AreaRAE network for remote data measurement and collection. The 3000 uses the same detection technology as the ppbRAE 3000, with the ability to measure toxic compounds below 50 ppb. The 3000 is intended for use in confined space entry, prescreening during refinery and plant maintenance, hazardous material response, marine spill response, and refinery downstream monitoring.

The instrument can be used for 60-sec snapshot assessments as well as longer short-term exposure limit surveys.

It also measures total volatile organic compounds in two ranges: 0-1,000 ppm with a resolution of 0.05 ppm or 1,000-10,000 ppm with a resolution of 1 ppm. The monitor also has integrated correction factors for more than 200 compounds.

Source: **RAE Systems,** 3775 N. First St., San Jose, CA 95134.

New analysis service for carbonate reservoirs

The newly released Carbonate Advisor petrophysics and productivity analysis service offers a systematic analytical framework to deliver a timely, comprehensive petrophysical evaluation of carbonate rocks.

The system integrates information from magnetic resonance and elemental capture spectroscopy, as well as other logs and core data, to produce a single, complete formation evaluation of carbonate reservoirs.

In field tests in a variety of carbonate reservoirs, relative permeability and water saturation measurements from Carbonate Advisor matched discrete core analysis data, the firm notes. These continuous measurements permitted a more accurate prediction of fluid flow leading to better production performance, the firm points out.

The company says its service can be applied easily and with equal effectiveness either packaged with newly acquired data or to suites of previously acquired data. It helps maximize the value of all the log measurements taken by using them together to solve a complex problem.

Source: **Schlumberger Ltd.,** 5599 San Felipe, 17th Floor, Houston, TX 77056.

SulphCo Inc.,

Houston, has appointed Dr. Florian J. Schattenmann chief technology officer effective Aug. 1. He will have management responsibility for the company's research and development programs involving Sulphco's patented Sonocracking™ technology. Previously, Schattenmann was technology director at the GE-Bayer Silicones joint venture, where he led innovation and new product introduction efforts. He remained with the JV after it was acquired by Apollo Management LP and renamed Momentive Performance Materials. Schattenmann has a Ph.D. in inorganic chemistry from the Massachusetts Institute of Technology and an undergraduate degree in chemistry from the Technische Universität München.


Schattenmann

Sulphco has developed a patented process employing ultrasound technology to desulfurize and hydrogenate crude oil and other oil-related products. The company's technology is designed to upgrade sour heavy crude oils into sweeter, lighter crude oils, producing more gallons of usable oil per barrel.

MOGAS Industries Inc.,

Houston, has appointed Jonquil Hill director of product engineering. She will oversee the production and product side of the company's engineering efforts. Previously, Hill worked for TapcoEnpro International and Hanking & Anderson Consulting Engineers.


Hill

She has a BS in mechanical engineering from the University of Witwatersrand in Johannesburg.

MOGAS designs, engineers, manufactures, and services severe-service metal-seated ball valves for use in oil and gas production, power generation, metals and minerals, refining, petrochemical/chemical, and specialty industries.

DO2 Technologies Inc.,

Houston, has signed a multiyear agreement with Winnipeg-based Tundra Oil & Gas Partnership to license DO2's solutions to automate and streamline their invoicing and accounts payable processes. Tundra and DO2 will begin implementation of a broad suite of DO2's products that provide functionality for not only electronic invoicing, but also the management of paper invoices (scanned invoices) within the electronic invoicing workflow, the management of early payment discounts, and the reconciliation of invoices against contracted prices.

DO2 is the leading global provider of electronic-invoicing software solutions that enable buyers and suppliers to automate shared financial processes.

Taide Network,

Holmestrand, Norway, a premium provider of high performance IP solutions via satellite and a member of the Vizada Group, has rebranded to Vizada Networks. The rebranding will clarify the entity's position as a key business unit within the Vizada Group. It will also enable former Taide customers to benefit from the Vizada Group's market position and reputation as leading provider of global satellite communications.

The Oslo-based Vizada Group was formed in September 2007 and combines the former Telenor Satellite Services and France Telecom Mobile Satellite Communications. The Group comprises two principal business divisions—Vizada Mobile Satellite Services and Vizada VSAT for Fixed Satellite Services.

Taide, founded in 1997, is one of the leading IP trunking providers in Africa and the Middle East and now operates in more than 50 countries worldwide.

PAS,

Houston, has named Grant Ostvig managing director for its Middle East operations. He will be based in Dubai and have overall responsibility for PAS's business in the Middle East region. Ostvig held various management positions at Honeywell for over 30 years and spent over half of his career in international sales for process control, representing Honeywell on five continents. He has a physics degree from the University of Utah and an MBA from the University of Minnesota.

PAS is a leading supplier of software products and consulting services to the process industries worldwide.

