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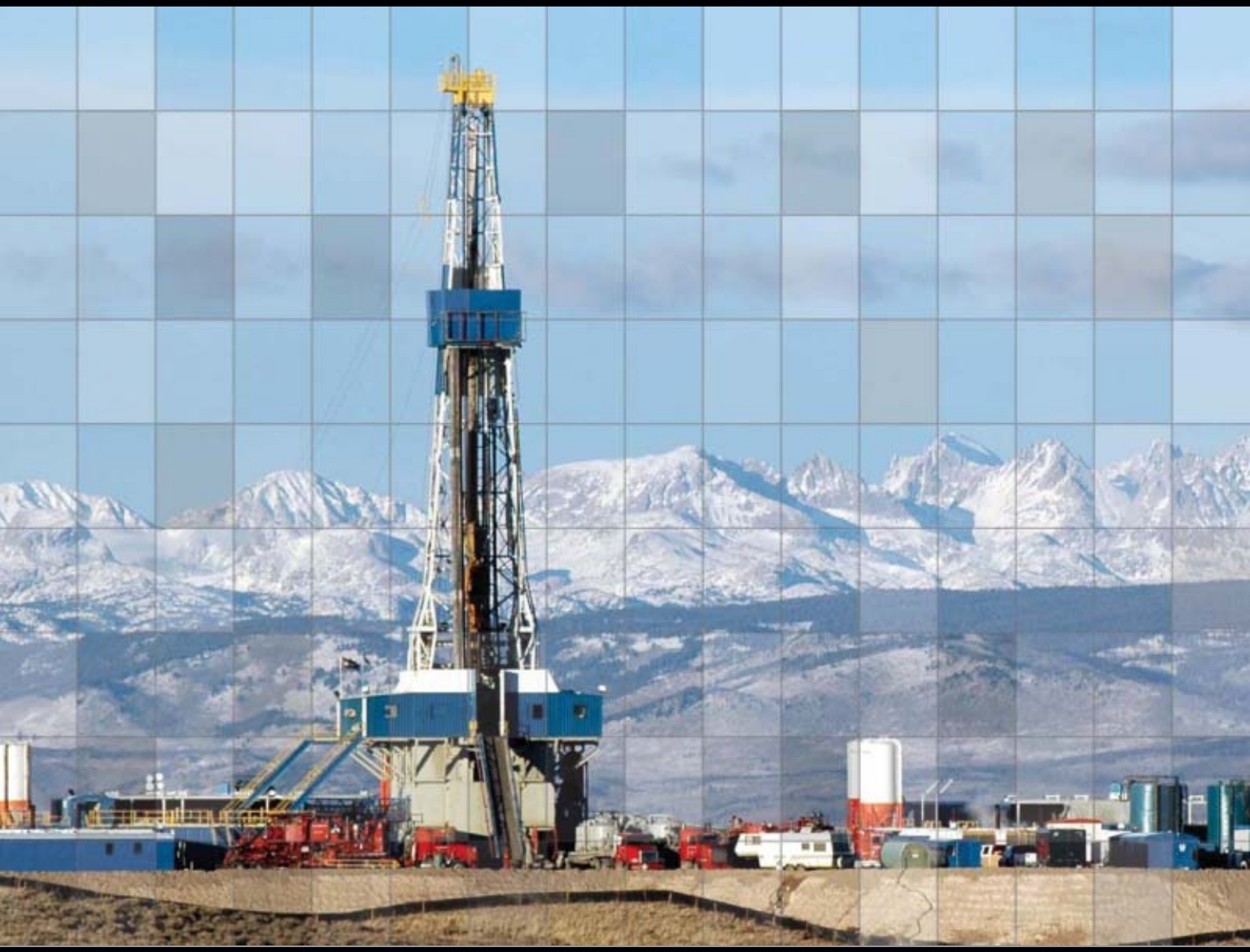

Downhole Technology Review

Recovery tactics outlined for foreign takeover losses
Western Canada structured belt has myriad of drillable features
Study examines use of refinery fuel gas for hydrogen output
Rockies Express pipeline to reshuffle gas supply, trade

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June 25, 2007
Volume 105.24

Downhole Technology Review

Various technologies unlock Pinedale anticline tight gas 39
Guntis Moritis

New, larger bore CT drilling beyond 7,000 ft 45

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Cover

Development drilling continues on the Pinedale anticline of western Wyoming that contains large volumes of natural gas in tight sands. Discovered in the 1930s, active development of this resource only began in the last few years as improved downhole tools and techniques made recovery of this gas economic. OGJ's special report starting on p. 39 discusses the procedures Shell Exploration & Production Co. employs for developing this gas. The second article in the special covers advances that allow the use of coiled tubing to drill 10,000-ft wells. Photo from Shell.

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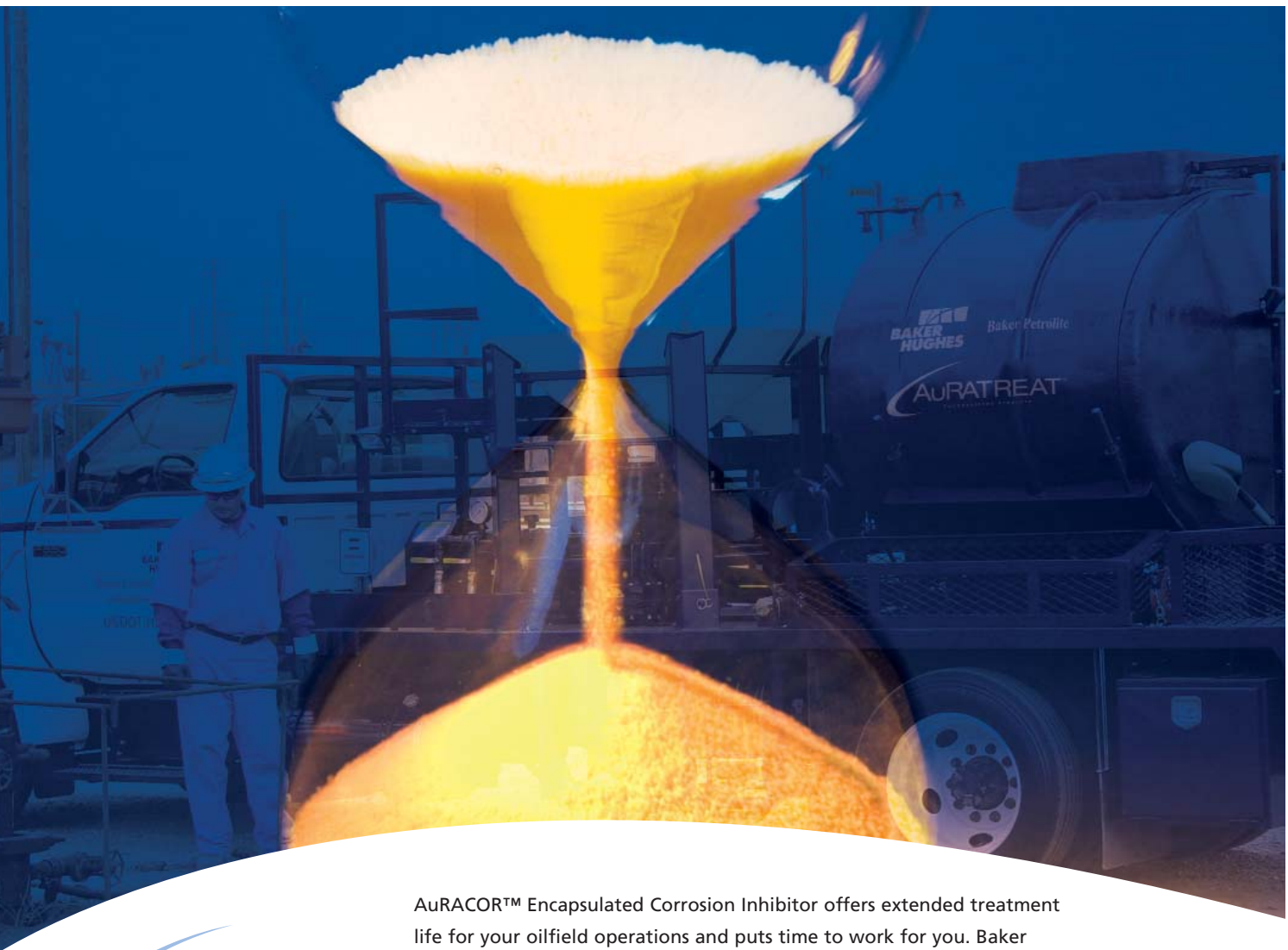

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General Interest — Quick Takes

Turkmen leader welcomes foreign investment

Gurbanguly Berdymukhammedov, Turkmenistan's new president, is changing the country's direction and is seeking foreign investment in his country's oil and gas sector.

Berdymukhammedov, who came to power last December following the death of former President Saparmurat Niyazov, in a recent speech showed his determination to open the country to foreign investment, a policy that Niyazov did not observe.

"We pay great attention to cooperation with leading companies in [the development of oil and gas fields] on the sea, in expanding and upgrading the network of gas pipelines, forming a national tanker fleet, and constructing new sea terminals," Berdymukhammedov said over Turkmen TV's Altyn Asyr channel.

"Turkmenistan is successfully dealing with delivering its natural resources to the world market via various routes," Berdymukhammedov said in televised remarks at a June 5 ceremony dedicated to the construction of a gas storage facility in western Turkmenistan.

"We are still adhering to our initiatives on the construction of Turkmenistan-China, Turkmenistan-Afghanistan-Pakistan-India gas pipelines as well as a Turkmenistan-Europe gas pipeline via the Caspian Sea," Berdymukhammedov said.

State newspaper Neutral Turkmenistan said Berdymukhammedov and Lukoil Chief Executive Vagit Alekperov reached an agreement at a June 12 meeting in Ashgabat, the Turkmen capital, stipulating Russia's OAO Lukoil Holdings to develop three fields in the Caspian Sea.

The paper said Lukoil plans to begin developing the "promising hydrocarbon fields" off Turkmenistan on the Caspian Sea shelf "in the near future." It did not identify the fields.

Berdymukhammedov also met with TNK-BP Chief Executive Robert Dudley to discuss the Anglo-Russian firm's interest in developing Turkmen oil fields.

A TNK-BP company spokesman said it was the first meeting of the company's leadership with the Turkmen president and that further meetings should be held to discuss details of potential deals.

Nigeria to prioritize gas for domestic use

Nigeria's new president, Umaru Musa Yar'Adua, has asked Nigeria National Petroleum Corp. (NNPC) to draw up a plan for providing gas for domestic needs, particularly power generation. Yar'Adua recently held a 3-hr meeting with senior NNPC officials, led by Group Managing Director Funsho Kupolokun.

Nigeria has 187 tcf of proved gas reserves, and Yar'Adua's requirement of NNPC raises questions about supplies for future gas export projects. Nigeria currently utilizes 2,000 Mw of power and wants to increase its power generation capacity to 12-15 Gw. An NNPC spokesman told OGJ that Nigeria would continue to honor its international commitments for gas supplies that have been set aside for export either as pipeline gas or LNG.

Local reports quoted Yar'Adua as saying "We cannot begin to address, in a fundamental manner, the problems of the economy until we successfully tackle the power and energy issue. It is critical to all my plans. So I am more interested in how much gas we can tap for domestic use than what we can get for export. We must power this economy."

Criminal activities in the Niger Delta have cut oil production by almost a quarter, with production shut-ins in May reaching a high of nearly 1 million b/d and averaging more than 800,000 b/d for the month (OGJ Online, June 11, 2007).

Yar'Adua has stressed that it is his priority to deal with these criminal activities through development in the region and enforcement of the law.

Meanwhile he will consult the National Assembly and stakeholders on the intervention plan. ✦

Exploration & Development — Quick Takes

Oil found in Ghana's deepwater Mahogany-1 well

Anadarko Petroleum Corp. and its partners have discovered light oil with the Mahogany-1 exploration well drilled on deepwater West Cape Three Points block off Ghana. The well, a Santonian turbidite stratigraphic trap, opens a new play fairway in the Tano basin.

Mahogany-1 encountered a 885-ft gross hydrocarbon column with 312 ft of net stacked pay in a Cretaceous sandstone reservoir. The well has so far reached 12,083 ft and is aiming for a TD of 13,780 ft. An Anadarko spokesman told OGJ that the well was targeting a Cretaceous formation. West Cape Three Points block lies in 4,330 ft of water.

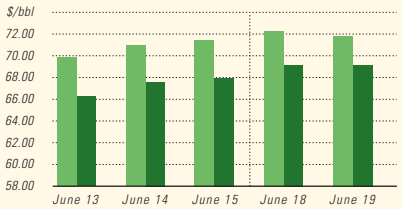
Once the partners hit TD, they will suspend the well pending further evaluation and appraisal drilling.

Mahogany-1 is being drilled by the Belford Dolphin deepwater drillship, which is under long-term contract to Anadarko. After finishing that well, Anadarko will use it to drill the Sota-1 well on Block 4 off Benin, in which it holds a 40% interest and is also the operator. Belford Dolphin will then move to the Gulf of Mexico to drill additional tests in Anadarko's 2007 exploration program.

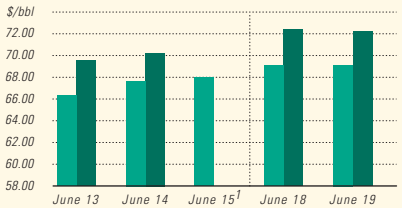
Anadarko is the technical operator of the well with a 30.875% interest. Kosmos Energy is the block operator and holds a 30.875% stake. Other partners are Tullow Ghana Ltd. 22.896%, Sabre Oil &

Industry Scoreboard

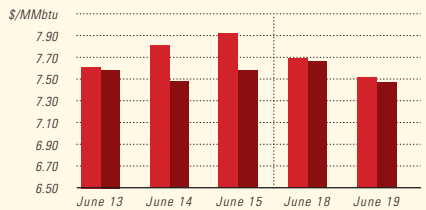
IPE BRENT / NYMEX LIGHT SWEET CRUDE



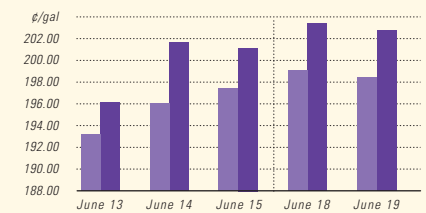
WTI CUSHING / BRENT SPOT



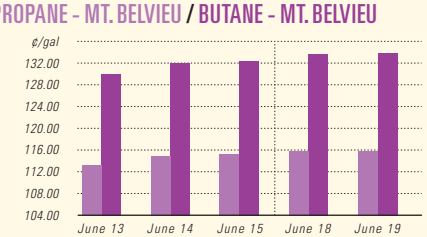
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



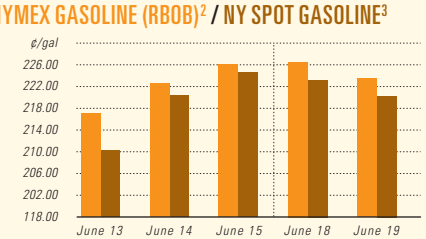
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Not available
[2]Reformulated gasoline blendstock for oxygen blending

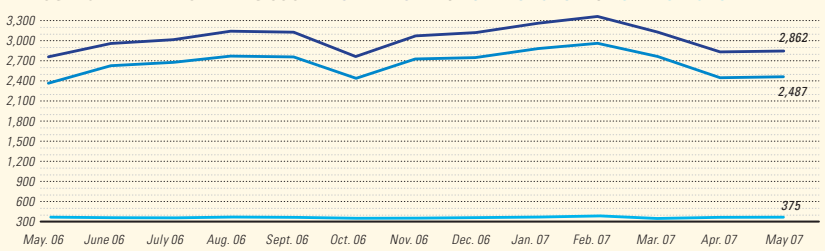
US INDUSTRY SCOREBOARD — 6/25

Latest week 6/15	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	9,473	9,381	1.0	9,189	9,097	1.0
Distillate	4,039	4,033	0.2	4,321	4,183	3.3
Jet fuel	1,656	1,674	–1.1	1,608	1,604	0.2
Residual	697	599	16.3	743	724	2.7
Other products	4,860	4,998	–2.7	4,952	4,832	2.5
TOTAL DEMAND	20,725	20,684	0.2	20,814	20,440	1.8
Supply, 1,000 b/d						
Crude production	5,184	5,164	0.4	5,237	5,083	3.0
NGL production[2]	2,287	2,228	2.6	2,378	2,140	11.1
Crude imports	10,093	10,469	–3.6	9,870	10,021	–1.5
Product imports	3,433	3,701	–7.2	3,252	3,555	–8.5
Other supply[3]	1,038	909	14.2	982	1,092	–10.1
TOTAL SUPPLY	22,034	22,470	–1.9	21,719	21,891	–0.8
Refining, 1,000 b/d						
Crude runs to stills	14,799	15,690	–5.7	14,713	15,047	–2.2
Input to crude stills	15,297	16,024	–4.5	15,160	15,388	–1.5
% utilization	88.3	92.1	—	87.5	88.6	—

Latest week 6/15	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	348,622	348,157	465	344,342	4,280	1.2
Motor gasoline	206,336	205,403	933	211,958	–5,611	–2.7
Distillate	123,170	122,157	1,013	123,368	–198	–0.2
Jet fuel	39,971	41,187	–1,216	39,603	368	0.9
Residual	36,561	35,343	1,218	41,485	–4,924	–11.9
Stock cover (days)[4] **6/8**			**Change, %**		**Change, %**	
Crude	22.1	22.1	—	22.2	–0.5	
Motor gasoline	21.3	21.3	—	22.8	–6.6	
Distillate	29.4	29.3	0.3	30.3	–3.0	
Propane	35.9	39.8	–9.8	41.5	–13.5	
Futures prices[5] **6/15**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	66.82	65.82	1.00	69.49	–2.67	–3.8
Natural gas, $/MMbtu	7.73	7.97	–0.24	6.67	1.05	15.7

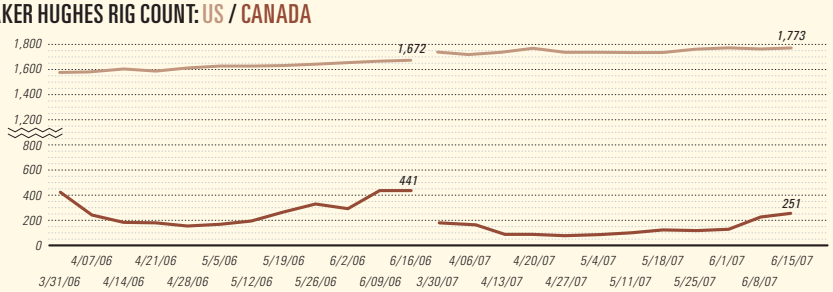
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

Gas Ltd. 1.854%, and Ghanaian oil and gas company E.O. Group 3.5%.

Ghana National Petroleum Corp. will be carried through the exploration and development phases with a 10% participating interest.

Pertra to drill on Norwegian North Sea license

Pertra ASA of Trondheim, Norway, and its partners plan to drill two exploration wells in 2008 on Production License 321 in the Norwegian North Sea. The group will target a prospect in sandstone from the late Jurassic period, which was deposited on the western flank of Frøyhøgda, which is a basement high.

The well will be drilled to 2,000 m TD. Under the first phase of the work program, 800 sq km of 3D seismic data have been collected.

The group won the license in Norway's 18th licensing round, which specified that the exploration period will extend until summer of 2010. License partners are Pertra 25% (operator), Talisman Energy 40%, Norsk Hydro 20%, and Aker Exploration 15%.

Aker Exploration will pay the cost for Pertra's share of the two first exploration wells in this license, Pertra said.

Eni, Santos seek better terms in Indonesia

Eni SPA and Santos Ltd. are seeking to renegotiate their agreements with Indonesia for better incentives, according to an official with BP Migas, the country's oil and gas regulatory body.

Achmad Luthfi, BP Migas director for planning, said Eni had requested a better split in connection with its operations on the Krueng Mane block in Nanggroe Aceh Darussalam, while Santos is seeking a better split together with additional incentives for its operations on the Jeruk block in East Java.

Luthfi said the companies' requests, said to be for a split of 51:49 in favor of the government, were based on one that had been applied in Block A in Aceh, where operators, including Eni and Santos, had also encountered difficulties in developing the block. Luthfi said the two companies' requests were informal and that official requests had yet to be filed.

Last month, Eni said it found significant oil and gas deposits in its Tulip-1 exploration well drilled in 800 m of water northeast of Kalimantan Island, Indonesia (OGJ Online, May 14, 2007).

Nexen developing Alberta Mannville coal gas

Nexen Inc., Calgary, has a $200 million budget in 2007 to develop 98 gross/41 net sections of Cretaceous Mannville coalbed methane in Alberta.

The company is drilling single and multileg horizontal wells in the Corbett, Doris, and Thunder areas near Fort Assiniboine.

The company estimated 3 tcf of gas in place on more than 700 net sections of CBM lands it holds in Alberta. Its production goal is to be producing at least 150 MMcfd by 2011.

CBM production is nearing 25 MMcfd and is projected at 50 MMcfd by yearend. Breakeven gas price for the CBM developments is $5 (Can.)/Mcf, the company told the Canadian Association of Petroleum Producers. ✦

Drilling & Production — *Quick Takes*

Heritage starts oil production from Siberian field

Heritage Oil Corp. has begun oil production from one well at its Zapadno Chumpasskoye field in Western Siberia. Russian federal and local authorities have approved a pilot development project for the field that includes the drilling of more than 50 wells.

The producing well—No. 226—flowed freely at a rate of up to 540 b/d of 39° gravity oil through an 8-mm choke, with wellhead pressure of 4,140 psi. The well produced a total of 4,086 bbl of oil with no water over 10 days of tests through various choke sizes.

It currently is producing 400 b/d of oil, and test results indicate that its production rate could be increased by installing a downhole pump. Before deciding on pump installation, the company is conducting further analysis and reservoir modeling to evaluate stimulation potential and assist in reservoir characterization.

The produced crude is being sold locally.

Following the recent completion of the Zapadno Chumpasskoye oil separation and testing facility, the next stage of field facility construction, including the export pipeline tie-in, are being fast-tracked to coincide with expected production increases.

Meanwhile, the deviated appraisal well P No. 3, which was spud in May, is due to reach its target depth of 3,490 m (2,800 m TVD) in a late Jurassic sandstone reservoir in about 10 days.

The well will then be logged, cased, and suspended prior to skidding the rig to the next surface location for drilling the second deviated appraisal well. A workover rig will be used to test P No. 3 in July. The company intends to complete the well as a future oil producer. It is the first to be drilled in a program comprising three appraisal wells and an initial 16 development wells.

The Zapadno Chumpasskoye field development plan includes significant production growth with the drilling of more than 50 wells and the future installation of waterflood injection facilities, Heritage said.

Petrobank starts third well pair at Whitesands

Petrobank Energy & Resources Ltd., Calgary, has begun air injection into its third well pair in the Whitesands pilot project in the oil sands region of Alberta. The company is using its "Thai" in situ combustion technology for recovery of the bitumen and heavy oil.

The company also has initiated a debottlenecking and expansion project that involves drilling three additional well pairs later this year.

Through the implementation of additional development phases, Petrobank said it expects to achieve an ultimate production level of 100,000 b/d from its existing Whitesands leases.

Petrobank's proprietary Thai technology is a new combustion process that uses a vertical air injection well combined with a horizontal production well. The process allows a portion of the oil in the reservoir to be burned, generating heat that reduces the oil's viscosity for easier flow through the production well. This method recovers an estimated 80% of OOIP while partially upgrading the crude oil in situ, Petrobank said.

Air injection in the first well pair began in late July 2006 and in the second well pair in early January 2007.

Mechanical problems with the temporary steam generator used in late December 2006 for the preignition heating cycle delayed air injection in the third well pair for 6 weeks, but Petrobank said that composition of produced gas indicates that combustion from the third well pair has been initiated and early gross fluid production capability is similar to that of the first two well pairs. Each well pair is capable of producing up to 2,000 b/d of fluid. During the first quarter, oil cuts in the wells rose to more than 50%.

Higher-than-anticipated sand production volumes required the use of a very low choke setting on the wells, but Petrobank installed a test sand knockout vessel on the first well pair that removed sand from produced fluids.

Petrobank since has designed a larger vessel that will allow the wells to be produced at their demonstrated capacity. The company expects to begin installing these units for each well pair early in the third quarter.

Meanwhile, the additional wells planned in the company's expansion project are expected to be 200 m longer than the existing 500 m well pairs. They will incorporate Petrobank's "Capri" technology, which allows a catalyst bed to be added around the outside of the horizontal production well bore to enhance the upgrading of the oil in situ.

The company also plans to implement a modified downhole completion to reduce sand production. It said it will incorporate lessons learned from the current project into the design of the three-well expansion, as well as the design of its first 10,000 b/d project—its initial full-scale development beyond current operations.

Petrobank expects to file application for this project by yearend.

Eni calls force majeure in Nigeria after attacks

Italy's Eni SPA said it declared force majeure June 17 at its Nigerian Ogobinbiri oil flow station after an attack by a group of militants.

Peak production at the facility is 37,000 b/d of crude oil, with Eni's share standing at 5,500 b/d, a company spokesman said.

Unidentified gunmen occupied the oil flow station, holding two dozen Nigerian workers and soldiers captive.

Eni, which did not know of any fatalities in the attack, said there were 24 Nigerian workers and 51 soldiers in the flow station. It said 8 workers and 40 soldiers were able to escape from the attackers.

The attack is the latest in a series stretching back some 18 months, with some 200 workers kidnapped during that time. The attacks have been stepped up in 2007, with more than 100 workers being kidnapped this year alone. ✦

Processing — *Quick Takes*

Private Hyperion plans Midwest US refinery

Hyperion Resources Inc., a privately held Dallas exploration and production company, announced plans to build a 400,000 b/d refinery in Union County, SD, or elsewhere in the US Midwest, according to the South Dakota Governor's Office of Economic Development (GOED).

The refinery, part of what the company calls the Gorilla energy complex, would be the first such facility constructed in the US in more than 30 years.

Hyperion Project Executive J.L. Frank confirmed that a tract of land in Union County is one of the sites in the Midwest being considered for the "green energy center." Frank called the Union County site "sufficiently attractive that we've taken several options on land there, and we may take a few more."

