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International Petroleum News and Technology / www.ogjonline.com

Offshore Europe

Cost shift signals changes in energy investment, use
3D pore pressure used to optimize well design
Cycles, adsorbents aid gas treatment, boost mol-sieve life
Study details errors in high-pressure pipeline infringement

OIL&GAS JOURNAL®

Aug. 4, 2008
Volume 106.29

OFFSHORE EUROPE

Discoveries, undeveloped opportunities persist as offshore Europe oil output falls 35
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UK first half drilling steady 39

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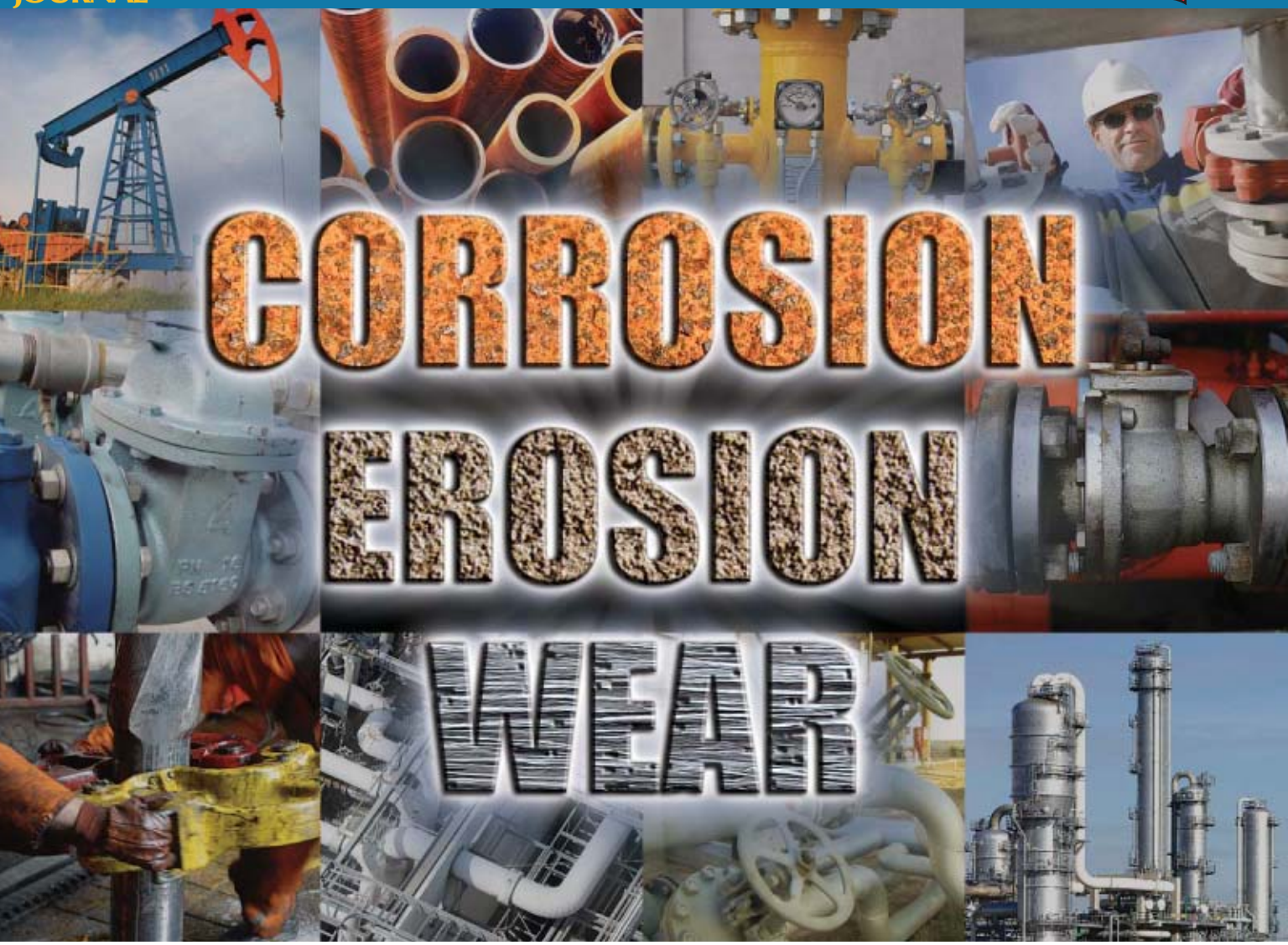
COVER

First oil production is expected in late 2009 from Causeway field in the northern UK North Sea. Various wells drilled by a group led by Antrim Energy Inc., Calgary, have gauged oil from the Tarbert, Ness, and Etive sandstones in the Jurassic Brent Group. OGJ's annual Offshore Europe issue special report sizes up spending and activity in the region, starting on p. 35. Photo courtesy of Antrim Energy.



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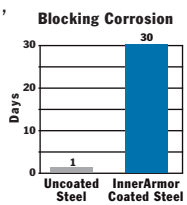
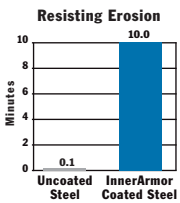


While uncoated steel only lasted a single day!

Standing up to erosion
In the ASTM-standard G76 abrasive air-jet test, again, InnerArmor was easily able to go the full ten minutes—with *zero* surface damage.



By comparison, on uncoated steel the surface erosion began after only a few seconds.

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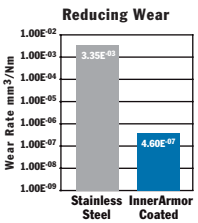

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 Oil & Gas Journal (ISSN 0030-1388) is published 48 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $89; Latin America and Canada: 1 yr. $94; Russia and republics of the former USSR, 1 yr. 1,500 rubles; all other countries: 1 yr. $129, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 106, No. 29) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

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Please submit press releases via e-mail to: news@ogjonline.com

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OGJ Newsletter

Aug. 4, 2008

International news for oil and gas professionals
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General Interest — Quick Takes

Dutch fund charged with US futures control

The US Commodity Futures Trading Commission (CFTC) on July 24 charged a global proprietary trading fund based in the Netherlands, two of its subsidiaries, and three employees with manipulating and attempting to manipulate US petroleum commodities markets.

Optiver Holding BV; subsidiaries Optiver US LLC and Optiver VOF; and employees Christopher Dowson, Optiver US's head trader; Randal Meijer, trading head and supervisor at Optiver US and Optiver VOF; and Bastiaan van Kempen, Optiver US's chief executive, were named in the CFTC's civil complaint filed in US District Court for New York's southern district.

They were charged with allegedly trying 19 times to manipulate light, sweet crude, New York Harbor heating oil, and New York Harbor gasoline futures contracts, which trade on the New York Mercantile Exchange.

The attempts were made during 11 days in March 2007, CFTC said. In at least five of the attempts, the defendants successfully manipulated energy futures contracts and created artificial prices, the federal commodities trading regulator continued. Futures prices were forced lower in three instances and higher in two instances, it said.

The scheme produced about a $1 million profit for the defendants, the complaint said. It said the defendants allegedly used a manipulative scheme commonly known as "banging" or "marking" the close, which involves acquiring a substantial position leading up to the closing period followed by offsetting the position before trading closes.

The complaint also charges Optiver and Van Kempen with concealing the scheme and making false statements in response to a NYMEX inquiry, CFTC said.

"These charges go to the heart of the CFTC's core mission of detecting and rooting out illegal manipulation of the markets," said CFTC Acting Chairman Walter L. Lukken. "Although this alleged energy trading scheme lasted only several days in March 2007, even short-term distortions of prices will not be tolerated by the commission."

The UK Financial Services Authority and NYMEX assisted CFTC in its investigation, he added.

Chavez: IOCs must transfer technology with pacts

Venezuelan President Hugo Chavez, renewing concerns about an old theme, said his country will stop doing business with international oil companies (IOCs) that fail to transfer technology as part of their contracts.

"The order I'm giving is the following: Any foreign company that doesn't transfer technology, well, their contracts will be canceled. We'll get others that want to be here," Chavez said on Venezuelan national television.

The issue of technology transfer is a sore one with the Venezuelan president as well as with IOCs themselves.

Last October ExxonMobil Corp. and ConocoPhillips, under pressure from the government, withdrew from Venezuela, leaving behind their right to produce oil as well as technology and infrastructure that could be used by their competitors.

Technology for advanced well drilling, upgrading oil quality, and prevention of accidents could fall into the hands of companies, such as state-owned Petroleos de Venezuela SA (PDVSA), that do not have the technical expertise to extract reserves with the same efficiency as the two US firms.

The future remains unclear as to the status and use of the left-behind technology, but it could prompt a legal challenge from the two companies.

Earlier in 2007, Chavez blamed former directors of PDVSA for allowing transnational companies to extract oil from the country without investing in new technology.

"The transnational companies did not uphold their agreements. They extracted a billion barrels of oil without investing in technology to produce heavy crude," Chavez said in his weekly Alo Presidente talk show.

Chavez said the former PDVSA directors who signed agreements with transnational companies during the period between 1958 and Chavez's first election in 1998 should be taken to court.

"It was authorized robbery," Chavez said.

Neptune TLP resumes full oil production

Full oil production has been restored on the Neptune tension leg platform in the deepwater Gulf of Mexico, BHP Billiton Ltd. said.

BHP and its partners recently completed remediation work to strengthen components inside the hull's pontoons (OGJ, July 14, 2008, Newsletter).

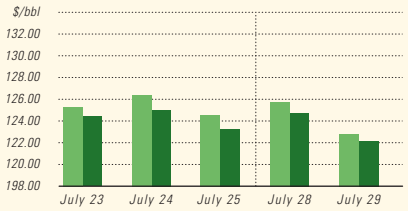
Production began July 6. As of July 25, Neptune had five of six wells on line, and its oil production was at full design capacity of 50,000 b/d.

Natural gas production continues to ramp up to its design capacity of 50 MMcfd of gas.

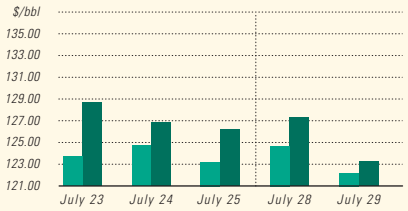
The TLP stands in 4,250 ft of water on Green Canyon Block 613, which is 120 miles off Louisiana. Field development includes six subsea wells. More development wells are expected to be drilled after interpretation of seismic data, being obtained this year. ✦

Industry Scoreboard

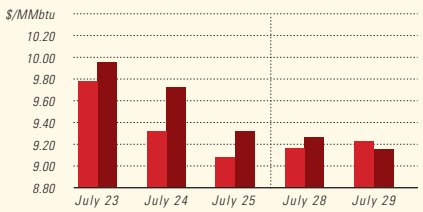
IPE BRENT / NYMEX LIGHT SWEET CRUDE



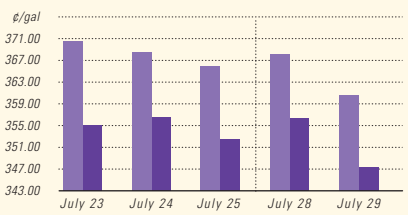
WTI CUSHING / BRENT SPOT



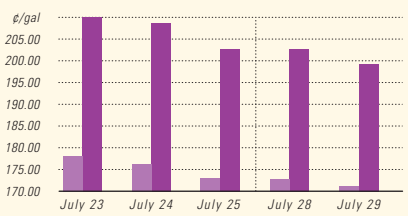
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



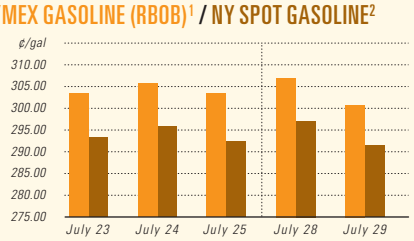
IPE GAS OIL / NYMEX HEATING OIL



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.

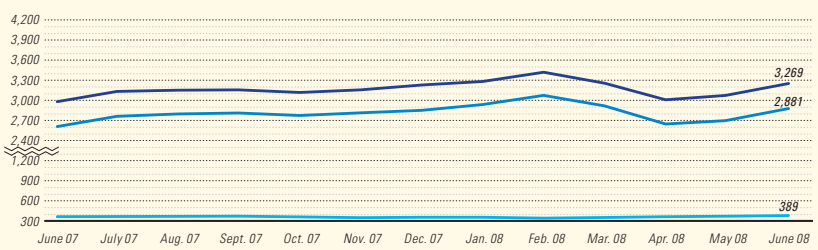
US INDUSTRY SCOREBOARD — 8/4

Latest week 7/18	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	9,348	9,578	–2.4	9,104	9,246	–1.5
Distillate	4,191	4,044	3.6	4,157	4,238	–1.9
Jet fuel	1,623	1,665	–2.5	1,572	1,625	–3.3
Residual	562	686	–18.1	619	764	–19.0
Other products	4,529	4,706	–3.8	4,796	4,825	–0.6
TOTAL DEMAND	20,253	20,679	–2.1	20,030	20,703	–3.3
Supply, 1,000 b/d						
Crude production	5,097	5,128	–0.6	5,120	5,181	–1.2
NGL production[2]	2,196	2,423	–9.4	2,224	2,361	–5.8
Crude imports	10,078	9,934	1.4	9,811	10,010	–2.0
Product imports	3,203	3,674	–12.8	3,214	3,560	–9.7
Other supply[3]	1,476	1,210	22.0	1,428	991	44.1
TOTAL SUPPLY	22,050	22,369	–1.4	21,797	22,103	–1.4
Refining, 1,000 b/d						
Crude runs to stills	14,894	15,672	–5.0	14,894	15,088	–1.3
Input to crude stills	15,111	15,747	–4.0	15,111	15,393	–1.8
% utilization	86.2	90.2	—	86.2	88.2	—

Latest week 7/18	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	295,330	296,888	–1,558	351,028	–55,698	–15.9
Motor gasoline	217,085	214,238	2,847	204,134	12,951	6.3
Distillate	128,109	125,690	2,419	123,653	4,456	3.6
Jet fuel–kerosine	39,992	38,954	1,038	40,665	–673	–1.7
Residual	38,469	39,084	-615	37,503	966	2.6
Stock cover (days)[4]			Change, %		Change, %	
Crude	19.2	19.3	–0.5	22.4	–14.3	
Motor gasoline	23.2	22.9	1.3	21.1	10.0	
Distillate	30.6	30.1	1.7	30.5	0.3	
Propane	47.3	48.8	–3.1	46.1	2.6	
Futures prices[5] **7/25**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	126.44	135.34	–8.90	75.14	51.30	68.3
Natural gas, $/MMbtu	9.75	11.19	–1.43	6.47	3.28	50.7

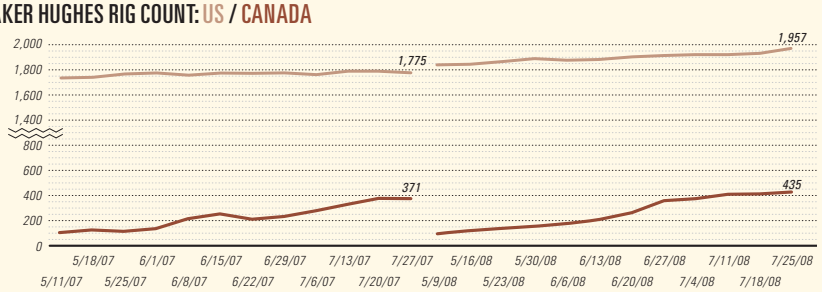
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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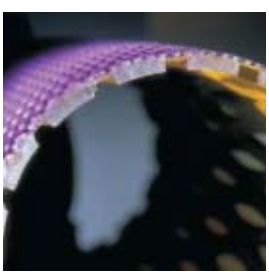

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Exploration & Development — *Quick Takes*

Sonangol OKs developments on Block 31

Angola's position as Africa's leading oil exporter is set to rise as new offshore deepwater discoveries on Block 31 are brought on stream by 2011.

Angola's state oil company Sonangol has given operator BP Exploration (Angola) Ltd. and its partners the nod to develop Pluto, Saturn, Venus, and Mars (PSVM) fields, which lie in the northeast part of the block.

Development is expected to start this year and oil production is expected to peak to 150,000 b/d by 2012. The fields lie in 2,000 m of water and are 400 km northwest of Luanda.

The PSVM field development will comprise a converted-hull floating, production, storage, and offloading vessel with 1.6 million bbl of storage capacity; 48 production, gas, and water-injection wells plus infill wells; 15 manifolds and associated subsea equipment; 170 km of flowlines; and 95 km of control umbilicals.

Sonangol's approval is key for BP's production profile into the next decade and beyond. Andy Inglis, chief executive of BP exploration and production, said, "It demonstrates the scale of the resource base in Block 31."

So far the consortium has discovered 15 fields on the acreage to date and it will develop the others in a similar manner to the PSVM group of fields. The partners have begun to plan the second development in the southeast part of the block. They are also ready to award major contracts for the first phase once it has been sanctioned.

BP holds a 26.67% interest in Block 31. Partners are Esso Exploration & Production Angola (Block 31) Ltd. 25%, Sonangol EP 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and TEPA (Block 31) Ltd. with 5%.

Santos JV makes gas find with Netherby well

Santos Ltd.'s offshore Otway basin joint venture, which includes Australian Worldwide Exploration Ltd. (AWE) of Sydney and Japan's Mitsui E&P Australia Ltd., has discovered 22 m of natural gas pay in primary reservoir target sands with its Netherby-1 wildcat drilled on permit Vic/P44 off Victoria.

The well, drilled using the Ocean Patriot semisubmersible rig to a total depth of 1,870 m, will now be assessed with wireline logs and a pressure-testing program.

Netherby is the second of three planned appraisal and development wells in this sector of the permit in which it is hoped to add reserves to the planned Henry field gas development as an adjunct to the existing Casino field production facilities.

Netherby-1 lies 4 km north of Henry. If the coming tests are successful, Santos plans an immediate sidetrack well to fully determine the reserves before moving the rig to the planned Henry-2 appraisal.

Operator Santos, Adelaide, has 50% interest in the project with AWE and Mitsui each having 25%.

In related news, Santos has appointed acting Chief Executive Officer David Knox as permanent chief executive of the company (OGJ Online, July 29, 2008).

Coogee behind with Montara development

Coogee Resources Ltd., Perth, is about 4 months behind schedule with its Montara oil development project in the Timor Sea. The project is now expected to come on stream by yearend.

One reason behind the delay, the company reported, is a labor shortage in Singapore, where the project's floating production, storage, and offloading vessel is being converted at Jurong Shipyard.

However China's Chiwan Schenzen Engineering had delivered the wellhead platform jacket on time and budget, and Clough Thailand is currently loading out the topsides.

Phase 1 of the Montara development includes production from four wells: two on Skua field (previously produced by BHP Petroleum, but abandoned in 1997) and one well each in Swift and Swallow fields. Phase 2, to be completed in 2009, includes two wells at Montara field itself and one more at Swift.

In addition, Coogee has completed feasibility studies into the potential commercialization of the smaller gas fields surrounding Montara, Jabiru, and Challis, and expects preliminary front-end engineering and design work to begin into on methanol production option during the third quarter. FEED itself is planned for 2009.

The company also is considering CNG and LNG options for these fields with potential partners. ✦

Drilling & Production — *Quick Takes*

BHP gets funding for Turrum development

Melbourne-based BHP Billiton Pty. Ltd. has given the green light to development of Turrum oil and gas field, which lies in the Bass Strait production area off southeast Victoria.

BHP holds a 50% share in the project, which is operated by fellow 50% interest-holder ExxonMobil Corp. BHP has now approved funding for its share of the $1.25 billion full field development.

Production will be channeled through the partnership's existing Gippsland facilities, which comprise offshore pipelines extending to the onshore production facilities at Longford.

BHP says the new facilities for Turrum will consist of a new platform, designated Marlin B, which will be linked by a bridge to the existing Marlin A platform. Since it is one of the original steel structures in the Bass Strait, the Marlin A platform will require an upgrade to accommodate the bridge as well as new equipment.

Turrum is scheduled to come on stream in 2011. For the first 4 years the oil and condensate will be stripped from the production stream and the gas reinjected into the reservoir. Commercial gas sales are expected to begin in 2015 at a rate of 200 MMcfd of gas.

Turrum, which was discovered in the 1970s, lies 42 km offshore in 60 m of water. Reserves are estimated to be 1 tcf of gas and 110 million bbl of oil and condensate.

ExxonMobil says the field will be a key contributor to the estimated 7 tcf of remaining known gas reserves in the Bass Strait—a

figure the company says will sustain gas production from its producing area for another 30 years.

Agip lets contract for Oyo field off Nigeria

Agip Exploration Ltd. has let a €75 million turnkey contract to Technip SA to design and produce the subsea system for Oyo oil field on Block OML 120/121 off Nigeria.

Technip's contract covers the engineering, fabrication, and installation of close to 20 km of flexible production, water injection, and gas injection flowlines and risers. It will also install 15 km of umbilicals supplied by Agip.

"The offshore installation is scheduled for the summer of 2009 and will be carried out by the Constructor, one of the Technip's pipelay and construction vessels," Technip said.

Oyo, which lies in 410 m of water, is expected to start production in 2009 and will produce 29,000 boe/d at its peak.

Gupco starts production from Taurt gas field

Gulf of Suez Petroleum Co. (Gupco) has begun natural gas production from Taurt field on the Ras El Bar concession off Egypt.

The offshore field is a subsea development and includes two subsea wells, a 70-km pipeline, and control umbilical tieback to upgrading facilities at the existing West Harbor processing plant.

Taurt lies 70 km northeast of Port Said in the West Nile Delta. Gas production started in July and will be used to supply the Damietta LNG plant.

Gupco is a joint venture of BP PLC, Egyptian General Petroleum Corp., and Eni SPA affiliate International Egyptian Oil Co. (IEOC). Taurt is BP's first subsea development in Egypt.

The parties to Ras El Bar Offshore Concession agreement are BP Egypt (operator 50%) and IEOC (50%).

IOCs can begin drilling in Chile, minister says

Chilean Mining Minister Santiago Gonzales said international oil companies (IOCs) that won bids to explore for oil and natural gas in the southernmost regions of Chile can begin drilling in August.

"The comptroller general approved the operating contracts so companies can begin drilling," Gonzalez said. In May, Chile signed contracts with four IOCs for exploration of eight blocks in the southern Magallanes region (OGJ, May 12, 2008, Newsletter).

As part of that bidding round, Chile's mining ministry July 15 awarded the Otway block in the Magallanes region to a consortium of Wintershall, GeoPark Holdings Ltd., and Methanex Corp., collectively WGM.

The award was made to WGM after Total SA, which last year won the Otway block in the round, inexplicably did not sign the special operating contract for the block in May.

The WGM consortium, which plans to invest $30.49 million on the Otway block, said it will acquire 330 line-km of 2D seismic data, 470 sq km of 3D seismic data, and will drill seven exploratory wells.

For its part, Chile's state-run oil company Empresa Nacional del Petroleo (Enap) said it plans to invest $300 million. Enap holds a 50% stake in the Coiron, Caupolican, and Lenga blocks in the Magallanes region.

Two weeks ago, GeoPark discovered an oil field on Chile's Fell block following drilling and testing at its Aonikenk 1 exploration well (OGJ Online, July 16, 2008). ✦

Processing — *Quick Takes*

China's NDRC approves biodiesel pilot projects

China's National Development and Reform Commission (NDRC), focusing on new output targets, has approved three biodiesel pilot projects involving total capacity of 170,000 tonnes.

PetroChina's Nanchong refinery will build a 60,000 tonne/year biodiesel plant in Sichuan province, Sinopec will build a 50,000 tpy plant in Guizhou province, and CNOOC will build a 60,000 tpy plant in Hainan province.

NDRC, which said the three biodiesel plants will use jatropha oil as feedstock, did not provide a timetable for the plants' construction.

In April, Gushan Environmental Energy Ltd., China's largest producer of biodiesel as measured by annual production capacity, began construction of new biodiesel production plants at its Chongqing and Hunan sites.

Gushan expects both plants to begin production in the fourth quarter. The Chongqing and Hunan plants are expected to add 60,000 tonnes—30,000 tonnes each—to Gushan's annual biodiesel production capacity.

Gushan currently operates four production facilities in Sichuan, Hebei, Fujian provinces and Beijing with a combined annual production capacity of 240,000 tonnes.

The company aims to increase its annual production capacity to 400,000 tonnes by the end of 2008 with the expansion or addition of production facilities in Beijing, Shanghai, Hunan, and Chongqing.

Samsung to build biodiesel plant in Indonesia

Samsung Group intends to invest $1.63 billion to develop a 25,000-hectare oil palm plantation and biodiesel plant in Indonesia's Riau province.

"They bought the land recently, and that was their first investment. The total investment will likely increase by 10 times," said Al Hilal Hamdi, who heads Indonesia's national team for biofuel development.

Hamdi, who claimed that Samsung had spent 1.5 trillion rupiah on acquiring the land and the plant, said the facility was expected to go online in 2009 and would produce 50,000 kl./year of biodiesel.

Indonesia currently produces two types of biofuel: bioethanol made from cassava, sugarcane, and sorghum; and biodiesel, which is made from castor and crude palm oil.

Output of both types is expected to increase greatly after October when Indonesia plans to impose a new regulation requiring that at least 2.5% of fuel consumed by manufacturers is comprised of biofuel. ✦

ExxonMobil cranks up Nigerian NGL project

ExxonMobil Corp. unit Mobil Producing Nigeria has begun operating its $1.3 billion East Area Natural Gas Liquids II project on Bonny Island, about 17 miles off Nigeria. The project is expected to recover 275 million bbl of NGL from associated natural gas produced in East Area reservoirs on Blocks OML 67, 68, and 70.

