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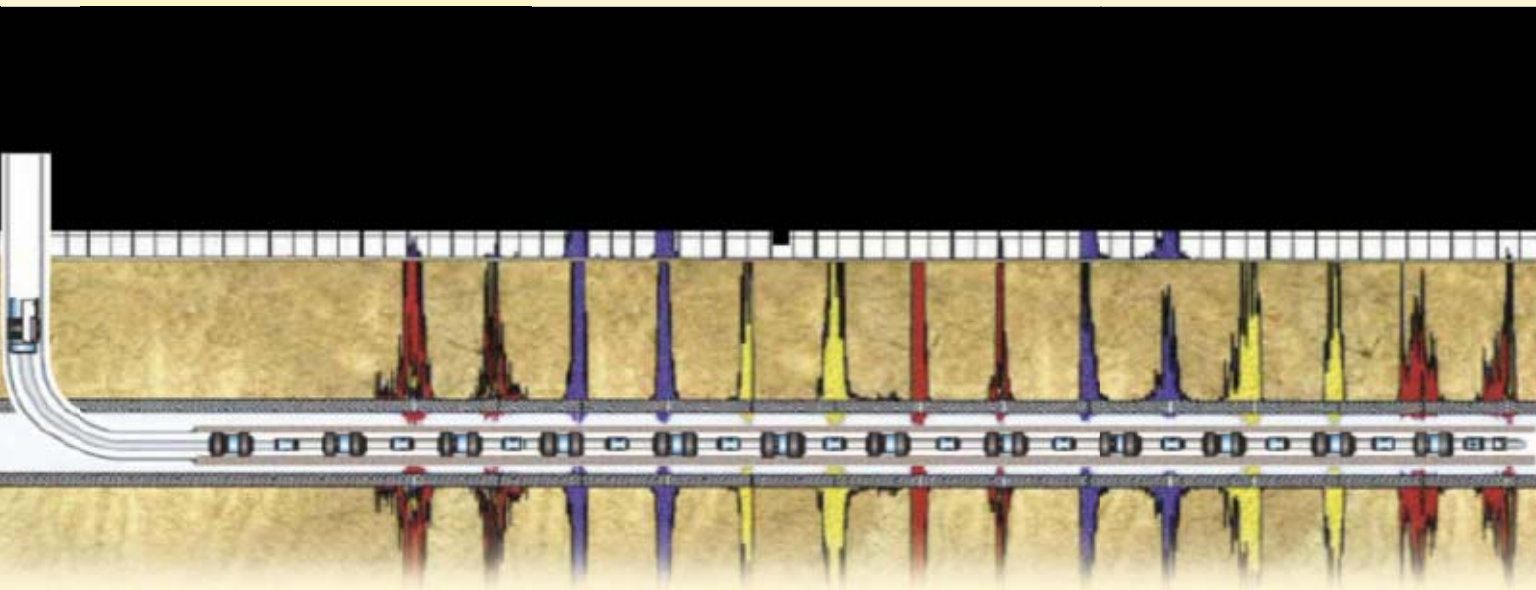
Trends In Unconventional Gas

Efficiency updates cut GHG emissions, help profits
Discovery off Sierra Leone may set up 700-mile play
La. refinery converts control system without shutdown
Effective defense requires thorough risk assessment

OIL&GAS JOURNAL®

Sept 28, 2009
Volume 107.36

TRENDS IN UNCONVENTIONAL GAS



REGULAR FEATURES

COVER

The hydraulic fracturing equipment is on the Nadel & Gussman-Jetta Operating Co.'s Franks 17 No. 2 well that is completed in the Haynesville shale, north of Shreveport, La. Hydraulic fracturing is one of the technologies that has allowed for the economic exploitation of the vast gas resources contained in shales, as discussed in two articles in OGJ's special report on trends in unconventional gas, starting on p. 39. Photo from Halliburton.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Sept. 28, 2009

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General Interest — Quick Takes

IHS Herold: Hofmeister wants independent agency

John Hofmeister, former president of Shell Oil Co., wants the US to come up with a comprehensive approach to energy and the environment rather than using one that's politically driven.

Speaking on Sept. 22 at the IHS Herold Pacesetters Energy Conference in Greenwich, Conn., Hofmeister called for the implementation of an independent regulatory agency for energy policy. He envisions something similar to what the Federal Reserve has been for banking.

He suggests a federal energy resources board that would have its own rules, its own funding, and an appointment process independent of election cycles.

"If we fail to take the politics out of energy, we are going to zig-zag our way into the future," Hofmeister said. "Energy is too important to leave to everyday politics."

He noted that eight presidents and 18 Congresses have promoted US energy independence while oil imports have continued to grow in the last 35 years.

"We have yet to get a grip on what it means to be a modern country regarding energy and environment," he said.

Currently, Hofmeister is founder and chief executive officer of Citizens for Affordable Energy, a grassroots organization seeking to educate the public about energy.

IHS Herold: Markets to have 'moderate' recovery

Prices for light, sweet crude are expected to average $67/bbl during 2010, a spokesman said Sept. 22 at the Pacesetters Energy Conference.

Oil prices dropped to about $35/bbl during February and have since rebounded with reports of improving global economic growth. Jim Burkhard, managing director of the IHS CERA's (Cambridge Energy Research Associates) Global Oil Group, believes that oil demand in the Organization for Economic Cooperation and Development nations likely peaked in 2005.

"We're not going to get back to that (oil) demand level again," Burkhard said, which means potentially less upward pressure on oil prices, primarily because oil demand in OECD nations continues to shrink.

The reasons behind lower oil demand include rising fuel economy standards in many countries and the penetration of alternative fuels, Burkhard said.

Sara Johnson, IHS Global Insight managing director of global macroeconomics, said the US real gross domestic product is beginning to recover, but she expects unemployment rates will continue to rise going into next year.

"Beware of early 2010," Johnson said, adding that she expects to see the start of job creation toward the end of the first quarter and beginning of the second quarter. "Don't expect a strong 'V-shape' recovery in the US."

The US dollar will depreciate and demonstrate more weakness through 2012, she said.

IHS Herold: Global reserves fall in 2008

Oil and gas companies' 2008 global investment for exploration and development projects totaled $492 billion—a 21% increase from 2007—yet oil and gas reserves fell, according to a report from IHS Herold Inc. and Harrison Lovegrove & Co. Ltd.

In the latest annual upstream performance review, the two companies reported that high oil prices during most of 2008 helped industry to generate record cash flow of $590 billion, up 36% from 2007. Report highlights were discussed Sept. 23 during the Pacesetters Energy Conference.

Industry's 2008 cash flow exceeded capital spending by $100 billion. Cash flow per boe increased 35% from 2007 to $29.66/boe. Last year marked the second consecutive year cash flow exceeded investment, the report said.