The energy center's refinery would produce transportation fuels including ultralow-sulfur gasoline and ultralow-sulfur diesel from heavy oil from Canada.

If built in Union county, the refinery could receive crude from TransCanada's proposed 2,965-km Keystone oil pipeline, which will deliver 435,000 b/d of oil from Hardisty, Alta., to Wood River and Patoka, Ill. (OGJ, Feb. 19, 2007, p. 48).

TransCanada has oil pipelines between Patoka to the hub at Cushing, Okla.

The Keystone system, now in approval stages, is scheduled for construction by early 2008 and for operation in late 2009. The part of the proposed system that would extend through South Dakota would cross the Missouri River near Yankton, just 30 miles west of Union County.

Frank, former president of Marathon Ashland Petroleum, said, "Gas prices are the highest in US history, and the US refining infrastructure hasn't seen a significant change since 1976. The fact is, refining capacity in this country has not kept pace with demand."

The Gorilla project, reportedly to cost $6-8 billion, is being touted in the Union County area for its strong economic advantages. The refinery's construction would employ about 4,500 workers over 4 years, Frank said, with a peak work force of about 10,000. When operational, the refinery would employ about 1,800.

The refinery would have an integrated gasification combined cycle plant, fed by petroleum coke from the refinery, to supply electricity, hydrogen, and steam, Frank said. Emissions would be substantially lower than those from conventional power generation plants.

A Hyperion executive involved with the Gorilla project was reported by the Sioux City Journal as saying the company hopes to select a site during the next year. Hyperion has not disclosed information about financing.

EPA fines California refiner in wastewater case

The US Environmental Protection Agency has fined a California refinery operator $1 million and has sentenced the company to 3 years of probation for breaking federal drinking water laws.

Santa Maria Refining Co. pleaded guilty on Apr. 12 and was sentenced in federal district court in California's central district for posing a risk to groundwater supplies by disposing of contaminated wastewater in wells that did not have permits for that use.

EPA said the wastewater contained benzene, which can cause anemia, excessive bleeding, and cancer as well as affect the immune system.

Santa Maria Refining, which is a Greka Energy Corp. subsidiary operating in Santa Maria, also was sentenced for making false statements to EPA and ordered to pay $15,000 in restitution and implement an independently audited environmental program, EPA said on June 15.

It said three individual defendants also pleaded guilty to making false statements to EPA. They each face 5-year federal prison terms, EPA said. Sentencing is pending.

EPA said it has been investigated allegations that Santa Maria Refining officials knowingly and routinely discharged refining waste into underground wells that only hold permits for the disposal of brine, which is separated from oil during the refining process.

It said it fined the facility $127,500 in June 2006 for unauthorized refinery wastewater disposal into the plant's injection wells.

UK firm to build biodiesel plant in China

British biodiesel producer D1 Oils PLC plans to build a biodiesel plant in China's Guangxi Zhuang autonomous region, the country's first such facilty using jatropha oil as a feedstock. Japan, India, and the Philippines already have plans under way for such plants.

D1 Oils said the plant would be built in a petrochemical industry park in Baise City in northwestern Guangxi. Expected to be online at yearend 2008 or early 2009, the facility will have an initial processing capacity of 10,000 tonnes/year, rising to 100,000 tpy over 5 years.

The plant will be fed by seed oil from an existing 1,667 hectares of jatropha plantations in Baise, rising to 30,000 hectares by 2008. ✦

Transportation — *Quick Takes*

Japan, Brunei sign free trade, gas agreement

Brunei has signed a free trade agreement with Japan, which had sought assurances of a stable supply of natural gas from the Southeast Asian producer.

Japan imports about 10% of its gas from Brunei, which has agreed to give Japan advance notice of any measures that would restrict the gas exports.

The agreement also stipulates the establishment of a government-level subcommittee on energy, provides that the two countries will honor existing energy agreements, and gives consideration to environmental concerns. The accord within 3 years will eliminate the 20% tariff imposed by Brunei on cars and almost all auto parts from Japan, while Japan will immediately end tariffs on agricultural and fishery products from Brunei.

In 2006, Japan imported some ¥252.5 billion worth of goods from Brunei, almost all of it gas and crude oil, while some 70% of Japan's exports to Brunei are comprised of cars and auto parts.

Hungary seeks LNG from Indonesia

The Hungarian government, as part of a wider effort to diversify the country's energy sources away from Russia, has approached Indonesia seeking LNG supply purchases.

Hungarian Economcs and Transport Minister Janos Koka made the request of Indonesia's Trade Minister Mari Elka Pangestu, saying supplies from Indonesia could be shipped to an LNG terminal under development by his country and Croatia.

Koka said the two sides would "touch on this further in October" during his visit to Indonesia. Meanwhile, Mari said she would discuss the request with Jakarta's ministries.

Hungary's request follows earlier efforts to increase gas supplies ahead of pending liberalization of Hungary's gas market.

In May, Hungarian oil and gas company MOL Nyrt said it was considering expanding capacity along the domestic stretch of the "Friendship" gas pipeline that carries Russian gas to Europe via Ukraine.

According to a report in the daily Nepszabadsag citing MOL Nyrt sources, the expansion would increase capacity to 10 billion cu m by increasing Russia's gas supply until other supply routes come on line by 2015.

The move is aimed at ensuring sufficient capacity available to new market entrants following liberalization on the gas market in 2008, according to MOL Nyrt, which earlier announced plans to enter the liberalized gas market in Hungary.

In May MOL Nyrt announced plans to team with ExxonMobil Corp. to undertake a joint survey of "unconventional" gas resources in Hungary.

Indonesia reneges on some Sempra LNG supplies

Indonesia, reversing an earlier decision, is reallocating supplies of Tangguh LNG originally earmarked for Sempra Energy LNG Marketing Corp. in order to boost the amounts available to state-owned utility Perusahaan Listrik Negara (PLN).

PLN power generation director Ali Herman Ibrahim said the decision was made during a June 14 meeting with the upstream oil and gas executive agency BP Migas. Ali said BP Migas will allow PLN to receive a portion of the LNG supply previously allocated to Sempra, but he did not specify the amount. In March, to obtain higher prices for its LNG exported from Tangguh in Papua New Guinea, Indonesia's Energy and Mineral Resources Minister Purnomo Yusgiantoro said the country wanted to renegotiate LNG contract terms with South Korean buyers and was seeking to divert to Japan supplies contracted for the US West Coast.

In particular, Purnomo said Indonesia was planning to talk to Sempra, with which it had agreed to deliver 3.7 million tonnes/year of LNG from Tangguh for 20 years at $5.90/Mcf. (OGJ Online, Mar. 6, 2007). The Tangguh LNG plant is expected to become operational by fourth quarter 2008.

Recently Indonesian media quoted Purnomo as saying the government is considering the possibility of diverting as much as 50% of Sempra's LNG supply to the Asian market.

According to operator BP, the Tangguh LNG plant has already secured long-term LNG sales to four customers: the Fujian LNG project in China, SK Power Co. Ltd. in South Korea, Posco Korea, and Sempra. ✦

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2007

JUNE

PIRA Scenario Planning Conference, Houston, 212-686-6808, 212-686-6628, e-mail: sales@pira.com. website: www.pira.com. 25.

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

API Exploration and Production Standards Conference on Oilfield Equipment and Materials, San Francisco, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 25-29.

PIRA Understanding Global Oil Markets Conference, Houston, 212-686-6808, 212-686-6628 (fax), e-mail: sales@pira.com. website: www.pira.com. 26-27.

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

Power-Gen Europe Conference, Madrid, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 26-28.

Russian Petroleum Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

Moscow International Oil & Gas Conference & Exhibition, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 26-29.

JULY

IPAA OGIS, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11.

Carbon Sequestration Development & Finance Summit, Houston, (818) 888-4444, website: www.infocastinc.com/sequest07.html. 11-13.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 18-20.

Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 236-0318, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.

com, website: www.purvingertz.com. 25-28.

West China International Oil & Gas Conference, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-27.

International Petroleum & Petrochemical Exhibition, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

AUGUST

Coal-Gen Conference, Milwaukee, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 1-3.

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

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

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

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

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

SEPTEMBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

✦Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713)

Calendar

337-1644 (fax), e-mail: Twilson@EventsiaGroup.com, website: www.ecc-association.org. 26-29.

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

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

OCTOBER

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

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

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

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

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

✦Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 3-6.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NOVEMBER

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

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

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

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

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

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

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

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

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

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

DECEMBER

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

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

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

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

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

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

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

2008

JANUARY

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

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

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

MARCH

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

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

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

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

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 2-5.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

JUNE

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

AUGUST

Offshore Northern Sea 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.

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Journally Speaking

Issues cloud CO_2 transport

Christopher E. Smith
Pipeline Editor

Research by several US Department of Energy Regional Carbon Sequestration Partnerships has a goal of safe, cost-effective, and long-term carbon management, mitigation, and storage. The RCSPs will be field-testing and validating sequestration through 2009, with deployment involving several large-volume sites starting in 2008 and running through 2017.

Current energy legislation also addresses carbon sequestration, including plans to conduct a large-scale demonstration in the vicinity of the Piceance basin.

These efforts have so far focused on capture technology and the viability of the various types of sequestration sites (depleted oil and gas reservoirs, unminable coalbeds, and deep saline reservoirs), rather than how to transport carbon dioxide from source to storage.

A Congressional Research Service report published Apr. 19, "Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues," points out economic and regulatory problems that need to be addressed in terms of CO_2 transport before carbon sequestration can occur.

The technology for transporting CO_2 via pipeline is mature, having been used since 1972 to carry CO_2 from a variety of naturally occurring and man-made sources to oil fields for enhanced oil recovery. CO_2 pipelines are also similar in construction and operation to natural gas pipelines.

Technological questions regarding CO_2 pipelines, therefore, are minimal. By contrast, the CRS report notes considerable uncertainty regarding the size, complexity, and configuration of the pipeline network required to implement a widespread carbon sequestration program in the US.

Costs uncertain

Many existing, large CO_2 point sources in the US are relatively close to potential saline reservoir injection points, making transport relatively straightforward (OGJ, May 14, 2007, p. 20). But US Geological Survey Director Mark Myers is among those who have noted that the behavior of CO_2 in saline formations is not fully understood (OGJ, Apr. 23, 2007, p. 37).

The resultant uncertainty over the proximity of sources to storage sites brings with it a wide range of possible pipeline configurations and costs, according to CRS, which also notes the economies of scale that would accrue if a CO_2 sequestration network were developed in an integrated manner rather than simply emerging piecemeal as each source found its own way to a sequestration site.

At a time when material and labor resources in the pipeline industry are stretched, issues of cost carry particular weight. Dedicated CO_2 pipelines would have to compete for resources with already planned expansions of the US gas and liquids transportation infrastructure, as well as potential new dedicated ethanol pipelines also under consideration.

Regulatory issues

Regulatory difficulties also exist. The US Surface Transportation Board regulates interstate pipelines carrying commodities other than water, oil, and natural gas. Its regulatory authority and oversight, however, are limited compared with the Federal Energy Regulatory Commission's administration of US natural gas and oil pipelines.

The STB is charged with ensuring that CO_2 pipelines fulfill common carrier obligations by charging reasonable rates, but it lacks the authority to begin a rate proceeding on its own initiative. Pipeline operators under its supervision are also under no obligation to notify the board of any rate changes, unlike operators under FERC jurisdiction. The STB further lacks regulatory authority regarding pipeline construction, including eminent domain.

Without federal regulatory authority over construction, the CRS report points out, CO_2 pipeline siting is regulated to varying degrees by each state. Without the ability to oversee rates, a varied and potentially unstable pricing environment would emerge. The potentially dampening effect of these factors on growth of an integrated pipeline network for CO_2 sequestration is clear.

According to the CRS, however, legislation placing CO_2 pipelines under FERC's jurisdiction might imply that CO_2 transport is interstate commerce and that captured CO_2 is therefore a commodity as opposed to a pollutant, leading to still broader regulatory issues and implications.

Carbon sequestration is one part of the effort to improve the sustainability and environmental responsibility of the US energy infrastructure. To the degree that other parts of this effort lead to the development of nonfossil fuels, the need for sequestration will be diminished.

Regardless of the twists and turns this process takes, however, the transportation of CO_2 should receive attention as urgent and careful as that now given other subjects related to sequestration.

Biofuels and oil prices

The secretary general of the Organization of Petroleum Exporting Countries irked observers in the oil-consuming world this month with a comment taken as a reactionary threat over biofuels. According to a June 5 report in the Financial Times, the official, Abdalla Salem El-Badri, said efforts in the West to develop biofuels might push oil prices "through the roof." His words zipped across the internet and drew scorn on radio talk shows in the US.

The popular interpretation is that OPEC will restrict investments in oil-production capacity as a political response to promotion by consuming-nation governments of biofuels. As the Financial Times reported the story, El-Badri "said the powerful cartel was considering cutting its investment in new oil production in response to moves by the developed world to use more biofuels."

A challenge

In a political world looking for a fight over oil, these words constitute a challenge, a view fortified by timing. El-Badri spoke the day before industrial-world leaders met in Germany to discuss, among other issues, climate change. If he hoped to dissipate the political momentum behind biofuels, El-Badri probably failed and gave OPEC's antagonists new leverage in their campaign of demonization.

But there's another, less political context in which to assess his words. It's the economic context, the one so frequently disregarded these days by governmental leaders acting on energy.

In the economic context, in fact, the politically charged analysis unravels. For example, the idea that OPEC invests in the ability to produce or refine oil is flawed. OPEC as a group invests in no such thing. Its members make their own investment decisions, following notably disparate strategies. Only in a political context distorted beyond reason might the suspicion thrive that OPEC can coordinate long-term investment strategies of its members to suit political goals. OPEC has trouble enough coordinating current production rates.

Indeed, El-Badri's through-the-roof remark just extends the logic of a concern OPEC has been expressing since before he became secretary-general in January: how uncertainty over future oil demand bedevils investment planning by group members. OPEC producers with undeveloped reserves must invest heavily now to bring on stream production capacity as it's needed to meet demand for oil years, even decades, in the future. As always, a large risk in those multibillion-dollar investments is failure of demand to reach forecast levels and the consequent costs of servicing capital tied up in unused capacity. That risk swells when consuming-nation governments disparage oil from the world's largest exporters and aggressively subsidize costlier alternatives.

A year ago, the OPEC secretariat examined demand uncertainty in a paper presented at an energy conference in Doha. To satisfy market requirements for their oil under reference-case assumptions about demand, the paper said, OPEC members must invest $100 billion in production capacity during 2005-10, at least another $100 billion through 2015, and nearly $150 billion more through 2020. Uncertainty about demand creates large and growing differences in investment projections between low and high-growth demand assumptions: $50 billion in 2010, $140 billion in 2015, and $240 billion in 2020, when cumulative investments needed to meet high demand growth would exceed $450 billion.

The risk

The uncertainty range in this assessment thus is more than half what the high-growth investment requirement for 2005-20 would be and more than the total low-growth requirement of about $225 billion. OPEC members understandably don't want to invest for a reference-case or high-growth market and have demand languish at low-growth levels, which would leave them collectively with tens or hundreds of billions of dollars in capital invested but generating no revenue.

While consuming-nation governments worry about security of supply, OPEC for years has been seeking attention to its concern for security of demand. The consumers now respond with a push for biofuels and repeatedly expressed distaste for foreign oil, making demand less predictable than ever. That this discourages OPEC members from making investments essential to future supply is economics, not politics. Restrained investment limits supply in a market trying to grow. In such a market, prices rise. Depending on demand, they rise through the roof. ✦

Recovery tactics outlined for foreign takeover losses

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Companies affected by recent nationalizations in South America and elsewhere may have a number of relief options available. Among these are political risk insurance (PRI), bilateral investment treaties (BITs) and other analogous bilateral and multilateral treaties, and any investment agreement between the company and the host government. Each of these must be analyzed to determine which procedural and substantive bodies of law they implicate and what obstacles or recovery avenues they present.

For some companies, recovering under a PRI policy and assigning their direct claims against the host government to their insurer may be preferable to direct arbitration against the host government. Other companies may have purchased too little or no political risk insurance or may determine that direct arbitration under BITs or analogous agreements would be more advantageous in their particular circumstance.

For some companies with PRI and an applicable BIT, both avenues might be available, and the company will need to assess which options afford the greatest potential for recovery.

Recently nationalized companies in Latin America may recover some losses this way.

Recent nationalizations

"Companies can mitigate losses... by purchasing political risk insurance and participating in investment treaties with the host countries before investing."

Recent nationalizations in countries such as Venezuela, Bolivia, and Ecuador are resulting in harmful losses to several industries doing business in those countries—most particularly international oil and gas companies. Several companies have been forced to renegotiate contracts, giving the host government majority ownership in their operations in those countries. Others have been forced to sell their equity stakes to the host government, arguably at well below fair market value, and some have had their operations seized outright.

These activities appear to be driven by shifting political trends and the host governments' desires to obtain a greater share of the revenue from their countries' resources.

Events in Venezuela illustrate how the combination of a resource-rich country and political volatility can rapidly change the climate for foreign investors.

Venezuela has the world's seventh largest proved conventional oil reserves, and its nonconventional oil deposits—the heavy crude oil found in the Orinoco belts—are equal to the world's total reserves of conventional oil.

However, for many years Venezuela did not have the investment capital to exploit the potential financial benefits from these resources. Consequently, the country turned to foreign investors and entered into service contracts with numerous foreign oil companies to invest in and operate Venezuela's oil fields. In the 1990s, almost 60 foreign companies, many from the US, participated in the Venezuelan oil sector at the government's invitation.

Under these service contracts, the companies would operate the fields and Venezuela's government-owned oil company Petroleos de Venezuela SA (PDVSA) would pay a fee and purchase the oil at market-linked prices. With the help of this foreign investment, Venezuela soon became the fourth-leading supplier of crude oil and petroleum products to the US.

Foreign investors also entered other Venezuelan industries. In 1991, Venezuela privatized its largest telecommunications company, CANTV. Verizon Communications Inc. ultimately purchased a 28.5% stake in CANTV. In 2000, US power company AES Corp., Arlington, Va., purchased an 82% stake in Grupo La Electricidad de Caracas (EDC), the largest Venezuelan utility.

However, Venezuela's hospitality towards foreign investors did not endure. In the past few years, as rising oil prices

spurred rapid economic growth, Venezuela's gross domestic product increased by 17.9% in 2004, 9.3% in 2005, and 10.4% in 2006. The Venezuelan government then sought to obtain a greater share of revenue from the industries in which it had previously encouraged foreign investment by forcing the renegotiation of contracts and by nationalizing entire companies.

"Events in Venezuela illustrate how the combination of a resource-rich country and political volatility can rapidly change the climate for foreign investors."

These efforts have been driven by Venezuelan President Hugo Chavez, who has pledged to implement "21st Century Socialism." After leading an unsuccessful military coup in 1992, Chavez was elected president in 1998, pledging broad reforms. He rewrote the constitution in 1999, and he was reelected in 2000 and again in December 2006. Since his most recent election, Chavez has pursued a strategy of nationalization with renewed intensity.

Venezuela's efforts to increase its share of revenue from foreign investor-run operations have ranged from regulatory measures to forced renegotiation of contracts, to outright nationalization. First, from 2004 to the present, Venezuela increased corporate income tax on foreign oil companies by 30-50%, in some cases retroactively, and it increased to 33% the formerly 1% royalties owed by those companies to the government.

Then, in 2005, Venezuela gave foreign oil companies operating conventional oil fields 1 year to convert their service contracts into joint venture agreements under which PDVSA was to be granted a minimum 60% stake. In April 2006, after Total SA and Eni SPA refused to enter into the proposed JV agreements, the Venezuelan government seized the oil fields operated by those two companies. The remaining companies either sold their stakes or acceded to the government's demands.

More recently, the Venezuelan government declared it would take a minimum 60% stake in the Orinoco basin heavy oil projects by May 1. ExxonMobil Corp. announced Mar. 1 that it would hand over to PDVSA operations of Cerro Negro—one of the four Orinoco basin oil fields that it operates as part of a JV with BP.

Earlier this year, Venezuela also began nationalizing companies in other industries, including the energy and telecommunications industries. On Jan. 31, Venezuela's congress granted Chavez "extraordinary powers" to pass laws by decree for 18 months. Less than 2 weeks later, AES sold its stake in EDC to the Venezuelan government for about $840 million, reportedly $550-650 million less than book value. AES reportedly had purchased EDC in 2000 for $1.7 billion and had since invested another $600 million in the company.

Days later, Verizon sold its stake in CANTV to the Venezuelan government for $572 million, about $100 million less than a sale price already agreed to in a deal that was awaiting Venezuelan regulatory approval.

Similar nationalization movements are taking place in Bolivia and Ecuador. In May 2006, the recently elected president of Bolivia, Evo Morales, announced plans to nationalize the country's oil and gas industry by "negotiate[ing] new contracts that will give ownership to the state." All foreign oil companies were told to either negotiate new contracts giving greater control to the state by Nov. 1, 2006, or be forced to leave the country. Morales also recently announced plans to nationalize companies in other industries and to implement new tax measures aimed at foreign investors.

In Ecuador, the law regulating the oil and gas industry recently was amended to require a minimum 50% state share in all oil revenues.

Means of recovery

Companies can mitigate losses from these types of actions by purchasing PRI and establishing or working with business entities in countries that have investment treaties with the host countries before investing in infrastructure.

Political risk insurance

PRI provides one potential avenue of recovery for companies whose foreign investment has been expropriated by a host government. PRI policies provide coverage for losses resulting from unpredictable actions of the host government, including government confiscation or nationalization of the insured's investment. Other insured risks include contract frustration, currency inconvertibility, political violence, and wrongful calling of guarantees or nonhonoring of guarantees.

PRI originated as a means of inducing direct private investment in developing foreign economies. Thus, the first political risk policies were issued by the US after World War II to encourage private investment in Western Europe. In 1969 Congress established the Oversees Private Investment Corp. (OPIC), a wholly owned government corporation, to provide direct financing and PRI for projects in developing countries.

OPIC remains a dominant provider of PRI. Other political risk insurers include the Multilateral Investment Guaranty Agency (MIGA), which is part of the World Bank Group; Lloyd's of London; Zurich Financial Services Group; Sovereign Risk Insurance Ltd.; American International Group Inc. (AIG); and Chubb Corp. PRI policies typically have large limits and long policy periods or "tenors" of 5-20 years.

OPIC and MIGA offer maximum limits of $250 million and $200 million respectively, while the limits offered by private insurers range from AIG's $85 million to Sovereign's $125 million.

Additionally, political risk insurers often form consortiums to increase the total limits available to the policyholder.

If the insurer disputes coverage, PRI policies generally contain arbitration clauses. The publicly available OPIC policy form requires arbitration in Washington, DC, under the commercial arbitration rules of the American Arbitration Association.

Other PRI policies contain similar provisions, although the location of the arbitration and the applicable rules vary. Because the OPIC policy form is publicly available, and because of OPIC's dominant role among political risk insurers, its expropriation coverage is used here to illustrate the issues likely to arise for companies affected by the recent wave of nationalization.

OPIC policies provide coverage for "total expropriation" if an act or series of acts by the host government violate international law or materially breach local law and directly deprive the insured of fundamental rights in the insured investment. The standard OPIC policy form does not further define when an expropriation constitutes a violation of international law. Thus, OPIC looks to general principles of international law. As a general matter, an expropriation violates international law when it is discriminatory or without just compensation or not for a public purpose.

"The real issue [in Venezuela] will be whether those companies have received 'just compensation.'"

Just compensation

While many recent disputes under international law have turned on whether a host government's regulatory measures and other acts so deprived the investor of the benefits of its investment that they were "tantamount to expropriation"—also referred to as "creeping expropriation"—that is not the issue in Venezuela.

To be sure, Venezuela's dramatic increases in taxes and royalties directed at US and other foreign oil companies operating in Venezuela may be characterized as examples of creeping expropriation. But there is no question that the Venezuelan government's recent overt policy of nationalizing private companies and operations owned by foreign investors, if found to be in violation of international law, would constitute outright expropriation. Thus, the real issue will be whether those companies have received "just compensation."

Not surprisingly, in public statements, Venezuela has taken the position that the terms it has offered to foreign investors such as AES, Verizon, and numerous oil companies have been fair. However, such statements have often been followed, virtually in the next breath, with contradictory statements suggesting that the companies have little choice but to accept whatever terms the Venezuelan government offers. For example, in discussing the nationalization of operations in the Orinoco belt, President Chavez stated: "We want to negotiate...but I have given instructions that on May 1 when the sun gets up, we will have all those oil fields under our control.... The company that wants to stay as our partner, we left the possibility open to them. The one that does not want to stay as minority partner, return the oil field and goodbye...good luck, thank you very much."

Indeed, recent history demonstrates that the terms offered by Venezuela have been nonnegotiable. As discussed above, when Total and Eni refused to convert their service contracts to joint venture agreements that would give PDVSA majority control, Venezuela seized control of the oil fields that they had been operating. At the time, Energy Minister Rafael Ramirez stated: "Those two companies resisted adjusting to our laws.... Companies that don't adjust to our laws, we don't want them to continue in the country." Thus, the choice for companies negotiating with the Venezuelan government appears to be either to take what is offered or risk getting nothing.

Other facts, as mentioned, suggest that companies such as AES and Verizon did not receive just compensation.

Fewer details are known about how much compensation, if any, Venezuela has offered the oil companies in which operations it has taken or will take a majority stake. However, it is unlikely that the amounts offered by Venezuela will compensate the companies for the substantial investments they have made.

Value of the loss

Assuming that a policyholder can show that the expropriation was a violation of international law, the next issue becomes, "What is the value of the loss?" i.e., how much is recoverable under the PRI policy? Unlike "just compensation," the value of the loss is determined by reference to the policy language. Under its form policy language, OPIC agrees to pay the "book value" of the insured investment, subject to certain adjustments and limitations. Book value is determined as of the date "the expropriatory effect commences" and is based on financial statements maintained by the policyholder in accordance with generally accepted accounting principles.

Thus, that the policyholder already has received some compensation from the host government, such as has been the case in Venezuela, does not mean that it cannot also recover under its PRI policy. Rather, the amount recoverable is likely the difference between the book value of the investment and the amount of compensation received.