W&O,

Jacksonville, Fla., has acquired the Portsmouth, Va.-based Valco/Premier Group. W&O, a division of Pon Equipment + Power Systems, is the largest US supplier of marine valves, pipe, fittings, engineered products, and valve automation solutions to the marine and offshore industries. Valco/Premier group includes Premier Copper Manufacturing, Valco Piping Products and Premier Copper & Brass/Pacific.

Intervera Data Solutions,

Calgary, has appointed Nick Beingessner director of sales and marketing. He will be responsible for global business development, promoting channel partnerships, and building client relationships. Previously, Beingessner was sales manager for Telvent's SCADA and Environment divisions, where he led a number of sales initiatives in North America, the Middle East, and Africa. He has more than 11 years of IT software sales and business management experience.


Beingessner

Intervera provides practical, end-to-end data quality services and software to E&P data managers and professionals.

Atlas Copco,

Garland, Tex., has been named to the Global 100 list of the world's most sustainable corporations. The listing, developed by Toronto-based Corporate Knights Inc. with Innovest Strategic Value Advisors Inc., New York, focuses on analyzing companies' performance on social, environmental, and strategic governance issues.

Atlas Copco Drilling Solutions, a division of Atlas Copco's Construction and Mining Technique business area, develops, manufactures, and markets a wide range of rotary drilling equipment for use in surface mining, exploration, construction, water well, aggregate, and shallow oil and gas applications worldwide.

Aker Solutions ASA,

Lysaker, Norway, has acquired Aberdeen-based Qserv Ltd., for an initial payment of 1 billion kroner (Nor.) and a deferred payment due in 2011.

Aker Solutions is a leading global provider of engineering and construction services, technology products, and integrated solutions for the oil and gas, refining and chemicals, mining and metals, and power generation industries

Qserv is a privately owned company that provides a range of services encompassing wireline, coil tubing, fluid and nitrogen pumping, subsea well intervention, leak testing, bolting, and pipeline commissioning in the North Sea and other markets.

The two companies are already cooperating on the delivery of integrated intervention services across a variety of disciplines, including wireline tractor services, logging services, and light well intervention vessels.

ABS,

Houston, has named Todd Grove president and COO of its Pacific division. Previously ABS chief of staff in Houston, he is relocating to the Pacific division's main office in Singapore. Grove will have responsibility for the society's activities in more than 20 countries, from India to New Zealand. With more than 1,000 employees, the Pacific Division is the largest of the three operational and administrative divisions within ABS. Having served as Pacific divisional director of technology and business development in the mid-1990s, Grove since has held a variety of roles within ABS, including president of the Americas Division, energy project development director, and manager of offshore engineering for the Americas.

Grove

Grove replaces Jim Liebertz, who has led the ABS Pacific Division for the last 5 years and has been named vice-president, global marketing, reporting directly to ABS Chairman Robert D. Somerville and charged with identifying new opportunities for expansion within the Asian region.

ABS is a leading international classification society devoted to promoting the security of life, property, and the marine environment through the development and verification of standards for the design, construction and operational maintenance of marine-related facilities.

Paradigm BV,

Amsterdam, has named Gary V. Morris chief financial officer. He will be accountable for all aspects of Paradigm's finance, including accounting, financial planning and analysis, tax, treasury, audit, and investor relations. Morris began his career as a senior auditor at Arthur Andersen & Co. With over 30 years in supporting global finance in a variety of roles, he joins Paradigm from Herodotus Energy LLC, a consulting company where he served as partner. His long tenure at Halliburton Co. began as a senior auditor and rapidly brought him through the ranks to serve as controller and vice-president of finance for Halliburton's Energy Services Group, through divisional executive vice-president and CFO assignments, and ultimately executive vice-president and CFO for Halliburton Co.

Paradigm is an industry leader in digital subsurface asset management that helps global oil and gas companies locate new reserves and optimize production in complex geological areas. Paradigm's technology advances the science of hydrocarbon detection with solutions in seismic data processing and subsurface imaging, prospect interpretation and modeling, reservoir characterization, and well planning and drilling.

Software Toolbox,

Charlotte, NC, has been named one of the first Endorsed Partners in Wonderware's Innovation Partner Program, a level reserved for Wonderware's closest business relationships. Software Toolbox was chosen to provide technical support services to Wonderware, their channel, customers, VARs (value-added resellers), and OEMs (original equipment manufacturers) for new device communications options announced in mid-July by Wonderware and Kepware. Software Toolbox was chosen by Wonderware to provide these services and as an Endorsed Partner because of its experience in providing device integration support to the Wonderware channel and their customers, OEMs, and VARs for nearly 10 years.

Wonderware is the leading supplier of industrial automation and information software solutions.

Software Toolbox provides the automation industry with drivers, components, development tools, and HMI/SCADA add-ins/enhancements.