In addition, the East Area NGL II project will produce at its peak about 50,000 b/d of NGL and ultimately recover 275 million bbl of NGL from about 950 MMscfd.

Major components of the project, according to a company announcement, include an offshore NGL extraction complex, more than 125 miles of new natural gas and NGL pipelines, and expansion of the existing onshore Bonny River fractionation terminal.

The NGL project is part of an integrated approach to reduce flaring in conjunction with the existing East Area Additional Oil Recovery project. "The projects will reduce flaring and improve oil recovery through reservoir pressure maintenance," the company said.

ExxonMobil said the NGL project follows successful start-up of the East Area Additional Oil Recovery project in June 2006. Together, the two developments "provide for recovery and commercialization of associated gas streams in the field and gas injection into existing reservoirs for recovery and production of additional oil volumes," it said.

Mobil Producing Nigeria (51%) operates the project with coventure partner Nigerian National Petroleum Corp. (49%).

Start-up of the NGL II project brings the total of ExxonMobil worldwide start-ups in 2008 to five, including Kizomba C Mondo (Angola; OGJ Online, Jan. 21, 2007), Volve (Norway; OGJ, Feb. 25, 2008, p. 9), Starling (UK; OGJ Online, Jan. 21, 2007), and ACG Phase 3 (Azerbaijan).

Dolphin lets contract for TFP gas line

The UAE's Dolphin Energy has awarded a $418 million contract to Russia's Stroytransgaz for the construction of the Taweelah-Fujairah natural gas pipeline (TFP).

Construction of the 48-in., 240-km line will begin in the third quarter, with completion expected in 2010. The line will link Dolphin's receiving facilities at Taweelah in Abu Dhabi with Fujairah on the UAE's eastern coast.

The award for the TFP line pipe was announced in December 2007, with the $200 million order going to Salzgitter Mannesmann International GMBH for the supply of 120,000 tons of X70, 48-in. coated line pipe. More than 40% of the pipe's length has been received, with delivery completion set for spring 2009.

Dolphin already supplies the UAE with gas from Qatar via a 48-in., 364-km subsea export pipeline connecting the company's Ras Laffan gas processing plant in Qatar with the receiving facilities at Taweelah. The pipeline can carry as much as 56.6 million cu m/day of gas or 20.7 billion cu m/year.

In June Oman started preparations for the import of Qatari gas. Omani Oil and Gas Minister Muhammad bin Hamed al-Rumhi said a key receiving station at al-Buraimi, on Oman's border with the UAE, was being readied ahead of the imminent arrival of the gas. "We are hopeful that Dolphin gas will begin flowing next month," said Al-Rumhi.

His statement followed earlier reports that Abu Dhabi National Oil Co. and Dolphin had signed a 25-year pipeline deal for Dolphin to lease and operate ADNOC's Eastern Gas Distribution System (EGDS) in Abu Dhabi (OGJ Online, June 18, 2008).

EGDS, which is used to supply gas to ADNOC's customers in Abu Dhabi and Dubai, will be leased by Dolphin to deliver the company's processed gas from Qatar to customers across the UAE, as well as Oman.

Sonatrach lets EPC contract for Arzew LNG train

Algerian oil company Sonatrach has awarded Saipem/Snamprogetti, in joint venture with Chiyoda, a €2.8 billion lump sum turnkey contract for a new LNG train (GL3Z).

The contract encompasses engineering, procurement, and construction of a single 4.7-million tonne/year train to be built near Arzew, Algeria, about 400 km west of Algiers. Work is to be completed by yearend 2012.

This is the first time Saipem has been named main contractor of a large LNG plant.

Saipem is 43% owned by Italy's Eni SPA.

Oil flow resumes from Iraq via Ceyhan pipeline

Iraq resumed sending some 480,000 b/d of crude oil through its northern pipeline after Turkey allowed exports to restart from its Mediterranean port of Ceyhan.

The Turkish government had ordered a halt to Iraqi exports on July 21 as a way of forcing Baghdad to pay an outstanding debt pegged at some $100 million for unspecified costs.

After Iraq paid half the debt on July 22, Turkish state pipeline operator Botas restarted loadings from the pipeline at Ceyhan. No statement was issued concerning the outstanding payment.

Earlier, there had been contradictory statements from Turkish and Iraqi officials about the shutdown.

An official of Turkey's state-owned Botas gas company told the Ihlas news agency that the flow of Iraqi oil exports through the Kirkuk-Ceyhan pipeline stopped July 22 for 17 hr.

He said the cause of the halt was technical not financial. "It is true that Turkey has claims. But the halt of the flow is not concerned with this debt," he said.

That contradicted earlier reports, attributed to Iraqi oil officials, that Baghdad's oil exports to Turkey were halted after a Turkish court ordered the stoppage pending settlement of a claim.

"A small Turkish court issued an order to stop Iraqi exports because of claims lodged against Iraqi entities," an official said. He said the claims were for "relatively small" amounts of money, without providing further details.

Iraq's northern pipeline, which carries crude from Kirkuk oil fields to Ceyhan, flows at about 430,000 b/d and accounts for more than 20% of Iraq's oil exports. The bulk of Iraqi crude oil exports, which stand at more than 1.5 million b/d, pass through its oil export terminal in the south of the country at the port of Basra. ✦

Calendar

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

OIL&GAS JOURNAL online

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

2008

AUGUST

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

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

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.

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

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

SEPTEMBER

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

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

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

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.

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

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

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

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

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

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

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.

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

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

Calendar

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

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

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

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

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

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

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

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

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

NOVEMBER

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

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, +971 (0) 2 4444 909, +971 (0) 2 4444 383 (fax), e-mail: info@adipec.com, website: www.adipec.com. 3-6.

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

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

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

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

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

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

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

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

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

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

Annual Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 18-20.

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

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

DECEMBER

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

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

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

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

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

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

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

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

Seatrade Middle East Maritime Conference & Exhibition,

Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

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

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

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

2009

JANUARY

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

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

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

✦API Exploration & Production Winter Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 19-23.

✦API/AGA Oil and Gas Pipeline Welding Practices Conference, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-23.

FEBRUARY

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

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

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

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

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

MARCH

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

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

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

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

✦NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

✦ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

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

✦API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

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

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

APRIL

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

✦API Pipeline Conference, Fort Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-22.

✦AIChE Spring National Meeting, Tampa, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 26-30.

✦API Spring Refining and Equipment Standards Meeting, Denver, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

MAY

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

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

✦NPRA Reliability & Maintenance Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 19-22.

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

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

JUNE

AAPG Annual Meeting, Denver, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 7-10.

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

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

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

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

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

AUGUST

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

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

SEPTEMBER

IADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

OCTOBER

✦API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

NOVEMBER

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

Journally Speaking

The unexplored Arctic

Alan Petzet
Chief Editor-Exploration

Most of the Arctic, especially offshore, is essentially unexplored with respect to petroleum.

With those words, the US Geological Survey in late July released its assessment of undiscovered, technical recoverable resources north of the Arctic Circle, 66.56° N. Lat.

In fact, the Arctic is so unexplored that those conducting the assessment had to rely on a probabilistic methodology of geological analysis and analog modeling. The sparse seismic and drilling data in much of the Arctic meant that the usual tools and techniques used in USGS resource assessments, such as discovery process modeling, prospect delineation, and deposit simulation, were not generally applicable.

"The extensive Arctic continental shelves may constitute the geographically largest unexplored prospective area for petroleum remaining on earth," USGS said.

Arctic resources

USGS concluded that the area north of the Arctic Circle has 22% of the world's undiscovered, technically recoverable resources.

The region has 13% of the undiscovered oil, 30% of the undiscovered natural gas, and 20% of the undiscovered natural gas liquids (OGJ Online, July 24, 2008).

Of the Arctic's estimated 90 billion bbl of undiscovered oil, 1,670 tcf of gas, and 44 billion bbl of NGL, 84% is believed to be offshore. These figures are the sum of the mean estimates for 25 provinces.

Eight other known provinces were not quantitively assessed because they were judged to have less than a 10% probability of having at least one significant accumulation of 50 million bbl of oil and oil-equivalent gas.

More than 70% of the undiscovered oil is estimated to occur in five provinces, and more than 70% of the undiscovered gas is believed to occur in three provinces.

The 400 existing oil and gas fields north of the Arctic Circle in Canada, Russia, and Alaska account for 40 billion bbl of oil, more than 1,100 tcf of gas, and 8.5 billion bbl of NGL.

Arctic oil and gas

USGS's Circum-Arctic Resource Appraisal (CARA) excluded nonconventional resources such as coalbed methane, gas hydrates, oil shale, and tar sand.

It said the 400 known fields account for 240 billion boe, or 10% of the world's known conventional petroleum resources.

The area above the Arctic Circle totals 8.2 million sq miles, 6% of the earth's surface. Of that, almost 3.1 million sq miles is onshore and more than 2.7 million sq miles is on continental shelves in less than 500 m of water.

Oil provinces

Arctic Alaska is the top Arctic undiscovered oil province with 30 billion bbl of undiscovered oil, 221 tcf of gas, and 6 billion bbl of NGL.

Second is Amerasia basin with 9.7 billion bbl, 57 tcf, and 542 million bbl. The Amerasia basin extends north and northeastward from Arctic Alaska and north of the Sverdrup basin.

Third is East Greenland Rift basins with 8.9 billion bbl, 86 tcf, and 8 billion bbl.

Next is East Barents basins with 7.4 billion bbl, 318 tcf, and 1.4 billion bbl.

Fifth is West Greenland-East Canada with 7 billion bbl, 51.8 tcf, and 1 billion bbl.

Gas provinces

West Siberian basin is the top Arctic undiscovered gas province with 651 tcf, 20 billion bbl of NGL, and 3.6 billion bbl of oil.

East Barents basins is second with 318 tcf of gas, 1.4 billion bbl of NGL, and 7.4 billion bbl of oil.

Arctic Alaska is third.

Other provinces

Other Arctic provinces estimated at 5 million boe or more of undiscovered, technically recoverable resources are the Yenisey-Khatanga basin, Laptev Sea Shelf, Norwegian Margin, Barents Platform, and Eurasia basin.

Provinces with 1-5 million boe are North Kara basins and platforms, Timan-Pechora basin, North Greenland sheared margin, Lomonosov-Makarov, Sverdrup basin, Lena-Anabar basin, North Chukchi-Wrangel Foreland basin, Vilkitskii basin, and Northwest Laptev Sea shelf.

Those with less than 1 million boe are Lena-Vilyui basin, Zyryanka basin, East Siberian Sea basin, Hope basin, and Northwest Canada Interior basins.

The USGS did not yet report the results of individual assessment units in the provinces.

What it means

The assessment represents an appraisal of possible future additions to world oil and gas reserves from new field discoveries in the Arctic.

USGS said, "The study included only those resources believed to be recoverable using existing technology, but with the important assumptions for offshore areas that the resources would be recoverable even in the presence of permanent sea ice and oceanic water depth. No economic considerations are included." ✦

Editorial

Skewed attention to supply

After years of neglect, US energy politics at last considers supply. The attention is skewed by the politics of a grueling election year. But skewed attention can be better than none.

Both major political parties, however, seem to construe oil and gas development as an instantaneous phenomenon that can be switched on and off at will. A reminder is in order that development involves a long sequence of contingent decisions and activities, all subject to a range of risks and the vicissitude of economics, politics, and corporate strategy.

Neither party would be discussing petroleum development if oil prices were low. They take up the subject only in response to pressure generated by the pain of high oil prices. They don't want to appear as powerless with prices as they really are. In fact, the market may be outrunning their promises, having lowered crude oil and product prices impressively in the past couple of weeks in what may or may not be a trend.

Grope for relief

Not every proposal emerging from the political grope for price relief lacks merit. President Bush has lifted presidential moratoriums from oil and gas leasing of the Outer Continental Shelf and challenged Congress to do likewise. Sen. John McCain, the Arizonan sure to be the Republican presidential candidate, has abandoned his opposition to OCS leasing. With this issue, Republicans seem to have found a way to show a testy electorate that they're doing something about gasoline prices.

Of course they're not really lowering gasoline prices—today's prices at any rate. At best, the OCS gestures might moderate futures prices for a while by assuring anxious traders about the potential for new supply. But OCS leasing relates to future oil and gas development and, therefore, prices years from now.

Increased OCS leasing certainly is in order and should have occurred long ago. OCS leasing is essential to new oil and gas production, which serves national interests by enhancing domestic energy supply and stimulating economic activity through the development of native resources. But no one should expect it to lower gasoline prices until whatever production results comes on stream, if then. That will be long after election day.

Democrats, by contrast, say they'll lower gasoline prices immediately by restricting commodity trading and pressuring holders of existing OCS leases to rush drilling and development. They want to avoid anything, such as OCS leasing, that would anger their environmentalist wing. Their desperate alternatives to OCS leasing would restrict the operation of markets and limit future supply. The effect on prices would be the opposite of what the Democrats suppose.

Both parties need to acknowledge the limits of their influence over markets. That step alone would represent progress in the making of US energy policy. Another helpful move would be to recognize that oil prices didn't surge because someone controlling supply suddenly decided they should. They increased for reasons not at all mysterious—reasons that include policy errors that shouldn't be repeated.

The biggest reason for prices to have risen during the past several years is that demand grew faster than supply. In the US, oil prices were so low for at least 15 years that sport utility vehicles and enormous pickup trucks filled highways while few in government heeded calls for attention to future supply. Refineries became ever more difficult to build and expand. And the costs of making gasoline and diesel fuel soared in response to a series of new environmental standards, some of them unnecessarily strict.

Blame irrelevant

Now, of course, there's no domestic production in places where there might otherwise be because wells can't be drilled on nonexistent or egregiously restrictive leases. And officials wonder why US refining capacity isn't greater.

Blame is irrelevant to current conditions. The US energy predicament developed over many years and partly reflects events, such as rising consumption elsewhere, outside the reach of US policy. What the fervor of politics obscures is that no politician has an immediate cure for painful oil prices, which are always addressed most effectively with preventive measures that ensure future supply. ✦

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A STAR ALLIANCE MEMBER

Cost shift signals changes in energy investment, use

Harry W. Parker
Lake Jackson, Tex.

Industrial energy costs have increased recently relative to industrial construction costs in a shift that will affect energy investment, production, and use.

For at least 4 decades, energy and construction costs have changed at nearly identical rates, as shown in the trend line in Fig. 1, which plots a data series dating back to 1930. The relative increase in energy costs apparent in the 2007 data point is only the second major upward departure from the trend to have occurred during the period.

In an earlier article, the author pointed to the inevitability of this shift and described a wide range of responses it would induce.[1] Among those responses are the application of significantly more-expensive exploration and production technologies, application of advanced enhanced oil recovery processes, and major increases in the production of heavy oil.

The recent rise in the cost of energy relative to the costs of industrial construction would be expected to encourage construction of new energy-producing and processing facilities. Higher retail energy costs for gasoline and electricity should also encourage new energy-related investments in the US.

This real surge in new domestic energy-producing investments is not apparent today, except perhaps for petroleum drilling. While environmental and regulatory constraints are major factors in this delay in energy-production investment, the long-term correlation of industrial construction with industrial energy costs also has been an important limit on investment in energy-producing facilities.

The data

The cost of energy for industrial uses and industrial investment costs correlate on a 1:1 ratio since 1930, as illustrated in Fig. 1.

The conveniently available data for this plot are the Nelson-Farrar Refinery Fuel Index and Refinery Construction Index tabulated in Oil & Gas Journal.

The computed slope for the plot is 1.00, although the fuel index shows considerable fluctuation relative to the construction index.

The author has previously published this curve in OGJ with data to 1992, among other observations regarding petroleum supply and price.[1] The 1:1 ratio of energy to investment cost has continued with peaks in industrial energy prices in 1984 and now in 2007. Between these two peaks, there was a prolonged apparent depression of industrial energy prices relative to investment costs.

The slope was calculated with the Excel Solver with the following equation:

1) log (energy cost index) = n log (investment index) + k

The Excel Solver calculated the two correlating parameters n and k to minimize the error associated with calculated industrial energy costs using the following equation applied to each year of the data:

2) error = (log (energy index calculated) – log (energy index tabulated))[2]

The above yearly errors were summed, and then the sum was minimized by the Excel Solver. The result was that n = 1.00, the slope of the curve shown in Fig. 1. The actual numbers that fit the first equation were n = 1.00525, k = 0.481 with the summation of errors being 1.225. This large summation of errors is due to the cyclic nature of the energy cost index with respect to the investment cost index, which is also obvious in Fig. 1. The value for k of 0.481 is just a scaling factor between the two indexes and is not a helpful part of this analysis.

Investment and energy

After the 1984 elevation of energy over construction costs, the cost of

industrial energy dropped below construction costs rapidly for more than a decade. So in 2008, potential investors must make a decision about the expected financial returns from new or expanded energy production and processing investments.

Potential investors realize that these financial returns are largely a function of energy policies, not technology or energy resources. So an optimal energy policy for international petroleum producers might be to randomize increasing petroleum prices. The implication of this external policy is that domestic energy policy should stabilize energy markets with loan guarantees for new economically attractive, long-term energy production and processing facilities, etc. In addition, environmental constraints, in particular carbon dioxide emissions, should be economically reasonable and stabilized.

Potential investors must also accept rather high investments required per unit of energy made available. The public example is drilling in ultradeep water, a production realm in which records of depth and distance from shore are being set frequently. Tar sands and heavy oil production also represent large investments per unit of hydrocarbon energy made available.

The world will never run out of oil, only the oil that can be produced economically relative to other energy sources. That concept was elaborated on in the previous article mentioned earlier, which estimated the amounts of oil ultimately to be produced based on historic production data. It was necessary to include a price of oil, fourfold greater than in 2002, relative to other energy sources to establish an amount of oil ultimately to be produced, Q_∞.

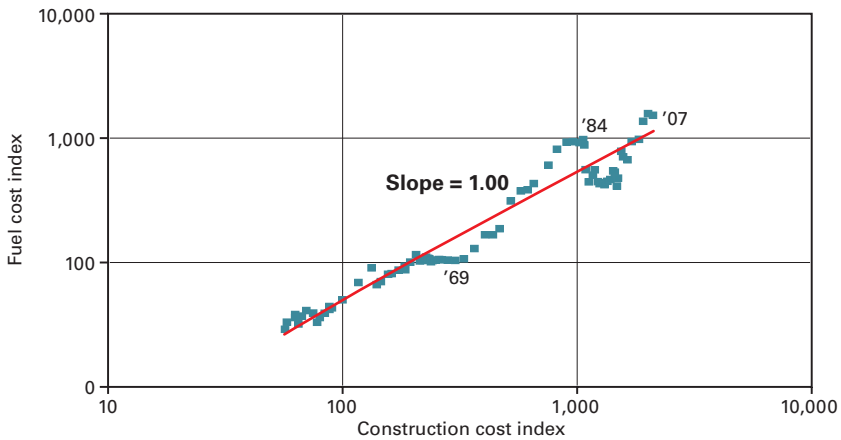
A value of 2.3×10^{12} bbl was chosen to fit historic world petroleum production data shown in Figs. 1 and 3 of that analysis.[1] A recent example of costs and energy policy constraining energy availability is the FutureGen coal-fired electric power plant. Increasing estimated investment costs have resulted in investing companies and the Department of Energy backing off from that project.

"Free" renewable energy resources such as wind and solar are particularly sensitive to high investment costs per unit of energy actually produced, since both wind and solar are intermittent and then vary in intensity, even when nominally available. In addition, the economies of scale for solar and wind are less favorable than they are with traditional chemical processing plants and refineries. It takes a whole line of duplicate wind turbines to generate major amounts of electricity since the size of each unit is limited by materials and mechanical design factors as well as the nature of the wind. Solar collectors are sold by the square foot, so doubling the output power approaches doubling the cost of the proposed solar power facility.

Another factor is the increase in estimated investment costs as more-detailed designs are completed for new processes. In 1981 the author estimated, using 27 data points, that these increases in investment costs resulting from more-realistic designs were 18%/year for proposed 250 MMcfd Lurgi synthetic natural gas plants over the 9-year period in which SNG plants were being discussed.[2] This is an 18%/year increase beyond the inflation of construction costs estimated with the Chemical Engineering Index.

INDUSTRIAL INVESTMENTS VS. FUEL COSTS*

Fig. 1



*Fuel and construction cost indexes are for refineries, plotted by the author from Nelson-Farrar cost data published in Oil & Gas Journal.

Indexes commonly used to correct construction costs as a function of time are for existing and proven plant designs. These indexes include the Chemical Engineering Index, Nelson Refinery Index, and Marshall Swift Installed Equipment Index. This historic observation of increasing estimated investment costs as more detailed design are completed contrasts with the promises of less costly facilities in the future. Reduced costs for construction of future facilities, termed the learning curve, are demonstrated for technologies that are already commercial.

It is easy to project new processes that have very desirable features in today's context. For example, high-pressure gasification of residual biomass with sequestration of carbon dioxide in deep saline aquifers would result in a process with a major negative carbon footprint: CO_2 would actually be removed from the atmosphere. Now, add membrane separators to separate hydrogen from the gasifier product gases for use in fuel-cell powered vehicles. Transposing this two sentence conceptual process into reality would require many million of dollars and several years of effort. It then might be found that the actual costs were still prohibitive.

Many people and firms promoting their own renewable energy or environmental cleanup processes fail to appre-

ciate the extensive costs associated with process development and then actual deployment.

The author would be pleased to supply the raw data and calculations to interested persons. There may be other ways to look at the data. Please request the Excel file by e-mail to the author at HarryWParker@comcast.net. ✦

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The author

Harry W. Parker is professor emeritus of chemical engineering, Texas Tech University. He has been involved in energy-related research at many levels, including in positions with Phillips Petroleum Co. and Washington, DC, research organizations. He was associate and full professor in the Texas Tech University Department of Chemical Engineering from 1970 until his retirement. He holds degrees from Texas Tech University and Northwestern University.

US congressional energy stalemate hardens as recess nears

Nick Snow
Washington Editor

US congressional Democrats and Republicans appeared unlikely to resolve their impasse over energy as the August recess drew closer. Republicans on both sides of the Capitol accused Democrats of stifling a full energy debate as Democrats charged Republicans were blocking other significant bills.

Senate Republicans continued to put pressure on Majority Leader Harry M. Reid (D-Nev.) to allow a full energy debate before the August recess by blocking other bills. Reid reiterated that the tactic would not work. "Republicans have had eight opportunities to vote on lower gas prices. I offered them the opportunity last week to vote on four amendments and they walked away," he said on July 29.

He dismissed Republican charges that Senate Democrats want to recess on Aug. 1 without discussing energy. "We don't need their permission to adjourn. If they want to stay here and work, it will be fine with us. We don't have any Democratic incumbents who are in trouble," Reid told reporters.

In the House, meanwhile, Republicans used the absence of a quorum to get several other bills tabled as a protest. "We'll not spend time trying to pass sham bills when the American people want us to act," Rep. Virginia Foxx (R-NC) said.

House Speaker Nancy Pelosi (D-Calif.) brought two energy bills to the floor the past 2 weeks that have failed because they arrived under suspended rules, which kept Republicans from trying to attach amendments but also required a two-thirds majority for passage. Republicans have used a parliamentary procedure to bypass committees and send their energy proposals directly to the floor for several weeks but to no avail.

Appropriations halted

Democrats have even stopped the fiscal 2009 federal appropriations process because they don't want Republicans to propose energy amendments, the ranking minority members of the House and Senate Appropriations Committees said on July 25. It would be the first time since before the 1950s that Congress has not passed a single appropriations bill before the August recess, they added.

"Despite the fact that energy prices are the most important issue to the American people today, the majority proposes to scrap our appropriations work altogether and pass a long-term continuing resolution that freezes alternative energy programs at current levels and extends provisions of appropriations law that restrict domestic energy development both offshore and onshore, all without debate or amendment. What a disservice to the American people," said Sen. Thad Cochran (R-Miss.).

Rep. Jerry Lewis (R-Calif.) said, "American families don't have the option of putting off their bills until next year, so why should Congress? Once again, the Democrat majority has put politics above people, and it has resulted in one of the largest legislative failures in a century."

Senate Republicans also blocked two bills that Reid proposed July 28-29. The first was an omnibus measure that would have combined nearly three dozen bills. The second include provisions to extend tax credits for renewable and alternative energy research and development. "We cannot allow the Senate to simply end debate on legislation to address high [gasoline] prices without passing a bill," Republican Conference Chairman LaMar Alexander (Tenn.) said.

Senate Democrats announced their own energy amendment on July 24 which included provisions similar to the bills which failed in the House, including repealing oil industry tax breaks, pressuring federal lessees to develop tracts they hold more quickly and ordering the sale of oil from the Strategic Petroleum Reserve. Republicans immediately denounced the proposal.

'Mired in the past'

Republicans and Democrats continued to make speeches about energy on the Senate floor on July 29. Lisa Murkowski (R-Alas.) said it was the opponents of leasing in the Arctic National Wildlife Refuge and on more of the Outer Continental Shelf who were "mired in the past" because they

refused to acknowledge technological advances of the past 20 years.

Directional drilling has reduced the well pad footprint at Prudhoe Bay by 88% in the past 20 years, she maintained. "More oil probably leaks on driveways here in Washington, DC, than touches the ground in Alaska. Let's use this ingenuity to develop more of our resources and move ahead on renewable and alternative technologies," she urged.

Byron L. Dorgan (D-ND) said Republicans still are promoting a "drive and drill" strategy. "The oil industry has many friends here who are willing to act like human brake pads and stop proposals which encourage alternatives and other real solutions. Is their policy going to be to just drill a hole, which is a relic of yesterday, or to engage in a game-changing strategy? We should have had 100 senators ready to shut down excessive oil speculation last week. We should have had 100 votes for solar, wind, biofuel, and conservation tax credits," he said.