Arbitration

PRI provides a means for companies to recover from their insurers for losses of their investments in foreign countries resulting from the actions of the host government. However, for any number of reasons, some companies affected by the recent wave of nationalism in South America may not have purchased PRI. In that case, companies may be able to recover directly from the host government through international arbitration.

Treaties

BITs are agreements between governments in which each government agrees to provide certain protections to investments in their countries by nationals of the other country. The provisions of BITs vary, but they typically include an arbitration clause identifying an arbitral body to which disputes may be submitted. Often the parties identify the International Centre for Settlement of Investment Disputes (ICSID).

BITs typically contain a provision prohibiting either country from expropriating the investments of nationals of the other country without due process or just compensation in violation of international law. Thus, like many PRI policies, BITs specify that international law will provide the applicable legal standards.

Unlike PRI policies—at least the OPIC form—however, many BITs contain their own definition of just compensation. In a recent arbitration between the Airport Development Co. and the Republic of Hungary, the BIT stated that "the amount of compensation must correspond to the market value of the expropriated investments at the moment of the expropriation" and that "the amount of this compensation may be estimated according to the laws and regulations of the country where the expropriation is made." This language would be particularly unfavorable to a company such as AES or Verizon that was paid "market value" for its assets "at the moment of the expropriation," as the market value had been driven down significantly as a result of acts of the host government leading up to the expropriation.

In contrast, the BIT between Canada and Venezuela defines "adequate and effective compensation" as "the genuine value of the investment or returns expropriated immediately before the expropriation or at the time the proposed expropriation became public knowledge, whichever is earlier." This language takes into consideration the fact that, as has been the case in Venezuela, the market value of the affected company's investment is likely to decline as soon as the threat of expropriation becomes publicly known.

Notably, there is no BIT between the US and Venezuela. That does not mean, however, that US companies whose investments in Venezuela have been expropriated have no forum in which to arbitrate. Often a company's foreign investments are made through a subsidiary or affiliate that is a national of a different country than the parent. Venezuela, along with 154 other countries, is a party to the Convention on the Settlement of Investment Disputes between States and Nationals of Other States, which is the instrument from which ICSID derives its jurisdiction, and Venezuela has entered into BITs with about 20 countries. Thus, US companies who have suffered a loss may be able to arbitrate their dispute directly with Venezuela if the expropriated investment was owned or controlled, directly or indirectly, by an entity that is a national of a country that is a party to a BIT with Venezuela.

Investment agreements

Additionally, companies should be aware that there are other forms of relief that are analogous to BITs. These include free trade agreements, such as the North America Free Trade Agreement, the Energy Charter Treaty, and others. Also, where the foreign investment involves an agreement with the host government (such as the operating agreements entered into in the 1990s by oil companies operating in Venezuela), the investment agreement itself typically will have an arbitration provision. ✦

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Caruso questions refining capacity manipulation claims

Nick Snow
Washington Correspondent

The US government's top energy economist questioned allegations that refiners intentionally reduced oil-processing capacity this year to drive product prices higher.

US Energy Information Administration Administrator Guy F. Caruso told the Senate Small Business and Entrepreneurship Committee June 14 that reduced product inventories that extended into May apparently were the result of unplanned refinery unit shutdowns.

During a hearing on the impact of higher gasoline prices on small businesses, Caruso explained that refiners schedule maintenance turnarounds in January and February to repair equipment and prepare for the summer driving season.

"The companies try to plan this to maximize their individual sales opportunities. No individual company would take down a refinery to reduce sales. Their objectives are to maximize sales. What went wrong was that there were a number of unplanned outages," Caruso said. "While we're not an investigative agency, we haven't seen any attempt to manipulate the marketplace."

Citing EIA's latest short-term energy outlook released on June 12, he said US regular gasoline prices are expected to average $3.05/gal nationwide this summer because of strong demand and low inventories. Crude oil prices, which EIA expects to average over $65/bbl for West Texas Intermediate through the summer, are expected to keep the average nationwide regular gasoline price above $3/gal through the summer, Caruso said.

"Recently, total gasoline imports have returned to normal levels. We believe these normal levels or possibly somewhat higher-than-normal levels will need to continue to avoid further upward pressure on prices," he told the committee. "With the hurricane season beginning, continued tight refining conditions and low gasoline inventories, and increased demand for summer travel, upward pressure on gasoline prices does remain a concern."

Business impacts

"Whatever the cause, the volatile and increasing cost of gasoline is wreaking havoc on small businesses," said another witness, Sal Lupoli, president and chief executive of Sal's Pizza in Lawrence, Mass. "Rising fuel costs have a direct impact on my means of delivery for my business, and on my employees who often can't afford gasoline for their cars so they can come to work. We encourage car-pooling and public transportation, but these options are not always available."

Janet Myhre, government services group director at Chuckals Inc., said the office supplies company in Tacoma, Wash., is feeling the impact of higher crude oil prices beyond its delivery fleet. Prices have risen for reporter binders because vinyl used on their covers is made from petroleum, she explained. "We're at a level where we have to decide whether to scale back our operations. Maybe we'll lay off some local employees and start to use an outside delivery service," she said.

Other witnesses described impacts of higher gasoline prices on larger operations. Frederick W. Smith, chairman, president, and chief executive of FedEx Corp. in Memphis, said the overnight delivery service decided it would use EIA's reported oil price to help determine its rates, which it posts on the Internet, instead of being in the oil futures market.

"As oil prices go up, we add surcharges. At times during this recent run-up, our prices have gone as much as 20% higher for our air express business, and slightly less for our ground business. Over the last 3 years, we have steadily increased the base crude oil price," he said.

Smith also cochairs the Energy Security Leadership Council, which has urged Congress to require the US transportation fleet to use fuel more efficiently, make alternative fuel sources more readily available, and increase access to unrecovered domestic oil and gas resources for responsible production.

Timothy P. Lynch, senior vice-president of American Trucking Associations Inc., said the organization's members are concerned about rising diesel fuel prices. ATA and its members do not oppose new engine designs and requirements to use ultralow-sulfur diesel, but they want Congress to understand that environmental improvements sometimes reduce fuel efficiency, he told the committee.

"Many of the problems anticipated [with ULSD] have not materialized. We support [biodiesel's] use but believe that national standards are needed, with preemption of state mandates, so it will be a uniformly high-quality fuel," Lynch said. ✦

API develops advised practices for refineries

Nick Snow
Washington Correspondent

The American Petroleum Institute is issuing a new recommended practice covering the placement of portable structures at refineries and petrochemical plants. RP 753 was to be formally released on June 21 following several months of discussions by a task force of

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Hot-dogging with ethanol

Oil and gas are expensive? Move aside, folks, and make way for higher priced hot dogs. No sooner did we write of George Soros's wish for a repeal of the current US tax on imported ethanol, than it was under way to being granted (OGJ, June 11, 2007, p. 35).

"Our goal as an economy should be to get ourselves off oil...and to move to ethanol production, which is the most efficient and cost-competitive," said US Sen. Judd Gregg (R-NH).

Gregg was speaking of his plans to offer an amendment to an energy bill that would repeal the current US tariff on imported ethanol, and he clearly had an eye on his home constituency, saying that the current import duty amounts to an "arbitrary tax on people in the Northeast."

Down with oil

As one observer put it, greater use of ethanol—as aimed at by the Senate energy bill Gregg supports—is seen as a way to boost development of US domestic energy sources and reduce the nation's use of foreign oil.

The bill, in fact, would mandate greater use of ethanol by requiring production of renewable fuels to increase by more than fourfold to 36 billion gal/year by 2022 from an estimated 8.5 billion gal/year in 2008.

Sounds good, huh? Well, the proposed bill will probably spark a lively discussion on the Senate floor where ethanol industry advocates argue that the tariff—which limits imports from key ethanol-producing nations like Brazil—is crucial in allowing the US ethanol industry to develop and thrive.

The downside, though, is that growing demand for corn and other farm products used in alternative fuels is pushing up food prices around the globe, a trend expected to place an increasing burden on households, particularly in developing countries.

Costlier tortillas

And guess what? Largely behind the global price surge are US energy policies promoting the use of ethanol as an alternative to gasoline. In fact, expectations of increasing demand for biofuels have caused corn prices to soar since last fall.

The international trading price of corn reached about $4.30/bushel in February, the highest level in 10 years and 7 months, and it remains high.

The jump in grain prices is also affecting prices of other food items, including meat, eggs, and dairy products. During January-March, the price of beef sold by Tyson Foods Inc., a major US meat processing firm, rose 3% year-on-year, and that of the firm's chicken jumped 9%.

In developing countries, rising food prices could become a source of social instability. In Mexico, for example, prices of tortillas—a corn-based staple—skyrocketed at the beginning of this year, prompting a number of public protests nationwide.

If not handled carefully, ethanol politics will clearly add a new level of meaning to the old question: Where's the beef? ✦

refiners, labor unions, and consultants, API officials said June 20.

The new recommended practice came in response to the US Chemical Safety and Hazard Investigation Board's urgent recommendation on Oct. 25, 2005, that API develop industry guidance for portable structures at processing facilities. CSB made the recommendation during its investigation of the March 23, 2005, explosion and fire at BP America Inc.'s Texas City, Tex., refinery that killed 15 people and injured 180 other workers.

RP 753 would ban light-wood trailers from a defined zone near process areas, prohibit nonessential personnel from being housed in any portable building (including blast-resistant structures) in or near process areas, and provide a simplified method for users with limited resources to safely place portable buildings, according to API.

The recommended practice also would provide controls over changes to people, location, and building designs, and require analysis of all occupied portable buildings near process areas, API said.

"We're trying to give people tools for looking at their individual circumstances," API Pres. Red Cavaney told reporters during a June 20 teleconference. "How and when each company implements this recommended practice is an individual decision. But I know many companies already have taken steps of their own," he said.

Rigorous approach

It took several months to develop the recommended practice after API determined that one was needed because the association follows the American National Standards Institute's formal, comprehensive, and rigorous approach, Cavaney said. "Speed shouldn't trump full and thorough consideration of these issues," he said.

The task force included members of the National Petrochemical & Refiners Association, chemical companies, consulting firms, and API members.

The procedure will join RP 752,

which outlines the siting of process plant buildings. The API task force will begin to review RP 752 once it formally issues RP 753. It also will formally brief CSB, the US Occupational Safety and Health Administration, and the United Steelworkers on RP 753's features on June 21.

Those features include the establishment of three zones for placing portable buildings, based on external cloud explosions and using technical data from CSB and other organizations. Minimum distances, based on the size of the unit (or congested volume), are recommended, starting with 330 ft for the smallest unit.

Light-wood trailers cannot be located closer than 330 ft from a process unit. For larger units, the minimum distance is 570 ft.

For plants that do not have the technical resources to perform a detailed consequence analysis or quantitative risk analyses, RP 753 sets a minimum range of 300-1,930 ft for portable structures. "A company still needs to conduct a detailed analysis to determine where to place these portable structures. If it is unable to, they should be farther out," API senior attorney Erik Milito said.

The document also provides guidance for placing personnel, Milito said. "The main thrust is to keep employees, contract workers, and temporary structures far from areas where their presence is not essential." ✦

NJ senators lead effort to keep acreage in OCS ban

Nick Snow
Washington Correspondent

New Jersey's two US senators led an effort to defeat an amendment proposed by Sen. John W. Warner (R-Va.) on June 14 that would have removed Outer Continental Shelf acreage off Virginia from a congressional oil and gas leasing ban.

During debate on the Senate majority's energy bill, Democrat Sens. Frank R. Lautenberg and Robert Menendez said they oppose oil and gas activity off Virginia's coast because it would be too close to New Jersey's shoreline resort areas.

"The scheme we defeated would not only pose short-term threats, but it could have led us down a slippery slope that ends in drilling up and down the East Coast," Menendez said following the defeat of Warner's amendment by 44 to 43 votes.

The amendment would have allowed each governor of the nine Atlantic Coast states from Maine to Florida to petition the US Interior secretary to begin gas leasing at least 50 miles beyond that state's coast. Other states' officials in the region would then have had the opportunity to respond.

Half of the revenues would have been deposited in the US Department of the Treasury. Of the remaining half, 75% would have gone to the state submitting the petition, 12.5% to the state through the Land and Water Conservation Fund, and 12.5% into a reserve to mitigate any environmental damage from exploration and development activities on the leases. A state would have had to previously pass legislation supporting oil and gas exploration and development off its coast before its governor could petition the Interior secretary under Warner's amendment. Warner also added a provision requiring the US Defense secretary's approval prior to leasing after Sen. Bill Nelson (D-Fla.) expressed concern that leasing could interfere with military activities.

Warner said Virginia approved legislation to authorize exploration off the state's coast, but not extraction of any resources. Consequently, he said his amendment would require passage of an additional bill to allow production before a state's governor could submit a petition to the Interior secretary.

"I once again note that this bill is natural gas only. There is no mention, no request for other products such as oil," Warner said.

Energy and Natural Resources

Committee Chairman Jeff Bingaman (D-NM) said drilling is not taking place off Virginia's coast not only because of the moratorium that Congress passes each year, but also because of a presidential withdrawal that remains in force.

Lautenberg said oil spills from production off Virginia's coast would still be possible despite leases being restricted to gas because oil almost always is discovered with gas. "So not only can natural gas have environmental problems, but drilling for natural gas can easily result in puncturing oil deposits and causing major spills," he said.

Governors from New Jersey, Connecticut, Delaware, and Maine have written letters to Congress urging it to not allow drilling off the East Coast, according to Lautenberg. "The energy we might be able to get there pales in comparison to the damage we could do to our coastlines in a very short time," he said.

Menendez initially offered an amendment that directly countered Warner's, and then one that required the Virginian's amendment to receive 60 votes for passage, which the Senate accepted. The Warner amendment was withdrawn after it was defeated ✦

US Senate rejects LNG siting change, passes OPEC measure

Nick Snow
Washington Correspondent

The US Senate rejected a proposal to give governors a final word in siting onshore LNG terminals but approved a measure authorizing the Department of Justice to prosecute members of the Organization of Petroleum Exporting Countries for violating US antitrust laws.

The proposals were offered June 19 as amendments to the Democratic leadership's energy legislative package that came to the floor earlier this month. Of the two, the LNG terminal siting amendment proposed by Sen. Benjamin L. Cardin (D-Md.) was more significant because it was the first effort to modify procedures established in the 2005 Energy Policy Act (EPACT). It failed by 53 to 37 votes.

The second amendment, so-called NOPEC (No Oil-Producing and Exporting Cartels), which passed by 73 to 20 votes, was similar to one the Senate passed in 2006 that did not survive in conference with the US House. Sen. Herb Kohl (D-Wis.), who sponsored the 2007 version, requested a roll call vote that he hoped would increase its stature. The House passed a similar bill by 345 to 72 votes on May 22, Cardin said.

Senate Energy and Natural Resources Committee leaders opposed both proposals. Chairman Jeff Bingaman (D-NM) and Chief Minority Member Pete V. Domenici (R-NM) said the LNG terminal siting plan would undermine EPACT and the NOPEC measure would violate the sovereign immunity principle and create other problems.

Cardin's proposal reflected concerns in Maryland and some other states that local and state officials don't have enough say in choosing where LNG terminals will be located. "This amendment is not about stopping LNG plants, but making sure they're located in the right places," he said.

Area of review

Cardin argued that the proposal would not affect the Federal Energy Regulatory Commission's authorization under EPACT to site onshore LNG terminals.

He said his proposal would amend Section 10 of the much-older Rivers and Harbors Act by adding a requirement for the Army Corps of Engineers to secure the approval of an affected state's governor before issuing permits to construct an LNG terminal.

"When we're talking about siting an LNG terminal, those who are the most affected—the state and the nearby communities—should have the most say," said Maryland's other senator, Democrat Barbara Mikulski.

Mikulski and Cardin said local concerns are being ignored as FERC considers a proposal for an LNG terminal at Sparrows Point, near Baltimore. Sen. Sheldon Whitehouse (D-RI) said his constituents are worried about the possible impact of a proposed LNG terminal in Fall River, Mass., on Narragansett Bay's recreation and environment.

Bingaman and Domenici maintained that giving a state's governor authority to veto any aspect of the LNG terminal permitting process would create delays as the US begins to compete more aggressively for overseas gas supplies. EPACT's provisions involve states and local communities during the National Environmental Policy Act review, when they can make their concerns known, Bingaman said.

He and Domenici also suggested that while supporting Kohl's NOPEC amendment probably would seem popular with voters back home who are frustrated over higher oil and gasoline prices, the measure simply was an empty gesture that lacks any legal foundation but could create serious problems.

Kohl, who chairs the Judiciary Committee's Antitrust, Competition Policy, and Consumer Rights Subcommittee, disagreed. He said the sovereign immunity doctrine makes an exception for commercial enterprises, and that there has not been any retaliation in other cases where DOJ has prosecuted cases against other foreign cartels. ✦

Senate Finance Committee proposes several new oil taxes

Nick Snow
Washington Correspondent

The US Senate Finance Committee proposed new taxes for the oil industry as offsets to incentives for alternative fuels and renewable energy research and development. The full Senate received the package in the early evening of June 19 as it continued debate on the Democratic leadership's energy legislation package.

The committee said its proposals included repealing the manufacturing deduction for major oil companies' domestic products, but leaving it intact for smaller independent producers. Petrochemicals, medicine, insecticides, and alcohols would be excluded. This would raise an estimated $9.433 billion over 10 years, the committee said.

It also proposed the following:

Eliminating the distinction between foreign oil and gas extraction income and foreign oil and gas related income (transportation and refining) by combining the two categories and applying the existing extraction income limitation to raise an estimated $3.187 billion over 10 years.

Extending the oil spill liability tax through Dec. 31, 2017; raising it to 10¢/bbl from 5¢/bbl; and repealing the requirement to suspend the tax when the unobligated balance exceeds $2.7 billion, which the committee said would raise $2.76 billion over 10 years.

Establishing a 13% excise tax on oil and gas produced from federal leases in the Gulf of Mexico, with credit allowed for royalties paid, to raise an estimated $10.684 billion over 10 years.

Taxing finished gasoline at the refinery gate or on its entry into the US as an import, and eliminating the bulk transfer exception, to raise an estimated $824 million over 10 years.

"These offsets make sensible improvements to the tax code, close loopholes, and reduce fuel fraud. And contrary to some criticisms, they should not reduce oil companies' incentives to produce energy," Finance Committee Chairman Max Baucus (D-Mont.) said.

But the American Petroleum Institute said the new taxes would increase US dependence on imported oil by discouraging new domestic production, discourage investments in new refinery capacity, and lead to the loss of US jobs. "A new 'severance tax' of up to 13% on production in the Gulf of Mexico, for example, would only serve to make these extremely expensive projects less competitive with foreign oil production," API said in a statement.

Meanwhile, the Senate Appropriations Committee inserted a requirement into the US Department of the Interior's fiscal 2008 budget for holders of deepwater Gulf of Mexico leases issued in 1998 and 1999 without price thresholds to renegotiate terms or be barred from future lease sales.

"For nearly a decade, an administrative error has allowed oil and gas companies to drill in federal waters for free. This has already cost taxpayers $1 billion and will cost billions more if we don't take action now," said the amendment's sponsor, Dianne Feinstein (D-Calif.).

Feinstein said the proposal in the Senate version of the Interior appropriations bill differs from a similar provision that passed the House by providing an exception for lessees who voluntarily agree to pay royalties on their 1998-99 leases. ✦

The US Bureau of Land Management authorized leasing and drilling of natural gas wells on part of the Roan Plateau, visible in the background. Photo from BLM Colorado.

IPAMS: Environmentalists nationwide target Roan Plateau

Paula Dittrick
Senior Staff Writer

Much of the opposition to drilling on part of the Roan Plateau in western Colorado comes from out-of-state environmental groups, said the Independent Petroleum Association of Mountain States (IPAMS) and the Colorado Oil & Gas Association (COGA).

The US Bureau of Land Management has authorized the drilling of up to 1,570 natural gas wells over 20 years on part of the Roan Plateau. The area involves federal land within the Piceance basin (OGJ, June 18, 2007, p. 31). The decision was issued by the Glenwood Springs, Colo., BLM field office.

US Rep. John Salazar, (D-Colo.), responded by saying he will try to get the House to amend the appropriations for the Department of the Interior. The measure would ban DOI spending on Roan Plateau leasing during the 2008 fiscal year.

Salazar said his decision stemmed from his constituents' opposition to drilling on top of the plateau. Salazar is working with US Rep. Mark Udall, (D-Colo.), who also wants to stop leasing of the Roan Plateau, sometimes called the Naval Oil Shale Reserve.

On June 13, IPAMS said most of the comments received by BLM against drilling on the Roan Plateau came from outside Colorado, with Colorado residents contributing 7% of the total.

BLM received 74,906 comments on the Roan Plateau resource management plan, and 73,166 were form letters, with 65,543 of them sent via e-mail.

"I believe that Congressman Salazar is trying to do the right thing for Colorado, but it seems he is being misled," said Marc W. Smith, IPAMS executive director. "There is no doubt that there are special interest groups who would like to stop all energy development in Colorado."

COGA Executive Vice-Pres. J. Greg Schnacke agreed that "the national environmental movement" is targeting the Roan Plateau. He said East Coast environmentalists frequently target the western US, including Colorado.

"The state of Colorado is going to be the loser [if drilling is blocked]. It's not like we're talking about a national monument," Schnacke said of the Roan Plateau. Wells already exist on private lands on the plateau outside BLM-administered lands atop Roan Plateau.

COGA estimates that the lease bonus payment alone could generate up to $1 billion the year the Roan is leased. In addition, the state could receive an estimated $166 million/year in royalties and production taxes.

BLM's decision authorizes a highly restrictive approach to development on top of the plateau. Development is to be conducted in a staged approach. The plan calls for no ground disturbance of 52% of the area and access restrictions on an additional 42%.

The plan also outlines clustered development and directional drilling from common well pads to reduce land disturbance. It calls for a density of four well pads/sq mile.

There is to be phased drilling in only one of six designated areas at any given time. No drilling would be allowed in sensitive valley bottoms. Trout habitat and scenic waterfalls are off limits to drilling activity.

Schnacke said the plan involves a development plan that would take decades, and he questions how attractive it will prove to be for gas producers.

"It's going to be a real challenge for some companies to be able to justify bidding on the projects," Schnacke said, adding that many producers will not want the "hassle" involved with the federally-administered Roan Plateau.

"There is development there now, but it's in areas not called the Roan Plateau. It's going to take decades to get the gas out of the Roan Plateau. It's ironic that an environmentally restrictive plan would force the industry to be up there longer than necessary," Schnacke said. ✦

California pushes EPA for waiver of Clean Air Act

Paula Dittrick
Senior Staff Writer

California Atty. Gen. Jerry Brown May 22 asked officials from the US Environmental Protection Agency for a wavier of the Clean Air Act (CAA) so that California and 11 other states could impose tougher standards on motor vehicle emissions than federal regulators require.

Following his testimony before an EPA panel in Washington, DC, Brown also testified on the same subject before the Senate Committee on Environment and Public Works.

Charging that the administration of President George W. Bush is "acting in collusion with the auto and oil industries," Brown said California is prepared to sue the federal government if it blocks the state's efforts to reduce motor vehicles emissions that contribute to greenhouse gases.

"The California legislature passed a greenhouse law in 2002 requiring automakers to reduce vehicle global warming emissions 30% by 2016," Brown said. "There is no doubt that automobile manufacturers can meet that goal, and since the federal government does not want to seek such a reduction, California intends to move forward."

He said 11 other states have adopted the California standard. Those states are Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington.

"Together we represent one third of the population of the United States, and the people of our 12 states want to act now to combat global warming. We are not willing to wait while President Bush offers only rhetoric, excuses, and delays," Brown said. "Suing the federal government is not our first choice, but we will have no choice if our legitimate efforts to protect our planet are blocked because of partisan political games in Washington."

California filed its request for an EPA waiver in December 2005. Under CAA, California can adopt stricter standards by requesting a waiver from EPA. Similar requests have been approved more than 50 times in the past, Brown said. Approval of California's waiver means the other states would get approval automatically.

It's "an unreasonable delay" that the waiver request has been pending for more than a year, said Brown. ✦

WCSB STRUCTURAL DOMAINS—4

Western Canada structured belt has myriad of drillable features

J.H.N. Wennekers
Consulting Geologist
Calgary

This last of four parts on the structured belt of the Western Canada Sedimentary basin describes in more detail the six structural domains and their exploration potential.

Liard/Mackenzie Fold Belt

The Liard/Mackenzie Gravity Slide Fold Belt is a regional Laramide gravity slide (Fig. 14).

It is characterized by a series of 100+ miles long and narrow anticlines and broad synclines, locally disrupted by strike-slip faulting. The slide butts against a NE-trending vertical basement strike-slip fault in NE BC and several vertical basement N-S strike-slip faults farther to the N in the Northwest Territories.

The present setting reflects the freezing of the main gravity slide, which while sliding contained several large anticlines and synclines that moved within the slide in the direction of its movement, much like ripples in a pond. The Beaver River, Kotaneelee, Pointed Mountain, Fort Liard, and P-66 anticlines contained 0.8 tcf of recoverable gas, some at 450°+ F. reservoir temperatures. Recently, liquids-rich gas was discovered in a fractured reservoir in an anticlinal core thrust structure in the N part of this fold belt.

In the northern portion of the region and extending N into the Yukon Territory and NWT, strike-slip in N-S direction over a width of some 100 miles produced E-W shortening and a regional N-trending structural depression in the filled-in Liard/Mackenzie basin.

A salt and shale layer, wet due to osmotic attraction of water, is present in the lower part of the basin's sedimentary section. It rests on Cambrian and Precambrian sedimentary strata. It is the sliding surface for the overlying sedimentary section that slid E from the W flanks of the depression into its deeper N-trending central portion.

Surface geology demonstrates these anticlines are complex and change along their axes into faulted homoclines and both high-angle and low-angle thrust-cored anticlines with rollovers above their core thrusts, changing to rollovers beneath the thrusts. Anticlinal core thrusts in this domain are small, both in dip and strike directions, when compared with the massive thrusts in the Thrust Domain farther S.

Frequently, core-thrusts experienced substantial subhorizontal slip. The S portion of the slide was disturbed by a large deep-seated basement strike-slip fault, which even today brings up very hot fluids. It dragged the E-moving gravity slide and bent the N-S anticlinal axes in a SW-NE direction and created four-way closed culminations, many of which contain economic gas accumulations in fractured Devonian Nahanni dolomite reservoirs, with numerous crystal-lined vugs, resulting from fractures and dissolution.