Electronic Power Design,

Houston, has added Washington Maurojorge to its sales department, where he will cover the expanding Latin American market. He brings 27 years of experience of working in South America, Central America, and Mexico in technical and executive positions at MANB&W, Wartsila NA, and Cummins Inc. Today, he is based out of Florida, where he owns and operates his own consulting firm, WMB Consulting. Maurojorge holds a degree in naval architecture and has an extensive international background in the marine, oil and gas, and energy industries working with new constructions and retrofits.

EPD is a global provider of electrical systems integration and a custom designer of power systems for offshore drilling, vessels, wind-power turbines, alternative energy systems, and industrial and manufacturing facilities.

Rigdon Marine Corp.,

Houston, has appointed Matthew Rigdon manager, sales and marketing. He will be responsible for domestic sales and brokerage, business development, and special projects.

Previously, Rigdon worked for Bourbon Offshore in a variety of positions after starting his career as an ordinary seaman on a Rigdon 5000 class platform support vessel. He returned to Rigdon Marine in February 2008.

Rigdon Marine operates a fleet of platform support vessels, fast supply vessels, and crewboats.

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Imports of crude and products

	Districts 1-4		District 5		Total US		
	7-11 2008	7-4 2008	7-11 2008	7-4 2008	7-11 2008	7-4 2008	*7-13 2007
	1,000 b/d						
Total motor gasoline	951	1,116	65	47	1,016	1,163	915
Mo. gas. blending comp.	537	580	17	47	554	627	510
Distillate	150	142	0	0	150	142	251
Residual	205	257	18	0	223	257	435
Jet fuel-kerosine	57	34	41	0	98	34	194
Propane-propylene	106	74	2	1	108	75	233
Other	876	629	127	64	1,003	693	968
Total products	**2,882**	**2,832**	**270**	**159**	**3,152**	**2,991**	**3,506**
Total crude	**9,406**	**8,435**	**1,385**	**1,112**	**10,791**	**9,547**	**10,375**
Total imports	**12,288**	**11,267**	**1,655**	**1,271**	**13,943**	**12,538**	**13,881**

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

Purvin & Gertz LNG netbacks—July 18, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	9.32	6.60	8.20	6.46	7.41	8.10
Everett	9.92	7.09	9.40	7.11	7.86	10.33
Isle of Grain	11.41	8.87	10.50	8.76	9.51	10.53
Lake Charles	7.90	5.25	7.58	5.49	5.95	8.78
Sodegaura	7.42	10.35	7.66	9.93	8.98	6.43
Zeebrugge	10.00	7.59	9.18	7.46	8.21	9.17

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	16,440	59,912	32,536	9,346	44,226	15,081	4,126
PADD 2	63,776	51,260	18,470	7,734	30,245	1,460	18,597
PADD 3	148,784	68,205	32,044	13,133	34,343	16,571	21,311
PADD 4	13,948	6,137	1,769	492	2,965	310	[1]1,256
PADD 5	53,940	28,724	22,227	8,249	13,911	5,662	—
July 11, 2008	**296,888**	**214,238**	**107,046**	**38,954**	**125,690**	**39,084**	**45,290**
July 4, 2008	**293,936**	**211,766**	**105,084**	**38,764**	**122,501**	**39,366**	**44,001**
July 13, 2007[2]	**352,131**	**203,341**	**91,590**	**40,954**	**122,225**	**36,899**	**47,824**

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

Refinery report—July 11, 2008

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,528	1,530	2,117	110	550	113	57
PADD 2	3,340	3,313	2,262	257	1,043	56	186
PADD 3	7,541	7,396	3,108	828	2,393	288	705
PADD 4	531	527	289	23	153	12	[1]130
PADD 5	2,804	2,701	1,281	479	597	143	—
July 11, 2008	**15,744**	**15,467**	**9,057**	**1,697**	**4,736**	**612**	**1,078**
July 4, 2008	**15,686**	**15,488**	**8,929**	**1,526**	**4,641**	**635**	**1,160**
July 13, 2007[2]	**15,880**	**15,650**	**9,165**	**1,441**	**3,980**	**686**	**1,114**
	17,594 Operable capacity		**89.5 utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*7-18-08	*7-20-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	143.26	87.28	55.98	64.1
Brent crude	136.22	78.20	58.02	74.2
Crack spread	7.05	9.08	–2.03	–22.4
FUTURES MARKET PRICES				
One month				
Product value	148.16	89.27	58.89	66.0
Light sweet crude	135.34	74.94	60.40	80.6
Crack spread	12.82	14.33	–1.51	–10.5
Six month				
Product value	150.88	86.41	64.48	74.6
Light sweet crude	137.52	74.00	63.52	85.8
Crack spread	13.36	12.41	0.96	7.7