The 2009 Global Upstream Performance Review is an annual analysis of 232 oil and gas companies based on reports filed with the US Securities and Exchange Commission and other similar agencies worldwide.

"It is a very capital-intensive job to maintain reserves," said Nicholas Cacchione, IHS Herold senior vice-president and co-director of equity research. He expects reserves probably will drop in 2009 unless finding and development costs see a dramatic decline.

In 2008, world oil reserves declined nearly 3%, primarily due to a 5.2 billion bbl decline in revisions that stemmed from reduced commodity prices. Natural gas reserves grew by 3%, the same as the past 5 years. Gas production accelerated nearly 5% to 44.2 tcf.

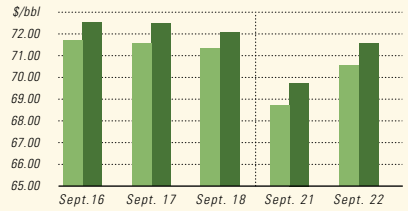
Reserve replacement costs surged to $23.44/boe, up 70%, while finding and development costs rose 66% to $25.50/boe, due to a sharp drop in positive reserve revisions. Reserve additions, both from all sources and via the drillbit, were down over 20%.

During 2008, worldwide oil and gas revenues were $1.2 trillion, but net income was constrained by rapidly rising depreciation charges. Net income for 2008 was just under $310 billion.

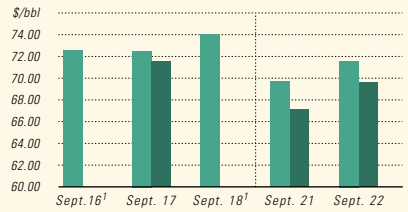
Spending for proved reserves dropped 30% to $44 billion as merger and acquisition activity collapsed during the last 5 months of 2008, particularly in the US and Canada. Competition for unconventional resources was up sharply, led by US gas shale plays. Global spending for unproved reserves more than doubled from 2007 to $62 billion. ✦

Industry Scoreboard

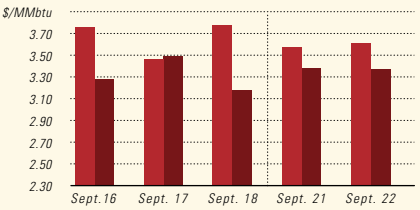
IPE BRENT / NYMEX LIGHT SWEET CRUDE



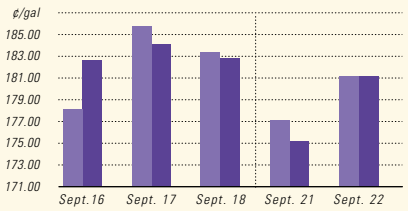
WTI CUSHING / BRENT SPOT



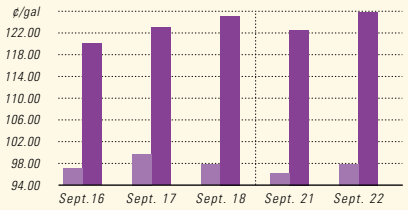
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



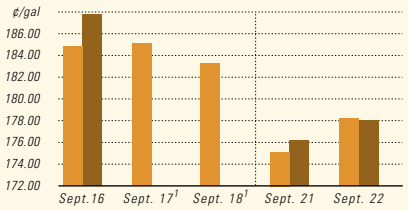
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

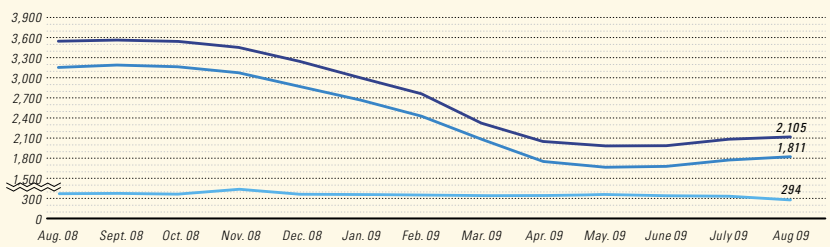
US INDUSTRY SCOREBOARD — 9/28

Latest week 9/11	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,217	8,907	3.5	9,008	9,041	–0.4
Distillate	3,437	3,688	–6.8	3,605	3,961	–9.0
Jet fuel	1,486	1,582	–6.1	1,397	1,587	–12.0
Residual	558	514	8.6	578	629	–8.1
Other products	4,755	4,069	16.9	4,202	4,482	–6.2
TOTAL DEMAND	19,453	18,760	3.7	18,790	19,700	–4.6
Supply, 1,000 b/d						
Crude production	5,247	4,550	15.3	5,225	5,044	3.6
NGL production[2]	2,188	2,084	5.0	2,006	2,140	–6.3
Crude imports	9,200	9,654	–4.7	9,255	9,849	–6.0
Product imports	2,430	2,908	–16.4	2,760	3,151	–12.4
Other supply[3]	1,696	1,542	10.0	1,717	1,546	11.1
TOTAL SUPPLY	20,761	20,738	0.1	20,963	21,730	–3.5
Refining, 1,000 b/d						
Crude runs to stills	14,501	14,088	2.9	14,501	14,697	–1.3
Input to crude stills	14,860	14,477	2.6	14,860	15,038	–1.2
% utilization	84.2	82.2	—	84.2	85.4	—

Latest week 9/11	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	332,753	337,482	–4,729	291,706	41,047	14.1
Motor gasoline	207,700	207,153	547	184,634	23,066	12.5
Distillate	167,793	165,556	2,237	129,625	38,168	29.4
Jet fuel-kerosine	45,152	45,341	–189	39,084	6,068	15.5
Residual	33,902	33,583	319	35,980	–2,078	–5.8
Stock cover (days)[4]			Change, %		Change, %	
Crude	22.3	22.9	–2.6	20.4	9.3	
Motor gasoline	22.5	22.4	0.4	20.1	11.9	
Distillate	48.8	47.8	2.1	32.1	52.0	
Propane	64.4	65.8	–2.1	56.8	13.4	
Futures prices[5] **9/18**			Change		Change	%
Light sweet crude ($/bbl)	71.36	70.91	0.45	102.85	–31.49	–30.6
Natural gas, $/MMbtu	3.52	2.96	0.56	7.41	–3.89	–52.5