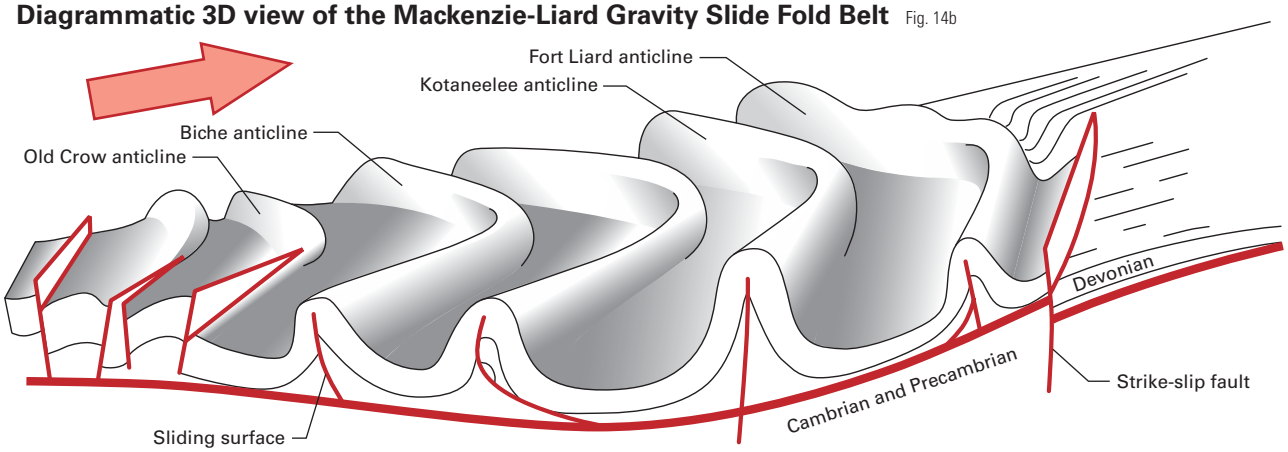
Higher topographic elevations in the W, E dip of strata, and associated strong E regional fresh ground water flow considerably have diminished the exploration potential of the Liard/Mackenzie Gravity Slide Fold Belt. Drilling should only be considered for structures with 1,500+ ft of vertical reservoir closure. Lesser closure means exploitation will soon have to deal with increasing production of formation water.

There might be an opportunity in exploring deeper targets: closures on extension fault blocks, strike-slip fault closures, and flower folds below the decollement in presalt strata. Surface structural geology and well data suggest the possible presence of many (50+) large anticlinal structures in Cambrian and Precambrian clastics of the "basement." It might be assumed the Precambrian section generates gas judging by the presence of giant gas fields in Precambrian strata in the NWT and Siberia.

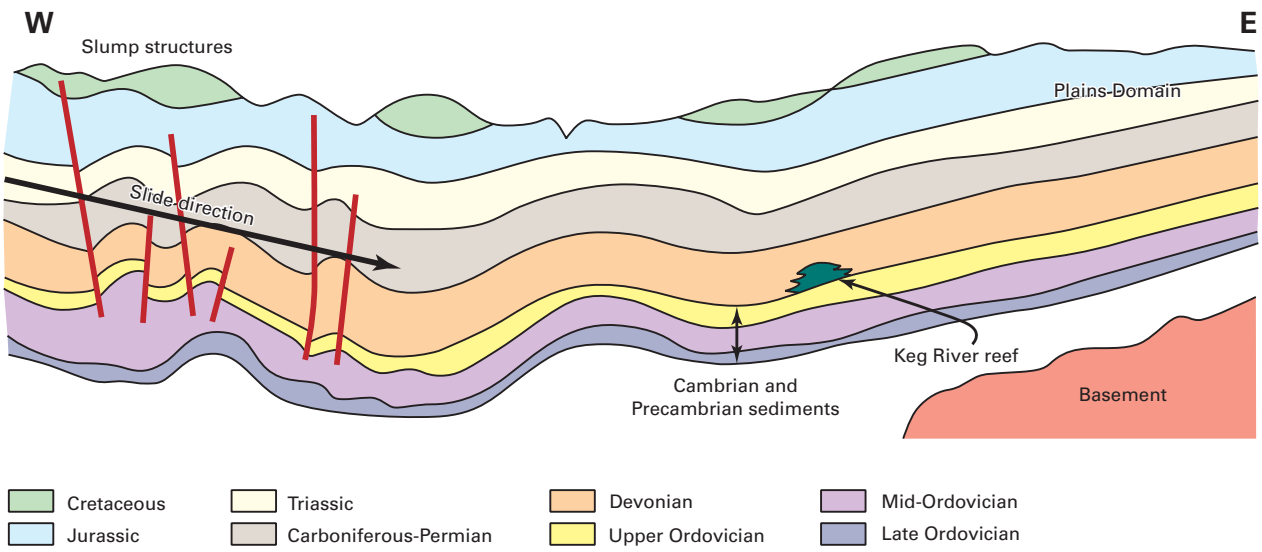
NORTHERN PORTION OF WESTERN CANADA STRUCTURED BELT

Fig. 14

Diagrammatic 3D view of the Mackenzie-Liard Gravity Slide Fold Belt Fig. 14b



Diagrammatic W-E cross section south of the Mackenzie-Liard Gravity Slide Fold Belt Fig. 14a



Thrust Domain

The Thrust Domain contains thrusts formed by E-directed subhorizontal transpression/compression/gravity sliding forces exerted upon a gently W-dipping regionally extensive sediment package, overlying a solid igneous and metamorphic basement—the Canadian Shield (Figs. 6 and 7). This domain is divided into three lesser domains: Main Range, Front Range, and Foothills.

Multiple thrusts formed and moved rock bodies E into the undisturbed section of sedimentary rocks overlying the basement. It was pushed E and overridden by the thrusts.

This dynamic process includes several massive rock ploughs pushing E. The Main Range pushed the Front Range, which in turn pushed the Foothills. The latter in turn pushed E evidenced by structures in the Triangle Zone and Imbricate domains.

The E blade edge of the Triangle Zone was the leading edge of all the E-pushing rock ploughs. It slid into the undisturbed Plains Domain, moving on the basement and underthrusting (wedging) the younger sedimentary section of the Plains Domain. In addition, the impact of regional shear (strike-slip domain) on the formation of structures was immense (seismic transects ST 1-15, Part 3 of this article).

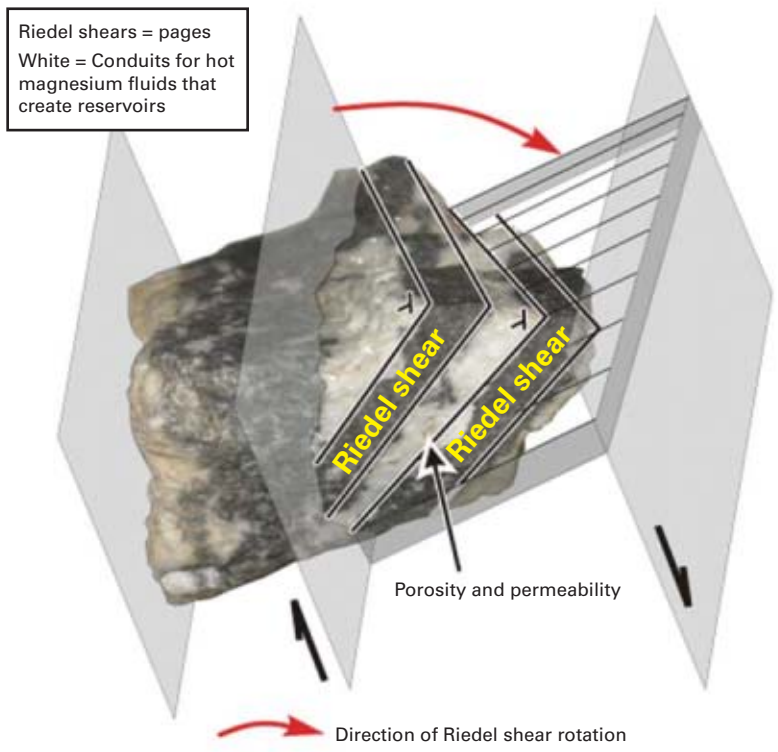
Main Range Domain

The W belt of the NW-trending Thrust Domain is the Main Range Domain (Figs. 6 and 7).

To the W, it borders the Rocky Mountain Trench. To the E it borders the Front Range Domain at the Pipestone Thrust. Many shingled parallel major thrusts are recognized in this domain, and these are thought to cut deep into the Precambrian sedimentary section. Little is known about the exact nature of these thrusts and their exploration

SHEAR OPENS ROCK LIKE A BOOK

Fig. 15



potential. With W-advancing exploration, this domain might become attractive as an exploration target.

Front Range Domain

The middle belt of the northwest-trending Thrust Domain is the Front Range Domain (Figs. 6 and 7).

To the W, it borders the Main Range Domain at the Pipestone Thrust. The McConnell Thrust separates this domain to the E from the Foothills Domain. Close to a dozen shingled parallel major thrusts are recognized in the Front Range. This domain is underexplored but supports numerous exploration targets: single and multistacked thrust sheet structures and such structures with stratigraphic anomalies.

Neither seismic acquisition nor drilling has advanced in this domain since accessibility is difficult and costly, distances are long to infrastructure, and risks are great. Despite all this, it is assumed that many undrilled structures await the drill bit.

Foothills Domain

The Foothills Domain is the E belt of the NW-trending Thrust Domain (Figs. 6 and 7—ST 1-14).

To the W, it borders the Front Range Domain at the McConnell Thrust. The Brazeau Thrust and sometimes subordinate thrusts separate this domain to the E from the Triangle Zone Domain. Up to five shingled parallel major thrusts are recognized in the Foothills Domain. It contains numerous local structures composed of multistacked thrust sheets with reservoirs that contain many gas fields.

Large parts of the Foothills Domain include up to six regionally extensive "horizontal detachment zones," mainly in shale sequences, >1/2 to 1 mile vertically apart. Two such surfaces enclose a rock body—the detached body. In total there are five such rock bodies: The Cambro-Ordovician, Silurian/Devonian, Mississippian, Permian, and Triassic rock bodies (ST 12 and 13) each >½ to 1 mile thick. A complex structured post-Triassic section (>2 miles thick) is present. These detachment zones correspond somewhat with regional unconformities, marking periods of major structural upheaval.

In map view, the Foothills Domain is bordered to the E by a narrow Triangle Zone Domain. Single and multiple thrust sheets and associated rollovers were main exploration targets since 1913. Success has been rewarding, and failure was inspiring to drill the next prospect.

In single thrust sheets the target is often a single rollover (broken through thrust-end-fold). In the multiple thrust sheet structures, multiple rollovers are the prime targets. Even with current advanced seismic acquisitions and processing, the transformation from seismic record to three-dimensional structures is difficult. Drilling results seldom accurately agree with deep-well prognosis.

Both size and shape of Foothills thrusts were determined by the lithological character and affected stratigraphic level. Majestic thrusts developed in a section composed of siliciclastics overlain by a massive carbonate section in turn overlain by siliciclastics, in the southernmost region. Numerous thrusts/imbricates formed where the main section affected is a siliciclastic one and overlies the carbonates. ST 6 depicts an imbricated (>15 imbricates/thrusts) Cretaceous section shortened by some 20 miles. It is a gravity slide that moved on a clastic ball-bearing layer on top of a gently dipping carbonate section. The latter was shortened only by 1 mile.

There is an abundance of single sheet and multiple thrust sheet exploration targets throughout the Foothills Domain. There is no absence of targets, but to highgrade and select the successful plays is one of the most difficult tasks in exploration. Numerous four-way closed thrust rollover structures, disharmonic thrust-related folds, and rollovers are present in Jurassic/Cretaceous and younger reservoirs (resource play), Triassic, Permian, Mississippian, deep

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Devonian, and possibly HPHT older reservoirs (classic foothills play), separated by regional detachment surfaces.

A little known fact is that many anticlines and four-way closed thrusted anticlines contain vertical shear zones perpendicular to their hingelines. These shear zones are the conduits for gas generated in the deeper parts of the structured belt in Ordovician to Precambrian strata.

Triangle Zone Domain

The Triangle Zone Domain includes a rock body of E-thrusted WCSB sedimentary section (Figs. 6 and 7).

It moved on top of the basement and underthrusted the younger sedimentary section of the Imbricate Domain. The domain resembles a rock plough that overrode the deeper section and pushed the shallower section out of its way, upward and possibly over its top.

At the surface this domain is narrow, but it widens with increasing depth as shown on two-way time seismic transects from S to N (ST 1-3, 5-7, 9-14). There is a complex structural and spatial relationship between this domain and the Foothills and Imbricate domains.

Inside the Triangle Zone its leading edge thrust and large Foothills domain thrusts are cut off by the bounding underthrust of the Imbricate Domain. This demonstrates the dynamic nature of this "rock plough." In the S, the domain includes large thrusts that incorporate Mississippian (ST 3—billion-barrel Turner Valley field) and Devonian carbonate sections. Farther N, it includes folded age-equivalent carbonates, albeit much thinner, and folded Permian and Triassic carbonates separated by substantial shale sections, and several regional detachment zones (ST 12-13).

High-density thrusting gradually gives way to undulating folds with decreasing amplitude in the E direction. Eventually and farther E, the low-amplitude folds merge with the gently westerly dipping sedimentary section of the Plains Domain. When the rock plough stopped moving and froze in place, its leading edge E upward-cutting thrust also froze in place. This thrust cuts at a low angle forward and upward into the younger overlying section.

In the Turner Valley field area, the Triangle Zone Domain includes a large thrust with a rollover that contains giant Turner Valley field (ST 3), where gas was flared for many decades, decreasing the oil recovery factor. It might be a thought to inject carbon dioxide from the Kevin-Sunburst Dome in Montana to energize the oil.

Exploration in this domain will concentrate on major thrust rollovers, strike-slip fault closures, flower structures, microshear faulted carbonate reservoirs that are thrusted, rolled over, and flower folded, and much deformed and sheared sections butting against the bounding underthrust fault plane.

Strike-Slip Domain

The Strike-Slip Domain is a wide belt characterized by numerous strike-slip faults and associated structures (Figs. 6 and 7).

Historically, strike-slip faults were not recognized and this belt was included in the Plains Domain. It contains many folds that gave rise to the term "Outer Foothills." Eventually, strike-slip faults and associated flower structures were recognized and the name "Strike-Slip Domain" was born (this article). This domain is divided into a north-south domain and a NW-SE domain. The latter also includes many NE-SW and some E-W strike-slip faults.

Strike-slip faults (Fig. 10) are abundant in this belt, which extends to the W and dives beneath the Rocky Mountain thrust belt. With increasing depth of the basement, however, high pressures and high temperatures are present, and the basement rock does not fault under shear stress but instead plastically deforms (Fig. 5).

The domain (ST 4-15) includes a) numerous parallel trending vertical to subvertical deep-seated dextral strike-slip faults (Type I) and associated negative and positive flower folds, b) many dextral strike-slip faults (Type Ia) and associated positive and negative flower folds, striking parallel to a) and confined to the thickened sedimentary section and not penetrating the basement, and c) a body of structurally thickened sedimentary intervals (ST 10), containing vertical faults, between which strata were squeezed (thinned), and positive and negative squeeze folds formed at the shallow end and deep ends of these faults, respectively. The domain includes the vertical Bovie, Liard, Ferrier (ST 8), Okotoks, Pine River, and many other strike-slip faults ranging in length from several miles to over 100 miles.

The strike-slip domain experienced little movement in its easternmost region (ST 1, 6-9, and 14), where it is anchored to the massive Canadian Shield. S to N movements progressively increased going from E to W through the domain. Farther W, SE-to-NW movements increased.

The combined subhorizontal S-to-N and SE-to-NW slips along these faults are estimated to be in the tenths of miles in the basement. W-to-E shortening due to shear of the domain might be calculated in miles. It is important to note that the effect of strike-slip movement in the basement on the overlying sedimentary cover is determined by the thickness of that cover and the type of sediments included in that cover.

The Strike-Slip Domain comes in from beneath the Liard/Mackenzie Gravity Slide Fold Belt in the N and extends some 1,000 miles to the US border in the S. It cuts SE across the W portion of the Plains Domain and runs parallel to the Imbricate Domain. Farther S, it cuts through the Imbricate Domain and at a low angle intersects the Triangle Zone Domain.

From there, it cuts into the Foothills Domain just W of Calgary and continues S underneath and past Turner Valley and Waterton fields. Then it turns SE and extends into the US. Strike-slip faults had a very important function in the initiation and formation of thrust ramps throughout the region (ST 2-4, 6, and 12-14).

A combination of complex strike-slip and Triangle Zone structures (ST 5) is

evident 30 km NW of Calgary. From there, the strike-slip strike changes to S and just W of the city was instrumental in determining ramping and degrees of rollover in shingled thrusts that contain Sarcee gas field (100 bcf). Continuing S, it "dives" beneath giant Turner Valley field and onward to the US border.

Turner Valley field resulted from a combination of N-S and SE-NW dextral strike-slip movements and simultaneous E-directed compression. The latter created a thrust-end fold, up against a dextral strike-slip fault block, that subsequently broke through and ramped up to create the Turner Valley thrust and four-way closed rollover (ST 3).

In the S and W parts of the disturbed belt, the E-thrusted thick overlying sedimentary cover prevented strike-slip faults from penetrating upward from the basement into and through that sedimentary section. Instead, many vertical shear zones are present, and these are observable on seismic sections and in the field. These shear zones do not contain an actual strike-slip fault but instead are zones in which shear was intense.

Such shear zones are present, although most often not recognized, in many NW-SE trending thrusts and enhance reservoir characteristics through intense shear microfaulting (fracturing). Not recognizing the existence of these shear zones, including strike-slip faults, puts in doubt the validity of many structural contour maps of thrust sheets.

In some instances, reservoirs have 1% original porosity and no permeability. Strike-slip shearing zones created substantial fracture numbers and permeability and some wells have produced over 290 bcf from such reservoirs (Waterton field).

The N-S Okotoks field is a closure against a large strike-slip fault. Its main reservoir is in dolomites of the Devonian Wabamun formation, which, undeformed, contains many irregular globules of anhydrite and little porosity and permeability. The high E side of the fault contains a narrow, elongated fault closure in which dolomite is heavily shear-fractured, contains crystal-lined dissolution vugs (leached fractured anhydrite globules), numerous fractures, and a permeability of up to 7 darcies. Farther E, the undeformed formation has little porosity and no fractures.

The most interesting aspect of the western strip of the Strike-Slip Domain is that dextral movement along many of the faults was simultaneous with E thrusting of the sedimentary section, starting in the Thrust Domain and continuing into the Triangle Zone Domain. The combined E-W and N-S movements resulted in many rather complex structures in the sedimentary section. All these structures, even negative/synclinal flower structures, are exploration targets.

Numerous strike-slip faults were cut off from their basement roots, during continued eastward thrusting, but when thrusting slowed, continued movement along the strike-slip faults in the basement penetrated upward and formed new strike-slip faults, flower structures, and strike-slip shear envelopes in the overlying sedimentary section.

In the Deep Basin, a common structure was formed when an E-moving thrust (sometimes a subhorizontal shear plane) with rollover encountered an active dextral N-S or NW-SE strike-slip fault. The collision sheared the E limb of the rollover against the vertical strike-slip fault and a vertical E limb (box fold) resulted.

Most expressions of strike-slip faulting and folding are in the subsurface; however, in some areas, imbricates associated with strike-slip faulting are present but are mapped as parallel thrusts. Their strike-slip provenance was not recognized. Few structural geologists have field-mapped strike-slip structures, including "fractures," in the subject region.

The most common fractures and fracture patterns investigated in the field are associated with thrusting in the Thrust, Triangle Zone, and Imbricate domains. Therefore, analyses and interpretations of shear "fractures" in cores or deduced from seismic interpretations should be handled with great care pending the strike-slip experience of the interpreter. Structures associated with strike-slip faulting were recognized some 35 years ago by the author in the WCSB.

A decade ago, the author field-mapped the classical N-trending Toumarolin strike-slip fault where it shears through the W flank of the Murzuk basin in southwestern Libya. This fault is well exposed for many miles in a desert terrain nearly void of vegetation. It cuts through a flat-lying sedimentary package resting on a gently E-dipping crystalline basement.

E-W seismic transects show the fault to evolve into a classical flower structure, where the sedimentary package reaches a thickness of 3-4 km. The two strike-slip faults that bound that flower fold do not reach the surface. Fault plane, fault zone, bed dips, micro to macro shear faults, and associated en-echelon complementary fault and associated fold structures, including "imbricates" with structural closures at low angles to the fault plane, were mapped in the field and are reference material for the current structural assessment.

In the Plains Domain, several similar large classical strike-slip structures are seismically documented well beyond the eastern boundary of the Strike-Slip Domain proper. In some areas, vertical shear movements resulted not in the formation in faults but gentle folds and imbricates (ST 1-7).

Exploration in this domain will focus on recognition of the strike-slip structures, amplitude anomalies associated with geothermal dolomitization in limestone, and both carbonate and siliciclastic reservoirs in flower structures.

The Deep Basin portion of this domain is a prolific exploration region. Additional targets, both stratigraphic and structural might be found in deeper Cambrian and Precambrian clastics truncated by an angular unconformity and underlying the younger WCSB section.

Imbricate Domain

The Imbricate Domain includes most of the shallower sedimentary section that overlies the Triangle Zone Domain (Figs. 6 and 7 and many STs).

While moving east, the Triangle Zone "rock plough" underthrusted the Imbricate Domain, lifted it, and in places turned beds to vertical at the bounding thrust. This domain is bounded by a large thrust (ST 1). It is cut from below by the leading edge thrust of the Triangle Zone. It is the last one in a series of many that developed in parallel fashion, stepping forward, and that were sequentially cut off by the underthrust when the rock plough moved E. Remnants of earlier leading edge thrusts are shown on ST 1.

The rock body of the Imbricate Domain includes many smaller thrusts/imbricates that trend parallel with the first bounding thrust and dip easterly. These imbricates have W-directed rollovers, a direction opposite that of the major thrusts in the Thrust Domain. The combination of thrusts, imbricates, the series of cutoff leading edge thrusts demonstrate the dynamic underthrusting nature of the rock plough (Triangle Zone Domain) and the Imbricate Domain.

Exploration in this domain will concentrate on more precisely defining the structural framework of this domain and the role of structure in combination with the more than 30 regional Plains exploration plays advancing into the zone from the E. Furthermore, the Late Jurassic/Cretaceous and younger resource plays require immediate attention. Large bodies of rock butt against the underthrust probably are severely fractured and might contain exploitable natural gas.

Plains Domain

This domain includes the "undisturbed" gently-dipping sedimentary Precambrian to Tertiary section of the WCSB that rests on igneous and metamorphic rocks of the Canadian Shield (Figs. 6 and 7 and ST 1-14).

This section extends from outcrops of the shield in the east and "dives" beneath the first main thrusts of the Foothills in the W. Historically it supported intense and successful exploration. Current drilling activity demonstrates exploration of the Plains Domain continues unabated.

Numerous play types are augmented by many unconformities, providing a wide array of traps for hydrocarbons. The unconformities correspond with a series of worldwide mountain-building episodes and continental drifting events, of which the most striking is the one that occurred at the end of the Cretaceous epoch some 60 million years ago.

More than 30 regional oil and gas exploration plays extend W from the undisturbed Plains Domain. The first addition of structure to a portion of these regional exploration plays is in the Strike-Slip Domain. This resulted in discovery of 8+ tcf of gas in place to date.

Numerous plays await the drill bit and will sharply increase the overall undiscovered gas volumes. Faults in this domain had a great impact on the formation of gentle structures (traps) and acted as conduits for high-pressured hot fluids to facilitate reservoir enhancement through dolomitization.

Future exploration will have to increasingly concentrate on the relationship between structure and stratigraphy. Successful exploration of the 30+ stratigraphic plays in the structured belt will be taxing for the oil and gas industry as it requires an understanding of the complex combinations of structure and such plays.

Acknowledgments

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References

A list of references is available from the author.

Rwanda

The Ministry of State granted Vangold Resources Ltd., Vancouver, BC, the nonexclusive right to undertake an 18-month technical review of oil and gas potential on 7,208 sq km in northwestern Rwanda.

The company's interest what it calls the White Elephant concession covering 11% of the country stems from the possibility that the geology that supports major oil discoveries near Lake Albert 230 miles to the north in Uganda might extend into Rwanda.

Arizona

Enhanced Oil Resources Inc., Houston, formerly Ridgeway Petroleum Corp., said its 11-06-31 well in Apache County flow tested a fractured basement zone for nearly 60 days at 245 Mcfd of carbon dioxide, 1% helium, without water or decline in flowing pressure or production rate.

The company said its 12-well drilling program has protected all 11 of the high-priority leases in Arizona that had been due to expire in February and April 2007 (OGJ, May 28, 2007, p. 41).

Various technologies unlock Pinedale anticline tight gas

Guntis Moritis
Production Editor

Various technologies have enabled Shell Exploration & Production Co. to produce economically from the tight gas sands found in the Pinedale anticline of Western Wyoming.

These technologies include optimally staged hydraulic fracturing, innovative pressure-acquisition modules with gauges and perforating guns mounted outside the casing, wireless transmission of downhole pressure data through the casing, fiberoptic distributed temperature sensing, development of complex 3D static and dynamic models, and microseismic mapping of hydraulic fractures.

"From a technology perspective, Pinedale has been our arena to test and develop new technologies to increase recoveries in these difficult reservoirs," said John Bickley, team leader, Shell EP Americas Tight Gas Task Force.

"Having a working relationship with the asset allows us to easily apply technologies we develop in the lab to real-world conditions in the field. We have pushed the application of existing technologies and tried new ones. By integrating the results of all these efforts, we have met our objectives to reduce costs, add production, and increase our scope for recovery at Pinedale in an environmentally responsible way."

Shell expects these lessons from Pinedale will apply to other, unconventional gas reservoirs.