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

OGJ GASOLINE PRICES

	Price ex tax 7-16-08	Pump price* 7-16-08	Pump price 7-18-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	366.4	410.8	298.1
Baltimore	359.9	401.8	295.1
Boston	362.9	404.8	289.0
Buffalo	360.2	419.8	299.1
Miami	370.2	421.8	300.1
Newark	361.7	394.6	284.0
New York	353.0	412.6	300.0
Norfolk	355.8	393.8	288.1
Philadelphia	360.1	410.8	301.2
Pittsburgh	350.2	400.9	290.1
Wash., DC	372.4	410.8	298.1
PAD I avg	361.1	407.5	294.8
Chicago	386.9	444.8	310.6
Cleveland	357.3	403.7	265.6
Des Moines	359.7	399.8	289.5
Detroit	356.4	410.8	303.9
Indianapolis	350.7	400.8	298.5
Kansas City	360.8	396.8	283.7
Louisville	367.0	403.9	297.3
Memphis	352.3	392.1	291.2
Milwaukee	361.6	412.9	296.4
Minn.-St. Paul	361.4	401.8	279.2
Oklahoma City	354.5	389.9	280.2
Omaha	359.3	401.6	309.1
St. Louis	357.9	393.9	298.2
Tulsa	354.3	389.7	284.2
Wichita	333.5	376.9	290.4
PAD II avg	358.2	401.3	291.9
Albuquerque	353.4	389.8	290.8
Birmingham	359.2	397.8	284.2
Dallas-Fort Worth	364.4	402.8	283.4
Houston	356.4	394.8	283.9
Little Rock	356.6	396.8	285.1
New Orleans	361.4	399.8	288.4
San Antonio	354.4	392.8	281.2
PAD III avg	358.0	396.4	285.3
Cheyenne	363.8	396.2	289.3
Denver	372.3	412.7	309.7
Salt Lake City	361.3	404.2	309.6
PAD IV avg	365.8	404.4	302.9
Los Angeles	393.3	457.2	312.0
Phoenix	386.8	424.2	302.0
Portland	388.8	432.2	310.0
San Diego	402.3	466.2	323.1
San Francisco	396.6	460.5	320.1
Seattle	387.1	441.5	301.0
PAD V avg	392.5	446.9	311.4
Week's avg.	**364.4**	**408.8**	**295.1**
June avg.	**360.2**	**404.2**	**309.4**
May avg.	**329.3**	**372.9**	**307.6**
2008 to date	**302.8**	**346.5**	—
2007 to date	**226.5**	**270.1**	—

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

REFINED PRODUCT PRICES

	7-11-08 ¢/gal		7-11-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	340.90	New York Harbor	404.00
Gulf Coast	341.65	Gulf Coast	401.50
Los Angeles	348.65	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	344.47	ARA	421.31
Singapore	345.95	Singapore	420.00
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	350.90	New York Harbor	283.05
Gulf Coast	344.90	Gulf Coast	291.07
Los Angeles	357.15	Los Angeles	286.45
		ARA	309.34
		Singapore	283.72

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

BAKER HUGHES RIG COUNT

	7-18-08	7-20-07
Alabama	5	5
Alaska	7	9
Arkansas	58	52
California	43	38
Land	43	37
Offshore	0	1
Colorado	106	106
Florida	2	1
Illinois	1	0
Indiana	2	3
Kansas	11	14
Kentucky	12	11
Louisiana	173	181
N. Land	63	59
S. Inland waters	25	25
S. Land	28	28
Offshore	57	69
Maryland	1	1
Michigan	1	3
Mississippi	8	15
Montana	14	20
Nebraska	0	0
New Mexico	83	80
New York	5	5
North Dakota	67	38
Ohio	13	13
Oklahoma	205	189
Pennsylvania	24	12
South Dakota	2	3
Texas	922	838
Offshore	9	8
Inland waters	1	0
Dist. 1	18	24
Dist. 2	29	32
Dist. 3	59	70
Dist. 4	89	88
Dist. 5	183	179
Dist. 6	129	124
Dist. 7B	31	33
Dist. 7C	70	55
Dist. 8	144	109
Dist. 8A	29	22
Dist. 9	45	35
Dist. 10	86	59
Utah	49	38
West Virginia	26	32
Wyoming	76	71
Others—OR-1; TN-2; VA-8; WA-1	12	12
Total US	**1,928**	**1,790**
Total Canada	**410**	**377**
Grand total	**2,338**	**2,167**
Oil rigs	385	287
Gas rigs	1,534	1,497
Total offshore	69	80
Total cum. avg. YTD	**1,828**	**1,749**