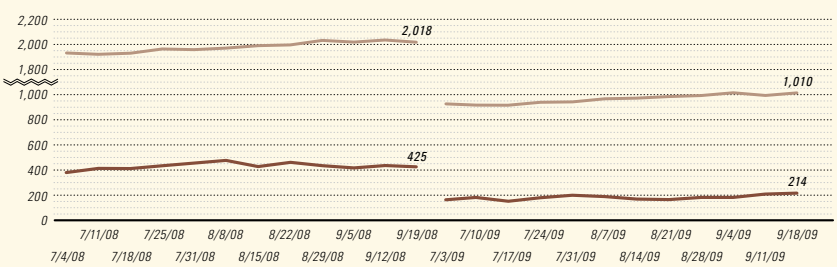
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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

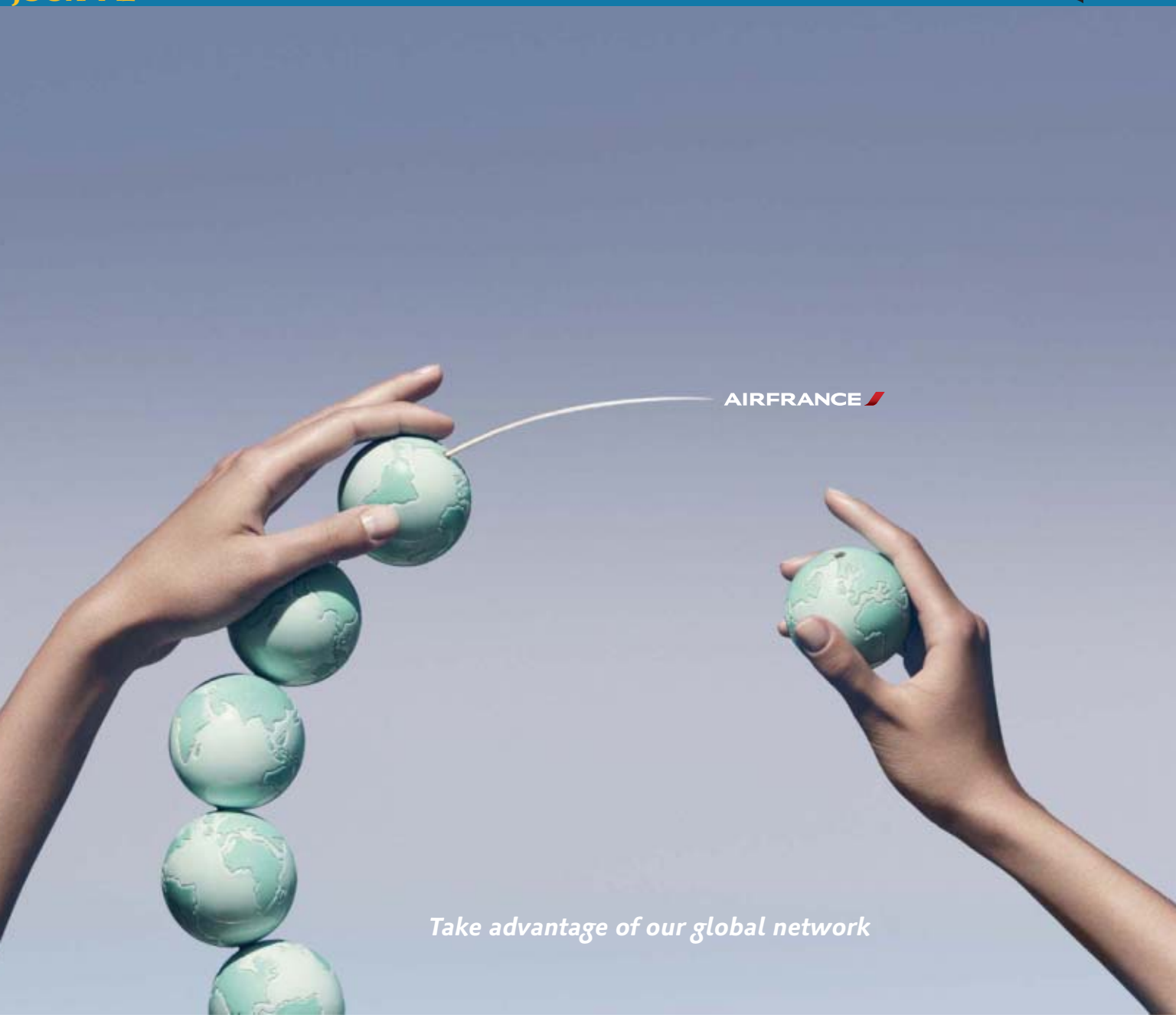


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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Exploration & Development — *Quick Takes*

McMoRan drilling ultradeep gulf shelf prospect

McMoRan Exploration Co., New Orleans, is setting intermediate casing at 23,500 ft, below a salt weld, at a proposed 28,000-ft ultradeep shelf prospect as part of its Gulf of Mexico exploration program.

McMoRan reentered a wellbore on South Marsh Island Block 230 in 20 ft of water south of Vermilion Bay. The Davy Jones prospect involves a large ultradeep structure on four blocks. The company will deepen the well to test Eocene Wilcox, Paleocene, and possibly Cretaceous Tuscaloosa.

Working interests in the prospect are expected to be McMoRan 25.7%, Plains Exploration & Production Co. 27.7%, Energy XXI 15.8%, Nippon Oil Exploration USA Ltd. 12%, W.A. "Tex" Moncrief Jr. 8.8%, and a private investor 3%.

Meanwhile, McMoRan plans to kick off a second sidetrack shortly at its Blueberry Hill deep gas prospect in 10 ft of water on Louisiana State Lease 340. The initial well and a first sidetrack established a 190-ft vertical hydrocarbon column, and the second sidetrack is to identify an optimum production take point.

McMoRan plans an updip sidetrack of the Hurricane Deep well on the southern flank of the Flatrock structure on South Marsh Island Block 217 in the fourth quarter of 2009.

Logs at the Hurricane Deep 226 well, drilled to 20,712 ft true vertical depth in early 2007, indicated an exceptionally thick upper Gyro sand totaling 900 gross ft, the top 40 ft of which were hydrocarbon-bearing. McMoRan believes the updip sidetrack could intersect a thicker hydrocarbon column.

McMoRan recompleted the Flatrock-5 well in September for production of 65 MMcfd of gas equivalent, bringing total output from five of the six Flatrock field wells to 265 MMcfed. Flatrock-4, shut-in in August due to a wellbore mechanical issue, is to return to production in the fourth quarter.

McMoRan plugged as noncommercial the Sherwood deep gas exploratory prospect on High Island Block 133. TD is 17,000 ft.

Talisman consolidates in Papua New Guniea

Talisman Energy Inc. has consolidated its foothold in Papua New Guinea by farming into Sydney-based New Guinea Energy Ltd.'s (NGE) onshore western province permits PPL 268 and PPL 269.