Pinedale anticline

The Pinedale anticline (Fig. 1) is a northwest-southeast trending, doubly plunging, asymmetric anticline covering 150 sq miles (35 miles long and 6 miles wide). The reservoir section has 6,000 ft of highly discontinuous fluvial sandstones, siltstones, and shales from the upper Cretaceous age Lance-Mesaverde interval.

Producing intervals lie at 7,000-14,000 ft depths and contain 300-1,300 ft of potential pay. The produced gas is mostly methane with few impurities and an average heat content of 1,080 btu/Mscf.

California Co. drilled the first well at Pinedale in 1939, but active field development did not proceed until mid to late 1990s as improved hydraulic fracturing techniques, higher natural gas prices, and commingled production operations enabled economic stimulation and production from tight gas sands.

Nearby Jonah field to the southwest, containing a similar section of tight sands, was the first to see active development.

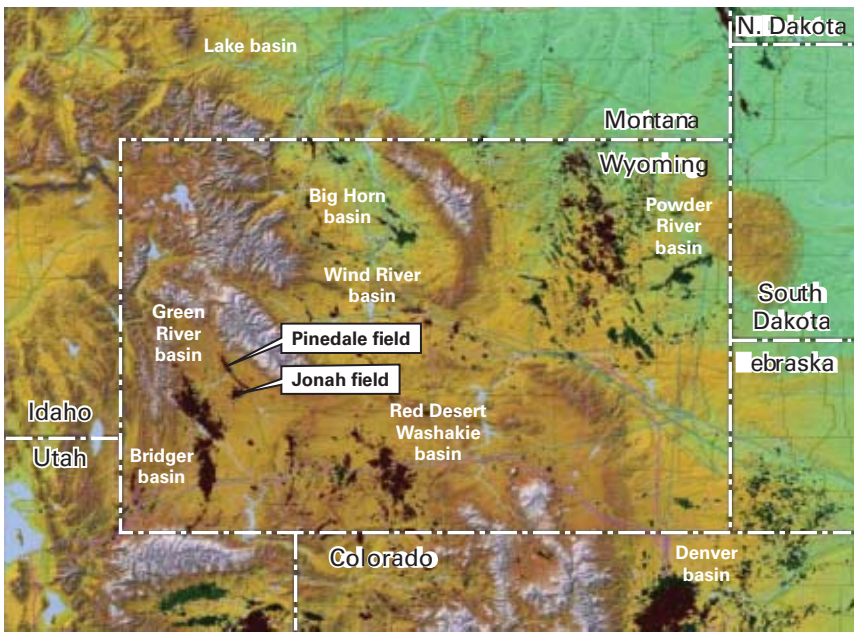
Shell began operations at Pinedale in 2001 and is one of the three main acreage holders in the field, holding about a 25% working interest. The two other companies with sizable acreage positions are Ultra Petroleum Corp. and Questar Corp.

Shell says its reentry into the Rocky Mountain area was part of the company's global strategic goal to expand its exposure to North America gas.

The area has huge gas resources: The US Geological Survey has reported that Pinedale contains 159 tcf of gas in place but requires application of both existing and new technologies in drilling and

PINEDALE

Fig. 1



Drilling and completion restrictions at Pinedale protect wildlife migration and winter habitats (Fig. 2). Photo from Shell.

completion operations to produce the gas economically.

Shell formed an internal Tight Gas Task Force (TGTF), a team of technical experts for identifying existing and developing new technologies for producing the gas from Pinedale. Shell says that although it had previous experience in developing tight gas fields in South Texas and Michigan, it knew little about the reservoir characteristics at Pinedale, which has a wide variability in drilling conditions and geology, as well as environmental restrictions that limit development operations for part of the year.

Drilling and completion restrictions exist year round on portions of Pinedale, and the Big Game Range winter restrictions for protecting wildlife migration and winter habitat currently shut down all drilling and completion activities for the northern two thirds of the anticline from November through May (Fig. 2).

Unraveling Pinedale

To determine the best development strategy for Pinedale, Shell undertook a major data-acquisition effort, performed special core analysis, and used experimental logging tools to predict gas volumes in place and understand well productivity. The Pinedale asset drilling team tested various drilling techniques, including use of skid rigs, underbalanced drilling techniques, slim-hole casing, and a variety of drill bits.

Shell says these modifications have reduced drilling cycle time and costs. The time to drill an average well decreased to 35 days in 2006 from 65 days in 2002, with 25 days being the best performance to date.

On the geophysical side, Shell's team experimented with reprocessing of seismic data and studied natural fractures and outcrops to understand the stress history of the anticline. It also drilled a horizontal well to characterize the natural fracture network.

Shell said the well demonstrated that natural fractures occur throughout the anticline, but in general, it does not believe that natural fractures represent a critical component of reservoir productivity.

Hydraulic fracturing

Massive hydraulic fracturing of the low-permeability reservoirs at Pinedale

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Well spacing at Pinedale ranges from 40 to 5 acres, with many wells drilled deviated from well pads that accommodate multiple wellheads and minimize the drilling and production footprint (Fig. 3). Photo from Shell.

has enabled operators to produced gas from the reservoirs more efficiently.

Shell says staged hydraulic fracturing increased stimulation efficiency and was one of the first opportunities identified by its task force. Stimulation efficiency is a measure of reservoir height contributing to production relative to the total targeted reservoir height completed. A higher stimulation efficiency will recover more reserves.

In stacked multiple-interval sands, Shell says companies had historically tried to stimulate too much of the vertical interval with a single-stage fracturing job. It, therefore, implemented a program with more stimulation stages per well. This raised completion costs but ultimately will increase stimulation efficiency and reserves recovery, the company said.

Shell describes that in its operations a typical fracture stimulation will include proppant from the 10s to the 100s of thousand lb. It uses both sand and ceramic proppant and places it several 100 ft from the wellbore.

The stimulation jobs include an external casing and perforating technique, EXcape, in which perforating guns are run external to the casing and the firing heads are actuated hydraulically to stimulate more of the pay and improve operational efficiencies. The Excape system developed by Marathon Oil Co., BJ Services Co., and Expro Group also has been effective for stimulating other tight gas sands such as in Alaska (OGJ, Sept. 2, 2002, p. 39) and Canada (OGJ, Oct. 25, 1999, p. 69).

Shell says stimulation designs at Pinedale have evolved to optimize interval staging, proppant types, proppant volumes, and transport fluids.

Completion operations also continue to change. Shell has accelerated cycle times from single-stage treatments and cleanup of 2 weeks duration/stage to 24 continuous completion operations with up to eight stages/day.

In drilling out frac-stage isolation plugs, it has changed the procedures from flaring gas volumes during rig-assisted snubbing operations to flareless, single-trip coiled tubing operations.

Another technology used by Shell is microseismic diagnostic monitoring that reveals the azmuthal orientation and created geometries of hydraulically induced fractures. The technology provides a better understanding of the effectiveness and efficiencies of the fracturing operations and helps optimize well drainage.

Shell says these data are critical for calibrating hydraulic fracture design models and static and dynamic reservoir models. These microseismic fracture maps provide an indication of remaining undrained areas that can be targets in with future drilling.

Data gathering, evaluation

One technology Shell employs at Pinedale is multiple-gauge wireless telemetry. The Cableless Telemetry System (CaTS) was sponsored by Shell and developed by the Expro Group (OGJ, Feb. 21, 2005, p. 41).

This technology uses the casing as the conductor for transmitting downhole pressure and temperature data, eliminating the need of running a separate conductor line in the well.

Shell has installed CaTS in either dedicated monitor wells or wells with the dual purpose of monitoring the completed intervals and producing from them.

The system provides formation pressure and temperatures at multiple depths, measures initial reservoir pressures in isolated reservoir intervals, provides depletion pressures of reservoirs completed and produced in the

monitor well, and indicates pressure communication and decline trends in reservoirs in communication with offset producing well.

Shell uses these measurements to assess well drainage areas and to optimize well pattern and spacing between development wells.

Most fluvial tight gas fields in the area begin with a 40-acre subsurface well spacing and subsequently, companies downspace the fields to 20, 10, or even 5-acre spacing. Greater well spacing reduces development costs because fewer wells are required but may not adequately deplete the field.

Shell notes that optimal well spacing eliminates the risks of drilling through depleted zones, avoids in-fill well placement problems, preserves the desired well pattern and interwell spacing, and maximizes capital efficiency of total completion costs.

The permeability of the sands at Pinedale is in the 5-10 µdarcy range, making it difficult and time consuming to acquire reliable pressure data. Shell says only after installing the long-term monitoring systems that it realized that after drilling, a well required 20-300 days to return to the original pressure.

The CaTS system also provided Shell with the first pressure profile as a function of depth in Pinedale. In addition to installing gauges in dedicated monitor wells, Shell worked with the Expro Group to develop both wireless and wired instrumentation systems external to the casing to enable pressure monitoring of the entire vertical reservoir interval, without compromising the integrity of the casing.

Shell says these technologies allow it to monitor reservoir pressures for a desired period of time and then complete the well for production with selective hydraulic fracture stimulations following the data-acquisition period.

A well in Pinedale may have 20-70 individual sands in a 7,000-14,000-ft interval, and Shell says pressure data are the only data that enable calibration of static and dynamic reservoir models. Pressure gradients in the anticline range from 0.43 psi/ft (normal hydrostatic) at the top of the producing section to 0.8 psi/ft at TD.

This single-well producing facility includes the wellhead in the foreground, with surface flowlines to an environmentally protected production building containing a heater and separator. In the far background is the electronic data gathering and transmission building. The three tanks, on the right, store condensate and water (Fig. 4). Photo from Shell.

Shell installed a world record of 44 individual external pressure-temperature modules in two wells over a 12-day period during the summer of 2006, bringing the total number of pressure gauges installed in monitor wells to 115 across the field during the past 2 years.

Shell says pressure tests show how the sands produce, how many wells are needed, and how to space them. Well spacing affects profitability and depends on where the wells are located on the anticline.

Data from pressure data provide the basis for understanding well performance and recovery efficiencies at Pinedale. Using the pressure information, Shell develops and calibrates 3D static and dynamic models to determine reservoir sand connectivity and drainage of individual wells to design further field development. These data show how pressure declines over time and when matched against complex reservoir models provide values for porosity, connectivity, and permeability.

Shell also employs fiber-optic distributed temperature sensing technology to measure temperature profiles across the massive, commingled production interval. The temperature change shows the movement of the gas within the wellbore. As gas enters the wellbore, it expands and cools, whereas water or condensate expands and becomes warmer. These temperature changes allow one to calculate gas flow rate from various intervals.

By continuously monitoring temperatures in the wellbore over the full reservoir life cycle, Shell can further develop and calibrate 3D models for the field. Operators currently are developing the field on 20 and 10-acre spacing, with 5-acre spacing being evaluated in certain areas.

Shell's asset team and task force also are working on production data analysis

for commingled production from the wellbore by running multiple production logs over time. From these data, the teams can evaluate and discriminate reservoir permeabilities and fracture characteristics, as well as to develop models for characterizing the drainage area.

Shell says these data enable better calibration of the static and dynamic models and provide information on how much gas a well will deliver in a 30-year life and the amount of reserves that can be booked.

Further development

Shell expects to drill thousands of wells to develop this field. Many of Shell's wells are drilled deviated from a single well pad to minimize the drilling and production operation footprint, although some wellsites have only single wells (Fig. 4).

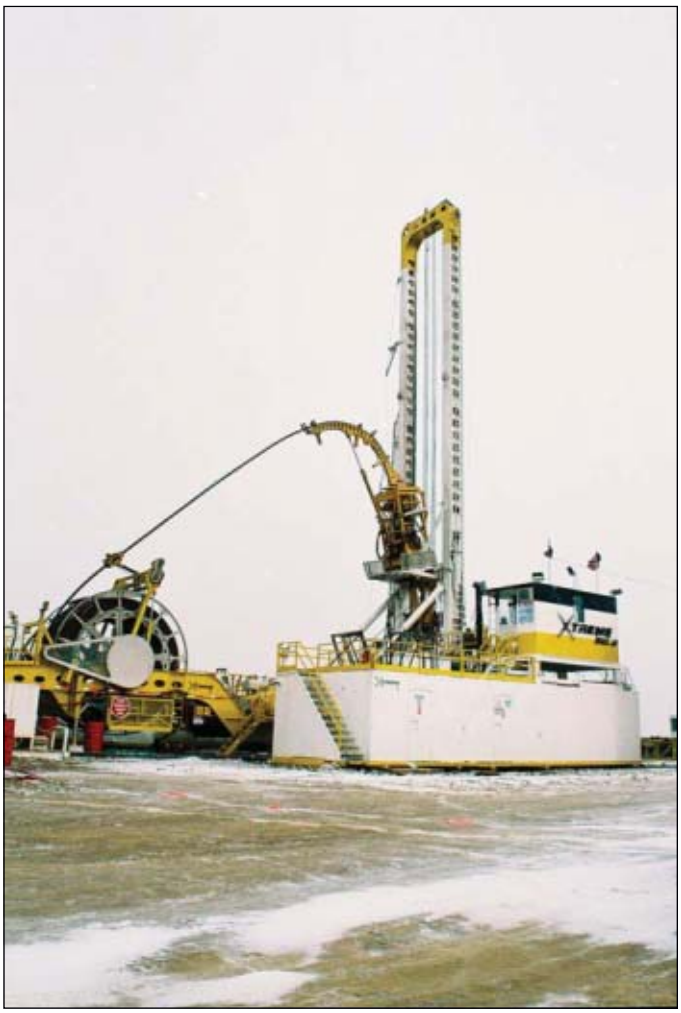
By yearend 2006, Shell had participated in drilling more than 260 wells and says its optimization exercise provided a huge savings while capturing economic incremental reserve volumes.

For 2007 and 2008, Shell says its task force is working with selected technology innovations to lead the development of new artificial-lift pump technology to unload liquids from the wellbore and improve outflow performance to ensure maximum recovery from the field.

Shell says application of various technologies at Pinedale has had the following results:

- Its total gross production reached 300 MMscfd by yearend 2005, and the latest yearly figure available, with 2006 and 2007 expected to show increases.
- Completions that once took more than 6 months now typically take 7-10 days.
- Its drilling time averages 39 days/well, considerably less than the nearest competitor.
- Its recoverable natural gas resources in Pinedale field have increased markedly. ✦

New, larger bore CT drilling beyond 7,000 ft



Xtreme's CT Rig 2, model 200ST, was drilling near Rock Springs, Wyo., in late 2006 for Shell Unconventional Resources (Fig. 1; photo from Tenaris Coiled Tubes and Xtreme Coil Drilling Corp.).

New coiled-tubing rigs are drilling to record depths, with larger diameter strings and top drives capable of holding 200,000-lb hook loads.

Tenaris Coiled Tubes and Xtreme Coil Drilling Corp. are working together on a project that is extending the limits of coiled-tubing drilling technology. Tenaris explains this pioneer effort to use deep coil drilling in the US Rocky Mountains (Figs. 1, 2).

Calgary-based Xtreme is a specialized coiled-tubing services company with a new coil-over top-drive (COTD) rig design (OGJ Sept 18, 2006, p. 48). The company has been using its new rigs to drill shallow wells in the aging, marginally economic, shallow oil fields of Colorado's Denver-Julesburg basin (OGJ, Dec. 18, 2006, p. 37).

Xtreme is pioneering the use of coiled tubing (CT) in downhole drilling applications to 10,000 ft, a depth that is 3,000 ft beyond coiled tubing's 7,000-ft historical technical drilling limit. As part of that project, Xtreme asked Tenaris Coiled Tubes, a manufacturer of coiled tubing, to produce the first strings of CT to support the project. Ultimately, that request required Tenaris to develop new 3½-in. OD tubing capable of drilling a 10,000 ft well.

Rough beginning

As an oil and gas technology, coiled tubing seems too good to be true. It is surprisingly simple and straightforward in its application on oil and gas wells, can be used for a wide range of tasks and, due to its operational efficiency, reduces overall well costs.

Yet, despite all of its advantages, CT was not always so highly regarded. For years, operators would only consent to using it for specialty jobs such as washing out sand, retrieving subsurface safety valves, and lifting fluids from wells using nitrogen. This was due to the fact that during its early period of

development it was plagued by safety and reliability issues because of its inability to withstand the repeated bending cycles and high tensile loads encountered during jobs.

Low yield-strength steels and the butt welds necessary to make the continuous tubing strings often failed, sometimes with catastrophic consequences. Equipment failures and lost tubing that required expensive fishing expeditions tarnished CT's reputation. Over time, operators simply lost confidence in the technology.

Xtreme's CT Rig 4, model 200DT, was drilling in the Denver-Julesburg basin near Greeley, Colo., in January 2007 for Anadarko Petroleum (Fig. 2; photo from Tenaris and Xtreme Coil Drilling).

In the late 1970s and early 1980s, improved manufacturing techniques allowed the tubing to be formed from much longer sheets of steel. This effectively reduced the quantity of required welds by at least half, according to Tenaris. Later, new developments in welding methods allowed butt welds to be entirely eliminated. Improvements in the quality of the steels used to make the tubing were also introduced, and a better understanding of CT fatigue enabled significant advancements in reliability and performance.1

The early 1990s brought a renaissance in CT technology and soon it was being applied to an expanding list of tasks that included acid and fracturing treatments, tool conveyance, drilling, artificial lift, well completions, and logging.

Xtreme said that continuing technology challenges include the slightly higher cost of coil rigs, shorter life cycle of coil tubing over conventional drill pipe, difficulty in fishing CT, and directional drilling with CT.

Xtreme began a joint venture with Shell Technology Ventures BV in December 2006—Coil-X Drilling Systems Corp. Coil-X is a private company (51% Xtreme, 49% Shell), which will address existing technology challenges of coiled tubing and expand the use of Xtreme's COTD design for conventional and unconventional resource exploration, according to Xtreme's April 2007 corporate update.

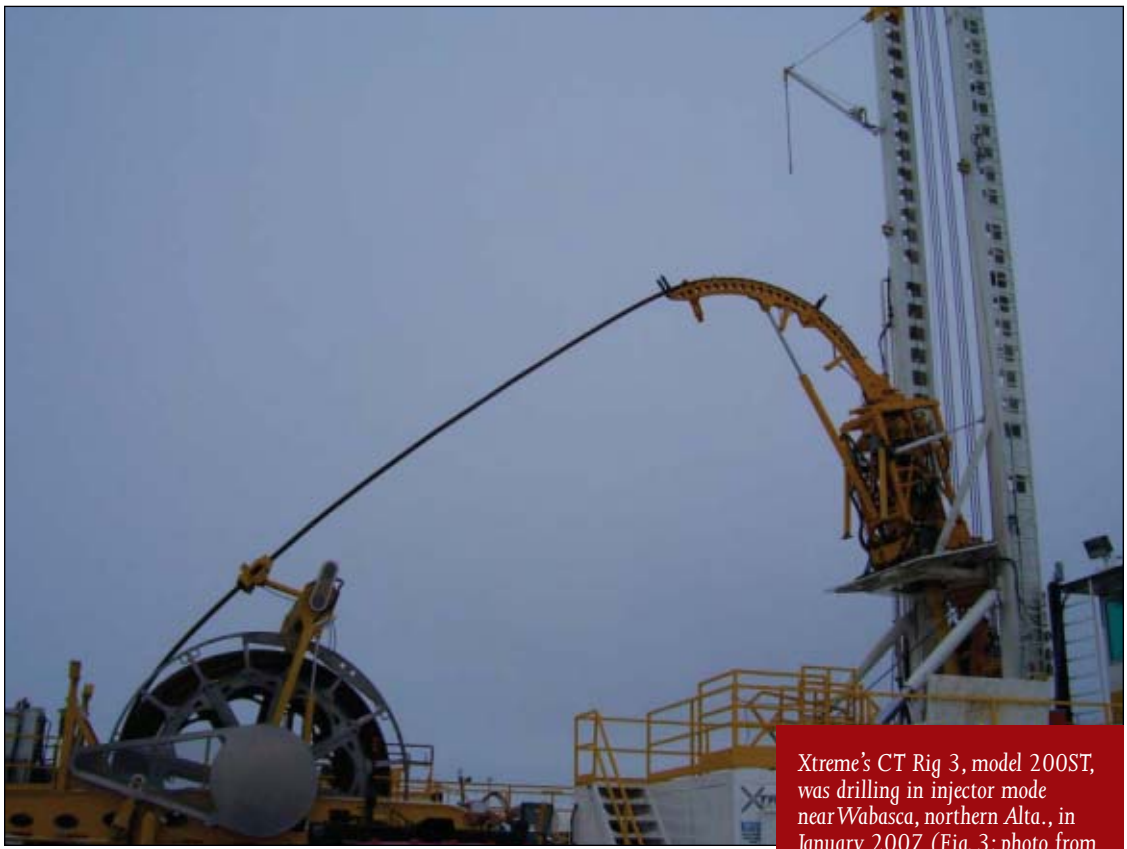
CT moves offshore

It was during the late 1990s that the CT technology movement turned toward offshore. The issues facing coiled-tubing technology offshore were much greater, however, and more complicated than those encountered on land. Among the numerous issues that offshore coiled-tubing operations had to overcome was an aging fleet of offshore platforms, extremely heavy CT equipment, platform space issues, on site CT welds on platforms, and the vertical or lateral movement of the platform rig when the CT is deployed from a floating facility.

A loaded reel is by far the heaviest single component of a coiled-tubing system. Existing platforms and cranes, whose lifting limits had been downgraded over time due to their ages, posed an obstacle for moving CT offshore because the coiled-tubing reels were too heavy and the power pack and control cabin footprints were too large for them.

Even in deep water, where very large floating platforms and cranes are rated to lift more weight than that of the largest coiled-tubing systems, limited available space remained a formidable obstacle for operators interested in using CT.

Also, using CT offshore often required welding operations due to



Xtreme's CT Rig 3, model 200ST, was drilling in injector mode near Wabasca, northern Alta., in January 2007 (Fig. 3; photo from Tenaris and Xtreme Coil Drilling).

weight restrictions. The preferred approach at the time was to take the coil offshore in two or three pieces and weld them together on the platform. This was expensive and time consuming.

Welding specialists were required to set up the operation. In most jurisdictions, a special work permit was required, and a discrete area on the rig used. In many instances, the wells had to be shut in for the duration of the welding job. Then the welds had to be x-rayed by yet another set of specialists with more equipment. As the tubing was used, the discrepancies between wall thicknesses and ovality became more significant and the welding process became harder to control.[2]

Finally, CT rigs used on floating platforms were subject to vertical and lateral movement. To compensate for these movements, they relied on heave compensators attached to the platform rig. However, the platform rig had to sit over the same well as the coiled-tubing unit. Before CT could become a truly useful tool offshore, this problem had to be solved.

Eventually, engineering innovations offered solutions to these problems.

Canadian endorsement

Globally, and particularly in Canada, CT drilling has become increasingly prevalent due to several technical improvements developed over the past 2 decades. Canadian oil and gas operators routinely use CT to drill shallow wells because they can drill them quickly and efficiently (Fig. 3). In shallower, unconsolidated formations, CT drilling rigs achieve penetration rates of 1,300 fph, compared to 300-400 fph accomplished with conventional rigs.

And the new generation of coil-tubing drilling rigs can drill two, 2,000-ft wells in a single day using preset casing. They can also rig up and rig down faster and their continuous circulation provides superior overall well control. They exhibit improved safety because less pipe is handled and crews are smaller, and they reduce costs by 15-50%.

Despite the increased presence of CT drilling in Canada, the use of CT technology in the US hasn't been as freely employed to drill anything other than shallow or moderately deep wells.

Hook-load increase

Xtreme's project represented an advance for CT drilling.

For example, the project needed larger injectors to handle the increased hook loads, which can weigh up to 120,000 lb. While some injectors rated to 200,000 lb have been built for other specialized field service work, their use in CT drilling has typically been limited to reentry operations using mostly smaller sizes of coiled tubing.

More recently, engineers have adapted the large coiled-tubing injectors so they can utilize larger diameter tubing sizes in open holes. As a result, the 10,000-ft well, which is very common in US drilling projects using conventional pipe, has become achievable with CT drilling.

Transporting the equipment required by these projects presented problems. Adding a top drive and injector along with the CT string made loads too heavy for existing US roadways. Therefore, it became necessary to redesign the transport logistics to break up the CT rig components into various modules that can be transported legally yet rigged up and down quickly.

Bigger rigs were also needed. Fortunately, technology has kept pace in this

area. Late in 2006, coil over top drive (COTD) rigs with 200,000-lb hook loads, which were capable of drilling to 10,000 ft with coiled tubing or to 14,000 ft with jointed pipe, were introduced (OGJ, Sept. 18, 2006, p. 48).

The biggest obstacle for the project was the coiled tubing itself. At the inception of CT drilling, tubing in 2⅜-in. and 2⅞-in. sizes sufficed. In drilling larger holes, however, the smaller tubing sizes experienced friction loss that resulted in high pressures and slower drilling rates as the bit went deeper. Engineers found that if 3½-in. CT was used to drill deeper 8¾-in, 7⅞-in. or 6½-in. holes, the friction loss and wear on the CT and surface equipment could be reduced.

Thus, pump pressures ranging from 1,500-2,000 psi could be achieved compared to the 2,000-3,000 psi required for circulating through the smaller sizes. Tenaris Coiled Tubes said its experience producing larger diameter coiled tubing in 3½-in., 4½-in., and 5-in. OD primarily for subsea pipelines and its handling equipment, capable of moving reels with up to 120,000 lb of pipe, were useful when developing CT for the project.

Thicker, lighter CT

The coiled-tubing strings that Xtreme required to drill 10,000-ft wells had to be light enough to transport on trailers, yet thick enough to withstand the abrasions of drilling horizontally. Staff at Tenaris Coiled Tubes worked with Xtreme's engineers to develop pipe that could withstand the load, operating and external pressures, and fatigue that punishes the CT in the course of drilling deep wells.

Bruce Reichert, Tenaris Coiled Tubes technical and R&D manager, said, "We examined different diameters, wall thicknesses, and grades in order to the produce pipe that would best fit their needs. The final product is the result of a team effort by both companies."

Tenaris recommended 0.204-in. gauge pipe with a 3.50-in. OD that would result in a string weight of almost 100,000 lb. In August 2006, Tenaris produced the first strings for the project at its Houston facility and became the only US mill that could, and still does, produce CT strings in this size.