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

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

SMITH RIG COUNT

Proposed depth, ft	7-18-08 Rig count	7-18-08 Percent footage*	7-20-07 Rig count	7-20-07 Percent footage*
0-2,500	79	3.7	62	6.4
2,501-5,000	132	48.4	107	50.4
5,001-7,500	266	15.4	254	24.8
7,501-10,000	473	3.1	417	2.8
10,001-12,500	494	2.6	462	1.5
12,501-15,000	309	—	273	—
15,001-17,500	149	—	103	—
17,501-20,000	87	—	65	—
20,001-over	38	—	34	—
Total	**2,027**	**6.7**	**1,777**	**7.8**
INLAND	31		38	
LAND	1,935		1,674	
OFFSHORE	61		65	

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

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

OGJ PRODUCTION REPORT

	[1]7-18-08	[2]7-20-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	710	716
California	654	667
Colorado	42	38
Florida	5	5
Illinois	26	27
Kansas	94	102
Louisiana	1,325	1,300
Michigan	15	16
Mississippi	54	56
Montana	93	94
New Mexico	162	161
North Dakota	118	123
Oklahoma	170	171
Texas	1,345	1,342
Utah	45	51
Wyoming	147	149
All others	60	93
Total	**5,080**	**5,131**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	7-18-08 $/bbl*
Alaska-North Slope 27°	120.20
South Louisiana Sweet	132.25
California-Kern River 13°	114.80
Lost Hills 30°	123.00
Wyoming Sweet	118.88
East Texas Sweet	125.00
West Texas Sour 34°	118.00
West Texas Intermediate	125.50
Oklahoma Sweet	125.50
Texas Upper Gulf Coast	122.00
Michigan Sour	118.50
Kansas Common	124.25
North Dakota Sweet	119.00

*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]	7-11-08
United Kingdom-Brent 38°	137.81
Russia-Urals 32°	132.62
Saudi Light 34°	134.55
Dubai Fateh 32°	136.82
Algeria Saharan 44°	140.38
Nigeria-Bonny Light 37°	143.54
Indonesia-Minas 34°	145.51
Venezuela-Tia Juana Light 31°	135.32
Mexico-Isthmus 33°	135.21
OPEC basket	138.76
Total OPEC[2]	135.76
Total non-OPEC[2]	135.28
Total world[2]	135.55
US imports[3]	133.32

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

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

US NATURAL GAS STORAGE[1]

	7-11-08	7-4-08	7-11-07	Change, %
	bcf			
Producing region	742	717	901	–17.6
Consuming region east	1,245	1,177	1,382	–9.9
Consuming region west	325	314	390	–16.7
Total US	**2,312**	**2,208**	**2,673**	**–13.5**
	Apr. 08	**Apr. 07**	**Change, %**	
Total US[2]	**1,436**	**1,720**	**–16.5**	

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

Statistics

World oil balance

	2008 1st qtr.	2007 4th qtr.	2007 3rd qtr.	2007 2nd qtr.	2007 1st qtr.	2006 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	20.15	21.00	21.03	20.97	21.07	21.09
Canada	2.34	2.34	2.38	2.28	2.34	2.29
Mexico	2.02	2.08	1.98	2.07	2.05	2.00
Japan	5.41	5.22	4.67	4.61	5.39	5.29
South Korea	2.32	2.31	2.06	2.12	2.35	2.32
France	1.96	2.00	1.93	1.85	1.97	1.95
Italy	1.60	1.72	1.63	1.67	1.69	1.71
United Kingdom	1.72	1.73	1.75	1.78	1.80	1.81
Germany	2.48	2.55	2.56	2.38	2.38	2.71
Other OECD Europe	7.38	7.60	7.52	7.25	7.35	7.55
Australia & New Zealand	1.09	1.12	1.09	1.07	1.09	1.10
Total OECD	**48.47**	**49.67**	**48.60**	**48.05**	**49.48**	**49.82**
NON–OECD						
China	7.72	7.87	7.59	7.52	7.33	7.45
FSU	4.34	4.32	4.22	4.32	4.25	4.36
Non-OECD Europe	0.86	0.79	0.73	0.78	0.85	0.78
Other Asia	8.81	8.93	8.64	8.83	8.74	8.80
Other non-OECD	15.23	15.02	15.30	14.99	14.71	14.47
Total non-OECD	**36.96**	**36.93**	**36.48**	**36.44**	**35.88**	**35.86**
TOTAL DEMAND	**85.43**	**86.60**	**85.08**	**84.49**	**85.36**	**85.68**
SUPPLY						
OECD						
US	8.64	8.56	8.40	8.53	8.43	8.40
Canada	3.35	3.32	3.35	3.33	3.42	3.39
Mexico	3.30	3.35	3.46	3.61	3.59	3.52
North Sea	4.46	4.57	4.28	4.49	4.80	4.76
Other OECD	1.54	1.57	1.56	1.54	1.50	1.55
Total OECD	**21.29**	**21.37**	**21.05**	**21.50**	**21.74**	**21.62**
NON–OECD						
FSU	12.60	12.66	12.55	12.60	12.61	12.48
China	3.93	3.86	3.87	3.96	3.92	3.81
Other non-OECD	11.06	11.33	11.36	11.16	10.83	11.22
Total non-OECD, non-OPEC	**27.59**	**27.85**	**27.78**	**27.72**	**27.36**	**27.51**
OPEC*	**36.76**	**36.18**	**35.44**	**35.07**	**34.98**	**35.49**
TOTAL SUPPLY	**85.64**	**85.40**	**84.27**	**84.29**	**84.08**	**84.62**
Stock change	**0.21**	**–1.20**	**–0.81**	**–0.20**	**–1.28**	**–1.06**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD total net oil imports