NGE announced in July 2008 that it had reached an agreement with a multinational oil company, but refrained from naming the company until the farm-in agreement had been finalized.

For permit PPL 269 NGE will assign an initial 50% interest and operatorship to Talisman. Talisman will then reimburse NGE for 75% of the direct costs of past expenditure—about $5 million—and fund an agreed seismic program up to a maximum of $6 million as well as comit to drilling, completing and testing a well up to a maximum of $15 million.

NGE will also have the option of progressively assigning up to an additional 20% interest in the permit based on the decisions over its funding share in the second and third option wells to a maximum of $15 million/well.

If NGE chooses to remain at 50% interest, Talisman will have the right to proceed with two additional wells by contributing 75% of the costs of the second and 65% of the costs of the third.

For PPL268, Talisman will assume an interest and operatorship of 15% by reimbursing NGE for 50% of past costs ($2.17 million) and funding an agreed seismic program up to a maximum of $5 million.

Talisman will be able to gain a further 35% by funding 80% of the costs of drilling, completing and testing a well. It can gain another 20% interest by funding 100% of two more wells.

NGE has decided not to farm out its third permit in the region (PPL267) and expects to drill a well on its Panakawa prospect before yearend.

Talisman's interests in PNG also include ownership of Rift Oil, which also has permits in the western province and a farm-in to nearby permits held by Horizon Oil.

Washington exploratory well disappoints Delta

Delta Petroleum Corp., Denver, said its plans for further drilling in the southern Columbia River basin in Washington state have been placed on hold until the company reviews completion and test information from the Gray 31-23 well, where tests have proved noncommercial thus far.

Delta perforated and tested the majority of the prospective zones in the Gray well at 11,580-12,280 ft.

"The six lowermost zones demonstrated high pressures as expected, but have flowed only fresh water to date. The zones located further uphole have flowed a combination of water and gas; however, the gas volumes have been minimal and substantially below precompletion expectations deeming these intervals uneconomic," the company said.

More tests are planned in the basalt section on intervals that had gas shows during drilling.

Delta and Husky Energy Ltd. hold 50-50 interests in 424,000 net undeveloped acres in the basin.

Aegean to start second phase at Epsilon field

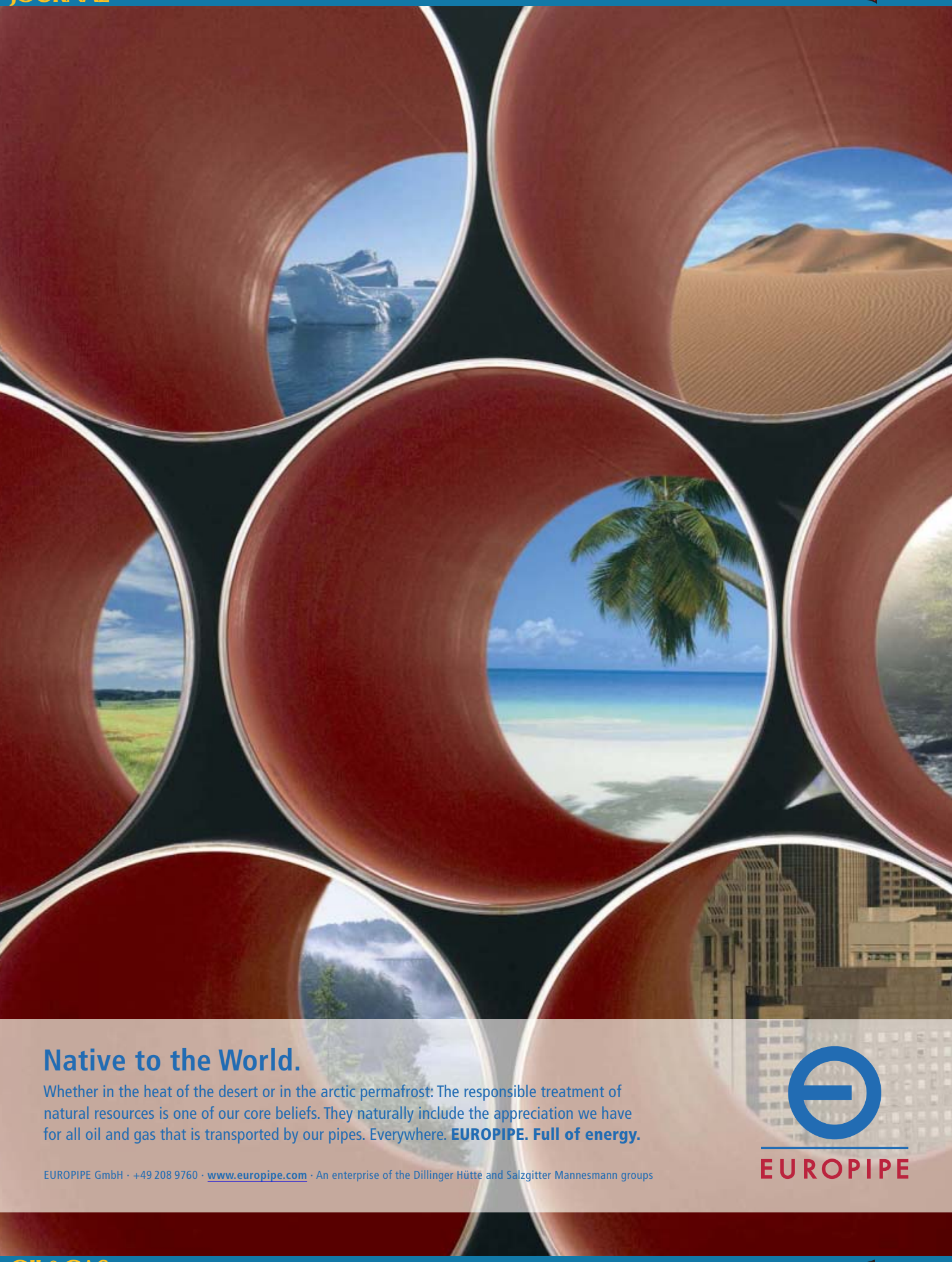
Aegean Energy SA and Kavala Oil SA will use the Ensco85 (E85) jack up rig to start the second phase of its drilling program in Epsilon field off Greece with what would be the deepest and longest well ever drilled there.

The program, which calls for drilling in the Gulf of Kavala about 8 km west of Thassos Island and 18 km south from the main coast, was approved by the Greek Ministry of Development. The well will be spudded by the end of September. It is expected to reach a TVD of 5,500 m and vertical depth of 2,900 m within 90 days.

Aegan Energy secured $50 million from Standard Chartered Bank to underpin its program and hired Schlumberger to provide drilling management services.

The 2,000-hp E85 rig is capable of a maximum drilling depth of 7,600 m.