To date, Tenaris has produced 12 strings of the new coiled tubing for Xtreme to use on the project and it anticipates that demand for 10,000-ft well strings will increase as more experience is gained drilling the deeper wells. "Xtreme's innovation in using CT drilling for deep gas wells could very well result in an overall increase in the amount of CT drilling in the US," said Reichert.

According to Tom Wood, chairman of Xtreme, further technological advancements may lead to the use of 4-in. OD CT. Xtreme will be drilling in deep gas fields such as Pinedale and Jonah in Colorado's Green River basin for EnCana Oil & Gas (USA) Inc. (OGJ, Dec. 18, 2006, p. 37).

Xtreme plans to have 18 CT drilling rigs operating in the US Rocky Mountains and Canada by early 2008. Xtreme also continues to market coiled tubing drilling services to major independents and other large operators who can apply CT technology to projects in the Piceance, Powder River, and DJ basins and in southwest Wyoming as well as other similar oil shale projects throughout the U.S. Rockies." ✦

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Study examines use of refinery fuel gas for hydrogen production

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Refiners faced with increasing hydrogen demand should consider producing additional hydrogen from fuel-gas streams.

The use of refinery fuel gas, excess LPG, butanes, and pentanes for hydrogen production is a logical fit for refineries. Refinery fuel-gas flow and composition variations can be frequent and sudden. Our experience is that this flexibility can be built into a hydrogen plant.

Difficulties with these designs include:

- Properly removing liquids and solids from refinery fuel gas upstream of compression.
- Compression of gas with varying molecular weights.
- Protecting the steam-methane reformer from undesirable components.
- Providing controls for continuously operating the plant at peak efficiency.

Special design provisions must be made to maintain a constant quantity of coproduct steam from the hydrogen.

This article discusses the difficulties in designing and operating hydrogen plants using multiple feeds.

Hydrogen demand

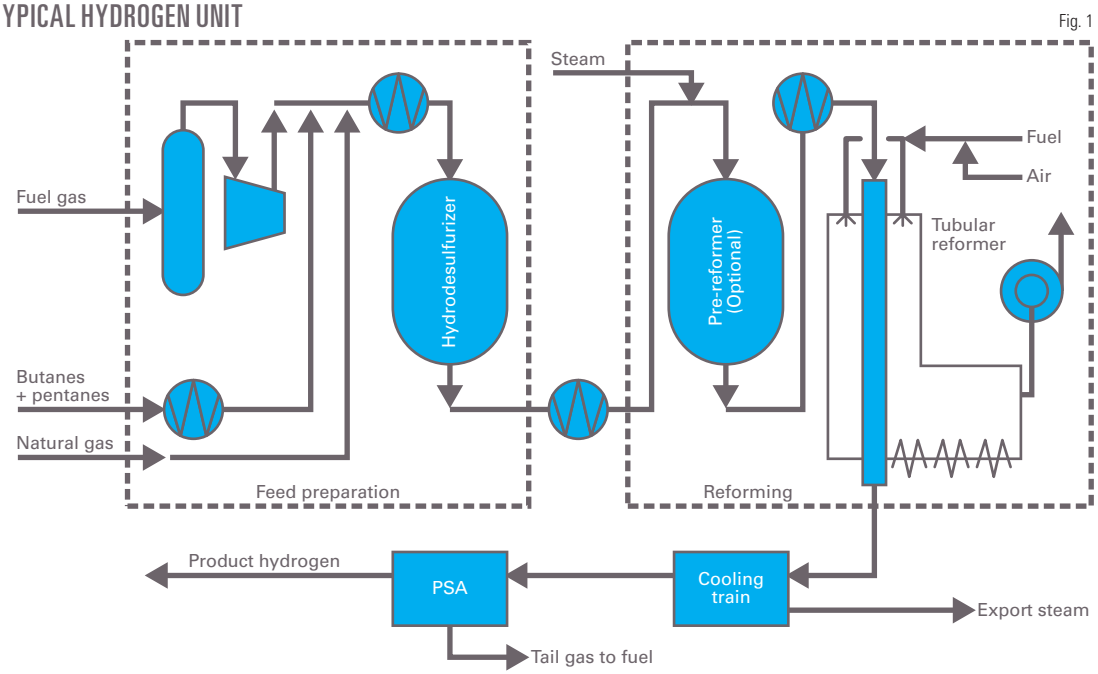
Refiners are experiencing increasing pressure to produce cleaner fuels while processing more sour and heavier crudes. The need to meet clean-fuel specifications requires additional investment in hydrotreating capacity. The use of residue-upgrading technologies, such as hydrocracking and coking, also increases hydrogen demand.

These technologies also create additional volumes of refinery fuel gas that must be used within the plant. Some refineries already have a very tight fuel balance, occasionally limiting crude processing.

The use of refinery fuel gas to make hydrogen is a logical solution. In the past, refinery fuel gas came from one or two sources such as a hydrotreater purge or catalytic reformer gas; today it comes from many sources, which increases hydrogen plant complexity and operation.

TYPICAL HYDROGEN UNIT

Fig. 1



Refinery gas sources

Refinery fuel gas is a mixture of streams generated in various refinery operations such as hydrotreating, hydrocracking, catalytic reforming, catalytic cracking, coking, etc. Today's refineries are built to accept varying qualities of crudes, such as heavy or light and sweet or sour. They may also operate differently during summer and winter months to meet different product slates. Unit start-ups or

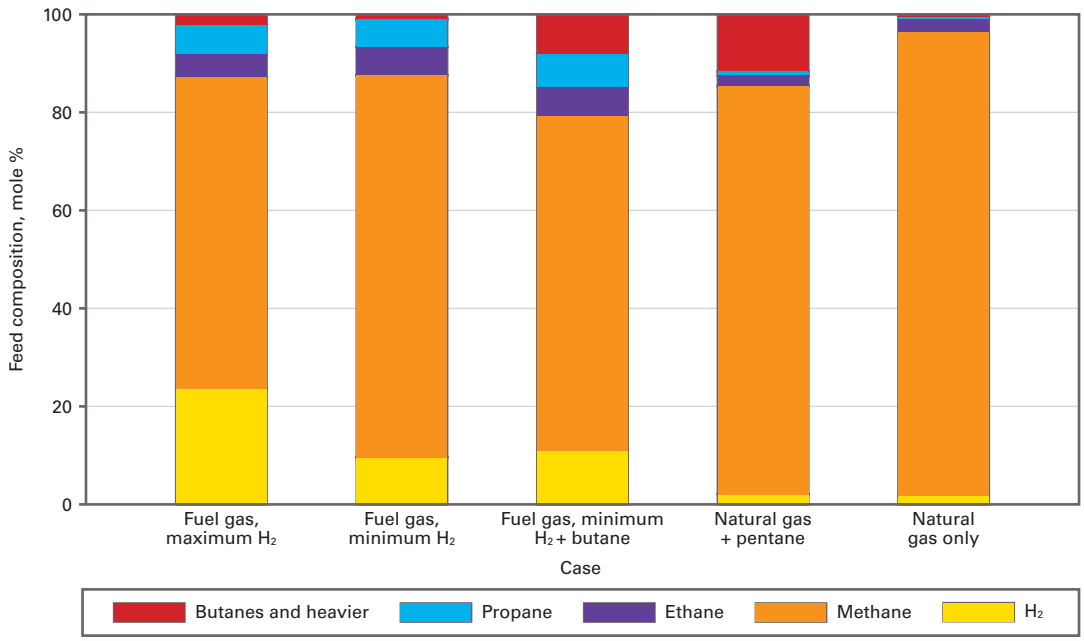
shutdowns add to this complexity.

Fuel gas is generally used as fuel in various process heaters and steam boilers in the refinery, but using it as a feedstock for hydrogen plants presents operators with real obstacles.

Normally, a refinery has two different fuel systems—one that collects gases with mainly saturated hydrocarbons, and the other that collects streams with significant unsaturated hydrocarbons. Saturated hydrocarbon streams originate from operations such as hydrotreating, hydrocracking, and catalytic reforming. Unsaturated streams originate from catalytic cracking, cokers, etc.

FEED SCENARIOS

Fig. 2



Refineries have little need to analyze refinery streams being sent to fuel because fully characterizing them is a tedious laboratory process. Whenever refiners do analyze these streams, they generally limit the analysis to pentane or hexane components.

Heavy components (up to C_{12}) may be present in concentrations less than 1,000 ppm; these heavier components reduce a stream's dewpoint and occasionally cause condensation. Based on the source of the fuel gas, it is prudent to account for heavy components during the design of hydrogen plant.

Because fuel-gas composition can change without notice, continuous composition monitoring is desirable. Monitoring can use gas chromatography, mass spectrometry, density meters, heating-value measurement, or dewpoint measurement.

The analysis is used for process control and protection of the hydrogen plant from unwanted components. Each of these analyzers has its limitation in terms of speed of analysis, accuracy, and reliability. It is important to match the process requirements with instrument capabilities.

Liquid, particulate removal

It is also important to remove condensed liquids and any solids from fuel-gas streams. Many streams are at their hydrocarbon dewpoint when leaving the final separator of their respective source.

Some of the streams may become saturated with water when processed in an amine treater. Liquid entrainment from the separator and condensation in the fuel-gas header results in significant amounts of liquid present in the fuel gas.

Safety concerns also arise if the fuel gases are used in furnaces in cold climates. Condensate will be a sour mixture of water and hydrocarbons. Proper removal and disposal of this condensate is an important consideration for plant operations.

Refinery fuel gas may also contain solids from their original sources or picked up from the fuel header. Removing these solids is important for safe, trouble-free operation of compression equipment or processing equipment such as burners and catalytic reactors handling the fuel gas. A coalescing filter for solid removal is desirable.

Reformer design for fuel gas

Fig. 1 shows a typical hydrogen plant using refinery gases and liquid hydrocarbons.

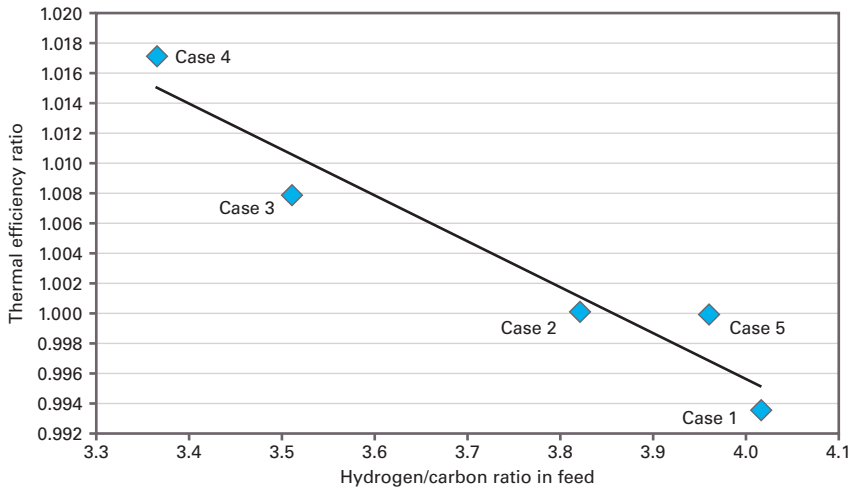
The feed-preparation section consists of gas compression and vaporization of the liquid feeds such as LPG, butanes, and pentanes. The hydrocarbon feed is desulfurized, mixed with steam, and sent for reforming.

The reforming section usually has a tubular reformer and may also have an adiabatic pre-reformer. A pre-reformer may be needed if a significant amount of heavy hydrocarbons such as pentanes are to be processed. It is critical to desulfurize the hydrocarbon feed properly because the pre-reformer and tubular reformer use nickel catalysts that are very sensitive to sulfur poisoning.

Reformed gases are cooled and sent to a shift reactor to convert carbon monoxide to hydrogen and carbon dioxide. The shifted gas is cooled and processed in a pressure swing adsorp-

OVERALL THERMAL EFFICIENCY

Fig. 3



tion (PSA) unit, which recovers 85-90% of the incoming hydrogen.

The rest of the hydrogen, unconverted methane, carbon monoxide, and carbon dioxide removed in the PSA are used as fuel in the tubular reformer.

Compression of fuel gas

Refinery fuel gas is normally available at 60-200 psig. It usually needs to be compressed to 400-600 psig to feed a steam-methane reformer. There are many compressors that can be used in this service, including centrifugal, reciprocating, and screws (oil-flooded as well as dry).

A centrifugal compressor may be a good choice from cost and ease of maintenance points of view, but the molecular weight of the gas being compressed greatly influences its performance. One should carefully evaluate the variability in fuel-gas composition to assess the suitability of such a machine.

A reciprocating compressor is more flexible; it can accept varying compositions in its feed. The gas composition affects the compressor discharge temperature for a given compression ratio. Because the specific heat of hydrogen is lower than that of hydrocarbons, a higher hydrogen content results in a higher discharge temperature. The temperature of the compressor valves is also affected by higher hydrogen content. A conservative design may require limiting compression ratio of each stage.

An oil-flooded screw can provide high compression ratios (6-8) in a single-stage machine, but the compression efficiency for these machines is significantly lower than reciprocating or centrifugal machines. Any condensation of water or hydrocarbons in the compressor contaminates its oil and, although these machines should be designed to avoid this, an upset at the refinery can bring in heavy components that could condense at the compressor's discharge conditions.

It is important to make a proper selection of the compressor based on operating experience, cost, and reliability requirements.

CONSTANT CONVERSION CASES

Table 1

Case	1	2	3	4	5
Feed description	Fuel gas with maximum H_2	Fuel gas with minimum H_2	Fuel gas with minimum H_2 and butane	Natural gas and pentane	Natural gas only
Reformer outlet temperature, °F.	1,601.2	1,598.2	1,593.6	1,591.0	1,600.0
Shift outlet temperature, °F.	799.0	796.5	792.8	790.4	797.9

Hydrodesulfurization design

Refinery fuel gas generally contains much more sulfur than a typical natural gas feedstock. Sulfur species in fuel gas such as carbonyl sulfide and heavier mercaptans are also harder to remove or hydrotreat.

In the first step in a hydrotreater, all organic sulfur species are hydrotreated to convert them to hydrogen sulfide. In the second step, a zinc oxide bed removes the hydrogen sulfide. Commonly used hydrotreating catalysts such as nickel molybdenum or cobalt molybdenum must be properly sulfided to be fully active.

Hydrogen must be present to convert various organic sulfur compounds to hydrogen sulfide. The amount of hydrogen in the refinery gas varies, but should be sufficient for this process.

If a feedstock with low sulfur, such as natural gas, is processed in the hydrotreating unit for any length of time, it tends to remove sulfur from the hydrotreating catalyst. Hydrogen in the feedstock should be a minimum to prevent it from stripping the sulfur off of the hydrotreating catalyst during such an operation.

Metals on the catalysts are reduced to free metals and become active for hydrocracking reactions. If these reactions are initiated, the resulting temperature runaway could be severe. Hydrotreating catalysts can be resulfided, if necessary, by addition of sulfur compounds such as dimethyl disulfide.

The presence of hydrogen in the fuel-gas feed also requires that the hydrotreating and zinc oxide reactors be built of materials suitable for hydrogen partial pressure in the feed gas.

Refinery fuel gas may also contain olefins. Olefin hydrogenation in a hydrotreating unit is exothermic and the maximum operating temperature limit for the catalyst in this reactor is 750° F. Assuming a minimum inlet temperature of 500° F. and a temperature rise of

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250° F., a maximum allowable limit of 5% olefins in feed would be acceptable. A recycle loop equipped with a cooler allows the process to handle more olefins in the feed.

The designer must pay special attention to acetylene, if present, in the fuel gas. Acetylene polymerizes on the hydrotreating catalyst. The maximum concentration should be 10 ppm (vol).

Feed measurement, analysis

The steam-to-carbon ratio is a critical parameter that the refinery must control for efficient and safe operation of a steam-methane reformer. The varying fuel-gas composition makes it difficult to obtain an accurate real-time measurement of the flow rate and carbon number of the stream.

A mass flowmeter or a vortex-type meter can accurately measure fuel-gas flow rate. Because the stream is usually at 600-1,000° F., the flowmeter may have temperature limitations.

Real-time measurement of the carbon number is more difficult. A gas chromatograph can continuously monitor the composition of the fuel-gas feed. Gas chromatographs operate with about a 10-min delay, however, and cannot be used for process control.

A mass spectrometer with a fast response time may be suitable. Its initial cost and reliability, however, may make it impractical. An inexpensive and reliable density meter can be used as a measure for the carbon number.

To maximize use of refinery fuel gas, a refiner may use it as makeup fuel in the tubular reformer. Fuel gas used as fuel is usually a different stream from the fuel-gas stream fed to a steam-methane reformer.

Temperature control of the reformer furnace is sensitive to variations in the quality of the makeup fuel. It is important to know the real-time flow rate, heating value, and gas density of the fuel gas to control a furnace properly. A quick-response calorimeter can make a heating-value measurement. The calorific value with a density measurement can be used for firing controls as well as for proper accounting purposes.

It is also important to have continuous H_2S and total sulfur analysis of the refinery fuel gas. The hydrogen plant must stay below a sulfur emission value limited by any environmental permit. The refinery must substitute an alternative fuel source, such as natural gas, for fuel gas when it exceeds a specified sulfur content.

Reformer optimization

Operating a steam-methane reformer at peak efficiency requires online optimization, and the variability of the refinery fuel-gas feedstock complicates this activity. An increase in hydrogen content in feed reduces reformer duty, which leads to reduced fuel usage. It also increases unconverted methane leaving the reformer for a given outlet temperature.

The amount of carbon dioxide produced in the reformer per unit of hydrogen production is also reduced. This lessens the amount of steam production in the convection section of the tubular reformer.

The reverse will be true if the amount of heavy components in the feedstock, such as butanes and pentanes, increase.

By-product steam available for export will vary with the quality of the refinery fuel gas. If a constant steam export is desired, the unit must be designed to augment the steam production by other means such as auxiliary firing in the furnace of the tubular reformer.

Case study

An optimization study, done for a hydrogen project for a refinery in North America, illustrates the effect of variations in feedstock on plant performance.

This plant was designed to produce hydrogen with various feedstocks including refinery fuel gas, butane, pentane, and natural gas. Fig. 2 shows some of the feed scenarios that we considered.

Assuming that the plant operates at a constant methane and carbon monoxide conversion, then varying the reformer outlet temperature and the shift inlet temperature can compensate for the effect of feed changes on the chemical equilibriums in the reformer and shift converter. Table 1 shows these effects.

These variations affect the overall process thermal efficiency (Fig. 3). Inherently, thermal efficiency falls as the feedstock becomes heavier, as reflected in a lower hydrogen-to-carbon ratio. The effect on efficiency is more pronounced if the operating conditions, such as reformer outlet temperature or shift temperature, are not adjusted for the feed composition.

As the feed quality varies, steam production and available export quantities will vary even at constant hydrogen production. Adjusting the temperature of combustion air for the tubular reformer furnace or auxiliary firing in the furnace will minimize variations in steam exports.

Additional measurements and controls in the convection section and PSA are also required for plant optimization. ✦

The authors

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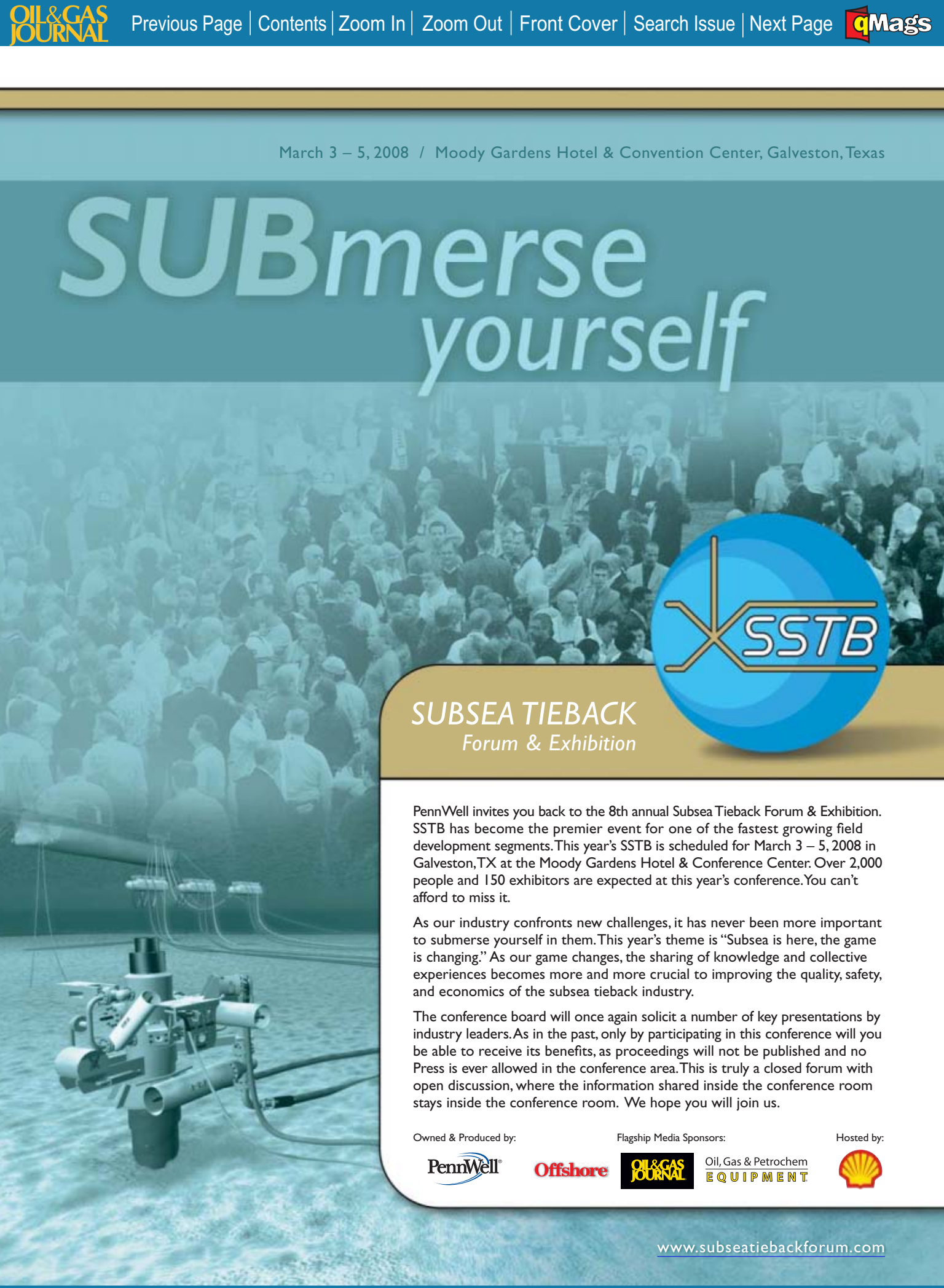

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US NATURAL GAS—1

Rockies Express pipeline to reshuffle gas supply, trade

Porter Bennett
E. Russell Braziel
Jim Simpson
Bentek Energy LLC
Golden, Colo.

The opening of the 1,663-mile Rockies Express Pipeline system, running from natural gas producing basins in Colorado and Wyoming to market in the Midwest and Northeast, will provide many US gas consumers with new access to cheaper gas from the Rocky Mountain region. This development will cause a major reshuffling of US gas transportation patterns by allowing consumers to shift their supply portfolios away from traditional supply areas in the Midcontinent and Gulf Coast to more economic production in the Rockies.

This first of two articles examines the background of the REX pipeline project and analyzes the effect on US natural gas markets of REX Phases I and II.

The concluding article will detail the market reorganization expected to be brought about by the combination of REX Phase III's completion and downstream capacity constraints.

Once the entire REX project is complete, its tariff rate structure will provide significant competitive advantage to REX shippers delivering to either Lebanon or Clarington, Ohio, compared to shippers bringing gas from supply areas in East Texas, South Texas, Louisiana, or the Gulf of Mexico.

This analysis only compares the variable components of each pipeline's tariff: commodity charge plus fuel loss. The much larger demand component is considered sunk, and must be paid regardless of whether the shipper actually moves any gas. From a market perspective, therefore, decisions about which transportation alternatives influence shipper behavior and market pricing hinge solely on the variable cost.

Assuming price differentials between market locations in the Rockies (Opal and Cheyenne) and the Gulf Coast are similar to 2006 averages, REX shippers will have a $0.90-1.17 advantage over shippers on Texas Eastern Transmission and Tennessee Gas Pipeline. REX shippers also will have a significant price advantage over shippers bringing supplies north on Columbia Gas Transmission, Texas Gas Transmission, and Panhandle Eastern.

Capacity constraints at Lebanon will restrict the ability of REX East shippers to unload 1.8 bcfd of incremental gas once the pipeline has been completed. East of Clarington, constraints also will shape the ability of existing pipelines to absorb 1.8 bcfd of incremental volumes.

On peak days, therefore, constraints will exist on all of the takeaway pipelines, preventing absorbtion of incremental supplies. At other times, available capacity will exist to carry REX gas to the regions' numerous large storage facilities, but during withdrawal periods constraints east of the storage facilities will prevent incremental volumes from reaching customers.

Accordingly, volumes delivered into the takeaway pipelines at either Lebanon

ROCKIES EXPRESS PIPELINE

Fig. 1

or Clarington will, for the most part, need to be offset by reduced receipts from traditional supply sources.

REX volumes may also displace Anadarko and Permian basin volumes during 2008, prior to commencement of service for REX Phase III. The REX price advantage, coupled with the capacity constraints at Lebanon and east of Clarington, suggests that significant volumes of Texas, Louisiana, and Gulf supplies will be displaced by REX supplies, increasing gas-on-gas competition in the gulf area. These gulf supplies will be forced to compete for other markets, presumably in the Southeast and in the Texas-Louisiana intrastate market.

Continuing this domino effect, some of the turned-back volumes will flow into the southeast legs of ANR, NGPL and to Trunkline. When REX volumes begin moving to eastern markets, however, Anadarko and Permian basin supplies should find their way back into their traditional Midwestern markets.