	Mar. 2008	Feb. 2008	Jan. 2008	Mar. 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,354	–1,320	–1,237	–1,273	–81	6.4
US	10,728	10,531	11,869	12,634	–1,906	–15.1
Mexico	–1,390	–1,160	–1,220	–1,667	277	–16.6
France	1,862	1,681	2,081	1,311	551	42.0
Germany	2,358	2,079	2,392	2,115	243	11.5
Italy	1,496	1,328	1,509	1,650	–154	–9.3
Netherlands	1,225	912	1,033	838	387	46.2
Spain	1,521	1,558	1,677	1,488	33	2.2
Other importers	3,946	3,826	4,490	3,706	240	6.5
Norway	–1,842	–2,206	–2,089	–2,476	634	–25.6
United Kingdom	142	29	–129	13	129	992.3
Total OECD Europe	**10,708**	**9,207**	**10,964**	**8,645**	**2,063**	**23.9**
Japan	5,357	5,426	5,444	5,013	344	6.9
South Korea	2,084	2,111	2,556	2,615	–531	–20.3
Other OECD	1,058	1,096	920	1,027	31	3.0
Total OECD	**27,191**	**25,891**	**29,296**	**26,994**	**197**	**0.7**

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

OECD* total gross imports from OPEC

	Mar. 2008	Feb. 2008	Jan. 2008	Mar. 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	396	542	581	415	–19	–4.6
US	5,934	5,850	6,413	6,486	–552	–8.5
Mexico	10	30	31	28	–18	–64.3
France	800	616	868	534	266	49.8
Germany	475	409	467	330	145	43.9
Italy	1,206	1,100	1,318	1,230	–24	–2.0
Netherlands	668	391	774	521	147	28.2
Spain	703	671	654	627	76	12.1
Other importers	1,169	1,210	1,269	1,021	148	14.5
United Kingdom	283	316	183	248	35	14.1
Total OECD Europe	**5,304**	**4,713**	**5,533**	**4,511**	**793**	**17.6**
Japan	4,497	4,567	4,822	4,801	–304	–6.3
South Korea	2,292	2,280	2,472	2,485	–193	–7.8
Other OECD	754	762	603	707	47	6.6
Total OECD	**19,187**	**18,744**	**20,455**	**19,433**	**–246**	**–1.3**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	Mar. 2008	Feb. 2008	Average YTD 2008	Average YTD 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	441	384	489	691	–202	–29.2
Angola	388	350	441	586	–145	–24.7
Kuwait	203	266	235	217	18	8.3
Nigeria	1,174	1,025	1,132	1,198	–66	–5.5
Saudi Arabia	1,542	1,627	1,556	1,342	214	15.9
Venezuela	1,033	1,131	1,152	1,277	–125	–9.8
Other OPEC	1,153	1,067	1,066	618	448	72.5
Total OPEC	**5,934**	**5,850**	**6,071**	**5,929**	**142**	**2.4**
Canada	2,542	2,464	2,532	2,407	125	5.2
Mexico	1,358	1,327	1,331	1,611	–280	–17.4
Norway	80	100	88	133	–45	–33.8
United Kingdom	218	155	196	251	–55	–21.9
Virgin Islands	290	351	340	363	–23	–6.3
Other non-OPEC	2,129	2,356	2,331	2,570	–239	–9.3
Total non-OPEC	**6,617**	**6,753**	**6,818**	**7,335**	**–517**	**–7.0**
TOTAL IMPORTS	**12,551**	**12,603**	**12,889**	**13,264**	**–375**	**–2.8**

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

Oil stocks in OECD countries*

	Mar. 2008	Feb. 2008	Jan. 2008	Mar. 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	177	176	182	166	11	6.6
Germany	277	272	276	289	–12	–4.2
Italy	131	129	136	134	–3	–2.2
United Kingdom	100	94	95	106	–6	–5.7
Other OECD Europe	694	680	691	663	31	4.7
Total OECD Europe	**1,379**	**1,351**	**1,380**	**1,358**	**21**	**1.5**
Canada	203	202	206	182	21	11.5
US	1,653	1,662	1,677	1,677	–24	–1.4
Japan	610	605	621	620	–10	–1.6
South Korea	143	149	155	156	–13	–8.3
Other OECD	108	111	108	101	7	6.9
Total OECD	**4,096**	**4,080**	**4,147**	**4,094**	**2**	**—**

*End of period.
Source: DOE International Petroleum Monthly Report
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- EPC for the revamp process units.
- EPC for utilities and offsites.
- Preparing the EPC bid packages for one or more grass roots units to be subcontracted on a lump sum basis. The Managing Contractor will supervise these subcontracts.