David Vitter (R-La.) said a full energy debate is needed, and that he had proposed seven amendments already. "This issue hasn't been the first question at my town hall meetings for the past year; it's been the first 10 questions. Everyone has asked why Congress hasn't done anything about high gasoline prices. Other senators have other good ideas. We need an open process that lets us call up amendments, debate the ideas and act on them," he said.

Majority Whip Richard J. Durbin (D-Ill.) said leasing of 12 million acres in the latest federal OCS sale when 200 million acres were offered indicates that the oil and gas industry isn't taking full advantage of its opportunities domestically. Calls to open more of the OCS, he continued, are "the administration's last attempt to give oil companies one last grab of federal land before it leaves town for good in another few months." ✦

Oil markets cling to 'Rising demand-Falling supplies' view

Nick Snow
Washington Editor

Expectations that supplies will continue to dwindle while demand keeps growing have pushed crude oil prices dramatically higher since the beginning of 2008, two leading energy analysts told US senators.

The notion fails to consider that recent major discoveries are significant and that $140/bbl crude oil prices might slow demand growth, they told an unusual workshop convened by the Energy and Natural Resources Committee on July 17. "An attitude has permeated the market that if any oil company says production from a new field will begin in 6 years, it actually will happen in 10 years. If you believe oil will cost $140 going forward, you'll see quicker demand destruction," said Roger Diwan, partner and financial advisory head at PFC Energy, a Washington strategic advisory firm.

International unrest and a weaker US dollar also have helped push oil prices higher, noted Daniel Yergin, chairman of Cambridge Energy Research Associates. "But there is a shortage psychology that demand will go through the roof and supplies will run out in 4-5 years which discounts significant events such as the substantial deepwater oil discoveries off Brazil," he said.

"When there's a cumulative shift away from the idea of scarce supplies and rising demand, there will be a change. We may need to adjust our demand forecasts to reflect the impact of higher prices," Yergin said.

Senate invited

Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) held the workshop to give senators who are not on the committee a chance to express their views and ask Diwan and Yergin questions about record-high oil prices. About 20 senators were there at various points, including Majority Leader Harry M. Reid (D-Nev.), who commended Bingaman for holding the event.

"Virtually every committee in the senate has an interest in this. I hope they follow your lead and cast aside partisanship. And I hope this event will bring forward new, sensible ideas," Reid said. While oil price increases clearly have been driven by several factors, he continued, excessive market speculation by noncommercial participants needs to be addressed first. "Without proper oversight, speculation has gotten out of hand. It's where we should start. It's one, but not the only, reason oil prices are so high," he said.

Pete V. Domenici (R-NM), the Energy and Natural Resources Committee's ranking minority member, said that Republicans also recognize that excessive speculation has affected oil prices and needs to be addressed. "But we also believe there is a domestic production issue," he told Reid.

Reid responded, "You may have one alternative to increase domestic production and we may have another. That doesn't mean they're mutually exclusive. We're speaking from the same handbook. We merely need to get on the same page."

Kent Conrad (D-SD) also thanked Bingaman for holding the workshop. "This is exactly what we should be doing, putting a focus on this issue in a bipartisan way to reach a solution," he said. Observing that there have been calls for several steps to address US dependence on foreign crude by developing alternatives as well as producing more oil and gas domestically, Conrad said that Congress already has passed several bills that have not fully gone into effect.

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WATCHING GOVERNMENT

Nick Snow, Washington Editor

Costly E&P behind high prices

Several members of Congress may try to minimize it. But experts say that a basic force behind dramatically higher oil and gas prices is more expensive exploration and production.

"Both the public and policy focus is on [the crude oil] price. But the dramatic increases in costs are bedeviling the industry, delaying new supplies and constitute one of the major reasons for rising prices," Cambridge Energy Research Associates Chairman Daniel Yergin told a US Senate workshop on oil prices on July 17.

"The problem is not only access but building facilities to produce new fields. An attitude has permeated the market that if an oil company says production will begin in 6 years, it actually will happen in 10 years," observed Roger Diwan, a partner and head of the financial advisory practice at PFC Energy, at the same event.

The oil and gas upstream sector's problems in responding quickly to soaring oil prices now are rooted in plunging prices 20 years ago, the two experts agreed. Companies concentrated on downsizing from 1998 to 2000 because they expected prices to stay low, Yergin said. Manufacturers produced less equipment and universities educated fewer petroleum engineers and geologists, Diwan said.

$100 then, $210 now

The latest Upstream Capital Costs Index compiled by CERA and its parent, IHS Inc., found that costs associated with constructing new oil and gas upstream facilities have doubled since 2005. The index grew reached a record 210, CERA said on May 14. Since the index's values are based on costs in 2000, that means that equipment costing $100 then would cost $210 now, it added.

Rising oil and gas resource development expenses have been driven by raw material costs, CERA's report said. Iron ore costs for finished steel have gone up by as much as 60% since the beginning of 2008 as contracts have been renegotiated, it noted.

Qualified employees

"Steel costs are a huge issue. So are labor costs. It gets harder to find qualified employees as we get into the Bakken shale and other less-conventional areas. Horizontal wells are more expensive," said Frederick Lawrence, vice-president of economics and industry affairs at the Independent Petroleum Association of America.

"Privately held independent producers are drilling about half the new US oil and gas wells. These costs are hitting them hard. They don't have the recruiting resources that large, publicly held companies have. Keeping qualified labor and having the best technology becomes more and more expensive each year," he said.

Yet wells keep getting drilled, he continued. "The number of rigs that have been put to work in the Barnett shale and other active plays has jumped dramatically. It's amazing that Congress says we're not using our leases to their maximum potential when the industry is breaking drilling records around the country," Lawrence said. ✦

OCS survey

Bingaman noted that the 2005 Energy Policy Act contained a provision requiring the US Department of the Interior to survey the OCS for the first time in more than 20 years. When it reported back after doing so in 2006, he said he noticed that it had tried to save money by not using three-dimensional seismic mapping. "Neither the administration nor Congress tried to get another survey done with modern, more accurate technology," Bingaman said.

When asked following the workshop if another OCS study could be part of DOI's fiscal 2010 budget, Bingaman said that it might.

Other Democrats questioned whether increasing available OCS acreage would send a strong, positive signal to world oil markets as some Republicans have claimed. Maria Cantwell (D-Wash.) said that bids were received on only 200 million of the 500 million acres of new Gulf of Mexico tracts offered in OCS Lease Sale No. 181, and producers have not fully developed onshore and offshore leases they already have. "This psychological effect idea is a specious argument. We really can't affect world prices with our geology," she said.

"Oil is a global commodity, influenced by supply, demand and events. How you affect these elements is on the fringe unless you make a massive effort. It would be false, as some people suggest, to think that opening up the OCS today would reduce prices tomorrow," added Robert Menendez (D-NJ).

But the two witnesses called for expansion of federal oil and gas leasing on the OCS. "Responsible development of part of the OCS should be part of the picture. The sense of new prospective territories becoming available and moving toward exploration would be very beneficial," Yergin said. "Many people have said that the United States needs to increase its supplies. I don't think it's fair to ask other countries to do it if we're not willing to do something ourselves," Diwan said.

When Lisa Murkowski (R-Alas.) suggested that crude oil prices dropped by

$9/bbl in the 2 days after US President George W. Bush lifted the executive withdrawal of US OCS tracts on July 14, however, they suggested that other factors might have been at work. Speculators might have sold oil positions to pay off losses in other markets, Diwan said. A US decision to negotiate directly with Iran may have had the most positive impact, he added. "There also could have been pessimism about the weakening US economy and its impact on future demand," said Yergin.

OPEC's spare capacity

The two witnesses emphasized that a wide variety of conditions over a long period led to 2008's dramatic oil price increases. A combination of supply and demand shocks from 1985 to 2005 wiped out the Organization of Petroleum Exporting Countries' spare capacity, which left markets without any down-side risk, Diwan said. Sluggish supply growth outside OPEC has fed the future scarcity narrative, which attracted financial players to oil commodity markets, he said.

Yergin added that from 1998 through 2000, major oil companies downsized dramatically to survive because oil and gas prices were so weak. Investments were not made in new equipment or in training new engineers, both witnesses said. "It's clear we're in an oil shock now. The fact that it coincides with a financial crisis means people are talking about stagflation for the first time since the 1970s. Changes in the makeup of the oil commodity markets are definitely a factor. So are the declining dollar and US relations with other countries," said Yergin.

"In the last 25 years, the United States has encouraged consumption and discouraged production. That needs to be changed. It took us 20 years to get to a truly tight market. It will take a long time for us to unwind it. The problem is not only access but building facilities to produce from new fields," Diwan said.

Strong worldwide economic growth ignited energy demand in China, India, and other countries, they noted, adding that these countries could embrace conservation next. "I think it's striking that the Chinese have put efficiency at the top of their energy list. China and India both need to feel that the energy security system built around the International Energy Agency will work for them too," Yergin said.

"If we put aside the geopolitical questions, I think the energy supply response has begun. Oil is not going to have as dominant a position 5 years from now," Yergin said. ✦

BLM decision sets stage for major NPR-A lease sale

Nick Snow
Washington Editor

The US Bureau of Land Management issued a record of decision that sets the stage for a major lease sale in the National Petroleum Reserve-Alaska's northeast portion.

Land in the NPR-A's northwest section also will be offered in the sale expected in the fall, the US Department of the Interior agency said on July 16. It said that the acreage, which will become available in the two sections, could result in as much as 8.4 billion bbl of oil being developed.

Several trillion cubic feet of natural gas also might be produced for shipment to markets in the Lower 48 states on pipelines which have been proposed, BLM added.

Officials emphasized that the announcement was not a response to a proposal by US House Democrats last week to require BLM to offer more leases within the NPR-A as an alternative to Congress authorizing leasing on the Arctic National Wildlife Refuge's coastal plain.

"We've been on a track to complete this planning process for some time. We completed this final [environmental impact statement] a month ago and made no secret about making a final decision after the 30 days we were required to wait. I don't think this has anything to do with whatever is happening on the Hill," Deputy BLM Director Henri Bisson told reporters during a teleconference.

"This is an opportunity for what we hope will be a major lease sale for land in the northeast NPR-A in October that has not been leased as well as for land in the northwest NPR-A. I think we've achieved a pretty good balance and that most people will be satisfied," he said. The decision includes a 10-year deferral of leasing on land north and east of Teshepuk Lake, Bisson said.

Wildlife protection

Tom Lonnie, BLM's Alaska state director, said that the decision provides for protection of high-value wildlife, including caribou and water fowl, and meets North Slope residents' subsistence needs while making land with high oil and gas potential available for leasing.

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

The NPR-A's supplement final plan under which the leases will be issued has phased leasing and performance-based measures as major components, according to Lonnie. Production of oil from this area will assure that the Trans-Alaska Pipeline System remains viable, he explained. TAPS throughput currently is around 700,000 b/d,

down from its full 2.1 million b/d capacity, he said.

ConocoPhillips has production just outside the NPR-A and has estimated that production from leases within the reserve could begin as early as 2012, Lonnie said. Existing infrastructure just east of the NPR-A connects with TAPS, he said.

"It's impossible to anticipate the size of production. It's always possible that there will be a discovery offshore and a pipeline would be brought in further west, which would allow us to hook in earlier," Lonnie added.

"It's also important to understand that NPR-A has future natural gas resources that potentially could be more important than oil, so any gas pipeline that is constructed will use them heavily," said Bisson. Producers which have expressed interest include Anadarko Petroleum Corp. and Pioneer Natural Resources Co., he said. ✦

Study: US unconventional gas resources underestimated

Nick Snow
Washington Editor

The United States has 2,247 tcf of natural gas reserves, enough to last 118 years at 2007 demand levels, a new study has said.

The study, released July 30 by American Clean Skies Foundation (ACSF) and Navigant Consulting Inc., explains why existing forecasts have underestimated unconventional natural gas potential from tight sands, coalbed methane, and gas shale formations.

"New technologies have allowed the rapid emergences of gas shales as a major energy source representing a truly transformative event for us energy supplies," said Aubrey McClendon, ACSF chairman and chairman and chief executive officer of Chesapeake Energy Corp.

"The assessments and estimates on natural gas supply are very impressive and have, frankly, caught industry forecasters off guard, said Richard G. Smead, one of the study's coauthors and overall project manager for Navigant.

The growth in proved US reserves has come almost exclusively from natural gas sources that have been termed "unconventional" but today are a large part of the future supplies. For example, proved CBM reserves are nearly 20 tcf today, up from 11.5 tcf in 1998, and less than 4 tcf a decade earlier. Proved shale reserves have grown to 15 tcf today from 3.5 tcf in 1998. And tight gas proved reserves today total 80 tcf up from roughly 36.6 tcf in 1998.

Two US house members who have cosponsored a bill to increase natural gas vehicle use said the study shows that a dramatic change is under way. "We're going to have a paradigm shift in the automobile business. You don't often get a hat trick in politics," said Rep. Rahm Emanuel (D-Ill.), chairman of the House Democratic Caucus. "Natural gas vehicles solve three problems: the environment, the economy, and energy security," he said.

"This legislation is personal to me," said Rep. Dan Boren (D-Okla.). "The Woodford shale play is in my district, which is one of the poorest in the country. The natural gas industry is spending money there, leasing property and hiring people. It's helping our economy. This changes the US energy debate," he said.

Smead said Navigant spoke to 114 producers covering 90% of North America's total gas supplies. Sixty-six of these provided substantial and meaningful information about the resource base and ultimate production levels. ✦

Indonesia to place BPMigas VPs within IOCs

Eric Watkins
Senior Correspondent

Indonesia, in a bid to exercise greater control over contract holders, will allow upstream oil and gas regulator BPMigas to assign officials to work as vice-president within international oil companies (IOCs).

The decision, which followed earlier reports of efforts to step up the monitoring of the upstream sector, also coincided with calls for the government to impose a windfall profits tax on IOCs.

BPMigas head R. Priyono, who named four officials to be assigned to holders of oil and gas cooperation contracts (KKKS), said the number of officials will gradually be increased over time.

"They will hold vice-president positions at the KKKSs and will be tasked with bridging the interests of oil and gas companies with ours," Priyono said after inaugurating the four officers on July 22.

The four vice-presidents, who will represent BPMigas at BP PLC, Total SA, Chevron Corp., and ConocoPhillips, are R.B. Heru Djoni Putranto, Bambang Prabowo, Taslim Z. Yunus, and Mulyani Wahyono.

Priyono, who said BPMigas has yet to decide which officers will be assigned to which companies, added that the government agency would soon name additional vice-presidents to be assigned to other oil and gas companies. "We are planning to inaugurate six vice-presidents by the end of the year," Priyono said, adding that the officers "will help the KKKSs accelerate the processing of operations and program budget proposals."

"They will be involved in the formulation of such proposals at an earlier stage. They will also advise companies on what items can be reclaimed as recoverable costs," Priyono said.

He said oil and gas companies are required to pass their project and budget proposals to three BPMigas deputies, and that processing could take more than 9 months.

The vice-presidents also will provide BPMigas with a greater understanding of how the contract holders conduct their management of national assets, Priyono said.

The announcement follows recent reports that said Indonesia's Corruption Eradication Commission and BPMigas, were creating a team to evaluate the monitoring mechanisms in the upstream oil and gas industry (OGJ Online, July 22, 2008).

Windfall profits tax

The announcement also coincided with calls for the government to issue a special tax on windfall profits reaped by oil and gas companies.

Marwan Batubara, a member of the Regional Representatives Council (DPD), July 21 said a windfall profit tax for oil and gas firms would be a "fair measure" to help relieve the burden of high gas prices on Indonesians.

"Oil and gas, just like other natural resources, belong to the people. But, it is the people who are suffering from skyrocketing oil prices—[while] with little effort, oil and gas firms are gaining tremendous profits from the hike," Marwan said.

"If the government applies a windfall profits tax of 50%, our state income will increase by 20.36 trillion rupiahs/year," Marwan said.

Energy analyst Kurtubi said such a tax would be fair as companies were not enjoying windfall profits due to the caliber of their strategies, investments, or technologies but "merely because of the soaring global prices."

However, Kurtubi said that such a tax would be best introduced in conjunction with measures designed to create a more conducive investment climate for the industry. "The government must for instance simplify the investment procedures and withdraw the production tax," Kurtubi said. ✦

Indonesia's OPEC withdraw decision 'sovereign'

Eric Watkins
Senior Correspondent

Chakib Khelil, president of the Organization of Petroleum Exporting Countries, while acknowledging that Indonesia has played an important role since joining the organization in 1962, said its plan to withdraw from the group is a "sovereign" decision.

Khelil also indicated that several options were available, saying that Indonesia could either suspend its membership or remain in the organization as an

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Mexico, US talk gulf reserves

The US and Mexico are reported to have begun talks on how to conduct oil exploration operations in the Gulf of Mexico beginning in 2011 when a 10-year moratorium expires.

News of the discussions between the US and Mexico came as analysts and officials of the Latin American nation expressed concern over declining production.

The US-Mexico talks are focused on the treaty, signed on June 9, 2000, between the two countries on the delimitation of the continental shelf in the western Gulf of Mexico beyond 200 nautical miles. The treaty specially mentioned the need for cooperation between the two nations, "taking into account the possibility that there could exist petroleum or natural gas reservoirs that extend across that continental shelf boundary."

New exploration framework

The daily El Universal newspaper said representatives from the two governments have been working together to establish a framework that will avoid conflicts and to develop a strategy on exploring underwater deposits in the area, known to Mexicans as the Hoyo de Dona.

The report follows an earlier statement by Adan Oviedo Perez, director of Compania Mexicana de Exploraciones, that Mexico should promote a treaty for cross-border oil reserve exploitation with the US and make observation of such a treaty by oil firms obligatory.

In June, Oviedo Perez told the Mexican Senate that he would like to see a group formed to prepare such treaty, which would extend cooperation beyond the relatively small area comprised by the Hoyo de Dona.

Oviedo Perez said he would like to see joint operation become the "standard way" concerning exploitation of cross-border reserves in the gulf.

His remarks chime in with observations by some Mexican experts that the exploitation of the waters on the US's side of the gulf boundary could reduce reserves on the Mexican side.

Migrating reserves?

"When they take petroleum from the American side, our petroleum is going to migrate," said Francisco Labastida Ochoa, head of the Mexican Senate's Energy Committee, in a recent interview with Mexico's Milenio newspaper. Discussions between the US and Mexico came as officials expressed concern over declining production by state-owned Petroleos Mexicanos, which, according to planning director Vinicio Suro, will close 2008 with oil output "stabilized" at 2.8 million b/d.

Still, according to a senior energy official, Pemex will need more than a decade of time to restore its oil production to 3 million b/d—its level of production prior to 2007. "The country needs to get back to these levels by 2020," said hydrocarbons director Jordy Herrera Flores. "Before that it will be difficult," he said.

According to analyst BMI, Mexico is suffering from considerable damage due to falling oil production and exports coupled with a rising fuel imports bill. It said such damage highlights the "urgent need" for reform in the country's "tightly-controlled" upstream and downstream segments. ✦

observer once its membership expires at yearend. "All the options are open, but it is up to Indonesia to make the decision," Khelil said.

Indonesia's Energy and Mineral Resources Minister Purnomo Yusgiantoro repeated his country's aim of leaving the group when its membership expires at the end of the year, saying that, "We have become a net oil importer."

Indonesia's future

Indonesia turned a net oil importer in 2003 on declining production of oil together with increasing domestic consumption. However, government officials have said Indonesia could rejoin OPEC in the future if its oil production and exports pick up again.

The discussion over Indonesia's future in OPEC coincided with reports that—due to continued low domestic production and spiraling consumption—the country's oil and fuels trade balance has been in deficit for the first half of this year and is likely to remain in deficit for the remainder of 2008.

Economist Faisal Basri of the University of Indonesia (UI) said the deficit stood at $5.5 billion as of the end of May, with oil and fuel imports reaching $13 billion while exports earned just $7.56 billion. "We are heading toward a very critical situation if we don't formulate a proper energy policy. The deficit is predicted to be $15 billion at the end of this year," said Faisal at a discussion on the energy crisis held by UI.

The big gap between the fuels import and export shows the country has poor production but massive consumption, said Faisal, who added that inefficiencies at state-owned Pertamina have contributed significantly to the wide gap between imports and exports.

Faisal offered a comparison to illustrate his point, saying, "Pertamina's cost recovery in 2007 was $36.10/bbl, while Chevron's [Corp.] was only $6.80/bbl."

Investors needed

Meanwhile, Indonesia's recent efforts to attract new investment into the oil

and gas sector have not been as successful as government officials had hoped.

According to Evita H. Legowo, the newly appointed director general of oil and gas in the ministry of energy and mineral resources, half of the 21 oil and gas blocks offered by the government last year failed to attract investors.

"We don't know exactly why some blocks didn't attract any investors. It could have been that investors had doubts about the data or maybe they needed more advanced technology to operate the blocks on offer," said Evita.

In a renewed effort to attract investment, the government plans to open a new auction for oil and gas blocks in October or November, and may include those blocks leftover from the last round. "We are still formulating which blocks we will offer. We are also still deciding whether the unsold blocks would be offered again or not," said Evita, who did not disclose which blocks remained unsold.

In May 2007, the government put up 21 oil and gas blocks for auction. ✦

Pertamina to offset downtime, hike August fuel imports

Indonesia's state-owned PT Pertamina will raise its fuel imports by 60% for about a month to compensate for a drop in production at its Cilacap refinery in Central Java. The state firm will be conducting an overhaul in August at the facility.

Ahmad Faisal, Pertamina director of marketing, said the company will increase its imports to match the normal monthly output from the Cilacap facility, which produces 350,000 b/d. About 60% of its output includes fuel, while the remainder is taken up by asphalt and oil-based lubricants.

The announcement followed reports that 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.

In 2007, Pertamina imported 321,000 b/d of crude oil and 300,000-350,000 b/d of fuel to help meet domestic demand of 1 million b/d of fuel. The country's six refineries reportedly have a combined production capacity of 652,000 b/d.

The Cilacap refinery has two crude distillation units with respective capacities of 118,000 b/d and 230,000 b/d. The facility also has a 29,000 b/d gasoline-making reforming unit and a 50,000 b/d visbreaker.

Last year, Pertamina and Japan's Mitsui & Co. announced plans to establish a joint venture to build a $1 billion gasoline cracker at the Cilacap refinery, and Pertamina processing director Suroso

Atmomartoyo said the new unit would have a capacity of 40,000-50,000 b/d.

In May, Pertamina processing director Rukmi Hadihartini said the state oil and gas firm would soon seek financial support to upgrade the refinery, adding that the company would reach a final investment decision in October for the project.

Pertamina estimates have put the cost at around $1.9 billion, but Hadihartini said recalculations are under way as "the price of raw materials, such as steel, has soared." ✦

API: US oil demand dropped 3% during first half

US oil demand dropped 3% in 2008's first 6 months as gasoline deliveries fell 1.7% in their first significant 6-month decrease since 1991, the American Petroleum Institute reported on July 18. Domestic petroleum demand had been faltering for 3 years, managing only to hold relatively steady, before deliveries for this year's first half averaged 20.08 million b/d, their lowest 6-month level since early 2003, API said in its monthly statistical report for June.

"Higher pump prices and a slowing economy were undoubtedly factors," said Ron Planting, API's statistical director. "What was really remarkable was that we had the largest decline in internal consumption in 17 years—to the lowest level since 2003."

The decline did not extend to diesel fuel, where demand for ultralow-sulfur diesel (ULSD) jumped 16% year-to-year to an average 3.25 million b/d from 2.8 million b/d, according to API. It said that low sulfur diesel deliveries climbed 7.2% to an average 3.58 million b/d from 3.34 million b/d during the comparable 2007 period.

Planting said refiners have supplied the US market with record diesel supplies. Domestic refiners have increased capacity and are making greater record amounts of diesel as a percentage of their total runs, he told reporters during a teleconference.

Diesel inventories

API's statistics showed that ULSD inventories at the end of June totaled 72.3 million bbl, 8.1% higher than their 66.9 million bbl a year earlier. Low sulfur diesel inventories grew 1.2% to 92.5 million bbl from 91.4 million bbl during the same period.

Gasoline inventories also grew year-to-year, increasing 3.6% to 212.1 million bbl at the end of June from 204.8 million bbl a year earlier. API measures demand based on deliveries, which fell 1.7% during the first half to an average 9.06 million b/d from 9.21 million b/d during 2007's initial 6 months, it said.

"Gasoline has a greater share at the consumer level, which is more discretionary. Diesel users already have figured out the shortest routes and ways to use fuel more efficiently, so they tend to be less flexible," Planting explained. US retail gasoline prices averaged $4.113/gal, and retail diesel prices averaged $4.764/gal, the US Energy Information Administration reported on July 14. Asked if motor fuel prices have reached a level impacting demand, API Chief Economist John C. Felmy replied, "Our data clearly show it in the United States.

"The issue here is more what's happening at the world level, particularly China, India, and the Middle East. Those areas still have subsidies and price controls. In China, it's hard to see much happening before the Olympics, but it could do something after. India is moving more toward a service economy that could reduce domestic pressure to continue subsidies. Producing countries in the Middle East also might take another look at subsidies," he continued.

Imports also drop

Slowing demand also influenced US petroleum imports, which sank below an average 13 million b/d, their lowest first-half level since 2003, API said. Crude oil imports, excluding purchases for the Strategic Petroleum Reserve, fell 2.5% year-to-year to an average 9.77 million b/d from 10.02 million b/d. Product imports dropped 9.9% to 3.19 million b/d from 3.54 million b/d during the same period.