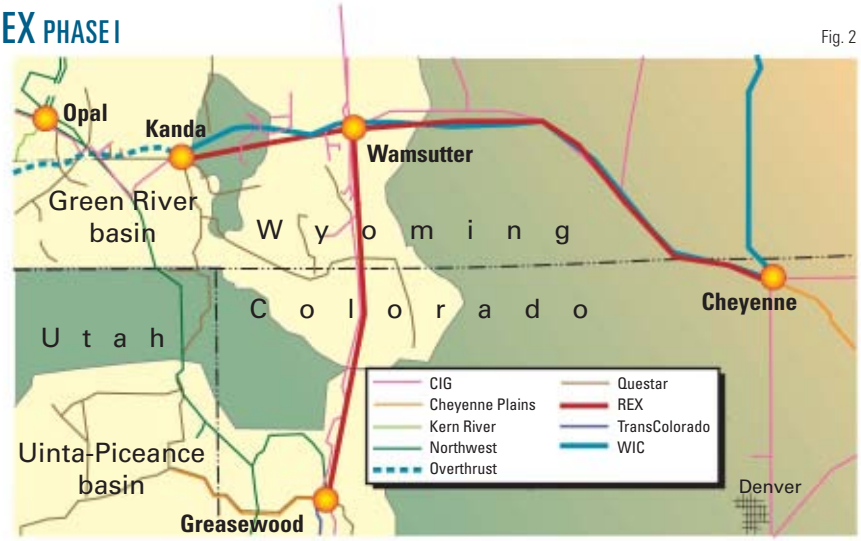
Gulf supplies will also come under pressure from production increases in the East Texas, Fort Worth, Arkoma, and Arkla basins. Increases in Northeast power generation demand could absorb some incremental supplies given new pipeline capacity east of Clarington to deliver REX supplies to the new markets. Lower Canadian imports also could make room for additional REX supplies.

Each of these developments will reshape regional supply-demand balances as the REX displacements roll through the market.

The REX gas flow displacements and other supply-demand developments will result in a radical realignment of regional price differentials. The Rockies-to-gulf area price realignment will be the most dramatic: Rockies prices will rise to near parity with the gulf and under some scenarios could even rise above the gulf. The differential between Ohio price points such as Lebanon (Columbia and Dominion Transmission-South) and Gulf Coast prices will fall sharply. Once REX East is open to Clarington, Chicago-Ohio price differentials will flatten.

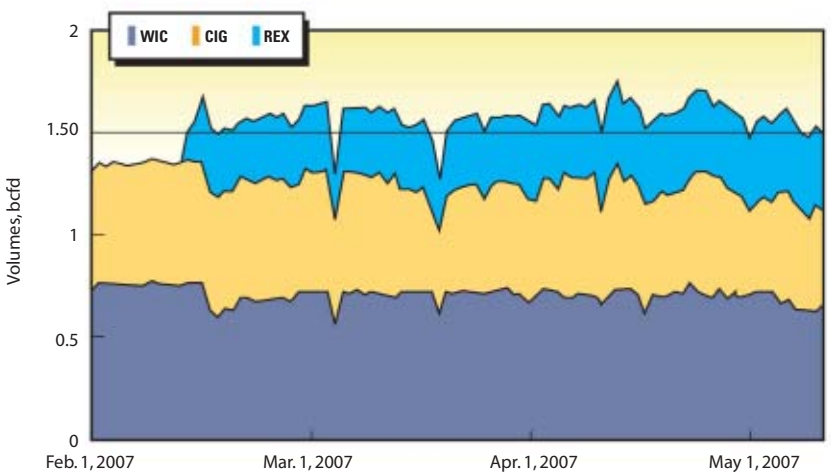
REX PHASE I

Fig. 2



NATURAL GAS TO CHEYENNE

Fig. 3



Recontracting on existing pipelines will also fuel realignment. Between 2007 and 2010, a number of contracts for firm capacity will come up for renewal. As local distribution companies hold most of the capacity on these pipelines, the next 3 years may see considerable realignment of their supply portfolios.

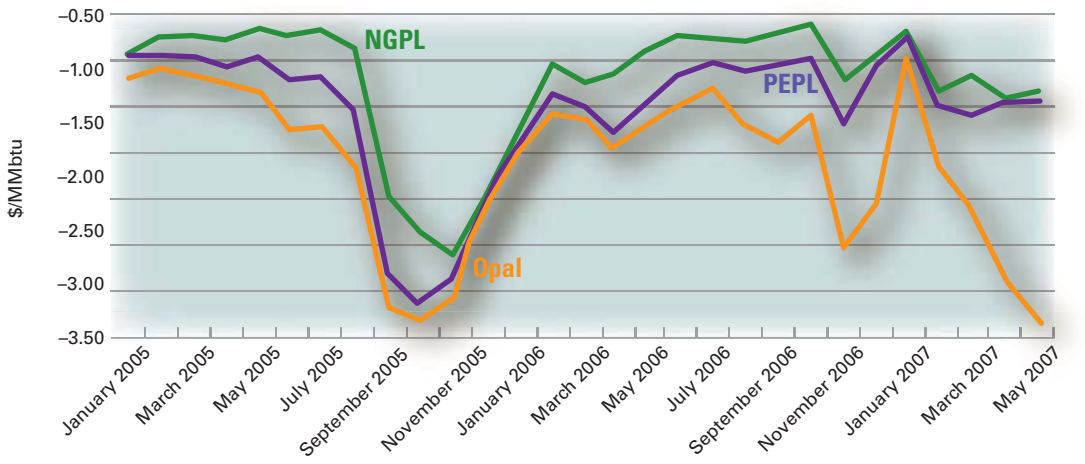
REX pipeline

The initial segment of REX Phase I went into service in February 2006 with completion of the pipeline segment formerly called Entrega, a 136-mile leg connecting Uinta-Piceance production in the Greasewood, Colo., area with Wyoming Interstate Pipeline and Colorado Interstate Gas at Wamsutter, Wyo. The segment completed in February 2007 extended REX east to Cheyenne Hub. Through a long term lease with Overthrust Pipeline, REX Phase I can also move up to 1.5 bcfd from the Green River-Overthrust area (near Opal, Wyo.) to Kanda, Wyo., and on to Cheyenne Hub.

REX Phase II is to begin commercial operation in early 2008, extending the system from Cheyenne Hub to Mexico, Mo. Capacity at Cheyenne will increase to 1.6 bcfd with the addition

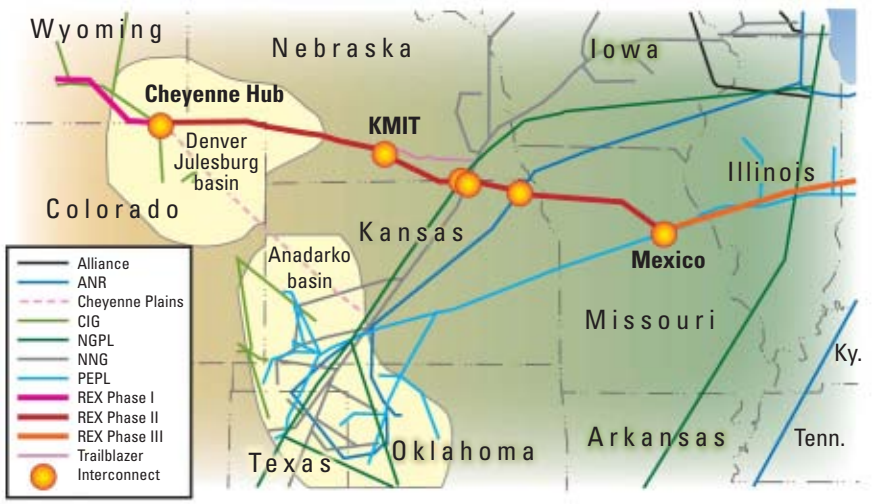
AVERAGE MONTHLY BASES

Fig. 4



REX PHASE II

Fig. 5



of compression. REX Phase III, planned for completion in 2008 and 2009, will extend the pipeline first to Lebanon and then to Clarington, Ohio, increasing overall capacity to 1.8 bcfd.

When completed, REX will span 1,663 miles and will be one of the US longest interstate pipelines.

Phase I

Within a few days after Phase I was placed into service, gas transportation patterns changed in ways that enabled more gas to flow from southwestern Wyoming to Cheyenne Hub (OGJ, Apr. 2, 2007, p. 56).

Before the shift, Uinta-Piceance gas received into REX in the Greasewood area moved to Wamsutter, where it was delivered to either Colorado Interstate Gas or Wyoming Interstate Co. Gas received by these two pipelines moved either west to Kern River and Questar or east to Cheyenne Hub. Capacity to Cheyenne Hub was usually at maximum utilization.

When REX Phase I capacity from Wamsutter to Cheyenne Hub became available, the gas that had moved to CIG or WIC stayed on REX all the way to Cheyenne Hub. That opened capacity on WIC from Wamsutter to Cheyenne Hub, and that capacity quickly filled. The volume previously moving on WIC from the Uinta-Piceance area was replaced by Green River-Overthrust volumes received from Overthrust pipeline.

Fig. 3 shows what happened. REX flows into Cheyenne Hub jumped to about 300 MMcfd within a few days. While there was a small initial dip on WIC, volumes have held very steady on both WIC and CIG.

Fig. 4 shows that basis at Opal averaged $0.73 less than Henry Hub from January 2005 through that summer. The Opal price was well below Panhandle Eastern and NGPL prices during the same period. After the hurricane-related disruptions of 2005, Opal basis again settled into a range averaging about $1.00 less than Henry. But in the summer of 2006 the specter of transportation curtailments emerged, and by November, Opal was running $2.50/MMbtu less than Henry, spiking to minus $5.00/MMbtu Nov. 14 due to mechanical problems at Opal.

REX Phase I brought no relief. In fact, the Opal to Henry Hub differential has widened since February 2007. The month-to-date May 2007 average differential has exceeded $3.00/MMbtu.

Although Phase I has increased capacity to Cheyenne Hub, factors including increased Rockies production, capacity constraints, maintenance issues, and rate-stacked tariffs farther downstream continue to pressure Rockies prices.

Phase II

REX Phase II is scheduled to go into service in January 2008. It will connect REX Phase I to Panhandle Eastern Pipeline, near Mexico, Mo. (Fig. 5). Phase

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3 250-MW+ Steam Turbine Generators
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5 GE Frame 9 GTGs

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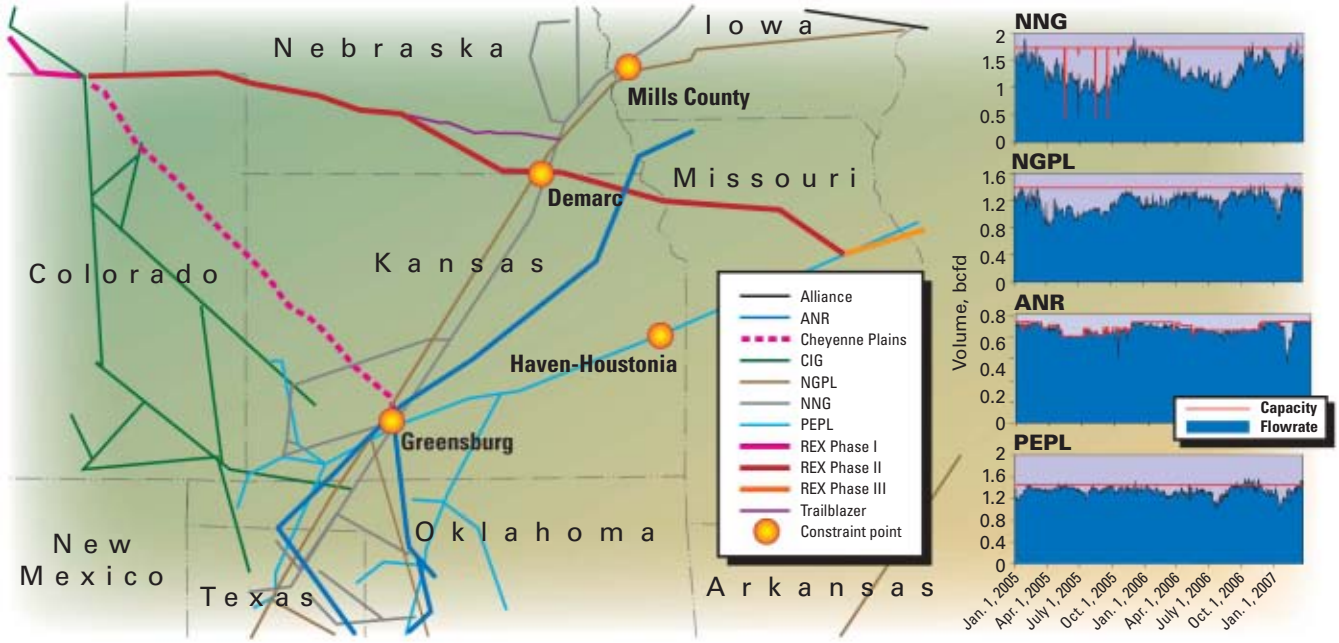
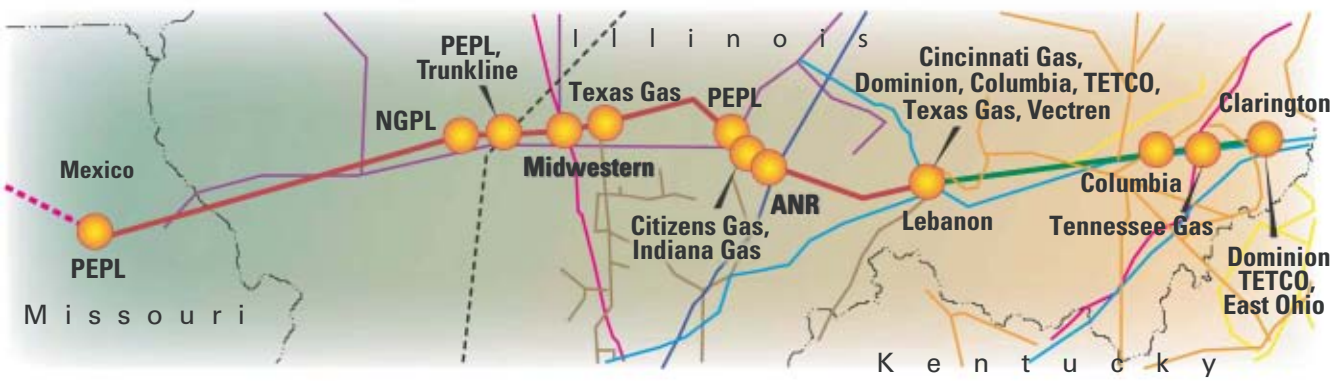
REX PHASE II, DOWNSTREAM BOTTLENECKS

Fig. 6



REX EAST INTERCONNECTS

Fig. 7



II includes construction of 713 miles of pipeline, several compressor stations along both it and the Phase I pipeline, and an additional supply lateral to Echo Springs, Wyo. Phase II will have the capacity to deliver 1.6 Bcfd to its Missouri terminus.

Phase II of REX will provide access to five interstate pipelines: ANR, Kinder Morgan Interstate, NGPL, Northern Natural Gas, and Panhandle Eastern. Analyzing available pipeline capacity and flows north of the REX interconnections with these systems shows that the key pipelines moving gas into Midwest markets (ANR, NGPL, NNG, and PEPL) have bottlenecks that will limit the gas they can receive from REX, unless they reduce traditional supplies from the Anadarko or Permian basins.

ANR's bottleneck constrains the entire mainline system from the Greensburg compressor in southwestern Kansas to points near Chicago. On Northern Natural Gas, the bottleneck is between the field zone and market zone as defined in NNG's tariff. NGPL's bottleneck lies where the pipeline crosses into Mills County, Iowa, from Nebraska. The bottleneck on Panhandle Eastern is between its Haven and Houstonia compressors in eastern Kansas and western Missouri.

Fig. 6 shows the location of each of these constraint points as well as daily flows at each point since Jan. 1, 2005. In 2006 ANR had virtually no available capacity as it ran at an average utilization rate of 98%. Panhandle also was nearly full, having an average utilization rate of 92% throughout 2006. The average annual utilization rate on NGPL was 89%; the summer months averaged 87% while the winter months averaged 90%. Northern Natural Gas was the

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"Oil & Gas Journal is my connection to the industry."

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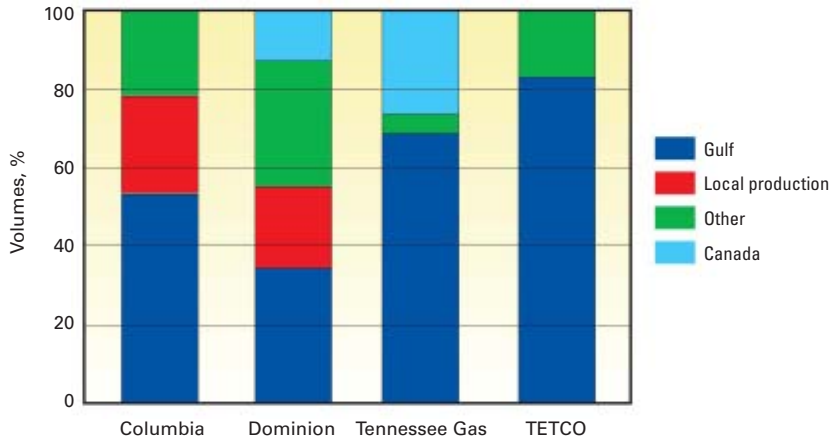
[1] *Signet Readership Survey (February 2007)*

Supply sources

Fig. 8



REX interconnects

Interstate pipelines to eastern markets
Columbia Gas Transmission
Dominion Transmission Interstate
Tennessee Gas Pipeline
Texas Eastern Transmission

Local utilities
Citizens Gas
Indiana Gas
Cincinnati Gas
East Ohio
Vectren

Interstate pipelines to midwestern markets
ANR
NGPL (from Brown County, Kan.)
Trunkline
Texas Gas Transmission
Panhandle Eastern
Midwestern Gas Transmission—has connections with TGP on the southern end of its system and is currently flowing gas that direction.

only pipeline with significant unused capacity. NNG's utilization averaged 78% of capacity during the year, including 71% during the summer months and 88% during the winter months.

Bottlenecks on these pipelines to move additional supplies into Midwest markets must either constrain volumes moving into these pipelines from REX or back out supplies moving into these markets from their traditional sources of supply in the Permian and Anadarko basins.

The most cost effective supplies will win this gas-on-gas competition and REX has a significant technological advantage over its competitors, allowing it to operate with a maximum allowable operating pressure up to 1,480 psig, compared to 700-900 psig for ANR, NGPL, Northern Natural Gas, and Panhandle Eastern (as measured at their bottleneck points). This advantage translates to lower charges for fuel and "lost and unaccounted for" gas in the REX tariff. Accordingly, the proposed tariff for REX is very competitive as compared to rival pipelines.

The competitive relationship between REX and these four pipelines should lead quickly to significant shifts once REX begins to flow east of Cheyenne Hub. Permian volumes will be the first to realign. Assuming that the existing price relationships between Cheyenne, the Anadarko, and Permian persist, the opening of REX Phase II will push significantly greater Permian volumes back to either the Texas intrastate market or to markets in California and Arizona.

Rockies supply also will realign, with REX cannibalizing volumes from Cheyenne Plains. Shippers on either NNG or PEPL that use Cheyenne Plains to transport Rockies supply to the Anadarko will gain a significant advantage by shifting their supplies to REX. Accordingly, REX will pull significant volumes from Cheyenne Plains.

Finally, competition from REX will cause Anadarko volumes to be pushed back into the Oklahoma and Texas intrastate markets. Assuming the current price differentials between Cheyenne and Anadarko, shippers on Northern Natural Gas, Panhandle Eastern and ANR all would be able to purchase gas at Cheyenne and move it to their respective pipelines at a lower cost than procuring supplies and transportation from the Anadarko. At first quarter 2007 price differentials, REX's costs are $0.07-0.18/MMbtu cheaper, a significant margin.

How much market share REX ultimately captures will depend on the magnitude of incremental Rockies production in 2007-08. Expansion by Rockies producers at current rates could force significant volumes of Anadarko gas to find markets elsewhere.

The unrealistic assumption that current pricing relationships remain unchanged underpins these supply realignment expectations. Clearly they will not. Employing this assumption, however, reveals the market pressures that will be created by REX II.

The realignment of pipeline flows brought about by the economic advantages of REX Phase II will lead to significant shifts in historical pricing relationships. In the Rockies, the introduction of new transportation capacity, and thus new demand pressure, will raise prices relative to other regions of the market. In the Permian and Anadarko, new competition from Rockies gas will constrain access to markets in the Midwest, decreasing prices relative to other regions.

For example, in 2006 Anadarko prices were typically 11-13 cents higher than prices at Cheyenne Hub. REX will drive Anadarko prices toward parity with Cheyenne Hub and Opal. Permian prices also will fall relative to Cheyenne Hub.

This first wave of flow realignment and shifts in price differentials will be temporary. Less than 1 year after REX II, REX III will create an entirely new array of realignment pressures in the East and Gulf regions, and in some cases will undo the market pressures created by REX II.

Phase III geography

REX Phase III (designated REX East in FERC documents) is scheduled to enter service in two stages over 7 months beginning in December 2008.

Phase IIIa (Fig. 7) extends from the eastern terminus of REX West to Lebanon, Ohio. This segment of REX East is to begin service in December 2008. Phase IIIb, the second segment of REX East, extends from Lebanon to Clarington (Fig. 7). It is to begin flowing in late June 2009. When completed REX East will be able to deliver 1.8 bcfd to Clarington.

REX East will access four interstate pipelines with the ability to move gas to Eastern markets, six with the ability to move gas to Midwestern and other markets, and several local utilities (see box),

REX East delivery points directly access utility markets primarily in Ohio. Cincinnati Gas, East Ohio, and Vectren (formerly Dayton Power & Light) are the major Ohio gas utilities and all will connect directly to REX. Citizens Gas and Indiana Gas, both in Indiana, will also connect directly to REX.

In addition to these utility markets, REX shippers will be able to supply markets in the Northeast. Northeastern shippers will be able to flow gas through REX to Dominion Transmission, Columbia Gas Transmission, TETCO, Tennessee Gas Pipeline, and to storage fields in western Pennsylvania or other locations east of Clarington.

Gas moving through REX East can also access the upper Midwest. ANR, NGPL, Panhandle Eastern, and Trunkline have interconnections with REX that will enable Rockies' gas to flow to Chicago, Michigan, and other upper Midwest markets. Since Ohio and northeastern markets have typically carried higher prices than Chicago markets, this analysis assumes that, if economically feasible, Rockies' gas will move past the Midwest markets to markets in Ohio and the Northeast, yielding higher netbacks to Rockies' producers.

The concluding article in this series will focus on the competitiveness of the REX East option as a supply source for the Ohio and Northeast markets.

While customers of the four primary pipelines that will receive gas from REX East—Columbia, Dominion, TGP, and TETCO—obtain their supplies from a variety of sources, the primary source is the gulf region. Fig. 8 shows the origin of the gas that serves these markets. ✦

The authors

Porter Bennett is president and CEO of Bentek Energy LLC, Golden, Colo. In his early career, Bennett held positions with consulting companies specializing in energy market analysis. He holds an MS in mineral economics from the Colorado School of Mines and an MA in international affairs from Columbia University in New York. He received a BA in history from Lewis & Clark College, Portland, Ore.

E. Russell Braziel is vice-president, marketing and sales, and chief technology officer for Bentek. He was previously vice-president of business development for the Williams Cos., vice-president of energy marketing and trading for Texaco, and president of Altra Energy Technologies. Braziel holds BBA and MBA degrees in business and finance from Stephen F. Austin University, Nacogdoches, Tex.

Jim Simpson is vice-president, operations, for Bentek. Before joining Bentek, Simpson modeled large structured transactions in both gas and power for Enron North America. Subsequently he led natural gas marketing and trading at MarkWest Hydrocarbon Inc. Simpson holds a BBA in finance from Texas A&M University.

Equipment/Software/Literature

New hydrohammer expands company fleet

Addition of the the S-280 expands this firm's fleet of hydrohammers.

The tool's ability to drive bigger piles and achieve deeper penetration enables the company to drive larger caissons required for many construction projects being carried out in the Gulf of Mexico.

The hydrohammer also may be used to drive well conductors. The tool has a maximum energy rate of 206,400 lb/blow and can deliver 45 blows/min.

The firm says it has already used the new hammer to install a monopod and a tripod platform. These projects were completed from derrick barges working in the Ship Shoal and Grand Isle areas of the Gulf of Mexico. Other planned installations include deep conductors and structure installations from derrick barges and lift boats.

Source: **BJ Services Co.**, 4601 Westway Park Blvd., Houston, TX 77041.

New fracture modeling software

FracPerm 2.0 is newly released fracture modeling software, .

The integrated, easy to use fracture modeling package enables geologists and reservoir engineers to create detailed permeability maps used in the flow simulation and history matching of reservoirs to reduce uncertainty.

Operating with the firm's modeling software, IRAP RMS, FracPerm 2.0 combines data, geological properties, geostatistics, and geohistory in a data-driven approach, designed to make maximum use of available data and allow rapid and interactive quality control of the model as it is being built. Specific additions in FracPerm 2.0 include a redesigned, easy to use interface, simplified work flow, and a new plug-in structure, which allows the reservoir engineer to better integrate and customize with other software tools.

FracPerm operates on either the geological or simulation model, thereby accessing the reservoir structure and facies distributions. The software's mix of structural geology, data integration, and visual assessment tools are specifically designed to allow the asset team, with their knowledge of the reservoir, to build models for validation by structural experts and by simulation testing.

FracPerm is suited to experienced fracture modeling users as well as nonspecialists, the firm says.

A new model visualizer, a clearer view of well data, simpler ways of attaching fractures to sets, and a new fracture model visualizer with color coding are included. Users also have the ability to change projects during a modeling session as well as full undo-redo functionality.

The firm notes that FracPerm 2.0 allows E&P companies to capture the true heterogeneity within fractured reservoirs, allowing better quantification of uncertainty and risk management.

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

Services/Suppliers

Knight Oil Tools

Lafayette, La., has named Howard Milligan as corporate director of quality, and promoted Paco McLaughlin to director of operations for the Rocky Mountain region.

Milligan has more than 32 years of industry experience, most recently serving as president of Advanced System Dynamics Inc.

McLaughlin holds a bachelor's degree in petroleum engineering from the University of Louisiana-Lafayette. In his new role, he will be based in Rock Springs, Wyo.

Knight Oil Tools is a rental and fishing tools business operating from 20 locations in seven oil-producing states of the US.

American Electric Technologies Inc.