Last month Aegean Energy completed the PNA-H3 horizontal well on Prinos North field in Greece, which reached a TD of 4,370 m over 135 days because of the reservoir's complexity. It



was drilled by the Energy Exeter jack up rig. The field lies in 50 m of water.

This and the Epsilon well are expected to increase production to 5,000 b/d from 1,300 b/d. ✦

Drilling & Production — *Quick Takes*

World's first acoustic optical fiber installed

Composite Energy Ltd., Stirling, UK, installed the world's first downhole distributed acoustic optical-fiber monitoring system in a coalbed methane well in Scotland, according to Fotech Solutions Ltd., Hampshire, UK, the fiber's manufacturer.

The system is providing data such as downhole pump conditions, water level, flow profiles across production intervals, wellhead vibrations, and gas flow. Fotech notes that other potential uses include monitoring and locating sand production, determining tubing integrity, and detecting cross flow.

The system includes a low-cost telecoms-grade optical fiber and Flotech's Helios interrogator that provides acoustic or vibration information for each meter along the fiber's length, Fotech says.

Composite Energy, established in 2004, is active in developing CBM and holds 21 licenses covering coal fields in Scotland, England, and Wales.

Camamu-Almada basin block to be relinquished

A group led by Petroleo Brasileiro SA (Petrobras) plans to relinquish the B-CAM-40 exploration block to Brazil's Agencia Nacional do Petroleo (ANP).

No further exploration is planned on the Camamu-Almada basin block, whose exploration license has expired, said Norse Energy Corp. ASA, Oslo, which holds 10% interest. Petrobras holds 35% interest, and Brazil's Queiroz Galvao Perfuracao holds 55%.

Production from Manati gas-condensate field on the block reached a record 7.13 million cu m/day on Sept. 17. Output had averaged 5.23 million cu m/day so far in the current quarter, and the record was made possible by the completion of maintenance at a fertilizer plant that takes the field's gas, Norse said.

Norse expects production to stabilize above 6 million cu m/day for the rest of 2009 and increase further in 2010 (OGJ Online, Jan. 22, 2007).

Meanwhile, the 2001 Camarao Norte discovery, 9 km south of Manati field, which extends into the BM-CAL-4 block held 100% by El Paso Corp., is to be unitized, and unitization discussions will occur within months.

Reservoirs at Camarao Norte, formerly BAS-131, are in Upper Jurassic Sergi sandstones, same as at Manati. Norse estimates its 10% share of recoverable oil and gas at 12.4 million boe. The field is a 17 sq km ring-fenced area in 40 m of water.

El Paso declared commerciality of the field in the BM-CAL-4 block and proposed the name of Camarao. ✦

Processing — *Quick Takes*

Siberian gas plant expansion starts up

Russian petrochemicals giant Sibur LLC announced earlier this month start-up of the second stage of its expansion at the Yuzhno-Balyksky gas processing plant in the Tyumen region, roughly 600 miles west of Novosibirsk.

The plant handles a hydrocarbon feed associated with crude oil production (called "associated petroleum gas") which it separates into natural gas, NGLs, and napthas. Its expansion doubles inlet capacity to 3 billion cu m/year (nearly 3 bcfd) and pushes Sibur's company-wide gas processing capacity to 19 billion cu m/year, said its announcement.

Sibur told OGJ that its current facilities under the Sibur Group include six gas processing plants—Nyagan, Muravlenkovsky, Gubkinsky, Yuzhno-Balyksky, Nizhnevartovsk, and Belozerny—and three compressor stations—Vyngopurovskaya, Varyeganskaya, and Vyngayakhinskaya. All are in western Siberia.

The new complex at Yuzhno-Balyksky consists of a booster compression station, drying and low-temperature condensation sections, a propane refrigeration plant, and other facilities.

Modernization of Yuzhno-Balyksky gas plant began in 2007 with the first stage increasing associated-gas processing capacity to 1.5 billion cu m/year from 900 million cu m/year.

The just-completed second stage of the expansion was designed by NIPIgazpererabotka JSC, Sibur's engineering center for gas-processing technologies, said the company. The control system was fully automated by Yokogawa Co., Japan. The new complex can handle both high and low-pressure associated gas.

When the entire new complex attains design capacity, the plant will produce 2.8 billion cu m/year of dry gas and 900,000 tonnes/year (about 28,000 b/d) of light hydrocarbons.

The capacity increase is aimed at receiving additional volumes of associated natural gas, mainly from the Priobskoye oil field that is being developed by Rosneft JSC. Sibur said modernization and expansion at the Yuzhno-Balysky plant have improved utilization of raw stream produced gas to 95%.

Partners break ground on Devil Creek gas plant

Joint venture partners Apache Energy Ltd. and Santos Ltd. broke ground at the Devil Creek domestic natural gas processing plant site in the Pilbara region of Western Australia about 50 km south of Karratha.

The plant will be fed raw gas through a 105-km subsea pipeline from the joint venture's offshore Reindeer field development in the WA-209-P permit.

The plant will supply as much as 220 TJ/day of gas into the Dampier-Bunbury trunk line. It will also produce as much as 500 b/d of condensate.

Santos has already signed up CITIC Pacific Ltd., Hong Kong, as the project's foundation gas buyer.

Under the $812 million (Aus.) contract, Santos will supply CITIC's Sino Iron magnetite mining project at Cape Preston, 100 km south of Dampier with 75 PJ of gas over 7 years from the latter half

of 2011. The gas will be used as generation fuel for Sino's 450-Mw electric power station now under construction.

Reindeer field was discovered in 1997 and has a recoverable resource range of 390-610 bcf of gas.

Perth-based engineering and construction company Clough Australia is engaged as engineering, procurement and module fabrication contract for the Devil Creek project.

The $54 million (Aus.) contract is for engineering, design work, and procurement of all permanent materials and equipment plus fabrication and assembly of all modules for the facility.

Apache Energy in West Perth, a subsidiary of Houston-based Apache Corp., has 55% of the project with Santos holding 45%.

Tullow will sell stake to fund Uganda refinery

Tullow Oil Ltd. plans to sell part of its Ugandan assets to finance an oil pipeline project and other production infrastructure, according to state media.

Uganda's state-owned New Vision newspaper said Tullow confirmed it would sell part of its wholly owned Block-2, to finance developments in the Lake Albertine basin.

"Uganda's oil basin development plan is an integrated project that requires building of a refinery that is linked with pipelines to supply local, regional and international markets," said Tim O'Hanlon, Tullow's vice-president for African business.

O'Hanlon said a joint venture undertaking is crucial because "we are an exploration and production company, but not in the pipeline or refinery business. …We need a partner with expertise in this area."