Domestic crude oil and condensate production slid 2.2% during the first half to an average 5.09 million b/d from 5.21 million b/d in the comparable 2007 period, according to API. Natural gas liquids production rose 5.2% year-to-year to an average 1.83 million b/d from 1.74 million b/d, it said.

Crude oil production in the Lower 48 states fell 2.1% during the first half to an average 4.4 million b/d, despite year-to-year increases in some regions, API said. It indicated that Alaskan crude oil output for 2008's initial 6 months was down 6.4% to an average 725,000 b/d.

"It's not for lack of trying. Exploratory drilling is up 53% this year. Footage drilled is up 50%. Development drilling increased about 15% in the second quarter, not as much as exploratory drilling. The industry is trying hard, but if you keep going back to the same areas, you find less oil and gas. That's the key point of our request for more access," Felmy said.

Production would not increase immediately even if Congress decided to open more of the Outer Continental Shelf and authorize leasing on the Arctic National Wildlife Refuge's coastal plain, he conceded. "Companies have to do a host of environmental impact statements, get permits and lease tracts. If Congress were to make a statement that we're serious about going forward into new areas, there would be sufficient time to develop the infrastructure. Churchill once said the best time to plant a tree is 20 years ago, and the second best time is now," API's chief economist said. ✦

Discoveries, undeveloped opportunities persist as offshore Europe oil output falls

John Westwood
Douglas-Westwood Ltd.
Canterbury, UK

Despite the growth of other regions, Europe remains one of the world's largest offshore producing theaters.

Nearly 600 offshore fields have been developed off Europe, involving a similar number of platforms plus some 380 subsea wells, over 200 subsea templates, and nearly 1,000 pipelines.

However, the corporate scene has changed dramatically as declining production and high costs have forced the original developers, the oil majors, off to other regions. This has opened the way for a new breed of smaller players better geared to economically extracting the remaining reserves from a multitude of small fields and squeezing the last drops out of massively depleted existing ones.

Across the supply chain the European offshore contractors are winning business worldwide and so are the European stock markets. London has hosted the initial public offering of a number of international oil field services companies.

This article is an annual summary of the status of plays and prospects and highlights some challenges ahead.

Europe's production

Douglas-Westwood expects global offshore oil and gas production to average 45.7 million b/d of oil equivalent, and it forecasts that by 2012 production will have grown 21% to 56.7 million boe/d.[1]

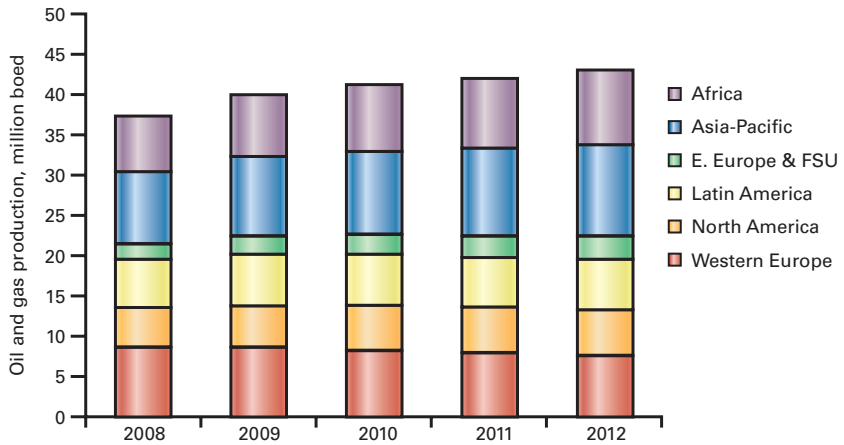
Growth will occur to varying degrees in all regions, led by the Middle East 4.3 million boe/d, Africa 2.4 million boe/d, and Asia-Pacific 2.3 million boe/d (Fig. 1).

The single exception to that growth will be offshore Europe, where we expect production to decline by a nearly 1 million boe/d from its 2008 forecast level of 8.6 million boe/d. Of the main European offshore producers and products, only Norwegian gas is on the increase (Fig. 2).

Natural gas is an issue of growing concern due to Western Europe's increasing dependence on supplies from Russia, where OAO Gazprom is growing into one of the world's most important energy companies, and with ambitions in Algeria, Libya, and Nigeria, it is spearheading a second Russian revolution.

THE GLOBAL CONTEXT

Fig. 1



Source: The World Offshore Oil & Gas Forecast 2008

In common with most other shallow-water offshore producing areas such as the Gulf of Mexico, the North Sea is postmature and now suffering severe production decline—recent analysis suggests the UK decline rate was 7.5% in 2007.

However, the North Sea, unlike the Gulf of Mexico, does not have the major deepwater reserves as an offset. The region's only current deepwater development is Ormen Lange in Norway, which began producing in 2007. No other big deepwater developments are planned.

What Western Europe does have is considerable remaining reserves, albeit in small reservoirs with numbers of small undeveloped prospects that have been variously reported as being in the hundreds.

Geography matters

Generally referred to as "the North Sea," the offshore play is more correctly the Northwest Europe Continental Shelf (NWECS), which includes the waters of six countries.

The prospective region off Denmark, Germany, Ireland, the Netherlands, Norway, and the UK spans a vast area from the Arctic to the warmer climes of Spain. Environmental conditions range from difficult to severe. However, it is Norway and the UK that claim most of the action.

The Norwegian and the far-north Barents seas cover a large area of the shelf and continental slope of Norway, while the UK also has production from the Irish Sea and the Atlantic shelf west of Shetland. Ireland has gas production off its southeast coast and developments happening off its environmentally challenging west coast.

This Atlantic basin is underexplored and contains a number of proven and emerging play types with potential for field developments in 500-2,500 m of water.

UK sector

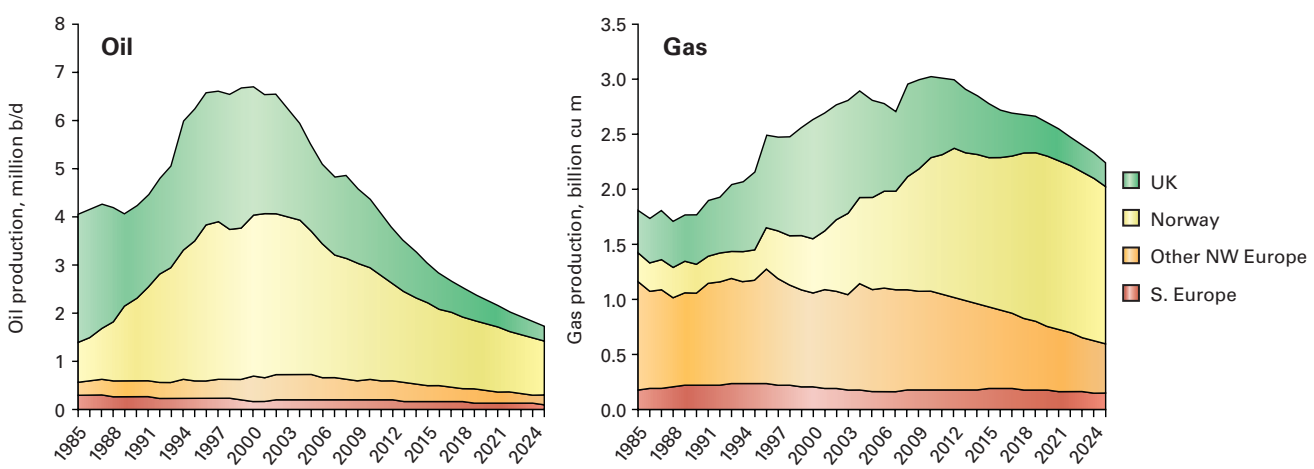
With the decline in production and in common with the rest of the world, costs have been rising.

The overall outcome is that we expect combined capital and operating expenditure off Northwest Europe to be the world's highest in 2008 at near $51 billion of a global total of $275 billion and to be at a similar level in 2012. However, as global spending grows to reach $361 billion by 2012 we expect Northwest Europe's share to decline to 14%.

Despite decline being severe in UK waters, production is still significant. In 2007 the UK was the world's 13th largest overall oil and gas producer. And looking to the future, according to government the UK will rely on oil and

OFFSHORE EUROPE OIL AND GAS PRODUCTION

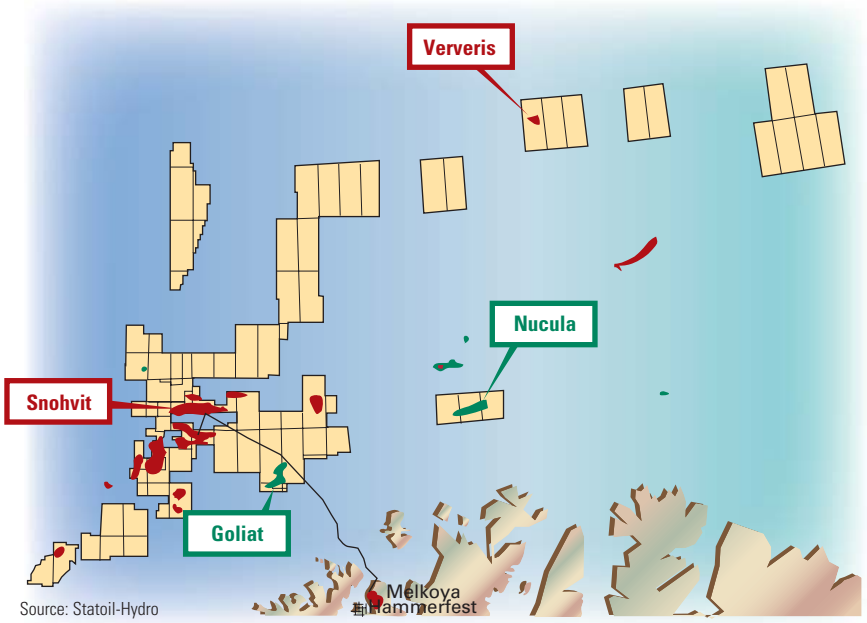
Fig. 2



Source: Energyfiles Ltd.

BARENTS SEA OFF NORWAY

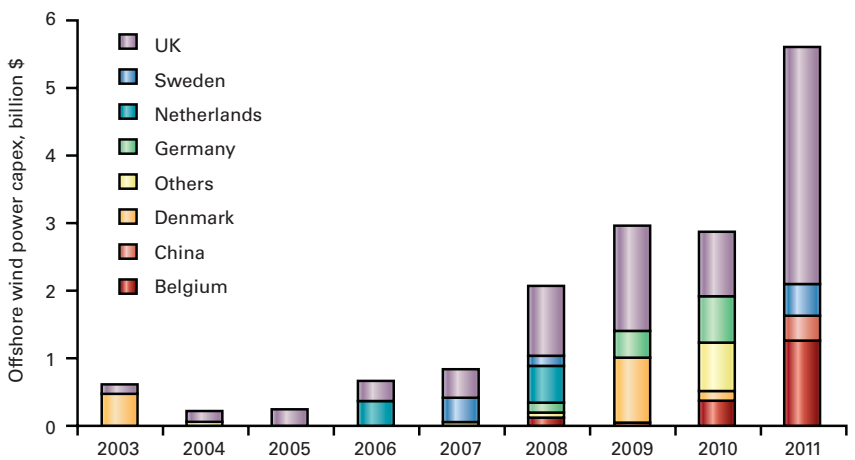
Fig. 3



Source: Statoil-Hydro

GLOBAL OFFSHORE WIND POWER CAPEX

Fig. 4



Source: Douglas-Westwood

gas to provide around 80% of primary energy needs in 2020, and the UKCS has the potential to provide 20-25% of UK gas demand and 60-65% of UK oil demand.

West Sole (1965), the first gas discovery in the UK North Sea, went on production in 1967. Since then, the UK has produced 37.5 billion boe and has the potential to deliver another 25 billion boe or more over time, according to the industry body Oil & Gas UK.

Current business plans outline the potential for the delivery of 10 billion boe from existing fields and new projects. However, they also note that further progress will require exploration to be sustained at current rates for decades, matched by improvements to the investment climate to encourage the maximum recovery of oil and gas from existing fields.

It has been reported that in 2007 around 40% of the region's exploration wells were successful, discovering 300-400 million boe. However, these were typically less than 20 million boe, and such accumulations bring to the fore the issue of costs.

Through mid-July 2008, five offshore fields have been approved for development; Maersk's BOA, Petrofac's Don South West and West Don, Venture's Grouse, and Oilexco's Shelley. Discoveries are still being made. In late June Oilexco reported an important dual oil and gas-condensate discovery at Moth in Block 23/21 in the UK Central North Sea (OGJ Online, July 1, 2008).

Big spenders

UK offshore operating costs rose almost 30% from 2006 to 2007 with the average technical cost of new developments (capex and opex combined) having reached $29/boe for projects coming on stream over the next 3 years, a level some 70% higher than in 2005.

UK Prime Minister Gordon Brown and the Chancellor of the Exchequer Alistair Darling ventured north on May 28 to meet with oil industry executives in Aberdeen. The meeting was to discuss the global oil supplies situation, but the minister was undoubtedly made aware of the fact that even at current oil and gas prices it is difficult for the North Sea to attract investment in marginal field developments and that the players need an improved fiscal package.

Turning to drilling, which consumes so much of offshore outlays, activity in the region is again dominated by the UK and Norway. A Douglas-Westwood study found that 83% of the 2,624 wells drilled off Western Europe in 2003 to 2007 were in these two countries, and the bulk was in the North Sea. A total of 2,349 exploratory and development wells is forecast over the next 5 years, and few are expected to be drilled in deep water.

During the last 5 years Western Europe attracted the third highest volume of offshore drilling spending in the world, almost all of it ventured in

Northwest Europe, mainly the UK and Norway. The region will fall to fourth over the next 5 years, surpassed by Africa for the first time.

Deepwater spending is modest due to a lack of significant deepwater basins outside Norway. Outlays on drilling off Europe are expected to fall slightly to $10.3 billion in 2012 from $11 billion in 2007.[2]

Norway

Norway probably holds about 50% of Western Europe's oil and gas reserves, and at the end of 2007 there were 56 discoveries yet to be approved for development.

Oil production peaked at 3.5 million b/d in 2000, and in 2008 total liquids production is likely to be some 2.5 million b/d.

Norway retained its status in 2007 as the largest gas exporter in Western Europe, at 89 billion standard cu m, up from 87 billion in 2006. Furthermore, gas production is forecast to increase to around 99 bcm in 2008 and in the words of the oil minister "expected to stay at today's level for the next 10 years." Douglas-Westwood's view is that the gas potential may still be understated.

During the course of 2007, eight plans for development and operation (PDO) were approved for nine new deposits. Around 10 PDOs are expected to be submitted to the authorities in 2008.

The largest discovery for which a plan is expected towards the end of 2008 is 7122/7-1 Goliat, operated by Eni (Fig. 3). However, the Norwegian Petroleum Directorate observed, "There are many problems that must be studied in connection with development of Goliat, which could lead to a postponement of the PDO."

Several of these plans call for large investments in new production facilities (Gjoa and BP's Skarv, and its Valhall redevelopment. StatoilHydro is Gjoa operator in the development phase, while Gaz de France takes over when the field starts up).

Talisman received PDO approval for two developments in 2007: Yme is a reopening of a field that was shut down in 2001. The field previously produced for 5 years with Statoil as operator. Talisman is responsible for development of Rev field.

Norway has been able to manage the wealth that has been generated in such a way as to forestall offshore oil and gas—the country's largest industry—from overheating the economy. In addition to a policy of carefully managed reserve development, it has invested its national oil and gas profits to fund the pensions of this, and perhaps the next, generation. At the end of June 2008 the Norwegian central bank stated that the value of the government oil fund was 1.991 trillion kroner ($373 billion).

The Far North

The region's Arctic frontier has generated much interest of late.

The Barents Sea is an area above the Arctic Circle whose border between Norway and Russia has been the subject of continual disagreement. Around 80 wells have been drilled in the Norwegian sector, of which around 20 have been small discoveries, mostly gas-condensate.

One of the more recent is the StatoilHydro group's Ververis 7226/2-1 well in 347 m of water, which found gas in mid-Jurassic sandstones. It bottomed at 2,992 m in the Lower Triassic Havert formation (Fig. 3).

The first discovery, Askeladd, was made with the fourth well in 1981 in the Hammerfest basin near the coast, where most of the discoveries are located. The largest field is Statoil's Snohvit, which began delivering gas to Europe's first LNG plant in 2007.

But at the top of the world a big

FPS PROSPECTS OFF WESTERN EUROPE, 2008-12 Table 1

Country	FPSO	FPSS	TLP	Total
	Installations			
Ireland	1	—	—	1
Norway	4	1	—	5
UK	9	1	2	12
Total	**14**	**2**	**2**	**18**

Source: The World Floating Production Report 2008-12

UK first half drilling steady

Offshore exploration and appraisal drilling in UK waters in the first 6 months of 2008 kept pace with 2007's level, said the Department for Business, Enterprise and Regulatory Reform.

First half land drilling was ahead of the full-year 2007 pace, while offshore development drilling was lagging.

Operators spudded 30 offshore exploration wells in the first half, compared with 34 in all of 2007. The 2008 figure includes 17 in the Central North Sea, 9 in the Northern North Sea, 2 in the Southern North Sea, and 2 West of Shetland. The 2008 total was 34 exploration wells.

They spudded 14 appraisal wells in the Central North Sea, 11 in the Northern North Sea, 5 in the Southern North Sea, and 1 West of Shetland in the first half. That compared with 77 appraisal wells in 2008.

Offshore development drilling totalled 69 wells in the first half, 43 of them in the Central North Sea, compared with 163 in all of 2007.

First half onshore drilling was 13 development, 1 exploration, and 3 appraisal wells, compared with 14 development, 1 appraisal, and 14 exploration wells in all of 2007.

Central North Sea includes inner and most of the outer Moray Firth and part of the Mid North Sea High. West of Shetland includes west of Scotland and the Rockall basin.

game is in play. Massive oil and gas resources (estimates range from 160 billion to 300 billion boe) may exist, and once the international posturing is over Russia may control over 60% of these. Developing them is another matter, and Russia will need many years, very capable technology partners, and huge investments.

Floating production

The waters off Western Europe have seen the deployment of more floating production systems than any other part of the world.

The region has 68 installations to date, including three tension leg platforms, 33 floating production, storage, and offloading vessels, and 32 floating production semisubmersibles (FPSS), 34 of which remain in operation.

Western Europe saw the world's first application of floating production technology. The UK's first offshore oil was produced at the Transworld 58 FPSS on Hamilton Brothers' Argyll field in 1975.

By and large, the regional environment is harsh and, in the northern North Sea and the Atlantic Margin in particular, weather can severely test these vessels. Wave damage has been reported on a number of FPSOs operating in these areas, including BP's Schiehallion which suffered cracks in its bow in the winter of 1999-2000.

However, European waters have seen relatively few floating production systems installed in recent times, just three in the past 5 years. But looking ahead, in the period to 2012 we expect a surge of activity with 18 units to be deployed of which 14 will be FPSOs.[3]

Offshore wind

A number of European offshore contractors are now beginning to deploy their skills in the development of a "new North Sea"—offshore wind power.

Douglas-Westwood forecasts that 1,157 offshore wind turbines will be installed worldwide in 2008-12, of which the great majority will be off Europe.

Annual capital expenditure totaled about $1 billion in 2007, but this is set to grow to near $6.5 billion by 2012 (Fig. 4). Of a total $20 billion in offshore business over the next 5 years, 94% of the spending will be off Europe.

Offshore wind power is not without problems familiar to oil sector players of hardware and installation vessel and skilled personnel shortages, all driving massive cost inflation. The fundamental problem is that all offshore industries are drawing from the same well of limited resources.

Gas production is climbing, and current business plans outline the potential for the delivery of 10 billion boe from existing fields and new projects off northern Europe.

The future

Offshore Europe has changed dramatically in 40 years and is now a very different place where even the names of many of the field operators would have been unrecognized only a decade ago.

And the changes will continue as the region's governments increasingly recognize the need to attract new players and put in place better deals for existing ones in order to suck the North Sea dry.

In the service and supply sector home-grown contractors now operate worldwide, designing, manufacturing, and operating technology developed in one of the world's most unforgiving oil patches.

And a relatively unsung activity has grown strongly. Many of the shiny new luxury vehicles clogging the streets of Aberdeen are a result of the strongly growing oil industry financial services business that is focused mainly on doing deals in the service and supply industry.

Most significantly, much of the revenue comes from outside the UK where the London market has even hosted the IPOs of several Russian oil field service companies.

A few years ago frequent questions to our firm were from companies seeking sources of finance, whereas nowadays they are from private equity firms looking for deals to buy into. In these days of subprime financial collapses, investors increasingly recognize oil and gas as being driven by strong fundamentals of supply and demand and these show no signs of changing. ✦

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1. "The World Offshore Oil & Gas Forecast 2008," Douglas-Westwood/Energyfiles.
2. "The World Offshore Drilling Forecast 2008-2012," Douglas-Westwood/Energyfiles.
3. "The World Floating Production Report 2008-2012," Douglas-Westwood.

The author

John Westwood (john@dw-1.com) is the founder of energy analysts Douglas-Westwood Ltd. With a technical background, he worked in the North Sea contracting industry, then worldwide, and has formed three energy-sector companies and sold two. He has spent the past 18 years heading Douglas-Westwood, which has completed over 500 projects since its formation in 1990 and provided services to clients in 37 countries. The firm has advised several governments and worked for energy majors and their contractors, but it primarily provides services to investment houses. In the past year it has advised on supply sector merger, acquisition, and financing deals across four continents totaling nearly $10 billion.

3D pore pressure used to optimize well design

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Pore pressure greatly affects drilling safety and the economics of drilling design and well construction.

This article focuses on how a calibrated 3D pore-pressure volume can be used to optimize well design when pore pressure and mud weight windows are the dominant issues in drilling.

Engineers often use estimated pore and fracture pressure profiles along the well path as primary input to the well design due to their overriding influence on casing seat selection. This, in turn, is the primary driver for hole geometry, casing program, and overall well cost. While this type of workflow has been used historically for wells in abnormally pressured areas, it also applies to wells drilled through depleted zones. More recently, this has also applied to deepwater wells, even when normally pressured, due to issues surrounding support of the mud column in the drilling riser.

High-quality 3D volumes of mechanical earth properties such as pore pressure and fracture gradient can provide detailed insight into relative pressure distributions within a volume. Reliable quantitative calibration, however, using data from drilled wells within the area, can deliver a more accurate pressure model in which to plan the well.

Integrating tools

Using 3D visualization with interactive well-path planning can provide more accurate modeling for drilling.

A typical well-planning workflow, based on a single 2D pore pressure and fracture-gradient prediction for the well, is forced to take the pressure profiles as fixed and build a casing and mud program around the constraints imposed by these profiles.

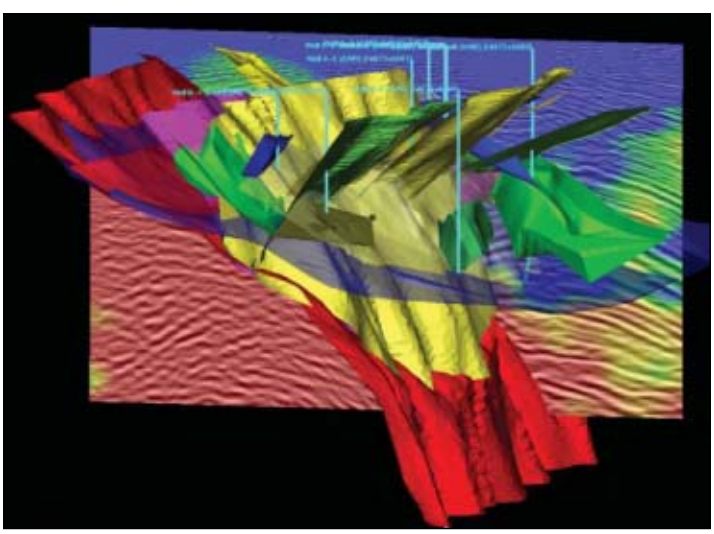
Integrating 3D pressure data with other appropriate tools allows the well-path trajectory to become an active variable in the well's planning process. This can produce far more effective solutions than those constrained by fixed pressure profiles.

The first requirement to use 3D pressure data effectively for well planning is a visualization tool with the ability to corender multiple volumes and isolate features and data ranges through combinations of color and opacity. Fig. 1 shows 3D pore pressure values corendered with seismic data and existing wells in a structurally complex reservoir.

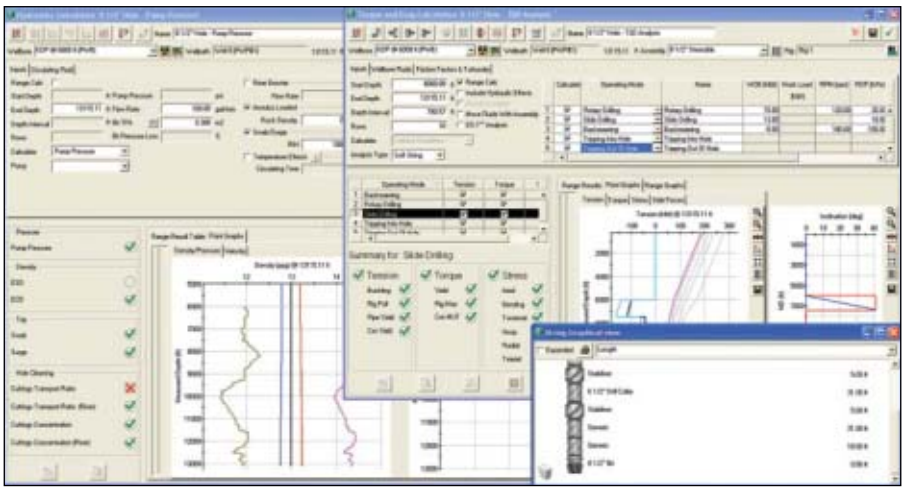
A volume-based seismic interpretation solution is ideally suited for this requirement. Pressure sealing and nonsealing faults and formations can be more clearly distinguished, based on the presence or absence of pressure discontinuities across specific geologic boundaries.