Houston, has announced that Jim Ingram has joined the company as segment manager in charge of the pipeline, refinery, and industrial market segments.

Ingram has more than 40 years of experience in industrial sales, most recently with Tesla Power & Automation LP.

American Electric Technologies Inc. is a leading global supplier of custom-engineered power delivery solutions to the energy industry. Principal markets served include offshore and land drilling and production, pipelines, service vessels, petrochemical and refining, and water and wastewater facilities industries.

CTC Marine Projects Ltd.

Darlington, UK, has promoted Jake Tompkins to business development director, and Nigel Ward to commercial director.

CTC Marine Projects Ltd., part of DeepOcean group of companies, is a leading marine trenching and installation contractor, operating in the subsea oil and gas, and other industries. Its major markets are the North Sea and Asia.

DeepOcean is a leading subsea service provider based in Haugesund, Norway, with major operations in the North Sea and Gulf of Mexico.

InterMoor Inc.

Houston, has named Don Hardin as vice-president of projects and engineering.

Hardin, who has more than 25 years of experience in structural engineering, offshore installation, project management, and general marine operations, joins InterMoor from Technip USA. He also has been involved with research, development, and implementation of new mooring technology.

Hardin

InterMoor Inc., an Acteon company, designs, provides, and installs integrated mooring systems worldwide for the offshore oil and gas industry.

Acteon is a group of specialist engineering companies serving the global oil and gas industry.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	6-15 2007	[1]6-8 2007	6-15 2007	[1]6-8 2007	6-15 2007	[1]6-8 2007	6-16 2006
	1,000 b/d						
Total motor gasoline	395	483	15	107	410	590	667
Mo. gas. blending comp.	859	720	45	34	904	754	837
Distillate[2]	154	171	30	22	184	193	290
Residual	209	165	21	37	230	202	431
Jet fuel-kerosine	151	43	87	122	238	165	132
LPG	271	231	3	3	274	234	200
Unfinished oils	525	670	23	15	548	685	473
Other	356	371	—	—	356	371	372
Total products	**2,920**	**2,854**	**224**	**340**	**3,144**	**3,194**	**3,402**
Canadian crude	1,367	1,728	215	261	1,582	1,989	1,772
Other foreign	7,940	7,448	1,227	882	9,167	8,330	9,243
Total crude	**9,307**	**9,176**	**1,442**	**1,143**	**10,749**	**10,319**	**11,015**
Total imports	**12,227**	**12,030**	**1,666**	**1,483**	**13,893**	**13,513**	**14,417**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—JUNE 15, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.17	4.22	5.40	4.12	4.77	5.38
Everett	6.25	4.22	5.87	4.33	4.76	6.54
Isle of Grain	2.21	0.44	1.64	0.36	0.86	1.73
Lake Charles	4.92	3.18	4.68	3.33	3.54	5.52
Sodegaura	4.65	6.70	4.86	6.42	5.78	4.16
Zeebrugge	5.43	3.57	4.85	3.50	4.01	4.87

Definitions, see OGJ Apr. 9, 2007, p. 57. Source: Purvin & Gertz Inc. 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

	*6-15-07	*6-16-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	87.09	81.89	5.20	6.4
Brent crude	55.41	66.30	–10.89	–16.4
Crack spread	31.69	15.59	16.10	103.3
FUTURES MARKET PRICES				
One month				
Product value	88.10	84.55	3.56	4.2
Light sweet crude	66.65	69.49	–2.85	–4.1
Crack spread	21.46	15.05	6.40	42.5
Six month				
Product value	82.86	82.11	0.75	0.9
Light sweet crude	69.76	72.11	–2.36	–3.3
Crack spread	13.11	10.00	3.11	31.1

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel Kerosine	Fuel oils		Unfinished oils
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PAD I	15,051	49,995	22,957	11,161	44,550	16,058	8,326
PAD II	74,171	50,381	16,936	6,774	29,161	1,076	12,658
PAD III	187,655	67,637	28,032	11,965	33,042	13,196	43,055
PAD IV	14,125	6,085	2,038	556	3,299	267	2,969
PAD V	[1]57,620	32,238	21,530	9,515	13,118	5,964	21,338
June 15, 2007	**[1]348,622**	**206,336**	**91,493**	**39,971**	**123,170**	**36,561**	**88,346**
June 8, 2007[3]	**348,157**	**205,403**	**91,268**	**41,187**	**122,157**	**35,343**	**89,708**
June 16, 2006	**344,342**	**211,958**	**91,380**	**39,603**	**123,368**	**41,485**	**92,951**

[1]Included in total motor gasoline. [2]Includes 6.560 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—JUNE 15, 2007

District	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,520	1,482	1,522	1,618	94.1	1,881	113	461	127
App. Dist. 1	124	94	94	95	99.0	49	0	44	0
Dist. 1 total	**3,644**	**1,576**	**1,616**	**1,713**	**94.3**	**1,930**	**113**	**505**	**127**
Ind., Ill., Ky.	2,332	2,133	2,177	2,355	92.4	1,287	90	548	43
Minn., Wis., Dak.	410	392	399	442	90.3	308	30	121	9
Okla., Kan., Mo.	959	677	699	786	88.9	484	18	272	7
Dist. 2 total	**3,701**	**3,202**	**3,275**	**3,583**	**91.4**	**2,079**	**138**	**941**	**59**
Inland Texas	788	441	456	647	70.5	416	27	159	7
Texas Gulf Coast	3,779	3,002	3,073	4,031	76.2	1,354	308	819	114
La. Gulf Coast	3,154	3,011	3,011	3,264	92.3	1,246	333	804	68
N. La. and Ark.	223	171	78	215	82.8	110	6	41	7
New Mexico	175	106	106	113	93.8	154	3	34	1
Dist. 3 total	**8,119**	**6,731**	**6,824**	**8,270**	**82.5**	**3,280**	**677**	**1,857**	**197**
Dist. 4 total	**681**	**567**	**574**	**596**	**96.3**	**280**	**29**	**164**	**14**
Dist. 5 total	**2,932**	**2,466**	**2,721**	**3,173**	**85.8**	**1,756**	**435**	**537**	**169**
June 15, 2007	**19,077**	**14,542**	**15,010**	**17,335**	**86.6**	**9,325**	**1,392**	**4,004**	**566**
June 8, 2007*	**19,325**	**14,543**	**15,059**	**17,335**	**86.9**	**9,111**	**1,500**	**3,986**	**631**
June 16, 2006	**18,313**	**15,993**	**16,410**	**17,115**	**95.9**	**9,174**	**1,420**	**4,161**	**620**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 6-13-07	Pump price* 6-13-07	Pump price 6-14-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	269.6	309.3	289.7
Baltimore	265.4	307.3	298.1
Boston	255.2	297.1	292.5
Buffalo	249.2	309.3	294.1
Miami	263.4	313.7	299.7
Newark	258.4	291.3	288.7
New York	248.5	308.6	301.9
Norfolk	260.6	298.2	290.9
Philadelphia	262.6	313.3	304.7
Pittsburgh	249.6	300.3	282.6
Wash., DC	269.9	308.3	308.4
PAD I avg.	259.3	305.1	295.6
Chicago	294.9	345.8	319.5
Cleveland	249.0	295.4	280.0
Des Moines	274.3	314.7	266.6
Detroit	277.5	326.7	282.6
Indianapolis	274.7	319.7	277.9
Kansas City	278.7	314.7	266.6
Louisville	280.9	317.8	286.3
Memphis	264.5	304.3	276.4
Milwaukee	270.6	321.9	288.1
Minn.-St. Paul	257.3	297.7	279.4
Oklahoma City	266.4	301.8	260.5
Omaha	256.3	302.7	274.1
St. Louis	275.6	311.6	267.9
Tulsa	265.0	300.4	260.6
Wichita	268.6	308.0	267.3
PAD II avg.	270.0	312.2	276.9
Albuquerque	287.9	324.3	284.5
Birmingham	261.4	300.1	276.8
Dallas-Fort Worth	254.2	292.6	286.4
Houston	251.1	289.5	286.7
Little Rock	259.5	299.7	272.6
New Orleans	266.9	305.3	278.1
San Antonio	255.7	294.1	268.7
PAD III avg.	262.4	300.8	279.1
Cheyenne	265.7	298.1	266.7
Denver	280.6	321.0	282.2
Salt Lake City	277.3	320.2	288.6
PAD IV avg.	274.5	313.1	279.2
Los Angeles	267.9	326.4	328.6
Phoenix	270.8	308.2	299.3
Portland	276.7	320.0	301.7
San Diego	282.2	340.7	334.7
San Francisco	286.5	345.0	336.3
Seattle	265.0	317.4	318.7
PAD V avg.	274.9	326.3	319.9
Week's avg.	**267.0**	**310.5**	**288.5**
May avg.	**264.1**	**307.6**	**288.5**
Apr. avg.	**234.7**	**278.3**	**270.5**
2007 to date	**220.3**	**263.8**	—
2006 to date	**211.4**	**254.4**	—

*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

	6-8-07 ¢/gal		6-8-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	208.55	New York Harbor	190.23
Gulf Coast	208.80	Gulf Coast	186.85
Los Angeles	216.05	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	199.29	ARA	190.73
Singapore	202.14	Singapore	194.76
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	218.05	New York Harbor	123.88
Gulf Coast	220.30	Gulf Coast	129.76
Los Angeles	228.05	Los Angeles	145.11
		ARA	117.03
		Singapore	131.84

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

BAKER HUGHES RIG COUNT

	6-15-07	6-16-06
Alabama	6	5
Alaska	8	9
Arkansas	45	23
California	32	35
Land	31	31
Offshore	1	4
Colorado	111	92
Florida	1	0
Illinois	0	0
Indiana	2	0
Kansas	14	9
Kentucky	8	6
Louisiana	171	192
N. Land	54	59
S. Inland waters	22	21
S. Land	31	35
Offshore	64	77
Maryland	0	0
Michigan	1	2
Mississippi	13	10
Montana	16	24
Nebraska	0	0
New Mexico	78	101
New York	5	6
North Dakota	36	28
Ohio	13	6
Oklahoma	197	180
Pennsylvania	13	17
South Dakota	4	1
Texas	837	752
Offshore	10	12
Inland waters	0	4
Dist. 1	18	24
Dist. 2	31	24
Dist. 3	60	61
Dist. 4	89	78
Dist. 5	177	129
Dist. 6	124	115
Dist. 7B	37	45
Dist. 7C	53	38
Dist. 8	113	89
Dist. 8A	28	31
Dist. 9	35	36
Dist. 10	62	66
Utah	40	43
West Virginia	35	24
Wyoming	77	104
Others—NV-3; TN-3; VA-3; WA-1	10	3
Total US	**1,773**	**1,672**
Total Canada	**251**	**441**
Grand total	**2,024**	**2,113**
Oil rigs	285	285
Gas rigs	1,484	1,383
Total offshore	76	94
Total cum. avg. YTD	**1,743**	**1,571**

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	6-15-07 Percent footage*	Rig count	6-16-06 Percent footage*
0-2,500	69	5.7	52	1.9
2,501-5,000	111	53.1	79	36.7
5,001-7,500	238	22.6	240	18.7
7,501-10,000	411	2.9	365	3.5
10,001-12,500	449	2.0	386	2.3
12,501-15,000	269	—	266	—
15,001-17,500	113	0.8	110	—
17,501-20,000	70	—	84	—
20,001-over	38	—	21	—
Total	**1,768**	**7.8**	**1,603**	**6.0**
INLAND	44		45	
LAND	1,659		1,485	
OFFSHORE	65		73	

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

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

OGJ PRODUCTION REPORT

	[1]6-15-07	[2]6-16-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	20
Alaska	779	789
California	668	687
Colorado	50	62
Florida	6	6
Illinois	32	28
Kansas	94	99
Louisiana	1,362	1,289
Michigan	15	16
Mississippi	48	48
Montana	92	98
New Mexico	165	161
North Dakota	106	111
Oklahoma	164	171
Texas	1,320	1,336
Utah	45	47
Wyoming	143	125
All others	60	71
Total	**5,167**	**5,164**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	6-15-07
Alaska-North Slope 27°	56.11
South Louisiana Sweet	72.75
California-Kern River 13°	58.45
Lost Hills 30°	67.30
Southwest Wyoming Sweet	65.09
East Texas Sweet	64.00
West Texas Sour 34°	57.65
West Texas Intermediate	64.50
Oklahoma Sweet	64.50
Texas Upper Gulf Coast	61.25
Michigan Sour	57.50
Kansas Common	63.75
North Dakota Sweet	60.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	6-8-07
United Kingdom-Brent 38°	70.70
Russia-Urals 32°	67.33
Saudi Light 34°	65.68
Dubai Fateh 32°	65.00
Algeria Saharan 44°	72.40
Nigeria-Bonny Light 37°	72.64
Indonesia-Minas 34°	67.60
Venezuela-Tia Juana Light 31°	64.10
Mexico-Isthmus 33°	63.99
OPEC basket	67.34
Total OPEC[2]	66.99
Total non-OPEC[2]	66.56
Total world[2]	66.79
US imports[3]	64.10

[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]

	6-8-07	6-1-07	Change
	Bcf		
Producing region	816	796	20
Consuming region east	1,097	1,036	61
Consuming region west	342	331	11
Total US	**2,225**	**2,163**	**92**
	Mar. 07	**Mar. 06**	**Change, %**
Total US[2]	**1,603**	**1,692**	**–5.3**

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

Statistics

World oil balance

	2006 4th qtr.	2006 3rd qtr.	2006 2nd qtr.	2006 1st qtr.	2005 4th qtr.	2005 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.00	21.13	20.86	20.73	21.14	21.22
Canada	2.26	2.27	2.14	2.21	2.33	2.28
Mexico	2.03	1.99	2.02	2.08	2.10	2.06
Japan	5.35	4.81	4.78	5.96	5.46	5.03
South Korea	2.30	2.02	2.03	2.28	2.23	2.01
France	1.96	1.95	1.89	2.10	1.96	2.00
Italy	1.69	1.66	1.63	1.86	1.78	1.68
United Kingdom	1.80	1.76	1.81	1.90	1.84	1.82
Germany	2.70	2.74	2.58	2.59	2.63	2.75
Other OECD Europe	7.42	7.39	7.17	7.36	7.49	7.31
Australia & New Zealand	1.11	1.07	1.06	1.06	1.10	1.04
Total OECD	**49.62**	**48.79**	**47.97**	**50.13**	**50.06**	**49.20**
NON-OECD						
China	7.53	7.25	7.34	6.97	7.07	6.86
FSU	4.57	4.34	4.39	4.57	4.66	4.10
Non-OECD Europe	0.70	0.65	0.69	0.74	0.69	0.64
Other Asia	8.77	8.45	8.55	8.46	8.69	8.27
Other non-OECD	14.49	14.67	14.38	14.24	14.02	14.02
Total non-OECD	**36.06**	**35.36**	**35.35**	**34.98**	**35.33**	**33.89**
TOTAL DEMAND	**85.68**	**84.15**	**83.82**	**85.11**	**85.39**	**83.09**
SUPPLY						
OECD						
US	8.46	8.48	8.35	8.18	7.74	7.95
Canada	3.40	3.32	3.16	3.29	3.28	3.02
Mexico	3.52	3.71	3.79	3.80	3.75	3.72
North Sea	4.76	4.51	4.71	5.11	5.05	4.95
Other OECD	1.51	1.51	1.40	1.39	1.51	1.55
Total OECD	**21.65**	**21.53**	**21.41**	**21.77**	**21.33**	**21.19**
NON-OECD						
FSU	12.42	12.22	12.03	11.78	11.97	11.74
China	3.83	3.83	3.85	3.83	3.75	3.80
Other non-OECD	11.67	11..87	11.67	11.49	11.75	11.81
Total non-OECD, non-OPEC	**27.92**	**27.92**	**27.55**	**27.10**	**27.47**	**27.35**
OPEC	**34.94**	**35.62**	**35.16**	**35.33**	**35.70**	**35.89**
TOTAL SUPPLY	**84.51**	**85.07**	**84.12**	**84.20**	**84.50**	**84.43**
Stock change	**–1.17**	**0.92**	**0.80**	**–0.91**	**–0.89**	**1.34**

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

OECD total net oil imports

	Feb. 2007	Jan. 2006	Dec. 2006	Feb. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,312	–1,310	–1,537	–1,360	48	–3.5
US	10,795	12,145	11,525	12,020	–1,225	–10.2
Mexico	–1,726	–1,601	–1,469	–1,734	8	–0.5
France	1,960	1,694	1,968	1,851	109	5.9
Germany	2,358	2,166	2,333	2,303	55	2.4
Italy	1,714	1,638	1,712	1,723	–9	–0.5
Netherlands	932	1,151	1,009	932	—	—
Spain	1,670	1,509	1,584	1,583	87	5.5
Other importers	4,050	3,977	3,811	4,381	–331	–7.6
Norway	–2,395	–2,673	–2,236	–2,324	–71	3.1
United Kingdom	–165	104	–4	113	–278	–246.0
Total OECD Europe	**10,124**	**9,566**	**10,177**	**10,562**	**–438**	**–4.1**
Japan	5,435	5,558	5,299	6,056	–621	–10.3
South Korea	2,087	2,349	2,250	2,339	–252	–10.8
Other OECD	792	760	880	1,013	–221	–21.8
Total OECD	**26,195**	**27,467**	**27,125**	**28,896**	**–2,701**	**–9.3**

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

OECD* total gross imports from OPEC

	Feb. 2007	Jan. 2007	Dec. 2006	Feb. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	304	480	395	431	–127	–29.5
US	5,342	6,093	5,852	5,925	–583	–9.8
Mexico	23	17	43	35	–12	–34.3
France	821	792	913	767	54	7.0
Germany	351	434	337	479	–128	–26.7
Italy	1,316	1,312	1,372	1,364	–48	–3.5
Netherlands	723	88	603	723	—	—
Spain	797	700	832	823	–26	–3.2
Other importers	1,426	1,245	1,342	1,130	296	26.2
United Kingdom	251	166	182	118	133	112.7
Total OECD Europe	**5,685**	**4,737**	**5,581**	**5,404**	**281**	**5.2**
Japan	4,382	4,433	4,622	5,357	–975	–18.2
South Korea	2,080	2,294	2,245	2,387	–307	–12.9
Other OECD	700	754	768	654	46	7.0
Total OECD	**18,516**	**18,808**	**19,506**	**20,193**	**–1,677**	**–8.3**

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

US petroleum imports from source country

	Feb. 2007	Jan. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	555	778	672	586	86	14.7
Angola	464	574	522	454	68	15.0
Kuwait	168	172	170	114	56	49.1
Nigeria	1,102	1,136	1,120	1,277	–157	–12.3
Saudi Arabia	1,207	1,563	1,394	1,408	–14	–1.0
Venezuela	1,359	1,195	1,273	1,508	–235	–15.6
Other OPEC	487	675	586	139	447	321.6
Total OPEC	**5,342**	**6,093**	**5,737**	**5,486**	**251**	**4.6**
Canada	2,448	2,470	2,460	2,287	173	7.6
Mexico	1,507	1,566	1,538	1,835	–297	–16.2
Norway	131	105	117	202	–85	–42.1
United Kingdom	268	194	229	196	33	16.8
Virgin Islands	312	425	371	297	74	24.9
Other non-OPEC	2,159	2,772	2,481	3,151	–670	–21.3
Total non-OPEC	**6,825**	**7,532**	**7,196**	**7,968**	**–772**	**–9.7**
TOTAL IMPORTS	**12,167**	**13,625**	**12,933**	**13,454**	**–521**	**–3.9**

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

Oil stocks in OECD countries*

	Feb. 2007	Jan. 2007	Dec. 2006	Feb. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	188	186	192	192	–4	–2.1
Germany	292	285	283	283	9	3.2
Italy	135	128	133	135	—	—
United Kingdom	107	105	109	104	3	2.9
Other OECD Europe	673	672	675	663	10	1.5
Total OECD Europe	**1,395**	**1,376**	**1,392**	**1,377**	**18**	**1.3**
Canada	171	176	179	178	–7	–3.9
US	1,666	1,723	1,721	1,724	–58	–3.4
Japan	631	638	631	600	31	5.2
South Korea	147	153	152	142	5	3.5
Other OECD	103	105	103	104	–1	–1.0
Total OECD	**4,113**	**4,171**	**4,178**	**4,125**	**–12**	**–0.3**

*End of period.
Source: DOE International Petroleum Monthly Report.
Data available in OGJ Online Research Center.

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Comprehensive bills stumble on complex issues

The political storm swamping US immigration reform helps explain troubles with energy policy.

The common element is a congressional preference for "comprehensive legislation."

The Energy Policy Act of 2005 (EPACT), which Congress was revisiting even before Democrats won control in 2006, was comprehensive legislation. It covered everything that every favor-seeking lobbyist for every energy form around could imagine.

The bill, however comprehensive, was incomprehensible while in Congress, incomprehensible when passed, and barely comprehensible as law. Hailed as a triumph of bipartisan compromise, EPACT now prepares for surgery as House and Senate Democrats remove parts they pretend never to have liked. Most are measures that might have boosted production of oil and gas. The same errant strategy seems to be guiding immigration reform.

It's a difficult problem, with those 12 million illegal residents making a mockery of US law, using public services they don't pay for, some maybe plotting terrorist attacks, and—things are never simple—doing jobs that few legal citizens want. So a Republican administration and Democratic legislature wrestled into being a reform package that, like EPACT on energy, tried to do everything at once on immigration.

Surprise! The compromises and deal-making that went into creation of the bill were nearly impossible to follow. Surprise! Hardly anyone liked the final product.

Whatever happened to simple problem-solving? Everyone agrees that border control needs work. Why can't Congress deal with that problem by itself?

Issues like treatment of the existing crowd of illegal residents, guest-worker programs, and admission preferences are trickier. Why not address them separately? Solutions would be better. Just as important, the compromises and deal-making would be easier to see. It's no mystery why politicians favor comprehensive legislation over targeted solutions to specific problems. Big bills make big news.

When they go wrong, however, big bills make big problems. Legislation that tries to do everything at once can be hard to get right. EPACT got too much wrong on energy: mainly too much market regulation and too little economic supply.

As with immigration, EPACT's difficulties started with law-making that tried to manage multiple issues needing focused attention in one historic package.

(Online June 15, 2007; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

OPEC reduces demand forecast

The Organization of Petroleum Exporting Countries expects demand for its crude to average 30.6 million b/d in 2007, a slight decline of 200,000 b/d from the previous year.

On a quarterly basis, demand for OPEC crude is estimated at 31.11 million b/d in the first quarter and respectively at 29.5 million b/d, 30.6 million b/d, and 31 million b/d in successive quarters. In 2006, demand for OPEC crude averaged 30.8 million b/d. The cartel expects non-OPEC supply to reach 50.6 million b/d in 2007, an increase of 1.1 million b/d over the previous year and a downward revision of 57,000 b/d from the last assessment.

In 2006, non-OPEC supply averaged 49.5 million b/d, representing an increase of 500,000 b/d over 2005. Total OPEC crude production averaged 30.03 million b/d in May, down 82,700 b/d from the previous month.

However, Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, said, "Reading the numbers rather than the headlines shows that all OPEC members (apart from Nigeria due to strife) have slightly increased production in May vs. April, with the losses of Nigeria offsetting those gains. OPEC will not commit now to a supply increase as it needs to see first how new developments in Nigeria impact production. If it was not for Nigeria, OPEC would have shown a supply increase in May."

OPEC said its basket of 11 reference crudes averaged $64.36/bbl in May, 97¢ higher than in April. Large commercial stocks of crude in the US were offset by a series of refinery glitches primarily in the US during a period of concern over rising demand with the onset of the summer driving season. Raids on oil field facilities and kidnapping of workers in Nigeria kept the market nervous about oil supply.

The OPEC basket price remained volatile in June as Cyclone Gonu threatened petroleum facilities and shipping in the Middle East. Prices rose under pressure from geopolitical tensions to over $67/bbl before dropping to just above $65/bbl. OPEC's basket price had increased to $66.74/bbl by June 14.

In its June report, OPEC forecast growth in 2007 world oil demand at 1.3 million b/d or 1.5%, broadly unchanged from its previous forecast. So far this year, US demand grew 2.3% or 470,000 b/d, boosted by strong gasoline consumption. Construction and petrochemical activity across the Middle East fueled strong oil demand growth in that region, while a robust economy raised oil demand in India by 7.1% or 189,000 b/d in April. That same month, China's demand rose by a stunning 9.8% or 700,000 b/d from a year ago to 7.9 million b/d.

China's apparent oil demand in the second quarter is expected to grow by 500,000 b/d to average 7.8 million b/d. For 2006, the world oil demand estimate was revised up by 150,000 b/d from our last month's estimate due to historical revisions in the developing countries, OPEC said.

IEA, EIA numbers

Earlier, the Paris-based International Energy Agency (IEA) raised its estimates of global demand for oil products by 250,000 b/d to 84.5 million b/d for 2006 and by 420,000 b/d to 86.1 million b/d for 2007. It also said in its monthly report that world supplies of crude in May fell by 565,000 b/d to 84.9 million b/d. IEA's estimate of non-OPEC production again was trimmed by 110,000 b/d to 50.2 million b/d, resulting in an overall increase of 900,000 b/d (OGJ Online, June 12, 2007).

"The IEA report and tone has become too predictable and as credible as OPEC," Jakob said. "For OPEC the supply situation is always under control and for the IEA we are always facing an acute shortage. The truth is somewhere in the middle, and in the end the market reacts more to the politically neutral weekly statistics from the US Department of Energy. The weekly DOE statistics will need to provide some support, otherwise the weekly charts will take a turn for the worse."

In its latest available report, DOE's Energy Information Administration (EIA) said US gasoline stocks were unchanged at 201.5 million bbl in the week ended June 8, instead of the 1.5-2 million bbl increase that many had expected. Refinery utilization dipped to 89.2% from 89.6% in the week ended June 8 vs. a consensus expectation for a 0.7% increase.

Gasoline production increased slightly, nonetheless; but gasoline imports declined by 350,000 b/d (23%) in the same period. US crude inventories inched higher by only 100,000 bbl to 342.4 million bbl that week. Distillate fuel inventories increased by 300,000 bbl to 122.6 million bbl (OGJ Online, June 13, 2007).

(Online June 18, 2007; author's e-mail: samf@ogjonline.com)