He said Tullow has "received many interested firms, but we are still screening them with the government to get the right partner."

Uganda's President Yoweri Museveni has said he will not allow international oil companies to refine the oil outside the country, saying it must be refined domestically to ensure that more profits are retained in the country.

Meanwhile, the discovery of oil in Uganda and plans to build a refinery could be delaying construction of the planned 320-km Eldoret to Kampala oil pipeline, according to a senior Kenyan ministry official.

Work has yet to begin on the pipeline, which was awarded to the Libyan-backed Tamoil East Africa in 2006, due to concerns that a refinery in Uganda will reduce profitability of their business and require more time to recoup their investment.

"The Libyans are asking for certain guarantees that should Uganda construct a refinery, it will in no way affect the pipeline usage," said Peter Nyoike, Permanent Secretary in Kenya's Ministry of Energy.

In June, Tamoil announced groundwork on the pipeline was expected to begin in July, with completion scheduled for 2011—4 years later than planned. Tamoil will hold a 51% stake in the pipeline, while Uganda and Kenya will jointly hold the remaining 49%. ✦

Transportation — *Quick Takes*

FERC issues final EIS for FGT expansion project

The US Federal Energy Regulatory Commission's staff issued a final environmental impact statement on Florida Gas Transmission Co.'s Phase VIII expansion project just 5 months after it issued a draft EIS on the proposed $2.46 billion project.

The proposed line expansion in Alabama and Florida would add 820 MMcfd of capacity to FGT's system, FERC said. The project would include laying 483.2 miles of multidiameter pipeline, adding 198,000 hp of compression to eight existing stations, building a 15,600-hp compression station, constructing three meter and regulator stations, and upgrading two existing meter stations and building a regulator station, FERC said Sept. 18 in the final EIS.

The proposed expansion, expected to cost $2.455 billion, would start service in Spring 2011, assuming that it receives the necessary permits and approvals, according to FGT. The system is owned by Citrus Co., a joint venture of Southern Union Co., the pipeline's operator, and El Paso Corp.

FERC's final EIS said the proposed project would have limited environmental impacts, with appropriate mitigation measures, for reasons similar to those it listed in the draft EIS on Apr. 17. Commissioners will consider public comments and the final EIS before making a final decision, FERC said.

Golar LNG sign Fisherman's Landing deal

Golar LNG has signed a heads of agreement to sell LNG from the Fisherman's Landing coalseam methane-LNG project near Gladstone to Toyota Tsucho Corp. of Japan.

Toyota has agreed to buy 1.5 million tonnes/year of LNG for 12 years beginning in 2014.

Negotiations are now under way for the Toyota Group trading company to also buy a minority equity interest in the Fisherman's Landing project.

It is the smallest of the five CSM-supplied LNG plants proposed for Gladstone. The $500-million plant, scheduled to come on stream in 2012, is being developed by Golar and Perth Co. LNG Ltd. and will be supplied by CSM from Brisbane-based Arrow Energy Ltd.'s fields in the Surat basin in central Queensland.

Arrow says it has more than enough gas to supply the first LNG train. Site preparation has already commenced and documentation for front-end engineering and design has been submitted. In addition shipping agreements are in place and Toyota has become the foundation buyer.

At the moment LNG Ltd. and Golar each have a 40% interest in the Fisherman's Landing plant while Arrow has the option to take the remaining 20% stake. ✦

Correction

Japan's refiners facing hard choices, must seek alliances to ease closings" (OGJ, Aug. 3, 2009, p. 44) by Tomoko Hosoe, the vertical axis (Million b/d) was inadvertently reversed. The increments should ascend the axis 0 to 6.

Calendar

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

OIL&GAS JOURNAL online

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

2009

SEPTEMBER

ERTC Sustainable Refining Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 28-30.

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

Unconventional Gas International Conference & Exhibition, Fort Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 29-Oct. 1.

ERTC Biofuels+ Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 30-Oct. 2.

OCTOBER

Interstate Oil and Gas Compact Commission Annual Meeting (IOGCC), Biloxi, Miss., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

SPE Annual Technical Conference and Exhibition, New Orleans, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-7.

Canadian Offshore Resources Exhibition & Conference (CORE), Halifax, NS, (902) 425-4774, (902) 422-2332 (fax), e-mail: events@otans.com, website: www.otans.com. 5-8.

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 6-8.

Kazakhstan International Oil & Gas Exhibition & Conference (KIOGE), Almaty, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-9.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.powergenasia.com. 7-9.

Renewable Energy World Asia Conference & Expo, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.renewableenergyworld-asia.com. 7-9.

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

API Fall Petroleum Measurement Standards Meeting,

Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

Expandable Technology Forum, Houston, +44 (0) 1483 598000, e-mail: sally.marriage@otmnet.com, website: www.expandableforum.com. 14-15.

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

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale/. 19-23.

Oil and Gas Transportation in the CIS and Caspain Region Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 20-22.

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

PICT-Passive Inflow Control Technology Meeting, Copenhagen, +44 (0) 1483-598000, e-mail: Dawn.Dukes@otmnet.com, website: www.inflowcontrol.com. 27-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

North African Oil and Gas Summit, Tunis, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

NOVEMBER

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 5.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO2symposium.com. 5-6.

Sulphur International Conference and Exhibition, Vancouver, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.sulphurconference.com. 8-11.

Gas Turbine Users International (GTUI) Annual Conference, Calgary, Alta., +9714 804 7738, +9714 804 7764 (fax), e-mail: info@gtui.org, website: www.gtui.org. 8-13.

Calendar

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

Multiphase User Roundtable-South America, Rio de Janeiro, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-sa.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Digital E&P Event, Houston, (646) 200-7444, (212) 885-2733 (fax), e-mail: cambrosio@wbresearch.com, website: www.digitaleandp.com. 9-11.

NPRA/API Operating Practices Symposium, Dallas, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 10.

Petroleum Association of Wyoming (PAW) Annual Oil & Gas Statewide Reclamation Conference, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: cheryl@pawyo.org, website: www.pawyo.org. 10.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 10-12.

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NPRA International Lubricants & Waxes Meeting, Houston, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 12-13.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

✦Latin America LPG Seminar, Miami, (713) 331-4000, (713) 236-8490 (fax), e-mail: ts@purvingertz.com, website: www.purvingertz.com. 16-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

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

DECEMBER

Advanced Contract Risk Management Europe for Oil & Gas, Aberdeen, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.contractriskmanagement.MAC=11579.003EDIARY. 1-2.

Refining and Petrochemicals in Russia and the CIS Countries Annual Meeting, Amsterdam, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 1-3.

World LNG Summit, Barcelona, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), e-mail: info@thecwcgroup.com, website: www.thecwcgroup.com. 1-4.