Effectively planning a well in a 3D pressure volume requires a full-functioned well planning tool that can interactively create geometrically valid well paths in the 3D volume based on specified engineering constraints.

Using 3D visualization with interac-

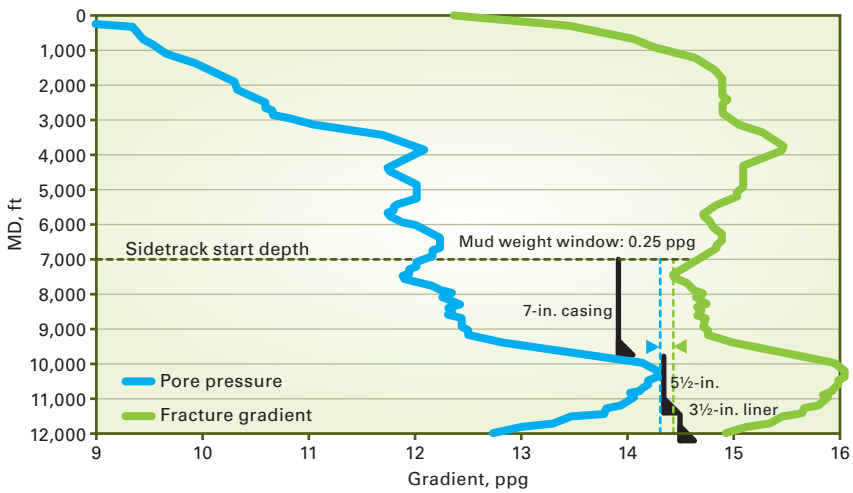


3D pore pressure values are corendered in color in this image, shown together with seismic data and existing wells in a structurally complex reservoir (Fig. 1).

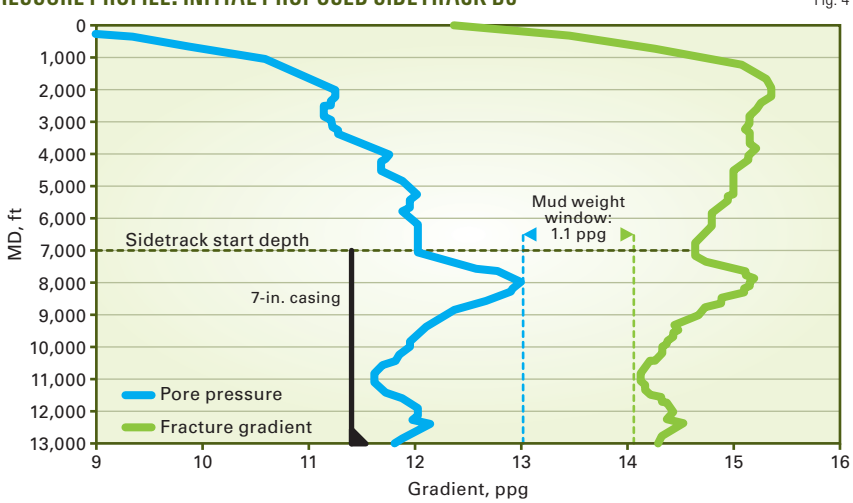


Engineering analyses are fully integrated within the same tool as the well planning functions (Fig. 2).

PRESSURE PROFILE: INITIAL PROPOSED SIDETRACK B2 Fig. 3



PRESSURE PROFILE: INITIAL PROPOSED SIDETRACK B3 Fig. 4



tive well path planning tools provides a powerful combination for optimizing the well-path pressure profile on a qualitative basis. For example, variable opacity displays can be used to identify visually areas where the pressure is above or below a certain gradient threshold. This can be effective in identifying routes to reach specific targets, avoiding isolated areas of abnormally high pressure. Furthermore, the ability to display volume data as ribbons and curtains along any well path allows visual determination of the pressure profiles in any given well.

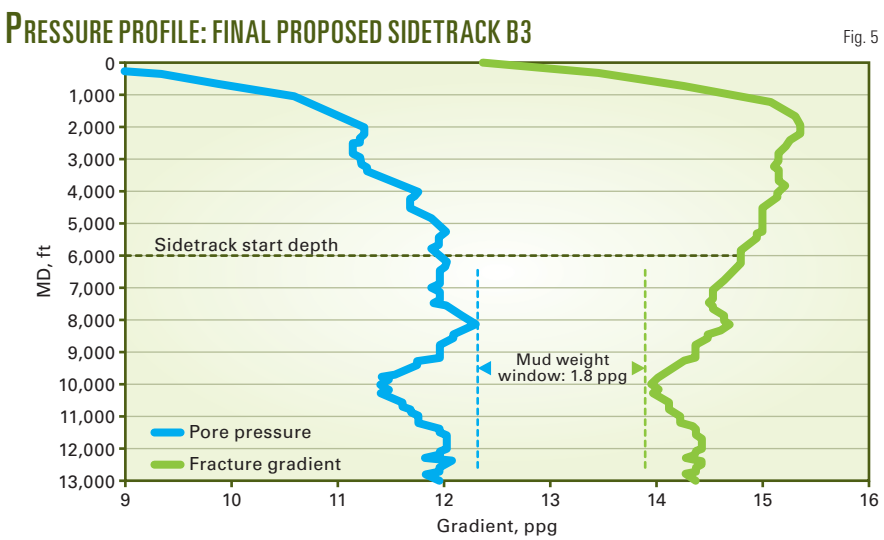
Trajectory design alone, however, cannot determine how easily or even whether a well can be engineered and physically drilled.

Unified solution

The large number of interdependent variables involved in well design make it impossible to identify a single "best" design for any well. While it is often possible to optimize for a subject of the variables, it is unrealistic in almost all cases to determine the absolute optimal design covering all aspects of the well trajectory, casing program, drillstring, mud system, hydraulic, and rig requirements. Thus, there is a need to be able to iterate rapidly through many design options, to identify practical alternatives, and to focus engineering resources on the integrity of a chosen design.

To examine all the alternatives and converge on this optimal well design, it is vital that all engineering analysis functions be fully integrated within the same application as the well-planning functions and reference a common drilling database (Fig. 2). The Paradigm Sysdrill application provides such a unified drilling engineering solution. Use of a common data model ensures that any changes to the well path and well path-related data, such as the pressure profile, are immediately available to all engineering analyses, removing the need for data exchange or replication.

Direct extraction of 3D volume data along a well path allows the pore and fracture gradient profiles specific to that wellbore to be used directly for calcu-



lating the required casing seats, based on user-specified criteria such as kick and trip margins.

Three examples

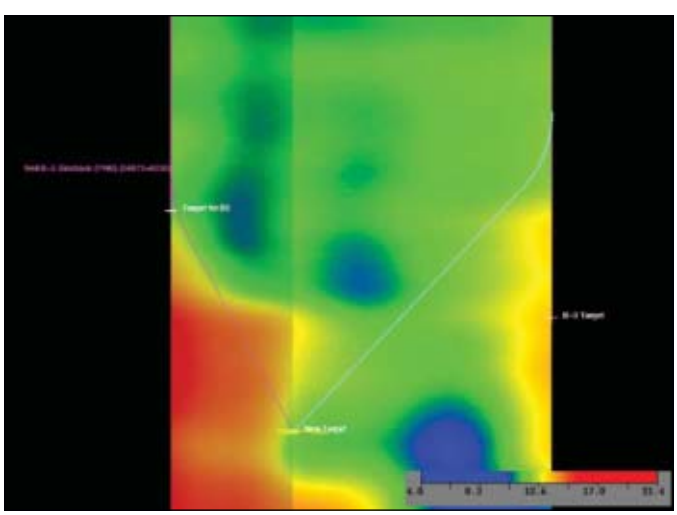
In the first example, the initially proposed sidetrack from the closest offset (B2) well represents the shortest well path to the target. Engineering analysis quickly reveals, however, that it is not feasible to drill because it would require three casing strings within an almost impossibly small mud-weight window (Fig. 3).

A sidetrack from the bottom of the B3 well provides a better, although longer, option than the original B2 sidetrack. The mud-weight window is extremely tight, however, likely making it difficult and expensive to drill due to the constraints on mud weight.

Fig. 4 shows the pressure profile of the initial proposed sidetrack, B3. It appears from the pressure distribution within the well curtain that a kickoff from higher in the well could potentially avoid the high-pressure area above the B3 target. This indeed turns out to be the case, and doing so significantly widens the mud weight window.

Fig. 5 shows the pressure profile of the final proposed sidetrack, B3. In this case, the longer sidetrack proves to be the easier to engineer and probably the most economical to drill of the options reviewed.

Fig. 6 shows pressure profiles along initially proposed sidetrack B2 on the left and final selected sidetrack B3 on the right. In a few steps, we have evaluated options that range from nondrillable to challenging, through to a relatively straightforward sidetrack plan, just on the basis of spatial variations in 3D pressure data.



This image from the 3D volume shows pressure profiles along the initially proposed sidetrack B2 on the left and final selected sidetrack B3 on the right (Fig. 6).

Design efficiency

Further engineering analysis would determine the actual drilling and casing programs required to drill this well in accordance with the geological constraints and company engineering design policies. This analysis, in some cases, might identify further issues or constraints that necessitate additional changes to the planned trajectory.

It is therefore essential that the well-planning and engineering functions are delivered as a unified solution, tightly integrated with a 3D visualization application, so that the workflow can be quickly rerun as required to optimize the well design. Integrating multidisciplinary applications is the key to well-design efficiency.

Acknowledgment

We thank John Turvill for his contribution to the article, originally published in a Paradigm newsletter. ✦

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Fossil fuel development requires long-term sulfur strategies

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Based on history, the world will require long-term sulfur management strategies because the increased development of fossil fuels likely will result in involuntary production of large amounts of surplus sulfur.

At present, the high price for sulfur has removed the stranded label from even the most remote sulfur blocks. Nonetheless, experience has shown that this situation may not last. If that surplus arises, it may persist for long time in comparison with the historical frequency of up and down cycles of the sulfur market.

Current management strategies have dealt with surplus sulfur, for the most part, satisfactorily over the short-term. These strategies, may be characterized, in part, by:

- Relatively short-term storage, during which older blocks have been preserved from the initial pour of about 25 years.
- Magnitude and duration of existing acid-gas injection schemes.
- Capacity of newly developed sulfur consuming products to use large amounts of sulfur relative to what may be produced.

If one considers that a period of sulfur surplus could extend as long as our dependence on fossil fuel consumption continues, the limitations associated with current strategies come into focus. These limitations arise from many factors, including the inherent physical and chemical properties of sulfur as well as regional variations in regulatory frameworks, prevalent climatic conditions, environmental impact tolerance, and available space at grade, below grade, or in subterranean formations.

In recent years, Alberta Sulphur Research Ltd. has been examining the chemistry associated with several concepts that deal with long-term management of surplus sulfur.

Concerning aboveground block storage, the company has examined certain protective barriers that may help preserve the physical and chemical integrity of the sulfur block. It has also investigated in laboratory and field demonstrations the feasibility and benefits of storing sulfur in shallow below-grade excavations with subsequent capping. Another study looked at certain aspects of acid-gas injection chemistry for facilitating modeling of the behavior of fluids rich in H_2S and CO_2.

Finally, it has investigated a new use for sulfur in which hydrogen sulfide is combusted to sulfur dioxide, the thermal energy captured, and the sulfur (and perhaps some CO_2) sequestered by injection into, for example, a depleted sour-gas reservoir.

The tiered sulfur block resides on a sound base pad (Fig. 1).

Based on a presentation to PennWell's Oil Sands and Heavy Oil Technologies conference, Calgary, July 16-17, 2008.

This sulfur block shows weathering after an intermediate storage period (Fig. 2).

Blocked sulfur storage

Much of the elemental sulfur recovered from oil and gas operations store & eventually is as calcium sulfate following its use as a raw material for producing sulfuric acid, most of which is used in producing phosphate fertilizer.

Storing sulfur produced from a Claus plant in excess of marketable amounts usually involves formation of large solid sulfur blocks created by a staged pour of molten sulfur within aluminum forms.

Various references document best practices for preparation of proper bases (topography, load bearing capacity, footprint, and materials of construction), pouring equipment and procedures, block geometry and acid run-off management.[1-3] Alberta's Energy Resources Conservation Board documents IL 84-11, GB 92-4 and Directive 055 Regulatory specify matters concerning sulfur storage.[4-6]

As a whole, Western Canadian operating companies and the sulfur technology service sector, together with the regulatory framework that guides and oversees both blocking and remelt operations, have demonstrated that for intermediate periods of time, sulfur storage in above grade blocks can be engineered in an economically sound and environmentally friendly manner. The structure in Fig. 1 is a good example of such an engineered block.

In long-term storage, however, the physical properties of sulfur combined with continuous exposure to elements creates a porous structure susceptible to physical breakdown. Upon solidification, elemental sulfur undergoes a subsequent phase change within the solid from a monoclinic to an orthorhombic crystalline configuration. The latter has a higher bulk density than its monoclinic counterpart; thus, cooling to ambient conditions over several hours creates internal stresses.

Release of these stresses cause fissures to develop, from microcracks to large fractures, that enhance porosity and make the block somewhat brittle.

Climatic forces such as abrasion from wind-born dust and sand, erosion from rainfall percolation and runoff, and fracture propagation from sequential freeze-thaw cycles can deteriorate the material. Perhaps the bacterial activity that leads to acid production may also play a role in the breakdown of solid sulfur.

During 20 years or more, the environment's action on the mineral can severely compromise the structural integrity of a block. Fig. 2 shows an example of such cumulative effects on a block.

UNDERGROUND SULFUR BLOCK

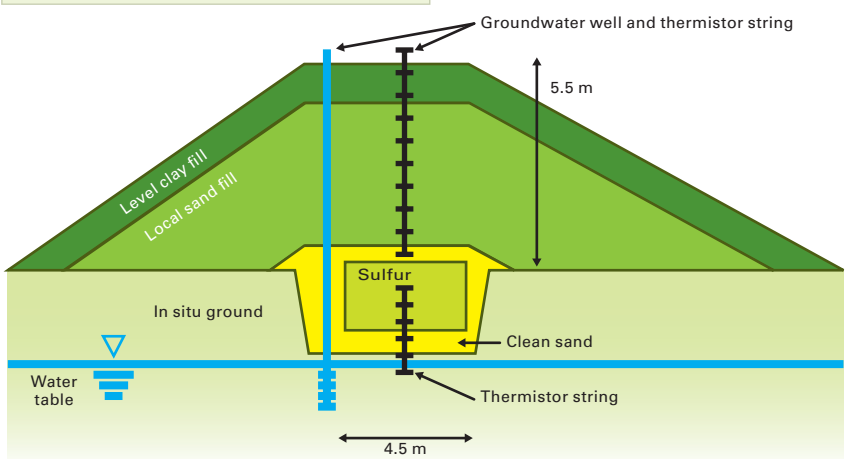
Fig. 3

Syncrude Canada Ltd. sulfur storage test site No. 2 - above water table

7 m × 4.5 m × 1.6 m sulfur block ≈ 100 tonnes

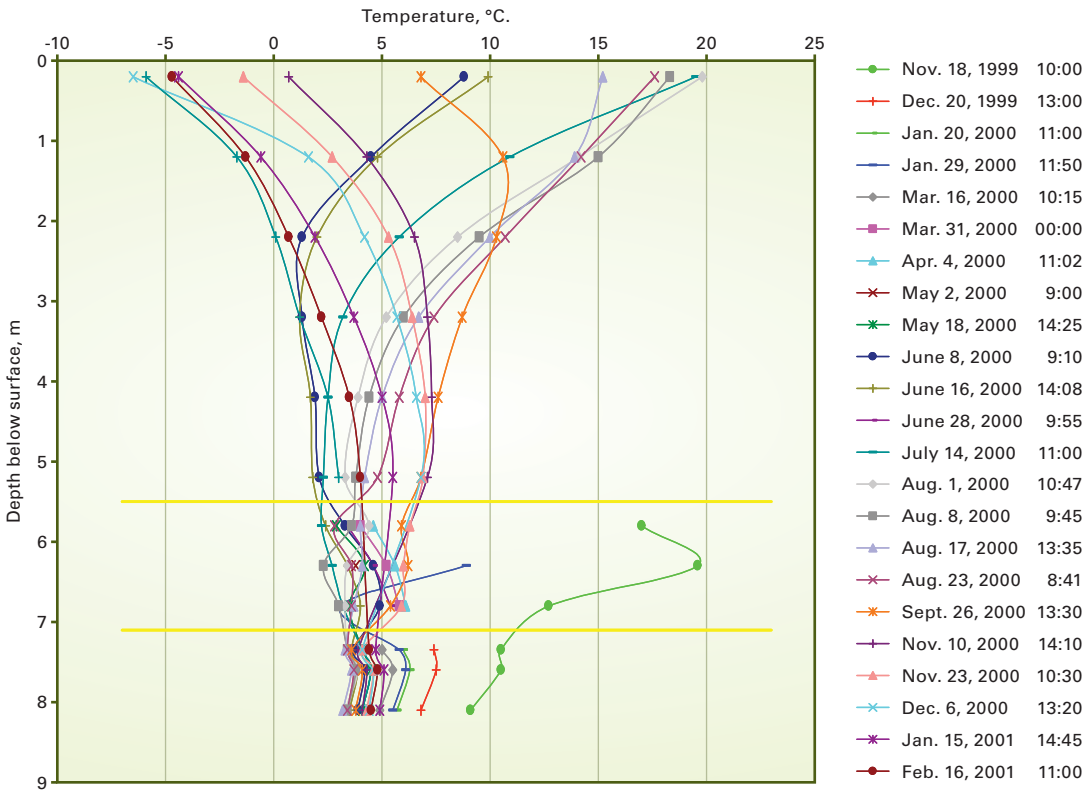
Covered with +5.5 m soil

Current temperature < 10° C.



BURIAL DEPTH INFLUENCE ON TEMPERATURE

Fig. 4



If aboveground blocking of sulfur remains an option for storing, not for 20 years but for 200 years, one might expect the condition of the block to be somewhat unrecognizable if left exposed to such forces. One should note that the effects of sulfur on the environment, in terms of dust liberation and acid runoff, would become exaggerated as the surface area of the block increases from structural breakdown.

In recent years ASRL has investigated two approaches for mitigating the influences of these factors on the long-term integrity of sulfur blocks. The first involves placing the block below grade and capping it with suitable materials for controlling one or more environmental conditions. A field test examined this concept at the Syncrude Canada Ltd. oil sands mine at Mildred Lake (Fig. 3).

Burial to slightly more than 5 m will reduce the temperature of a small block to 5° C., ±3° C. (Fig. 4), and reduce the flux of water by use of high-density clays for the sloped side walls and capping layers. If the block is above the water table, water flux is even easier to control.

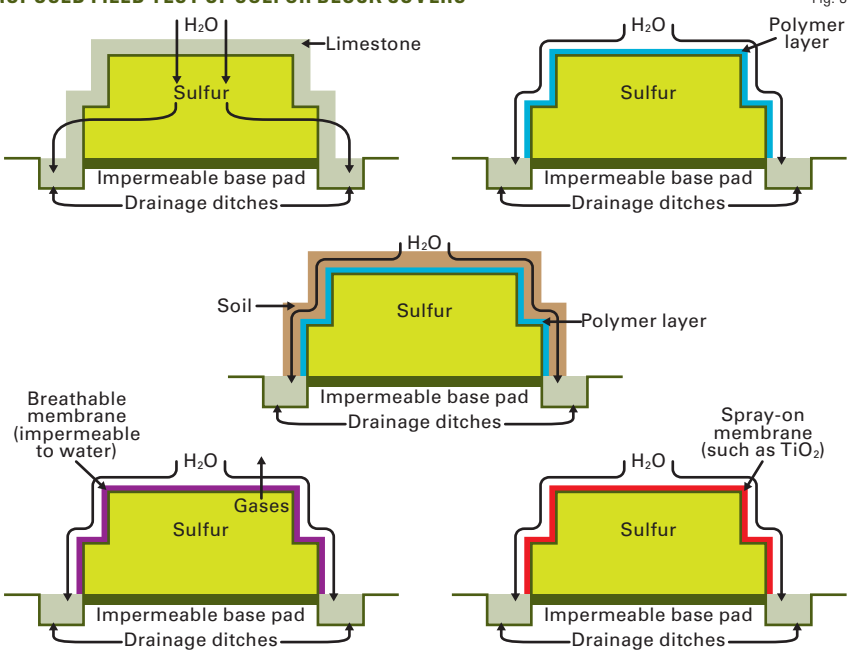
The control of temperature and water in such a manner may reduce bacterial activity of thiobacilli to low levels and completely eliminate freeze-thaw cycles.

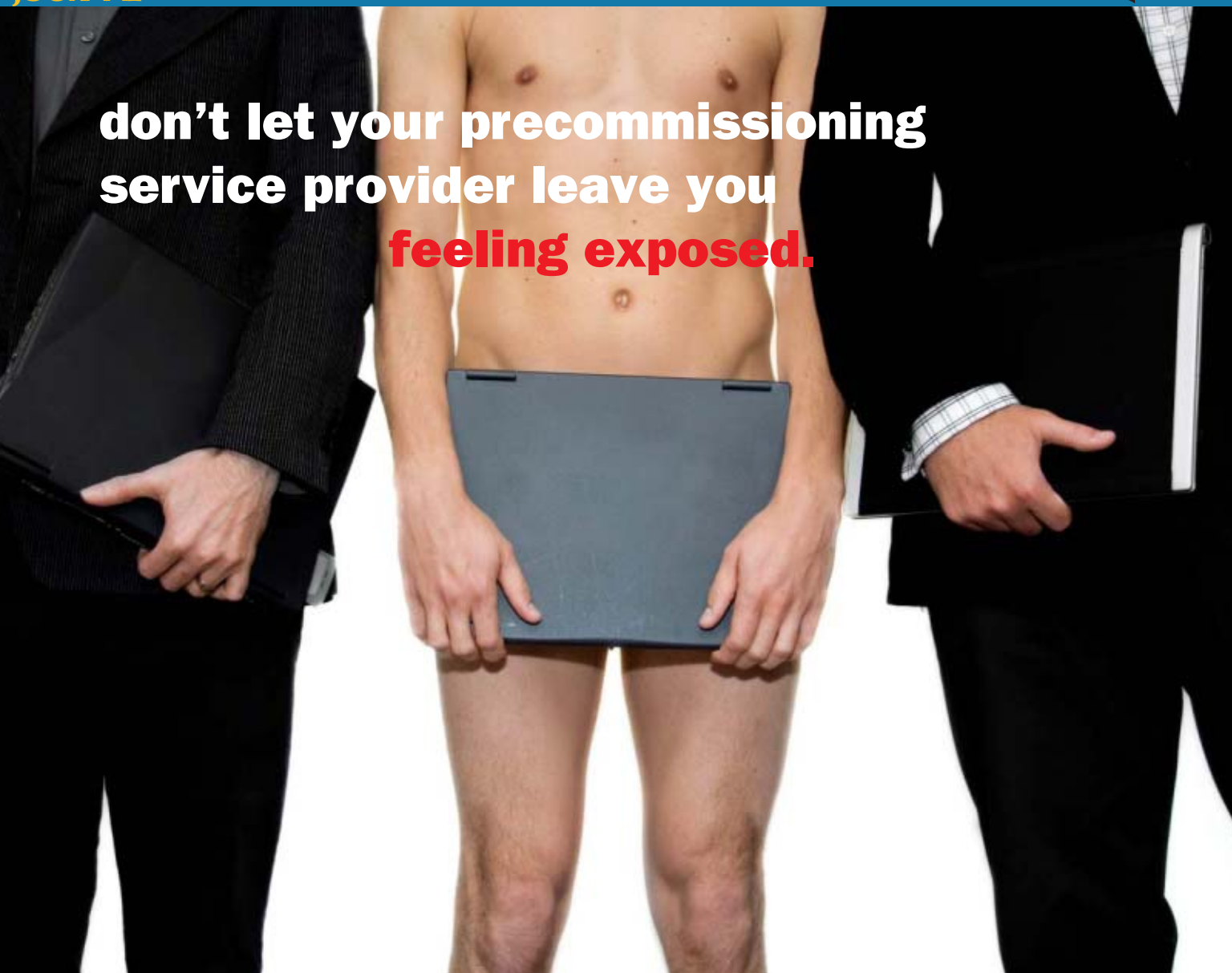
A second possible strategy for preserving the integrity of sulfur blocks is to cover the finished block surface with a protective layer of material that will act as a barrier to the elements. ASRL has examined in laboratory scale two such barriers: limestone and stucco.