In addition to the above, Petrojam Ltd. may call upon the Managing Contractor to provide both technical and operations personnel to support the refinery in the start-up and initial operations of the above process units.

The Managing Contractor will function on a reimbursable cost basis.

Firms satisfying the pre-qualification evaluation criteria will be short-listed and invited to submit bid proposals for the role of Managing Contractor by mid October 2008.

Eligibility Conditions: Local firms are required to submit the following:

1. A valid Tax Compliance Certificate (TCC)
2. Valid National Contracts Commission (NCC) Certificate

The **Terms of Reference** outlining the scope of work and prequalification questionnaire is available from Petrojam Ltd. at their offices (see address below) between July 25, 2008 and August 12, 2008 or may be requested via email to: bmc@petrojam.com

Submission of Responses: Original (hard copy) responses must be submitted by **3:30 p.m. on Friday, September 5, 2008** and deposited in the "Tender Box" located in the lobby at Petrojam Limited, 96 Marcus Garvey Drive Kingston 15. Responses must be submitted in sealed envelopes addressed as follows:

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Petrojam Limited
96 Marcus Garvey Drive
P.O. Box 241 GPO
Kingston 15
Jamaica W.I.

In addition to the hard copies, firms may also send their proposals electronically in pdf format to the email address quotation@petrojam.com by 3:30 p.m. on Friday, September 5, 2008.

For further information you may contact:

1. Mrs. Andrea Reid at telephone (876) 923-8613 extension 2205 or via email amr@petrojam.com or
2. Mr. Brian Case at telephone (876) 923-8613 extension 2376 or via email: bmc@petrojam.com

Petrojam Ltd. reserves the right not to shortlist firms for the position of EPC Managing Contractor.

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JOINT VENTURE BID PROPOSAL

Joint Venture «Asia Trans Gas» Limited Liability Company calls for Tender on Project Management Consultancy Services for Uzbekistan – China Gas Pipeline Project:

The Uzbekistan-China Gas Pipeline Project, which is a part of the Central Asia Gas Pipeline project, begins from the border of Uzbekistan and Turkmenistan, and terminates at the border of Uzbekistan and Kazakhstan. The total length of the trunk line is 497km. The pipeline has double line which is laid in parallel, with diameter of 1067mm (X70) and pressure of 9.81MPa. There are 33 valve chambers and 3 compression stations and 2 metering stations.

For realization of the project Joint Venture «Asia Trans Gas» LLC requires company which will render following Project Management Consultancy Services:

- Project management
- Procurement support
- Detail design supervision
- Pre-construction and construction activities
- Site construction supervision
- Pre-commissioning and commissioning supervision services
- Handover

The detailed scope of work, specification and terms of rendering of services are specified in bid documentation.

Eligibility requirements for organization interested in obtaining of tender documentation:

- The Bidder shall have successfully completed PMC at least three (3) projects in the last five (5) years, in general conform to the follow requirements: the PMC for engineering design, procurement and construction (EPC contract) of no less than 500 km of NPS 40" or larger pipeline in a remote location, and a cumulative turnover in pipeline and related EPC activities of no less than US$10 million.
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Sulfur crunch could limit bitumen output

Production of bitumen and heavy oil in Alberta faces a constraint unrelated to problems receiving the most attention.

The usual worries are water and energy supplies, rising royalty rates, and air-emission regulations.

But specialists at the Oil Sands and Heavy Oil Conference in Calgary July 15-17 said a bigger problem might be sulfur.

A strong global market that now prices sulfur at a robust $800/tonne will cycle into "extreme oversupply," according to Bill Kennedy, retired from Shell Canada Ltd.

"It's only a matter of when," he said.

His reasoning: After a period of strong growth, demand for sulfur is leveling. But supply is zooming from bitumen upgraders in northern Alberta, refineries responding to gasoline and diesel desulfurization regulations in the US and Europe, and large sour-gas projects in China, Kazakhstan, and the Middle East.

Kennedy said he expects sulfur supply to double in the next 5-10 years, creating "a market meltdown and transportation gridlock."