European Drilling Engineering Association Expandables, Multilaterals and Technologies Meeting, Vienna, +44 (0) 1483-598000, e-mail: Dukes@otmnet.com, website: www.dea-europe.com. 3-4.

Nuclear Power International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.nuclearpowerinternational.com. 8.

Power-Gen International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.power-gen.com. 8-10.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

PIRA Understanding Natural Gas and LNG Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 14-15.

PIRA Understanding Global Oil Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 16-17.

2010

JANUARY

Plant Maintenance in the Middle East & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 10-13.

Oil & Gas Maintenance Technology Conference & Exhibition Co-located with Pipeline Rehabilitation and Maintenance, Manama, Bahrain, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 18-20.

Pipeline Rehabilitation & Maintenance Co-located with Oil & Gas Maintenance Technology, Manama, Bahrain, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pipeline-rehab.com. 18-20.

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

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

SPE Deep Gas Conference, Manama, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 24-27.

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

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

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

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

Annual Gas Arabia Summit, Abu Dhabi, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. Jan. 31- Feb. 3.

International Process Analytical Technology Forum (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. Jan 31-Feb 4.

FEBRUARY

Deep Offshore Technology International Conference & Exhibition, Houston, (713) 963-6271, (713) 963 6296 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 2-4.

IADC/SPE Drilling Conference and Exhibition, New Orleans, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@.org, website: www.iadc.org. 2-4.

Russia Offshore Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 2-4.

Global Petrochemicals Conference & Annual Meeting, Vienna, Austria, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. Feb 9-11.

SPE International Symposium & Exhibition of Formation Damage Control, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NAPE Expo, Houston, (817) 847-7701, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. Feb 11-12.

Annual Petroleum Coke Conference, Seattle, (832) 351-7828, (832) 351-7887 (fax), e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 12-13.

SPE North Africa Technical Conference & Exhibition, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 14-17.

✦IP Week, London, +44 0 20 7467 7132, +44 0 20 7255 1472 (fax), e-mail: jbia@energyinst.org.uk, website: www.energyinst.org.uk. 15-18.

Pipeline Pigging & Integrity Management Conference & Exhibition, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 16-18.

Pipe Line Contractors Association Annual Conference (PLCA), Scottsdale, Ariz. (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 17-21.

Laurance Reid Conditioning Conference, Norman, Okla., (512) 970-5019, (512) 233-2877 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 21-24.

International Petrochemicals Technology Conference & Exhibition, Madrid, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 22-23.

Photovoltaics World Conference & Exhibition, Austin, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.Photovaltaicsworldevent.com. 23-25.

Renewable Energy World North America Conference & Expo, Austin, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.renewableenergyworld-events.com. 23-25.

SPE Unconventional Gas Conference, Pittsburgh, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

International Downstream Technology & Catalyst Conference & Exhibition, Madrid, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 24-25.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference and Exhibition, Kuala Lumpur, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 24-25.

Nitrogen + Syngas International Conference and Exhibition, Bahrain, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.nitrogenandsyngas2010.com. Feb. 28-Mar. 3.

MARCH

APPEX Conference, London, +44 0 20 74341399, +44 0 20 74341386 (fax) website: www.appexlondon.com. 2-4.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 2-4.

Middle East Geosciences Conference and Exhibition, Manama, +973 17 550033, +973 17 553288 (fax), e-mail: fawzi@aeminfo.com.bh, website: www.geobahrain.org. 7-10.

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-9.

Annual International LPG Seminar, The Woodlands, Tex., (713) 331-4000, (713) 236-8490 (fax), website: www.purvingertz.com. 8-11.

CERA Week, Houston, (617) 866-5992, e-mail: info@cera.com, website: www.cera.com. 8-12.

NPRA Security Conference & Exhibition, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-10.

Annual European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 9-12.

NACE International Corrosion Conference & Expo, San Antonio, (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org. 14-18.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 845-1835 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 15-18.

API Spring Committee on Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 15-18.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 16-18.

Journally Speaking

Algae's growing popularity

Paula Dittrick
Senior Staff Writer

Established investors, including one notable oil major, are putting money into early-stage companies developing algae-based biofuel. A handful of algae companies are among various entrepreneurs racing to commercially produce a next-generation biofuel.

ExxonMobil Corp. recently joined the race to develop algae-based biofuels, saying it will invest $300 million with Synthetic Genomics Inc., a San Diego company founded by J. Craig Venter. ExxonMobil is spending another $300 million internally on algae research.

Emil Jacobs, vice-president of research and development at ExxonMobil Research & Engineering Co., shared some of the company's thinking about its collaboration with Synthetic Genomics.

The collaboration likely will last 5-6 years, Jacobs told reporters during a July conference call in which ExxonMobil announced its investment.

Jacobs said he is unsure what fuels ultimately might result from the collaboration. He and Venter would not discuss specific technology with reporters, saying researchers will investigate all options.

Synthetic Genomics plans to build a test plant in San Diego to study growing algae in open ponds and in closed photosynthetic bioreactors. The test plant's researchers also will study oil-extraction techniques.

The gist of Venter's research involves genetic engineering on an industrial-scale culturing of algae to yield hydrocarbons. Previously, Venter worked on sequencing a human genome. He likes to describe his current algae research as biomanufacturing.

ExxonMobil estimates that ultimately billions of dollars worth of investment could be needed before achieving commercial production of an algae-based fuel. The initial $300 million investment is intended to help Venter tweak a biochemical path to alter the molecules of algal oil, leaving a hydrocarbon.

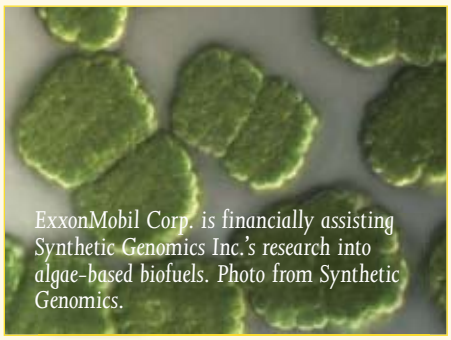
ExxonMobil's thinking

The major's decision came after its executives quietly investigated biofuels in general for more than a year. After considering the technical challenges of potential next-generation biofuel options, algae rose to the top of ExxonMobil's list.

"As far as products to expect from this program, our intent is to make hydrocarbons that look a lot like today's transportation fuels," Jacobs said. "We want to produce hydrocarbons that can go into a refinery to be processed along with other petroleum streams and then used in the transportation fleet or even jet fuel."

ExxonMobil planners want a biofuel that can attain large-scale production. Environmental footprint was another consideration. ExxonMobil considered water use, land use, and carbon emissions likely to result from the production of various biofuels.