Limestone rock has the benefit of reducing surface temperatures on the block and neutralizing some of the acidity that may be generated at the surface. According to Crescenzi, the resulting salt may also act

PROPOSED FIELD TEST OF SULFUR BLOCK COVERS

Fig. 5





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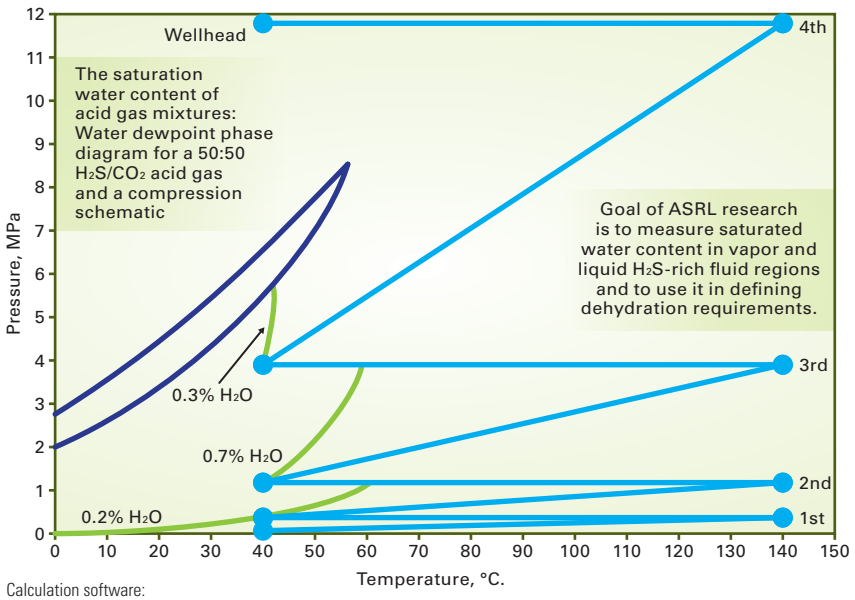
ACID-GAS INJECTION COMPRESSION PROFILE

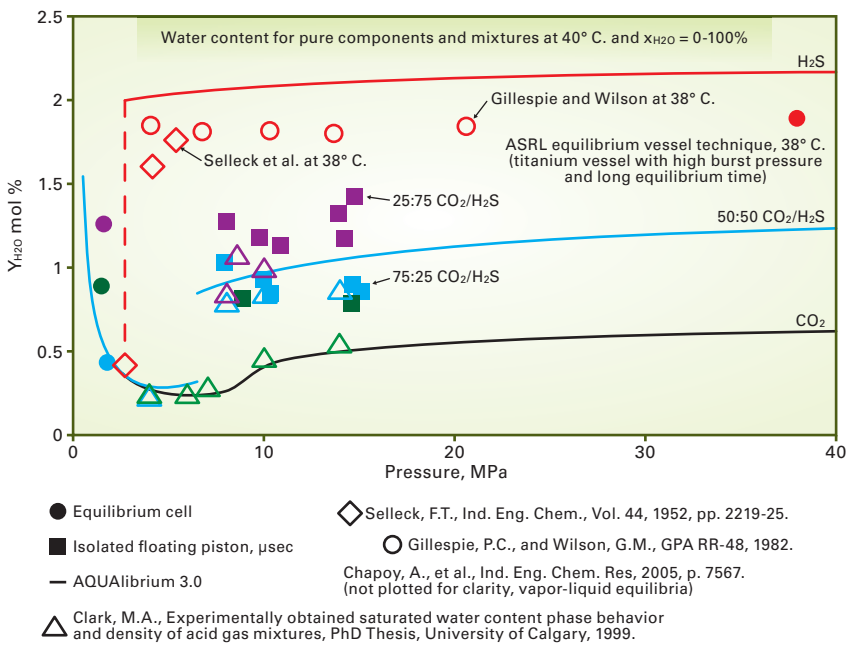
Fig. 6



Calculation software:
VMGSim 2.8.0 (dry-phase packet)
AQUAlibrium 3.0 (aqueous dewpoint lines)

ACID-GAS WATER CONTENT

Fig. 7



Equilibrium cell
Isolated floating piston, μsec
AQUAlibrium 3.0
Selleck, F.T., Ind. Eng. Chem., Vol. 44, 1952, pp. 2219-25.
Gillespie, P.C., and Wilson, G.M., GPA RR-48, 1982.
Chapoy, A., et al., Ind. Eng. Chem. Res, 2005, p. 7567. (not plotted for clarity, vapor-liquid equilibria)
Clark, M.A., Experimentally obtained saturated water content phase behavior and density of acid gas mixtures, PhD Thesis, University of Calgary, 1999.

as a biocide to inhibit further bacterial action.[7]

A pilot program, initiated at two locations, is testing various types of barriers or coatings. In 2005, Syncrude Canada Ltd. poured miniblocks at their mine site in Fort McMurray to test four barriers together with an unprotected block. An overseas company also has initiated a pilot investigation of covered-block storage. ASRL hopes to initiate a similar field test in south central Alberta within the year (Fig. 5).

The concept of a protective strategy will not, in all likelihood, relieve the owner of the block from a requirement to collect and possibly even treat runoff before release to the environment. Furthermore, the block may require periodic maintenance to preserve the integrity of the barrier over many years.

This would seem a suitable business for third-party contracting following closure of a mine.

Acid-gas injection

Since 1989, companies in Western Canada have disposed of acid gas by injecting it into subterranean formations. Target reservoirs have consisted of deep saline aquifers, depleted sour-gas reservoirs, and at least one active sour-oil reservoir.

To date the largest operation in Canada is the Talisman-Spectra operation at Kwoen in northeast British Columbia. This operation injects close to 660 tonnes/day (tpd) sulfur (as H_2S) and 320 tpd of CO_2.

The ERCB reported in its 2006 Annual Report on Sulphur Recovery that 38 acid-gas injection schemes were in operation in Alberta with total licensed injection capacity of 572 tpd sulfur.[8] Furthermore, the same document reports that of the 14 sour-gas processing plants degrandfathered during 2001-06, half selected acid-gas injection as the H_2S-CO_2 management option.

While most schemes to date are small in scale, relatively few technical obstacles exist for scaling up from the 1.7 million cu m/day operation at Labarge in Wyoming to much larger operations compressing raw sour gas or amine acid gas.

The sequestration of H_2S by aqueous phase trapping, mineralization, and mobile-phase migration have been studied, but some concerns remain regarding long-term containment.

One area that required further research was the generation of additional phase-equilibrium data to predict dewpoint temperature and pressure of various acid-gas compositions for the injection. The prediction would enable the design engineer to decide on the

requirement for active dehydration or, conversely, use of stainless steel for construction of the pipeline to the injection well.

In June 2007, ASRL presented more than 150 new experimental data points for the acid gas and water system covering conditions illustrated in Fig. 6. Fig. 7 plots data generated at 40° C. together with literature data for the pure-component moisture capacity.

Alami recently analyzed these results with a semiempirical model.[9]

New sour-gas processing developments that are relevant to acid-gas injection schemes include acid-gas separation technologies that result in a high-pressure, acid-gas stream (actually a dense-phase fluid or a subcooled liquid) off the back end. This, of course, saves on compression horsepower requirements.

These developments include the Kvaerner Cryogenic Fractionation scheme,[10] the ExxonMobil Controlled Freeze Zone (CFZ) process,[11] and the Total Sprex process.[12]

Acid-gas combustion

One specific drawback to acid-gas injection is that hydrogen sulfide returned to the reservoir is an energy-rich molecule.

By foregoing the Claus operation, the plant loses a source of steam that is typically used to regenerate the rich-amine stream.

Clark has proposed a one way of recovering that energy and returning sulfur to the reservoir.[13] The method is to combust the acid gas to sulfur dioxide and compress and liquefy the SO_2 stream and inject it downhole. The target reservoir would be a depleted sour gas or a sour-oil formation.

Once the SO_2 or the SO_2-CO_2 mixture reaches the reservoir, the SO_2 will react almost instantaneously with the residual hydrogen sulfide in an underground Claus reaction. This reaction will produce two condensable products: sulfur and water. These products should not migrate laterally to any extent.

Depending on the dominant sequestration mechanism, the pressure in the reservoir may not increase but could decrease in time. The H_2S content of the reservoir fluid also will decrease in time. Thus, this is an opportunity to take a sour-hydrocarbon resource, generate sweet gas with no sulfur emission and no carbon emission to generate steam or electricity from the combustion and sequester the SO_2 and CO_2 downhole.

Downhole there is little pressure build up, and the process eliminates long-term concerns about cap rock or wellbore integrity. Fig. 8 illustrates the concept. Of course, one could burn the surplus sulfur to generate heat and SO_2 as well. An engineering company has already proposed a two-step combustion process.[14]

An intensive program in the laboratory has focused on this concept, which ASRL presented in 1999. To date, the program has examined the properties of sulfur (melting point and viscosity under high acid-gas partial pressure) and the properties of SO_2-CO_2 mixtures under elevated temperature and pressure (density, solubility in aqueous fluids, and saturated water content).[15 16]

Water content parameters in acid gas and water system

Table 1

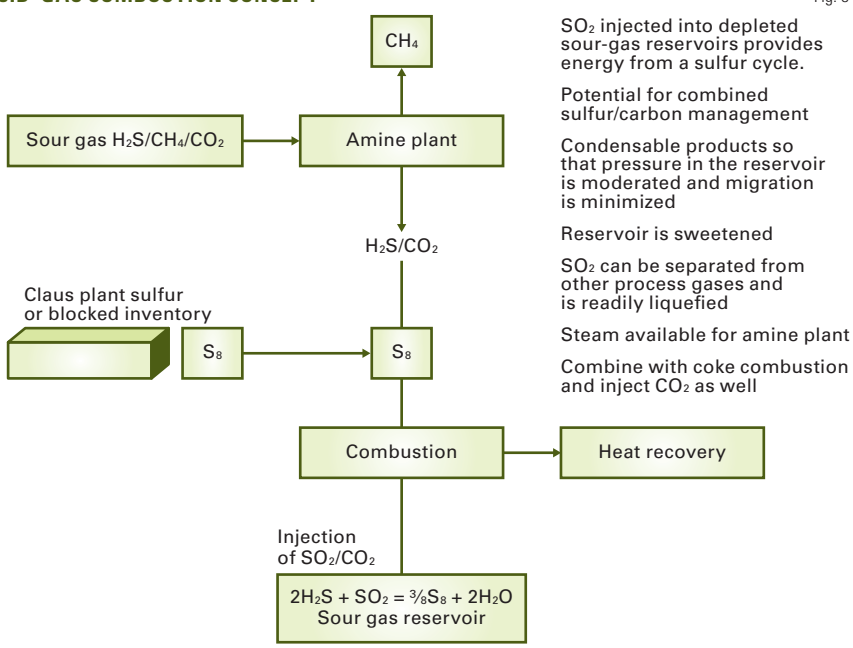
Data source	n	– Temperature, °C. – Min.	Max.	– Pressure, MPa – Min.	Max.	— x_{H_2}, mol % — Min.	Max.
Clark[1]	91	–1.3	98.5	0.77	37.9	1.2	85.9
Huang et al.[2]	16	38/9	176.7	4.82	18.2	9.4	81.0
Stirred autoclave	42	30.0	90.0	2.00	10.0	20.0	80.0
Equilibrium cell	62	24.6	60.8	1.21	7.85	9.3	89.6
Visual dewpoint	10	9.0	23.0	4.65	10.5	48.1	50.0
Isolated floating piston, μsec	39	39.9	60.1	6.03	15.5	20.3	89.5
Summary	260	–1.3	176.7	0.77	37.9	1.2	89.5

[1]Clark, M.A., Experimentally obtained saturated water content phase behavior and density of acid gas mixtures, PhD Thesis, University of Calgary, 1999. [2]Huang, S.S., et al., "The Phase Behavior of Two Mixtures of Methane, Carbon Dioxide, Hydrogen Sulfide and Water," Fluid Phase Equilibria, Vol. 19, 1985, pp. 21-32.

Note: ASLR experimental techniques include:
- Stirred autoclave (low pressure, vapor-liquid equilibria)
- Equilibrium cell (low pressure, vapor-liquid equilibria)
- Visual dew point (high pressure, hydrate region, solid-liquid equilibria)
- Isolated floating piston with micro sampler (high pressure, liquid-liquid equilibria)

Acid-gas combustion concept

Fig. 8



SO_2, H_2S REACTION IN RESERVOIR

Fig. 9

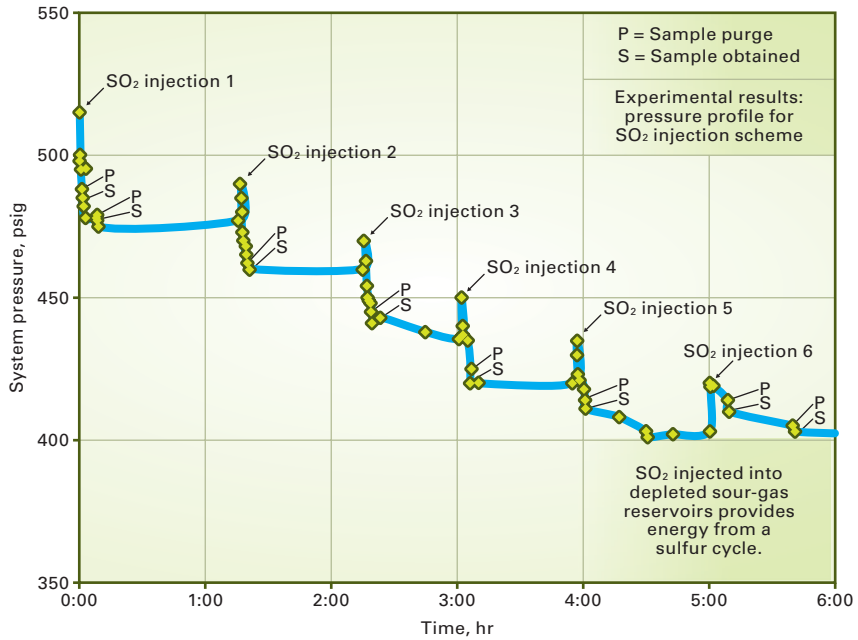


Fig. 9 shows evidence of the rate of reaction between the residual H_2S and the injected SO_2. This plot shows pressure vs. time for a set of sequential injections of SO_2 into an autoclave containing sour gas.

The transducer trace picks up the momentary increase in pressure following each injection event, followed by the drop in pressure. The investigation also sampled the headspace and analyzed it following each injection to determine the presence of either reactant following the reaction.

The work also has observed the progress of the experiment, as given by the pressure trace, through a sapphire-windowed cell in the ASRL laboratory, and the reaction is fast. In this case, the system temperature was 125° C. and the initial pressure was about 475 psi.

Currently the concept is the subject of a joint-venture special project to conduct core flood experiments for generating viscosity data for SO_2 or SO_2-CO_2 mixtures under pressure and to model the dynamics of the injection scheme within the wellbore and reservoir.

Topside engineering design and economic study will round out Phase 1 of the project. Phase 2 will consist of a field demonstration of the injection itself. ✦

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Modified cycles, adsorbents improve gas treatment, increase mol-sieve life

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Natural gas treatment often uses adsorbents for contaminant removal. Special materials, such as molecular sieves, remove sulfur-containing impurities like mercaptans, as well as water vapor. Such operation may be prone to problems, particularly during regeneration of these molecular sieves. The transient thermal waves produced during regeneration, for example, may create unwanted byproducts like COS.

Improper regeneration may ultimately reduce product quality if the temperature is too low or time is too short. On the other hand, excessive temperatures or heating times may reduce adsorbent life or cause adsorbate decomposition (or coking) in some instances.

Modified cycling, as well as additional adsorbents (such as alumina), can reduce degradation of molecular sieves. Such additional adsorbents also allow targeting and removal of other contaminants, including oxygenates like methanol that may promote undesirable side reactions on valuable molecular sieves.

This article will discuss effective compound-bed configurations and process techniques to address problems sometimes encountered with conventional mole sieve treatment.

ExxonMobil Corp. operates dozens of gas-treatment plants worldwide and is committed to using modern, advanced materials, as well as lowering regeneration-energy requirements, thereby reducing emissions.

MIXED-BED DEHYDRATOR

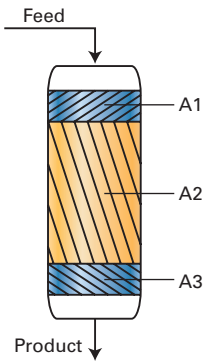


Fig. 1

Improving performance

Molecular-sieve (MS) adsorbents have become widespread for removing contaminant from natural gas. Over the last 3-4 decades, they have proven suitable and economic in reducing contaminant levels during gas processing. With increasing treatment requirements, however, including more stringent product and effluent specifications, greater plant size, and increasingly difficult feedstocks, there is considerable incentive to improve MS performance.

Simultaneously, decades-long experience from operating plants has begun to reveal limitations in conventional use of these materials. With guidance from the past, MS end-users and manufacturers are developing effective strategies for enhancing use of these materials and maximizing their potential.

ExxonMobil has been involved in adsorption and adsorbent use for at least a half-a-century, with both operating experience and ongoing MS and adsorbent development programs. Relevant experience includes gas treatment at several locations worldwide conducted over the entire gamut of operating conditions. It is one of the largest users of adsorbents supplied by vendors and maintains its own internal programs and research into new adsorbent materials and chemistry.

This unique combination of breadth of operating experience and depth of in-house research capability has allowed ExxonMobil to approach the problem of optimizing adsorbent performance from a unique vantage point.

Key limitations exist in conventional MS operating practice, including deactivation via exposure to certain contaminants, suboptimal regeneration (e.g., refluxing), unwanted byproducts during regeneration, and lowered adsorbent life due to increased regeneration frequency and severity. The company's strategy addresses these limitations using:

Based on a presentation to the Laurance Reid Gas Conditioning Conference, Norman, Okla., Feb. 25-27, 2008.

• Enhanced adsorbents including structured adsorbents and adsorbent combinations (compound-beds).

• Modified thermal or pressure cycles including variable-frequency cycling.

• Modified partial desorption regeneration,[1] or combinations thereof. The company is seeking patents on some of these combinations and exploring more selective adsorbents to reduce hydrocarbon loss and regeneration energy requirements.

Delaying degradation

The desire to reduce adsorbent fill cost and to increase the lifetime of solid-bed dehydrators has led to consideration of alternative adsorbents, including their use with compound beds. Compound (or "mixed") beds consist of two or more layers of different types of MS for water and mercaptan sulfurs, for example.

Fig. 1 shows such a compound bed of adsorbents, where A1, A2, and A3 represent different solid materials. Adsorbents can be MS, such as 4A (often used for dehydration) or 13X (used for removal of larger molecules), or other zeolitic adsorbents. Additional layers of specific adsorbents may also be used to remove trace mercury, for example, if the treated gas is to be fed to an LNG plant.

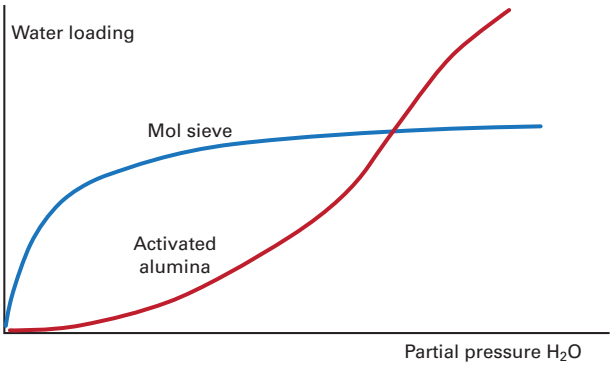
Additional layers can also offer significant protection of sensitive molecular sieves from both contaminants and damaging conditions that might result from upsets during the feed cycle or refluxing during the regeneration cycle. The air-separation industry often uses compound beds as pre-purifiers.[2]

Typically, contaminated feed gas enters from the top of the bed during the adsorption cycle. As the bed adsorbs contaminants over the course of the service cycle, it ultimately must be taken off-line before it exceeds treated-gas specifications. Usually, another bed is placed in service, and the spent bed regenerated.

During the regeneration cycle, dry, heated gas flows in from the bottom

ADSORPTION ISOTHERMS FOR WATER ON MS, AA

Fig. 2



of the bed and progresses up through the packed bed. A "thermal wave" moves up through the bed as contaminants flow out. In general, there is a lag between arrival of the thermal front and arrival of the mass transfer front. This can create conditions for unwanted side reactions.

The contaminant-saturated regenerated gas is usually cooled to condense water and heavy hydrocarbons. If other contaminants are present, the regeneration stream must be treated in some manner. For example, the stream may be washed with physical solvent to absorb sulfur compounds, so that the treated gas may be used for fuel.

The unsteady nature of the regeneration process generates a "peak" of contaminants. Generally, the solvent system must be operated in a way to provide a steady concentration of contaminants to the next process (e.g., sulfur-recovery unit).

The addition of activated alumina (AA) to the top of these compound beds of MS protects the MS from unexpected liquid (hydrocarbon, brine, glycol, or condensed water) carryover into the bed from upstream separation facilities sometimes as aerosols. Well-designed separation equipment upstream of the MS bed can reduce such fouling.

AA can also protect the MS from "refluxing," when water condenses in the upper, cooler part of the bed during early stages of regeneration (discussed below). AA, because of its higher water capacity, also helps ensure that the heavy compound (e.g., mercaptan) removal specification will be met by reduction of the chance of water breakthrough from a compound bed consisting of 4A MS and 13X MS, for example.

Even a relatively small amount of water breakthrough into the 13X MS will reduce the mercaptan-removal capacity substantially because of the adsorbent's greater affinity for the more polar compound. 13X capacity cannot be restored until the water is desorbed. There are several benefits of using an AA/MS compound bed including lower overall adsorbent cost and higher resistance to liquid upsets and liquid carryover (described above). AA can also have a higher equilibrium capacity than MS when the feed gas is near saturation, as shown by the isotherms in Fig. 2.

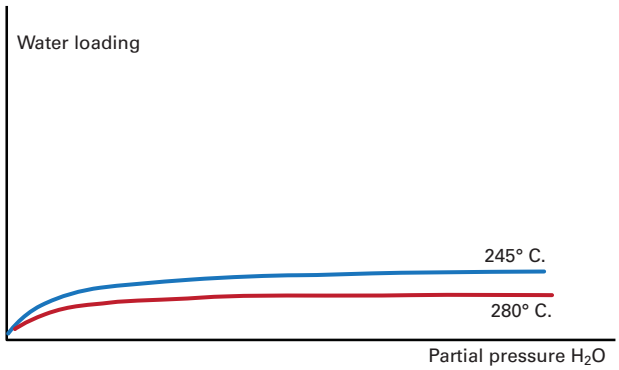
Regeneration temperatures required for AA are furthermore lower than those of MS, thus lowering the heat requirement to desorb the water in the AA relative to MS. This lowered energy requirement translates to savings of steam or fuel gas, depending on how the regeneration gas is heated. Others in industry have recognized the benefits of compound beds for natural gas treatment, and compound beds of AA/MS have been used in commercial natural gas dryers at several installations for decades.[2-7]

Sweet gas dehydration

A particularly undesirable limitation of conventional MS use occurs if there is uncontrolled water condensation during regeneration. At the start of the regeneration cycle, the MS at the top of the bed is already near its maximum water-adsorption capacity (for that temperature and partial pressure of water) because it has been in drying service cycle for some time. The regeneration thermal wave moving up from the bottom of the vessel drives off water from the heated adsorbent and carries it in the gas phase.

ADSORPTION ISOTHERMS FOR MS AT HIGH TEMPS

Fig. 3



Hot gas moving up through the cooler part of the bed cools and may reach the point of water saturation, particularly if the regeneration is at high pressure. Since the remaining incremental capacity of the MS is small (for fixed temperature) the water may condense, which can be damaging to the binder of the sieve particles. The advancing thermal wave can then vaporize the condensed water, potentially causing pressure build-up in the MS particles. If the rate of temperature rise is too rapid, the particles may be damaged. Also, if the bed is internally insulated, it may be possible for liquid water to get behind the insulation. In sour service, this could create corrosion issues.

In the worst cases, liquid water may condense, start flowing down the bed, and be revaporized by the advancing regeneration thermal wave, a phenomenon known as "refluxing." The ultimate result is often a doughnut-shaped region of powdered MS material at the top of the adsorbent bed. AA, on the other hand, generally resists disintegration by liquid water,[8] although its porosity may decrease under these conditions.

It has been suggested to reduce the effect of refluxing by use of alternate types of molecular sieves that are mechanically stronger and more resistant to disintegration.[9] Like the use of AA, however, they do not actually address the root cause of the problem.

One way of reducing the chance of refluxing is more slowly to ramp the temperature of the regeneration gas over the course of the cycle. This may lengthen the regeneration step to achieve the same level of water removal. This milder regeneration scheme, however, is generally preferable to premature aging and unscheduled changeout of the MS.

In many cases, the regeneration heater is immediately activated to maximum temperature (typically around

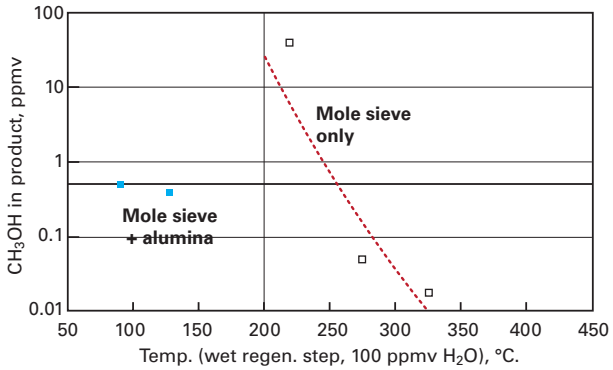
315° C.) and held there throughout the regeneration step. While this does minimize the time for regeneration, it also maximizes the severity of conditions for the adsorbent, as well as such ancillary equipment as switching valves, support screens, and internal insulation (if present).

In the simplest cases, reducing the final regeneration temperature can lengthen the life of the adsorbent. While a small amount of net adsorption capacity may be lost (Fig. 3) and the cycle time may be increased slightly, the decreased rate of water desorption will decrease the supersaturation of the gas at the top of the bed, reducing the chance for reflux.

Testing the method at one installation, ExxonMobil found that a reduction of up to 35° C. in regeneration temperature was possible (245° C. vs. 280° C.), with no apparent immediate effect on the drying cycle. This also yields the benefits of reducing undesirable side reactions and total energy requirement. One possible means of countering the increased regeneration cycle time would be to increase the hot-gas flow rate. Velocities, however, are limited to those that will not cause lifting of the bed.