In a sulfur-market collapse, said Kennedy, Alberta—along with other high-cost producers like Russia and Kazakhstan—will be unable to sell the byproduct.

Storing sulfur will be necessary. But acquiring permits to build sulfur-storage facilities, called blocks, is time-consuming and likely to remain so in Alberta. Other options, such as hydrogen-sulfide injection or burial, are limited or lack approval.

In Alberta, noted Doug Houston of Kinder Morgan Devco USA, most sulfur storage facilities are in central and southern regions. Transportation connections to them from upgraders in the north are poor.

Producers and processors unable to dispose of or store sulfur will have to curtail operations.

Kennedy said the inability to handle byproduct sulfur could shut down not just upgraders in Alberta but also gas processing plants in the province and refineries in the US with limited sulfur storage.

Response to the possible sulfur crunch by oil and gas companies has been limited, Kennedy said.

Gerard d'Aquin of Con-Sul Inc. urged companies to develop new storage strategies and new markets for sulfur, now used mostly in fertilizer and chemicals.

"The funding is there to do something," he said. "You've got to think about it now. You've got to be market-makers."

(Online July 18, 2008; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Dollar values and oil prices

For months now, members of the Organization of Petroleum Exporting Countries and many western analysts have blamed the weak US dollar as a primary cause of the escalation of oil prices. "It's not because of a lack of crude on the market," they claim, although demand growth has been rampant in India and China.

As oil prices recently peaked at record highs, the US dollar fell to record lows against other key currencies as the Federal Reserve Bank lowered interest rates to stave off inflation and cushion the US credit crunch. In the process it has lowered the cost of oil to many foreign buyers and has encouraged investments in crude as a hedge.

In its largest 3-day price fall ever, the front-month crude contract lost $15.89 over July 15-17 to close at $129.29/bbl on the New York Mercantile Exchange. The dollar rallied July 17 from earlier losses, but then turned slightly weaker against the euro.

That same day, the Centre for Global Energy Studies (CGES), London, reported, "The falling value of the US dollar may have had a marginal impact on the price of oil, but it is clearly not the prime driving factor, and OPEC's assertion that prices are reacting to the euro-dollar exchange rate is really just another way of saying that it is all down to speculation, while ignoring their own role in the process."

Certainly, there is a high degree of correlation between the price of oil in US dollars and the exchange rate between the dollar and euro. On a monthly average basis from January 2002 through mid-July 2008, "the correlation coefficient between the two is around 0.8," CGES reported. "If we concentrate only on the period since January 2007, this rises to 0.95—very high indeed—and strong evidence, surely, that OPEC has got it right." However, the analysts asked, "Is this evidence really compelling enough?"

Between January 2002 and the first half of July 2008, the value of the US dollar fell from 1.132 euro to 0.634 euro, a lost of nearly 45% of its value. "Over the same period, dollar-denominated oil prices have risen from $18.42/bbl to $137.57/bbl for OPEC's reference basket of crudes, an increase of almost 650%. The rise in the oil price over this period has far surpassed the fall in the value of the dollar," said CGES analysts.

Moreover, they said, "Neither the run-up in oil prices between May 2004 and September 2006, nor the surge since January 2007, was accompanied by any appreciable increase in the rate of the dollar's slide in value against the euro." Focusing on the most recent period of soaring oil prices since the start of 2007, CGES analysts said, "The argument weakens even further. Over this shorter period, the value of the dollar has fallen by around 20% against the euro, while dollar-denominated oil prices have increased by more than 170%."

Comparative correlations

The correlation of comparative monthly changes in both the dollar's value and the price of oil "is not good," CGES officials said. In fact, over the period of January 2002-July 2008, they said, "There is no correlation at all, while for the period since January 2007 the correlation is considerably weaker than that between the absolute values, with a coefficient of around 0.57."

Then there is the matter of timing. Analysts said, "The biggest month-on-month jump in oil prices so far this year occurred in April, when the price of the OPEC basket leapt by 14%. In that same month the value of the US dollar rose against the euro, suggesting that there were other factors at play in driving the oil price upwards. Actually, since March of this year the dollar has been remarkably stable against the euro on a monthly-average basis, yet oil prices have risen by almost 40%."

If oil prices really are being driven upwards by the falling value of the dollar against the euro, analysts said, "Then we would expect the euro-denominated price of oil to be much more stable than the dollar-denominated price. To a degree this is indeed the case." From January 2002 through mid-July 2008, the dollar-denominated price of the OPEC reference basket of crudes increased 650%, while the euro-denominated price rose 320%. "The euro-denominated oil price may not have been rising as dramatically as the dollar-denominated price, but it was far from stable," analysts said. "Since the beginning of 2008, the dollar has lost 8% of its value against the euro, while the dollar-denominated oil price has risen by 58% and the euro-denominated price is up by 46%."

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