MODEL: COMPOUND BED LOWERS REGEN. TEMP.

Fig. 4



The addition of heat to the top end of the vessel at the start of regeneration could mitigate refluxing. This may not necessarily fully protect the MS in the middle (radial sense) of the upper portion of the bed, but it will address the area of greatest thermal inertia and could prevent formation of the ring of disintegrated MS that is sometimes observed when a spent bed is opened. One must avoid water condensation on downstream carbon steel piping, however, when it is exposed to sour gas.

Even when refluxing does not occur, molecular sieves are subject to hydrothermal aging during normal operation. Because the loss of activity can be substantial after a 3-5-year lifetime, the beds are generally designed for end-of-run (EOR) conditions. Thus, at start-of-

run (SOR) adsorbent conditions, extra capacity in the design can be used to advantage.

One alternative is simply to run for a longer period in drying service, rather than for a fixed (EOR) time. Another possibility is to utilize lower regeneration temperatures at SOR conditions. Some residual capacity may be lost during these cycles, but the severity of regeneration is reduced. This scheme will increase the total number of cycles achieved before EOR conditions are reached. Of course, regeneration temperatures may have to be adjusted upward over time to compensate for the hydrothermal aging that eventually occurs.

Ultimately, there is a trade off between milder regeneration conditions, which reduce operating expenditures (OPEX; through decreased material changeout frequency and reduced energy) and increasing capital expenditures (CAPEX). Because lower regeneration temperatures reduce net capacity slightly, a corresponding increase in bed size is needed to offset this, increasing CAPEX.

If the added volume of material requires an additional dehydration vessel, then the required CAPEX clearly exceeds any incremental OPEX savings obtained through energy savings and increased adsorbent life. For existing installations at SOR adsorbent conditions, lagniappe in the design can be used to advantage, since facilities are generally designed for EOR conditions, when adsorbent activity is decreased after many cycles.

Use of lower temperatures at SOR conditions can increase the total number of cycles achieved before EOR conditions are reached.

If only dehydration of a sweet gas stream is required, a common means of avoiding the negative effects of gas-phase impurities (such as benzene, toluene, and xylene) is to use small-pore zeolites (3A or 4A).[10] Mercaptans, heavy hydrocarbons, and other large molecules cannot fit into the small pores. Thus, they are not present in large concentration when the thermal wave arrives. Thus, degradation via coking is not generally an issue (though hydrothermal aging may be).

Sour service

It has been long observed[4,11] that CO_2 and H_2S can react to form COS according to $H_2S + CO_2 \rightarrow H_2O + COS$.

This reaction is particularly prone to occur at the elevated temperatures of regeneration.

For dehydration-only service (i.e., no H_2S removal), it is possible to use a small-pore zeolite (3A) MS in order to exclude the reactants from the pore space.[12] Alternatively, it has been shown that 5A MS catalyzes COS formation to a lesser degree than 4 A MS because it is less basic than 4A MS.[11]

HC, mercaptan removal

In some cases, it is desirable to remove heavy hydrocarbons from a sour-gas stream. ExxonMobil has successfully used silica gel in this application to reduce heavy hydrocarbons going to a solvent-based acid gas removal process.[13] Interestingly, regeneration temperatures had to be lowered to reduce the effects of sulfidation in the regeneration gas heater coils.

Removing mercaptans from gas typically employs larger pore-size molecular sieves (like 13X). Heavy hydrocarbons (like BTX) and other impurities (like methanol) will coadsorb with mercaptans. Consequently, it is possible for these compounds to crack and form coke if the thermal wave "outruns" them during regeneration.

Some reports have also noted the decomposition of mercaptans on 13X.[14] Thus, if the impurities are not desorbed and flushed out before the thermal wave arrives, they may react in some fashion, possibly catalyzed by the solid itself. Again, reduced regeneration temperatures will tend to reduce these undesirable side reactions.

Another means to reduce decomposition reactions is to ramp the temperature more slowly during initial stages of regeneration. This allows more time for the molecules to desorb, diffuse, and flow out of the bed before the high temperature front arrives. A variation of this theme is to bring the temperature up to some intermediate value and hold it there for some time, then ramp to the final temperature. Ramping, or holding at intermediate temperatures, also reduces the thermal stress placed on the system but increases the regeneration cycle time.

Of course, any modification to regeneration cycles requires agreement from operations, as adjustment of the regeneration stream cleanup system may also be needed. It is ideal to have the material vendor in agreement with the changes, but this may not always occur.

Compound beds

To minimize adverse effects of the cracking of heavy components, we suggest using compound beds (i.e., MS and desiccant), including modified alumina in the product zone, for example in Zone A3 in Fig. 1. ExxonMobil's studies indicate that, by doing so, one could use a regeneration stream with lower temperature and also a regeneration stream that contains a small amount of water vapor that may suppress coking reactions.[14]

Adding water vapor to the regeneration stream for a short period may act to desorb heavy molecules (BTX and mercaptans) before the thermal wave arrives. In effect, it may be a modified desorptive,[1] or displacement type of regeneration.[15] Use of alumina controls the rate at which water is added to the regeneration stream.

Figs. 4 and 5 exemplify the advantages of our approach compared with using only MS (the conventional approach). These figures were generated with the aid of an in-house

EQUATIONS

$$\frac{G}{L} = \frac{c_1 P}{(c_1 P_1 - c_2 P_2^s)} \frac{(1 + c_2 P_2^s)}{(1 + c_2 P_2)}$$

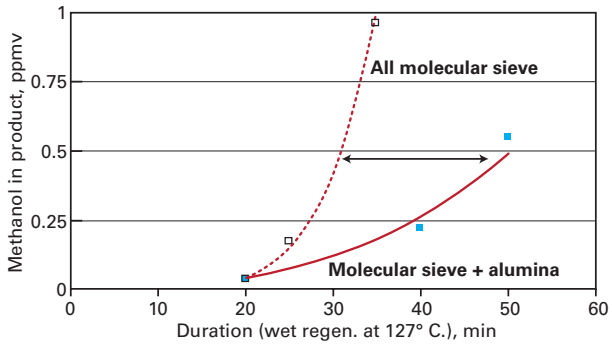
Ratio of gas-phase mixed Langmuir loading/liquid-phase Langmuir surface excess

computational simulator of cyclic adsorption processes, which derives from data from ExxonMobil's upstream, downstream, and chemical companies.

Fig. 4 illustrates the conclusion that use of AA in the bottom layer ("mole sieve + alumina" points on the graph) allows for a substantially lower regeneration temperature than MS alone, while still meeting a <1 ppm methanol specification in the product stream after a typical service time. The product spec will not be met for the mole-sieve-only case for regeneration temperatures less than 200° C. (Decomposition effects were not considered.)

Fig. 5 shows the potential effect of allowing wet regeneration to go for too long (total regeneration cycle time is 124 min). If residual water remains on the MS, product quality will suffer. This is particularly true for the molecular-sieve-only case.

MODEL: COMPOUND BED +MPDR LOWERS SEVERITY* Fig. 5



*MPDR = modified partial desorption regeneration.

Alternative adsorbents

ExxonMobil is also testing an entirely new class of adsorbents for natural gas purification. These adsorbents are mixed-metal oxide catalysts with mixtures of alumina or silica substrates. Our tests have determined that these materials have reasonable capacity for the principal contaminants found in natural gas.

Experiments with both fresh and sulfided forms of these catalysts indicate that it may be possible to recycle catalysts after their use in refining operations such as hydrotreating and hydrofining. (The material would likely require coke removal, however, using a standard decoking procedure before its new life as an adsorbent.)

The spent catalysts also show reduced uptake of nonsulfurous components (i.e., heavier hydrocarbons). This feature makes these catalyst materials attractive, compared with conventional natural-gas-treatment molecular sieves. The latter are generally indiscriminate in the uptake of all heavy components of natural gas.

Selective adsorbents would not remove as many valuable heavy hydrocarbons from the feed stream. These valuable molecules would then not end up in the sulfur-recovery unit (SRU) where they consume a lot of air (and, if not completely destroyed, soot the SRU catalyst).

ExxonMobil's test results have also shown the possibility of using regeneration techniques of reduced severity (temperature or duration) with the mixed-metal oxide catalysts as adsorbents. This reduces the thermal energy (steam or direct fire) required to heat the regeneration gas, thereby reducing emissions. Reduced severity of regeneration also prolongs adsorbent life. Taking this to the extreme, modified pressure swing cycles can eliminate hydrothermal effects altogether.

We have employed the analogy between adsorption from liquids and adsorption from unsaturated vapors to help quantify the potential effectiveness of these new adsorbents. In our experiments, breakthrough curves of sulfur-containing compounds were obtained from contaminated liquid hydrocarbons passing through a bed of cobalt molybdenum hydrotreating catalyst. We observed early breakthrough of thiophenes; these compounds, however, are not generally present in appreciable concentration in gas streams.

Liquid-phase adsorption is well known to possess limitations due to lower diffusivities (lower mass transfer) and higher densities, which promote capacity-reducing adsorption non-idealities. The loading and uptake observed in our liquid-phase experiments indicate good capacity using the analogy of adsorption from liquids and adsorption from gases. The analogy shows that enhancement of adsorption from the binary gas vs. that from binary liquid is possible when the mixed-gas isotherms are compared. The ratio of gas-phase mixed Langmuir loading and liquid-phase Langmuir surface excess can be derived as shown in the accompanying box.[16]

Gas-phase testing of these adsorbents has yet to be done. We recognize, however, that these materials are used in hydrogenating services and that they may become sulfided during regeneration with sour gas and could also require special handling. Given that the materials themselves are essentially free of charge (spent catalyst that would otherwise require disposal) and given the potential for much greater selectivity toward sulfur compounds, these materials warrant further evaluation.

Acknowledgment

This article is dedicated to the memory of our friend and colleague Francis Wu. ✦

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NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

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

	1962	1980	2005	2006	2007	Apr. 2007	Mar. 2008	Apr. 2008
Pumps, compressors, etc.	222.5	777.3	1,685.5	1,758.2	1,844.4	1,841.8	1,918.3	1,922.1
Electrical machinery	189.5	394.7	513.6	520.2	517.3	517.7	515.0	515.5
Internal-comb. engines	183.4	512.6	931.1	959.7	974.6	969.5	986.5	984.6
Instruments	214.8	587.3	1,108.0	1,166.0	1,267.9	1,261.4	1,328.0	1,330.5
Heat exchangers	183.6	618.7	1,072.3	1,162.7	1,342.2	1,374.7	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	1,062.1	1,113.3	1,189.3	1,193.0	1,224.5	1,225.5
Materials component	205.9	629.2	1,179.8	1,273.5	1,364.8	1,409.7	1,466.1	1,558.9
Labor component	258.8	951.9	2,411.6	2,497.8	2,601.4	2,560.7	2,664.1	2,665.5
Refinery (Inflation) Index	237.6	822.8	1,918.8	2,008.1	2,106.7	2,100.3	2,184.9	2,222.8

Refinery operating (1956 Basis)

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

	1962	1980	2005	2006	2007	Apr. 2007	Mar. 2008	Apr. 2008
Fuel cost	100.9	810.5	1,360.2	1,569.0	1,530.7	1,526.4	2,019.5	2,107.2
Labor cost	93.9	200.5	201.9	204.2	215.8	223.8	221.8	220.7
Wages	123.9	439.9	1,007.4	1,015.4	1,042.8	1,078.8	1,023.8	1,035.1
Productivity	131.8	226.3	501.1	497.5	483.4	482.0	461.6	468.9
Invest., maint., etc.	121.7	324.8	716.0	743.7	777.4	775.0	806.2	820.2
Chemical costs	96.7	229.2	310.5	365.4	385.9	371.6	431.2	454.4
Operating indexes								
Refinery	103.7	312.7	542.1	579.0	596.5	596.9	659.6	675.3
*Process units**	103.6	457.5	787.2	870.7	872.6	872.6	1,055.5	1,090.8

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

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

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

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Study details errors contributing to high-pressure pipeline infringement

A new case study written by Julian Williamson and Christine Daniels and published by the UK's Health and Safety Executive details issues contributing to a third-party pipeline infringement in February 2007. In its findings, the report emphasizes that even ostensibly informed individuals will both make errors and commit violations and that effective safety policy must account for this.

Based on interviews conducted in August-September 2007 with those involved in the incident, the report breaks identified risk factors into six main categories:

- Systemic risk factors.
- Organizational change.
- Communication.
- Planning.
- Risk awareness, perception.
- Provision of risk information.

It then makes recommendations for managing risk of third-party damage in each category.

Four pipelines operated by UK's National Grid Gas PLC cross this location, the site of a future car park. Two of the pipelines operate at 32 bar, qualifying them as major accident hazard pipelines under UK Health and Safety Executive guidelines. Source: UK HSE (Fig. 1).

Infringement

The project in which infringement on the pipelines occurred involved two phases. Phase 1 consisted of construction of a commercial building and Phase 2 construction of an accompanying car park. The work site is adjacent a canal and opposite an oil refinery and tank farm (Fig. 1). A concrete sewer pipe and four pipelines run across the site parallel to the canal.

The UK's National Grid Gas defines a major accident hazard pipeline (MAHP) as operating at greater than 7 barg and requires cathodic protection on such lines. Two of the four pipelines crossing the site met this criterion. Fig. 2 shows the site, with the pipelines as follows (starting closest to the building and moving toward the canal):

- 32 bar (high pressure, MAHP) 16-in. steel.
- 32 bar (high pressure, MAHP) 24-in. steel.
- 7 bar (intermediate pressure) 14-in. steel.
- 7 bar (intermediate pressure) 10-in. steel.

In August 2006 the client's chairman met with the principal contractor and NGG to determine what would be required to turn the unused portion of the lot into a car park over the pipelines. The client agreed to perform NGG-supervised trial-hole digging to find the exact position and depth of the pipelines. This marked the principal contractor's last involvement in Phase 2 of the project.

The client directly contracted the subcontractor for Phase 2 in December 2006. The projected duration of the project (30 days) required that it be registered with HSE, but this was not done. The subcontractor began ground

clearance in January 2007, without any notice being given to NGG.

An NGG inspector making a routine visit to a neighboring site noticed the work on Feb. 14, 2007, and stopped it immediately. The inspector found that the pipes themselves had not yet been damaged, but their CP cables had been uprooted during excavation and any pipeline markers had been moved to the site perimeter (Figs. 3-4). Ground preparation for Phase 2 also destabilized the shoring along the canal.

The client incurred the costs of repairing the canal, replacing the local CP apparatus, and associated delays in completing the site and securing tenants.

Risk factors

The HSE report listed a number of risk factors associated with this project in each of its six categories.

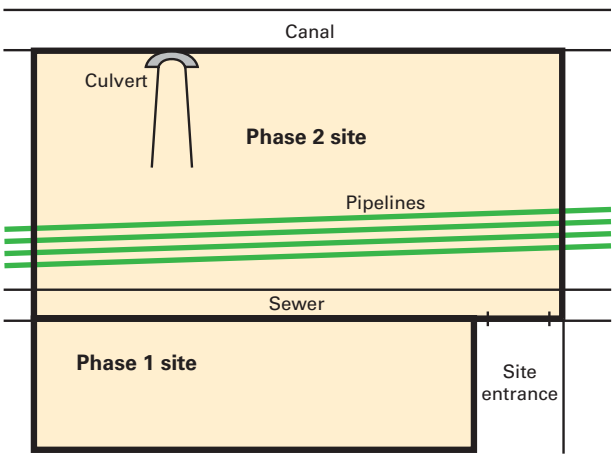
- *Systemic risk factors.* The system in place depended on the knowledge and competency of key individuals, relying on them to comply with defenses and procedural barriers. The system also used an overly complex series of arrangements between contractors and subcontractors, working against communication at the site level, while the lack of an effective risk-management system led to on site confusion regarding individual risk-management responsibilities.
- *Organizational change.* Rapid organizational change furthered this confusion in roles and responsibilities. Staff allocation did not necessarily follow an assessment of a given individual's experience and competencies, a situation only worsened by a dominant client chairman with relatively little experience of his own in managing construction projects near MAHPs.
- *Communication.* A lack of formal coordination between the project designer and the client regarding communication with the NGG and acquiring proper authorizations contributed to assumptions by the client that formal approvals had been given when this was not the case. Similarly, NGG approval hinges on the knowledge of the individual making the request, without any systemic connection to any previous requests that might have been made regarding a specific site.

A lack of formal procedures for passing risk information from client to contractor to subcontractor became even more hazardous when a breakdown in the relationship between the client and the principal contractor occurred right before the project was handed to a subcontractor for the second phase of construction.

- *Planning.* Commercial pressures for project completion led to an ad hoc approach to planning that gave productivity precedence over risk management. Other commercial pressures led the subcontractor to be on site only intermittently, weakening verification of safety procedures.
- *Risk awareness, perception.* Generally low awareness existed regarding both the consequences of damaging MAHPs and the role of the NGG in addressing these risks. Ongoing construction and existing car parks in the immediate vicinity of the work site further deadened any potential risk awareness.
- *Provision of risk information.* The subcontractor did not verify the accuracy of topographical information. Communication of risk information between the principal contractor, designer, client's lawyer, and client chairman was abridged. The subcontractor contacted NGG (via telephone using the number found on a pipeline marker) but might not have been categorically instructed to stop construction at that time.

CONSTRUCTION LAYOUT

Fig. 2



Source: UK Health and Safety Executive

Recommendations

The HSE study makes several recommendations addressing the problems

The mechanical digger used to excavate the site did not damage any of the pipelines, but uprooted their cathodic protection cables. Source: UK HSE (Fig. 3).

Subcontractors charged with building the car park removed pipeline markers from their original locations and placed them at the site's perimeter. Source: UK HSE (Fig. 4).

discovered. In addition to accounting for the fact that individuals will make errors and commit violations, a system for communicating risk information should be simple enough that the proper information reaches the site level.

Organizational change should occur in a manner preserving the clarity of individual roles and responsibilities and allowing challenges or questions, particularly regarding risk management, to move up from the construction-site level. Individuals should also be aware of their own professional responsibilities when taking on new tasks.

The person communicating regarding hazards with the pipeline operator on behalf of the project should be qualified to do so and documented procedures should exist for passing on his or her knowledge to any successors.

Communication of risks should take place at every stage from design through completion of construction.

Project timescales should not contribute to productivity taking precedence over risk management. Experience and competency should guide contracting and staffing decisions.

Company-wide awareness of MAHP hazards and the pipeline operator's role in managing these should be established. Such awareness will help foster an environment in which the accuracy of risk information is confirmed, communication with the operator happens at the planning stage, and any required authorizations are transmitted clearly to appropriate parties. ✦

Equipment/Software/Literature

Field data capture system offers updated version

Field data capture system eVIN has released its latest version—eVIN 2008.

The company says its mobile application for oil fields captures daily well information on about 25% of the producing wells in the US and about 15% worldwide. With the 2008 release of eVIN, the firm is broadening its use and expanding its capabilities to remote environments around the world. eVIN's new framework provides integration into production forecast systems, putting production targets into the hands of the pumper down to the measurement point level.

This latest release provides:

- Complete route and stop management.
- Advanced field data capture of daily data, run ticket, and tank volumes.
- Automated alarms and graphs for problem resolution.
- Accountability to meet production targets.

The program allows field operators to compare on a daily basis actual vs. forecasted performance of a particular tank battery or gas meter, validating the forecasting process and allowing for adjustments to reach production targets.

eVIN provides Pocket PC and PC-based field data capture with on-line American Gas Assocation calculations, error checking, data validation, and graphing. The firm notes that eVIN applies the same process of collecting data as gauge sheets.

Source: **Merrick Systems Inc.,** 4801 Woodway, Suite 200E, Houston, TX 77056.

Updated system aids production optimization

A new version of AssetObserver web-based operating environment is designed to allow production specialists to access and integrate data from a range of sources and monitor complete workflows and assets in real time.

Built on Mission Viejo, Calif.-based Incuity Software's IncuityEMI platform, the new version addresses a need for comprehensive data access and holistic asset analysis in field production, the company notes. The web-based operating environment frees production engineers to focus on analyzing data and developing smarter production plans.

With the addition of the IncuityEMI platform, AssetObserver integrates data from more sources and provides greater utility and efficiency. The IncuityEMI platform maximizes the AssetObserver environment's existing capabilities, allowing it seamlessly to read, update, and delete data from almost any third-party or proprietary data source.

Embedding IncuityEMI into AssetObserver unites two applications for the benefit of oil and gas production specialists, the firm says.

Source: **Landmark,** 2107 CityWest Blvd., Bldg. 2, Houston, TX 77042-3051.

The International Association of Drilling Contractors (IADC),

Houston, has elected Steven Richards of Key Energy Services Inc. to the chairmanship of IADC's newly created Advanced Rig Technology Committee (ART). Also elected to the committee were Vice-Chairmen Jeff Swain, Chevron Corp., and David Reid, National Oilwell Varco Inc. The IADC ART Committee comprises five subcommittees, of which four have chosen vice-chairmen to chart the working group's progress. They are Vice-Chairman-Software Interface Zain Master, Caterpillar Inc.; Vice-Chairman-Guidelines Logan Puckett, Pride International Inc.; Vice-Chairman-Reliability Robert Urbanowski, Grey Wolf Drilling Co. LP; and Vice-Chairman-Future Technology Frank Springett, National Oilwell Varco.


Richards

Newpark Resources Inc.,

The Woodlands, Tex., has named William D. Moss president of Newpark's Mats and Integrated Services business. To be based in The Woodlands, he is also an executive officer of Newpark Resources Inc. Before joining Newpark, Moss held management positions at BJ Services Co., most recently—since 1997—as division president of BJ Chemical Services, a provider of production and industrial chemicals, remedial pumping, and capillary services to US and international customers. He previously served as director, logistics, of BJ Services with responsibility for the worldwide logistics organization. From 1988 to 1995, Moss was vice-president, international operations, of Western Petroleum Services International Co. Prior to that, he spent 10 years in numerous leadership positions at Western Co. of North America. He holds an MBA from Texas Christian University and a BBA from Texas Tech University.


Moss

Newpark Resources is a worldwide provider of drilling fluids, temporary worksites, and access roads for oil field and other commercial markets, as well as environmental waste treatment solutions.

Synthesis Energy Systems Inc. (SES),

Houston, and Aker Solutions US Inc., a Houston-based unit of Aker Solutions ASA, Oslo, have entered into an engineering agreement. Aker's expertise in the gasification and chemicals industries will assist SES in its strategy to build, own, and operate coal-to-chemicals plants worldwide.

SES is an energy and technology company that builds, owns, and operates coal gasification plants that utilize its proprietary U-GAS® fluidized bed gasification technology to convert low-rank coal and coal wastes into higher-value energy products, such as transportation fuels and ammonia. The U-GAS® technology, which SES licenses from the Gas Technology Institute, gasifies coal without many of the harmful emissions normally associated with coal combustion plants.

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

ABB Group,

Zurich, has appointed Joseph Hogan CEO, effective Sept. 1, 2008. He currently is CEO of GE Healthcare, the global leader in medical diagnostic technology and biosciences, and is a member of the GE Senior Executive Council. Michel Demaré, ABB's chief financial officer, who has held the CEO position on an ad interim basis since Feb. 13, will continue to serve as ABB's CFO. Hogan's career at GE spans 23 years and a wide range of positions. He led GE Medical Systems and then GE Healthcare from November 2000. Prior to this, he served as president and CEO of GE Fanuc Automation North America Inc., a global supplier of industrial controls systems and a joint venture between GE and FANUC of Japan. Previously, he held a number of key positions in sales, marketing, and product development at GE Plastics. Hogan holds a BBA from Geneva College and an MBA from Robert Morris University.


Hogan

ABB is a leader in power and automation technologies that enable utility and industry customers to improve performance while lowering environmental impact.

MOGAS Industries Inc.,

Houston, has named Jeff Diestler account manager for control valves. He will be responsible for promoting MOGAS's FlexStream® technology, working with Kevin Jackson, global manager for oil and gas, transport and storage, and LNG. Diestler spent the past 2 years working for a water treatment equipment manufacturer, Tonka Equipment Co. in Plymouth, Minn., where he assisted engineers and owners in solving hydraulic and chemistry-related challenges. He also worked selling valves and instrumentation after his graduation from Minnesota State-Mankato, with a BS in mechanical engineering.


Diestler

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

Carbonetworks,

Vancouver, BC, has closed on its $5 million Series A round of financing. The funding was provided by NGEN II LP, part of the NGEN Partners group of leading "clean-technology" venture funds. The capital raised strengthens Carbonetworks' ability to support the growing global demand for its software and services. At present, the company is helping more than 180 organizations in 23 countries create and manage their greenhouse gas emissions strategies. Customers come from

a range of industries, including energy, financial, materials, manufacturing, offset project providers, and governments. In the coming months, the company expects to significantly expand its operations.

Earth Search Sciences Inc.,

Lakeside, Mont., has acquired General Synfuels International Inc. (GSI) and its patented technology to recover hydrocarbons through an environmentally benign gasification process. GSI has agreed to the buyout involving an undisclosed amount of cash and shares. The acquisition enables key Earth Search subsidiary Petro Probe Inc. to establish a joint venture and commercial licensing program to develop domestic oil shale and other heavy oil resources. Petro Probe plans a full-scale field test of this technology as early as fall 2008 and subsequent commercial development as early as 2009.

Earth Search's hyperspectral technology provides the ability to accurately read the chemical properties of surface substances from great altitudes and produce easily interpreted maps allowing the user to identify specific minerals and substances on the surface of the earth by their diagnostic reflectance patterns.

KPMG LLP,

New York, has hired John P. Gimigliano as a principal in its Washington National Tax practice. He is based in the firm's Washington, DC, office. At KPMG, Gimigliano will serve as principal in charge of the firm's newly formed Americas Climate Solutions and Energy Sustainability Practice. In this role, Gimigliano will work with clients to help identify potential opportunities to develop their corporate sustainability strategy in a tax-efficient manner, utilizing the alternative and clean energy tax incentives created by Congress in recent years. He will also monitor energy-related legislation and oversee the firm's various energy credits services, including credits for alternative energy sources, and services related to industry transactions. He is a former senior tax counsel for the House Committee on Ways and Means and staff director for the Subcommittee on Select Revenue Measures. Prior to his positions in the public sector, Gimigliano spent 11 years with another Big Four accounting firm, serving as the national director of its electric and gas energy tax group. In helping to build that practice, he worked closely with leading regulated and nonregulated utilities throughout North America. An adjunct law professor at Georgetown University, he teaches a course on taxation of energy markets that is currently the only one of its kind. Gimigliano holds an LLM in taxation from Georgetown's Law Center, a JD from the University of Cincinnati's College of Law, and a BA from Miami University of Ohio.


Gimigliano

KPMG LLP, the audit, tax, and advisory firm, is the US member firm of KPMG International.

SulphCo Inc.,

Houston, has appointed Richard K. Sell director of business development-Americas. Sell will lead the company's business development initiatives in the Western Hemisphere. He brings more than 30 years' experience in crude oil markets. He served as senior managing director, crude oil supply and trading, and senior managing director, petroleum origination (commercial activities), at El Paso Merchant Energy-Petroleum Co., a subsidiary of El Paso Corp. Prior to that, Sell was a senior vice-president at Coastal States Trading Inc. and Coastal Petroleum NV, where he managed the economic supply of crude oil for the entire Coastal Corp. refining system. More recently, he was a partner in Riverway Petroleum Partners LLC, an oil industry consulting group. Sell has a BA in economics from Texas Christian University.

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.

Sensornet,

Elstree, UK, has appointed John Perrin vice-president for North and South America and Doug Walker vice-president for the Asia-Pacific region. In addition, Richard Kluth has been promoted to chief operating officer. Perrin has more than 10 of years industry experience, specializing in wireline logging in both open- and cased-hole environments. He joins Sensornet from an international oil services company, where he worked as a petrophysicist in Canada. With more than 20 years of industry experience, Walker has held senior management positions with a global energy services business in Abu Dhabi, Norway, the Gulf of Mexico, and Vietnam. While he originally specialized as a wireline field engineer, his most recent position was district manager for India and Bangladesh. Since joining Sensornet in 2003, Kluth has been responsible for a number of the company's key developments, including the installation of the world's first fiber-optic in-well distributed temperature sensing (DTS) system. He has substantial experience in drilling and reservoir monitoring and has worked in North America, the Middle East, and Europe. He previously was Sensornet's operations director.


Perrin


Walker

Kluth

Launched in 1998, Sensornet provides advanced asset monitoring solutions, using real-time distributed temperature and strain measuring systems to the global oil and gas industry and offers its own temporary and permanent DTS installation capability. The company has offices in Europe, North and South America, the Middle East, and Asia.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	7-18 2008	7-11 2008	7-18 2008	7-11 2008	7-18 2008	7-11 2008	*7-20 2007
	1,000 b/d						
Total motor gasoline	1,128	951	17	65	1,145	1,016	1,652
Mo. gas. blending comp.	743	537	17	17	760	554	1,119
Distillate	102	150	—	—	102	150	257
Residual	147	205	4	18	151	223	315
Jet fuel-kerosine	60	57	3	41	63	98	189
Propane-propylene	75	106	3	2	78	108	83
Other	726	876	66	127	792	1,003	298
Total products	**2,981**	**2,882**	**110**	**270**	**3,091**	**3,152**	**3,913**
Total crude	**8,507**	**9,406**	**1,299**	**1,385**	**9,806**	**10,791**	**10,378**
Total imports	**11,488**	**12,288**	**1,409**	**1,655**	**12,897**	**13,943**	**14,291**

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

Purvin & Gertz LNG netbacks—July 25, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	9.32	6.63	8.22	6.49	7.43	8.12
Everett	8.53	5.81	8.03	5.84	6.59	8.93
Isle of Grain	10.90	8.52	10.19	8.38	9.20	10.20
Lake Charles	6.55	3.98	6.25	4.21	4.66	7.38
Sodegaura	8.43	10.36	8.66	9.95	9.01	7.43
Zeebrugge	10.11	7.83	9.43	7.67	8.47	9.42

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,942	60,972	33,735	9,737	45,194	14,391	3,833
PADD 2	62,343	51,069	17,917	7,476	30,766	1,414	19,776
PADD 3	149,068	69,962	32,630	13,148	35,799	16,710	20,529
PADD 4	14,141	5,793	1,631	504	2,930	316	[1]1,349
PADD 5	54,836	29,289	22,923	9,127	13,420	5,638	—
July 18, 2008	**295,330**	**217,085**	**108,836**	**39,992**	**128,109**	**38,469**	**45,487**
July 11, 2008	**296,888**	**214,238**	**107,046**	**38,954**	**125,690**	**39,084**	**44,997**
July 20, 2007[2]	**351,028**	**204,134**	**92,521**	**40,665**	**123,653**	**37,503**	**47,940**

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

Refinery report—July 18, 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	1,433	1,439	2,101	96	527	100	57
PADD 2	3,255	3,225	2,306	189	990	59	211
PADD 3	7,399	7,299	3,205	781	2,345	311	687
PADD 4	520	516	289	24	163	12	[1]146
PADD 5	2,724	2,633	1,309	453	600	168	—
July 18, 2008	**15,331**	**15,112**	**9,210**	**1,543**	**4,625**	**650**	**1,101**
July 11, 2008	**15,744**	**15,467**	**9,057**	**1,697**	**4,736**	**612**	**1,078**
July 20, 2007[2]	**15,989**	**15,822**	**9,271**	**1,446**	**4,133**	**732**	**1,064**
	17,594 Operable capacity		**87.1 utilization rate**				

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

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

OGJ crack spread

	*7-25-08	*7-27-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	135.50	85.20	50.30	59.0
Brent crude	128.17	77.08	51.09	66.3
Crack spread	7.32	8.12	–0.80	–9.8
FUTURES MARKET PRICES				
One month				
Product value	138.77	86.97	51.80	59.6
Light sweet crude	126.44	75.26	51.18	68.0
Crack spread	12.34	11.71	0.62	5.3
Six month				
Product value	141.36	85.36	55.99	65.6
Light sweet crude	128.39	73.67	54.72	74.3
Crack spread	12.97	11.69	1.28	10.9

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

OGJ GASOLINE PRICES

	Price ex tax 7-23-08	Pump price* 7-23-08	Pump price 7-25-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	365.8	410.2	298.0
Baltimore	359.3	401.2	295.0
Boston	362.3	404.2	288.9
Buffalo	357.3	416.9	299.0
Miami	365.9	417.5	300.0
Newark	361.2	394.1	283.9
New York	350.2	409.8	299.9
Norfolk	355.2	393.2	288.0
Philadelphia	356.2	406.9	301.0
Pittsburgh	349.5	400.2	290.0
Wash., DC	369.5	407.9	298.0
PAD I avg	359.3	405.6	294.7
Chicago	381.0	438.9	339.5
Cleveland	353.1	399.5	264.5
Des Moines	356.4	396.5	284.4
Detroit	354.8	409.2	295.2
Indianapolis	349.1	399.2	280.1
Kansas City	358.5	394.5	285.8
Louisville	365.7	402.6	286.4
Memphis	350.2	390.0	279.0
Milwaukee	358.9	410.2	288.1
Minn.-St. Paul	359.8	400.2	284.3
Oklahoma City	351.5	386.9	274.7
Omaha	356.8	399.1	295.0
St. Louis	356.9	392.9	280.0
Tulsa	350.4	385.8	286.0
Wichita	336.5	379.9	281.4
PAD II avg	356.0	399.0	287.0
Albuquerque	352.8	389.2	290.2
Birmingham	358.6	397.2	284.0
Dallas-Fort Worth	361.1	399.5	282.7
Houston	357.1	395.5	283.9
Little Rock	356.3	396.5	285.0
New Orleans	359.8	398.2	288.1
San Antonio	354.5	392.9	281.0
PAD III avg	357.2	395.6	285.0
Cheyenne	365.6	398.0	288.7
Denver	374.4	414.8	309.2
Salt Lake City	365.1	408.0	308.5
PAD IV avg	368.4	406.9	302.1
Los Angeles	384.4	448.3	307.3
Phoenix	377.9	415.3	280.6
Portland	379.9	423.3	295.3
San Diego	382.8	446.7	314.3
San Francisco	389.9	453.8	332.0
Seattle	378.0	432.4	297.6
PAD V avg	382.2	436.6	304.5
Week's avg.	**361.7**	**406.1**	**292.2**
June avg.	**360.2**	**404.2**	**295.2**
May avg.	**329.3**	**372.9**	**309.4**
2008 to date	**304.7**	**348.5**	—
2007 to date	**227.2**	**270.8**	—

*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

	7-18-08 ¢/gal		7-18-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	302.17	New York Harbor	367.35
Gulf Coast	303.42	Gulf Coast	365.85
Los Angeles	305.92	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	308.06	ARA	384.90
Singapore	309.55	Singapore	391.19
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	312.17	New York Harbor	255.43
Gulf Coast	312.67	Gulf Coast	268.17
Los Angeles	314.42	Los Angeles	295.88
		ARA	279.34
		Singapore	269.78

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

BAKER HUGHES RIG COUNT

	7-25-08	7-27-07
Alabama	3	5
Alaska	7	7
Arkansas	57	51
California	44	37
Land	44	36
Offshore	0	1
Colorado	110	101
Florida	2	1
Illinois	1	0
Indiana	2	3
Kansas	12	15
Kentucky	12	10
Louisiana	187	185
N. Land	75	59
S. Inland waters	24	26
S. Land	31	32
Offshore	57	68
Maryland	1	1
Michigan	2	3
Mississippi	10	14
Montana	12	20
Nebraska	0	0
New Mexico	84	82
New York	5	5
North Dakota	70	39
Ohio	13	13
Oklahoma	207	188
Pennsylvania	25	16
South Dakota	2	4
Texas	926	825
Offshore	7	8
Inland waters	1	0
Dist. 1	15	25
Dist. 2	35	32
Dist. 3	63	70
Dist. 4	87	85
Dist. 5	185	173
Dist. 6	125	112
Dist. 7B	30	37
Dist. 7C	71	58
Dist. 8	134	110
Dist. 8A	32	23
Dist. 9	46	29
Dist. 10	95	63
Utah	49	37
West Virginia	26	32
Wyoming	76	70
Others—OR-1; TN-2; VA-8; WA-1	12	11
Total US	**1,957**	**1,775**
Total Canada	**435**	**371**
Grand total	**2,392**	**2,146**
Oil rigs	393	296
Gas rigs	1,555	1,474
Total offshore	67	79
Total cum. avg. YTD	**1,832**	**1,750**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	7-25-08 Percent footage*	Rig count	7-27-07 Percent footage*
0-2,500	90	3.3	61	6.5
2,501-5,000	144	49.3	108	52.7
5,001-7,500	244	11.8	243	24.2
7,501-10,000	480	3.7	410	3.1
10,001-12,500	485	2.6	467	1.2
12,501-15,000	329	—	280	—
15,001-17,500	145	—	105	—
17,501-20,000	89	—	65	—
20,001-over	35	—	35	—
Total	**2,041**	**6.5**	**1,774**	**7.8**
INLAND	33		38	
LAND	1,952		1,671	
OFFSHORE	56		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]7-25-08	[2]7-27-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	717	719
California	660	667
Colorado	43	62
Florida	6	5
Illinois	27	27
Kansas	98	102
Louisiana	1,333	1,205
Michigan	16	14
Mississippi	56	56
Montana	94	95
New Mexico	162	157
North Dakota	120	124
Oklahoma	171	171
Texas	1,350	1,325
Utah	48	55
Wyoming	149	146
All others	63	74
Total	**5,128**	**5,024**

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

US CRUDE PRICES

	7-25-08 $/bbl*
Alaska-North Slope 27°	120.20
South Louisiana Sweet	126.75
California-Kern River 13°	109.35
Lost Hills 30°	117.55
Wyoming Sweet	113.26
East Texas Sweet	119.25
West Texas Sour 34°	112.25
West Texas Intermediate	119.75
Oklahoma Sweet	119.75
Texas Upper Gulf Coast	116.25
Michigan Sour	112.75
Kansas Common	118.75
North Dakota Sweet	113.50

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

WORLD CRUDE PRICES

$/bbl[1]	7-18-08
United Kingdom-Brent 38°	139.34
Russia-Urals 32°	134.37
Saudi Light 34°	134.50
Dubai Fateh 32°	136.70
Algeria Saharan 44°	140.26
Nigeria-Bonny Light 37°	143.49
Indonesia-Minas 34°	145.19
Venezuela-Tia Juana Light 31°	135.77
Mexico-Isthmus 33°	135.66
OPEC basket	138.80
Total OPEC[2]	135.80
Total non-OPEC[2]	136.97
Total world[2]	136.32
US imports[3]	134.44

[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]

	7-18-08	7-11-08	7-18-07	Change, %
	bcf			
Producing region	752	742	909	–17.3
Consuming region east	1,308	1,245	1,438	–9.0
Consuming region west	336	325	395	–14.9
Total US	**2,396**	**2,312**	**2,742**	**–12.6**
	May. 08	**May 07**	**Change, %**	
Total US[2]	**1,836**	**2,179**	**–15.7**	

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

PACE REFINING MARGINS

	May 2008	June 2008	July 2008	July 2007	Change	Change, %
	$/bbl					
US Gulf Coast						
West Texas Sour	17.01	14.07	8.17	16.80	–8.63	–51.4
Composite US Gulf Refinery	16.85	13.69	7.65	14.21	–6.56	–46.1
Arabian Light	13.44	12.48	2.97	12.68	–9.71	–76.5
Bonny Light	7.75	3.71	1.27	6.59	–5.31	–80.7
US PADD II						
Chicago (WTI)	16.52	11.86	6.27	21.22	–14.95	–70.4
US East Coast						
NY Harbor (Arab Med)	13.64	12.67	6.86	8.02	–1.16	–14.5
East Coast Comp-RFG	16.05	12.52	6.48	7.76	–1.28	–16.5
US West Coast						
Los Angeles (ANS)	15.97	15.84	7.93	13.68	–5.75	–42.0
NW Europe						
Rotterdam (Brent)	7.04	4.34	–0.77	3.31	–4.08	–123.2
Mediterranean						
Italy (Urals)	20.44	14.14	4.94	4.65	0.29	6.3
Far East						
Singapore (Dubai)	12.03	7.86	13.09	4.89	8.21	167.9

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	May 2008	Apr. 2008	May 2007	May 2008-2007 change	Total YTD 2008	Total YTD 2007	YTD 2008-2007 change
	bcf						
DEMAND							
Consumption	1,639	1,837	1,553	86	10,919	10,474	445
Addition to storage	458	295	498	–40	1,008	1,100	–92
Exports	66	76	63	3	467	316	151
Canada	35	46	35	0	281	195	86
Mexico	26	26	24	2	168	99	69
LNG	5	4	4	1	18	22	–4
Total demand	**2,163**	**2,208**	**2,114**	**49**	**12,394**	**11,890**	**504**
SUPPLY							
Production (dry gas)	1,736	1,679	1,608	128	8,496	7,806	690
Supplemental gas	4	5	4	0	20	27	–7
Storage withdrawal	56	106	39	17	2,053	1,984	69
Imports	326	319	380	–54	1,729	1,932	–203
Canada	294	286	283	11	1,589	1,525	64
Mexico	NA	1	3	–3	NA	30	–30
LNG	32	32	94	–62	140	377	–237
Total supply	**2,122**	**2,109**	**2,031**	**91**	**12,298**	**11,749**	**549**

NATURAL GAS IN UNDERGROUND STORAGE

	May 2008	Apr. 2008	Mar. 2008	May 2007	Change
	bcf				
Base gas	4,226	4,223	4,221	4,251	–25
Working gas	1,836	1,436	1,247	2,179	–343
Total gas	**6,062**	**5,659**	**5,468**	**6,430**	**–368**

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

WORLDWIDE NGL PRODUCTION

	Apr. 2008	Mar. 2008	4 month average Production 2008	4 month average Production 2007	Change vs. previous year Volume,	Change vs. previous year %
	1,000 b/d					
Brazil	87	86	87	85	2	1.8
Canada	671	692	691	719	–28	–3.9
Mexico	370	367	368	413	–45	–11.0
United States	1,880	1,847	1,835	1,723	112	6.5
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	200	195	199	207	–8	–4.0
Western Hemisphere	**3,408**	**3,386**	**3,379**	**3,348**	**32**	**0.9**
Norway	278	301	294	305	–11	–3.6
United Kingdom	164	186	178	163	15	9.3
Other Western Europe	11	10	11	10	—	3.2
Western Europe	**452**	**497**	**482**	**478**	**4**	**0.9**
Russia	418	420	420	426	–6	–1.3
Other FSU	150	150	150	160	–10	–6.3
Other Eastern Europe	15	16	16	16	—	0.5
Eastern Europe	**583**	**586**	**586**	**601**	**–15**	**–2.6**
Algeria	355	353	353	340	12	3.6
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	126	140	132	126	6	5.0
Africa	**643**	**631**	**636**	**616**	**20**	**3.3**
Saudi Arabia	1,440	1,440	1,440	1,440	—	—
United Arab Emirates	250	250	250	250	—	—
Other Middle East	880	880	875	870	5	0.6
Middle East	**2,570**	**2,570**	**2,565**	**2,560**	**5**	**0.2**
Australia	68	57	60	75	–15	–19.4
China	180	180	180	180	—	—
India	—	—	—	9	–9	–100.0
Other Asia-Pacific	179	180	180	183	–3	–1.5
Asia-Pacific	**427**	**417**	**421**	**447**	**–27**	**–6.0**
TOTAL WORLD	**8,072**	**8,099**	**8,068**	**8,051**	**18**	**0.2**

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

OXYGENATES

	May 2008	Apr. 2008	Change	YTD 2008	YTD 2007	Change
	1,000 bbl					
Fuel ethanol						
Production	18,543	16,868	1675	83,641	58,597	25,044
Stocks	12,044	11,539	505	12,044	8,950	3,094
MTBE						
Production	1,639	1,613	26	7,997	9,857	–1,860
Stocks	1,956	1,727	229	1,956	1,353	603

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

US COOLING DEGREE-DAYS

	June 2008	June 2007	Normal	2008 % change from normal	Total degree-days July 1 through June 30 2008	2007	Normal	% change from normal
New England	120	87	63	90.5	125	117	69	81.2
Middle Atlantic	198	156	117	69.2	205	208	140	46.4
East North Central	168	175	147	14.3	178	251	198	–10.1
West North Central	179	203	192	–6.8	211	306	266	–20.7
South Atlantic	399	349	319	25.1	786	747	680	15.6
East South Central	365	354	296	23.3	550	616	489	12.5
West South Central	510	416	431	18.3	978	870	858	14.0
Mountain	257	267	229	12.2	371	464	374	–0.8
Pacific	140	112	100	40.0	205	143	157	30.6
US average*	**265**	**236**	**213**	**24.4**	**423**	**423**	**375**	**12.8**

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

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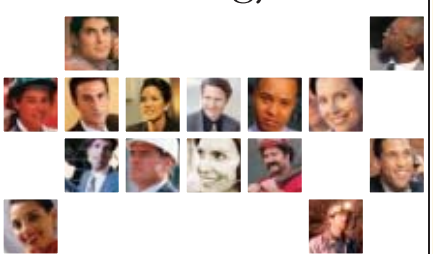

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High oil prices form weak base for state power

Most Americans base their distaste for foreign oil on presumed instability in the Middle East. They should note recent events in Moscow and Minsk.

Venezuelan President Hugo Chavez visited Russia and Belarus to sign energy deals and, as usual, chatter about US "aggression" and "imperialism."

This is the despot who has embraced truculent Iranian President Mahmoud

The Editor's Perspective

by Bob Tippee, Editor

Ahmadinejad and supported terrorists in Colombia. In Moscow he signed separate deals with TNK-BP, Lukoil, and Gazprom for exploration and development in Venezuela's Orinoco heavy oil region, where his government has expropriated interests of western oil companies in existing projects while raising taxes.

He also sought a second agreement to buy Russian military equipment and proposed, according to Fox News, an alliance with Moscow through which "we can guarantee Venezuela's sovereignty, which is now threatened by the United States."

As though to hedge his bets, the Venezuelan leader stopped in Minsk to schmooze with Belarusian President Alexander Lukashenka, who called him a "brother."

Lukashenka also regularly denounces the US and, like Chavez, holds office by virtue of elections widely regarded as rigged.

Belarus, though, has squabbled with Russia over oil and other matters. So when Chavez agreed in Minsk to expand an energy cooperation agreement that the governments entered last year, he might have been playing his chums against one another.

After Chavez left Moscow, meanwhile, fractures widened between the 50-50 partners in TNK-BP: BP and Alfa Access Renova. BP responded to pressure from AAR by withdrawing its seconded employees. Then Robert Dudley, the British head of the joint venture, left Russia citing harassment from the four Russian billionaires that make up AAR. The partners had been calling for Dudley's resignation since a board meeting in Cyprus earlier this month. After the meeting, the government did its part for the home team by refusing to renew Dudley's 1-year visa.

So goes business in Russia and Venezuela, where citizens seem to like the immoderate exertion of state power. The power of the moment, of course, owes much to oil prices that have defied the laws of economic gravity—until recently.

What was that about "instability?"

(Online July 25, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

A week of falling prices

The biggest ever work-week fall of crude prices dropped a total $16.20 July 14-18 to $128.88/bbl, "below key price points that bulls may have needed to hold onto to continue their rally," said analysts at Pritchard Capital Partners LLC, New Orleans.

"Some think enough damage was done to the complex to usher in $120/bbl crude oil as the next technical 'must hold,'" the analysts said at the time. Prices continued falling the following week, with the August contract for benchmark US light, sweet crudes expiring July 22 at $127.95/bbl. As the Energy Information Administration reported a bigger than expected drop in US oil inventories and an unexpected jump in gasoline stocks, The new front-month September contract dropped $3.98 to $124.12/bbl July 23 before rebounding to $125.49/bbl July 24 on the New York Mercantile Exchange.

Prices for crude and petroleum products made moderate gains in early trading July 25. Pritchard Capital analysts said, "Product inventories continue to build amid soft demand, but in order for reformulated blend stock for oxygenate blending (RBOB) and heating oil to test some of the critical support levels, it will need some cooperation from crude oil, particularly in the case of RBOB where crack spreads are miserable."

Dolly, a category 2 hurricane, came ashore at South Padre Island, Tex., July 23, and then subsided to a tropical storm as it drenched South Texas. Although the storm inflicted no damage on most oil and gas operations in the Gulf of Mexico, the US Minerals Management Service reported workers were evacuated from 62 of the 717 manned production platforms in the gulf and from 8 rigs of the 123 offshore rigs by the time the hurricane made landfall.

MMS estimated 4.47% of oil production and 7.87% of gas production in the gulf was shut in due to the storm. Total production from US leases in the gulf was estimated at 1.3 million b/d of oil and 7.7 bcfd of gas as of January. Workers quickly returned offshore after the hurricane passed.

Inventory surprises

EIA reported commercial US crude inventories fell 1.6 million bbl to 295.3 million bbl during the week ended July 18, exceeding a Wall Street consensus of a 700,000 bbl draw. Gasoline stocks jumped by 2.9 million bbl to 217.1 million bbl in the same period, vs. Wall Street's expectations of a 100,000 bbl decline. Only the distillate fuel consensus was on target, with inventories up 2.4 million bbl to 128.1 million bbl. Propane and propylene inventories were up 300,000 bbl to 45.3 million bbl.

Imports of crude into the US fell 985,000 b/d to 9.8 million b/d in that same week. Input of crude into US refineries was down 355,000 b/d to 15.1 million b/d with refineries operating at 87.1% of capacity. Gasoline production rose to 9.2 million b/d during that period, while distillate fuel production decreased to 4.6 million b/d.

"The larger-than-expected draw was primarily due to a drop in imports to 9.81 million b/d from 10.79 million," said Michael C. Schmitz, Banc of America Securities LLC, New York. "Imports have averaged 9.88 million b/d year-to-date, 2.3% lower year over year. Otherwise, refinery utilization dropped 2.4% to 87.1% vs. consensus for no change as refining margins remain weak due to deteriorating product demand."

Jacques H. Rousseau, an analyst at Soleil-Back Bay Research, reported, "Weak demand led to a 6.3 million bbl (1.7%) build to refined product inventories (gasoline plus distillate plus jet fuel), the largest increase since Jan. 4." As a result of the rising inventories and falling margins, refiners reduced their utilization rate to 87.1%, well below year-ago levels of 91.7%. Refinery runs were at the lowest levels since 1997.

Soleil-Back Bay Research lowered its estimates of refiners' earnings in the last half of 2008 through 2009 primarily on expectations that weak demand for refined products will continue over the next 12-18 months.

Based on US data, July has been a weak month for gasoline demand while the overall level of US oil demand remained relatively robust. Compared with an all-time record high demand in July 2007, Paul Horsnell, Barclays Capital Inc., London, said, "Gasoline demand is noticeably weaker in year-over-year terms than it has been in any month this year." Despite talk of demand destruction, he said, "When the fall already released in wholesale prices is passed through to retail prices, and with the rate of increase tailing off, we would expect US gasoline demand to recover somewhat from the relatively gentle 1.4% decline seen for 2008 to date."

(Online July 28, 2008; author's e-mail: samf@ogjonline.com)

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