The initial plan is to come up with a modular design involving an optimal plant size. Then other production sites can be built as needed, Jacobs said.



ExxonMobil Corp. is financially assisting Synthetic Genomics Inc.'s research into algae-based biofuels. Photo from Synthetic Genomics.

Others react

Paul Dickerson, a partner with Haynes & Boone LLP, welcomes ExxonMobil's involvement in algae research. Dickerson launched the law firm's clean technology practice group. Formerly, he was chief executive of the US Department of Energy's Office of Energy Efficiency and Renewable Energy.

"All alternative energy provides a wonderful opportunity for incumbent energy companies," Dickerson said. "Exxon has been focused on energy production and distribution for generations. If we are bringing Exxon's expertise to alternatives, we as a nation are stronger."

He sees the clean technology industry entering a development phase where oil and gas companies can provide financial backing and also can provide valuable experience on converting successful laboratory results into practical commercial application.

"Clean-tech entrepreneurs are now looking to scale up, and oil companies know this drill," Dickerson said. "Oil companies have a long track record of planning, financing, and overseeing large projects. There are many areas for potential technical collaboration."

Michelle Ashby, chief executive officer of MINE LLC, and an organizer for energy investor meetings, notes algae may be the first in a new age of biofuels in which researchers carefully examine the whole life cycle involved in creating a fuel.

"There are a lot of tracks moving at the same time, one of them will emerge," to become mainstream, she said.

ExxonMobil believes any significant algae-based commercial development is still years away. "This is very early days," Jacobs said. "We've got a lot of work ahead of us." ✦

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Editorial

Dissent is just dissent

According to liberal assertions, to resist the radical stampede under way in the US is to be rude, violent, or racist. And liberals making these assertions want to improve political discourse. Does anyone see contradiction here?

The allegation of rudeness comes from President Barack Obama. On Sunday public-affairs television programs Sept. 20, Obama criticized three cable news networks for encouraging misbehavior. "The easiest way to get on television right now is to be really rude," he said on ABC's This Week with George Stephanopoulos. On CNN's State of the Nation, he urged networks to "reward decency and civility in our political discourse." And on CBS's Face the Nation, he said news programs and blogs "can't get enough of conflict," adding, "It's catnip to the media right now."

Liberal blitz

Who opposes civil discourse? But where's civility in the liberal blitz Obama has tried to press on the nation since taking office, including nationalization of US automakers, previously unimaginable government spending, state-centered overhaul of health care, and reconfiguration of the energy mix?

Offering blithe and often indefensible assurances to the contrary, the president proposes to expand government and hike costs of American existence for dubious reasons—and to do so swiftly. He has shown scant interest in discourse; he has, in fact, started a fight. To now scold the media for reporting conflict is disingenuous.

Woops. The fight metaphor implies violence, fear of which brought House Speaker Nancy Pelosi (D-Calif.) to tears during a Capitol Hill news conference Sept. 17. Asked whether intensifying political debate in the US might incite violence, Pelosi likened currently heated rhetoric with language in use during a gay rights controversy that led to the assassinations of two San Francisco officials in 1978. "I think we all have to take responsibility for our actions and our words," the weepy speaker said. Of pointed commentary, she warned, "The ears that it is falling on are not as balanced as the person making the statement might assume."

Pelosi's choke-up followed formal admonishment of Rep. Joe Wilson (R-SC) for an alarming indiscretion during Obama's Sept. 9 speech to Congress on health care reform. When the president said legislation wouldn't provide illegal immigrants free coverage, Wilson blurted, "You lie!" Wilson apologized for what he described as a spontaneous breach of decorum. But the outburst revived suspicions that he is racist, which he denies.

By then, the racist cobra was out of the basket and riling the crowd. Did opposition to the first African-American president in US history betray racism? Yes, declared former President Jimmy Carter after Wilson's blunder. "I think an overwhelming portion of the intensely demonstrated animosity toward President Barack Obama is based on the fact that he is a black man, that he's African-American," Carter said on NBC Nightly News a day before making similar observations in a speech at Emory University.

All these allegations dangle on threads of truth. Rudeness happens, even in public life. Much more regrettably, some sick people commit violence, sometimes acting out political delusions. And, yes, racism lingers in American society. But it's possible to disagree with Obama's program without being guilty of any of that. In response to Obama's very liberal and urgently promoted program, dissent can be simply dissent, however hard its edges.

Familiar theme

Oil and gas professionals may sense a familiar theme in these utterances by liberal celebrities. It's how the statements characterize opposition instead of responding to it. The dominant political party, controlled now by its most liberal members, serves up an agenda that many Americans see as radical then treats disagreement as evidence of behavioral disorder. No wonder people are angry.

For the oil and gas industry, such treatment is standard. Industry expertise has come to be seen as perversion. US energy policy therefore heads in more errant directions, more rapidly, than ever before. Like Americans staging latter-day tea parties, the industry no longer can afford just to express rational concern about important issues. It first must redress condemnation by antagonists who'd rather moralize than argue. ✦

Efficiency improvements cut GHG emissions, help profits

Rick Beaubien
Consultant
Houston

Policy makers and business leaders are sharpening their focus on ways to reduce greenhouse gas (GHG) emissions in the belief these reductions could improve the economy, weather, and quality of life. This topic has grown to such global pervasiveness that GHG issues now provide a common touchstone for all industrialized and emerging economies. While the merits and concerns surrounding GHG emissions are too complex to examine fully in a single article, the drive to reduce emissions has identified a universal benefit and is gaining momentum.

When applied selectively, increases in production efficiency reduce GHG emissions and increase business margins. Various regulatory initiatives would require operating improvements to account for GHG reductions of from 2% to more than 10% between 2010 and 2015.[1] Overall, increased production efficiency involves:

- Energy recovery; heat losses to the environment.
- Higher mechanical reliability; less shutdowns, flaring, and process venting.
- Improved energy transfer processes—thermal and mechanical.
- Recovery and reuse of processing chemicals and byproducts.

Government regulations at all levels are demanding higher efficiency ratings and stepped up energy reduction programs.[2] Individual states also are instituting their versions of GHG reduction programs, which, combined with federal programs, are included in the expanding requirements for project permitting, operations, and GHG reporting.

Communities surrounding US production centers are encouraged to participate in the development of policies that regulate industrial projects and operations in their area. This pattern is being repeated around the globe, albeit at a slower pace in developing nations, with GHG initiatives becoming part of international trade, customs, and tariffs.[3]

Benchmarking GHG reductions is now an aspect of corporate sustainability. A corporate record of GHG reductions can be considered for the evaluation of preferred suppliers, partnerships, alliances, government regulations, and investor decisions.

Environmental policies that add GHG provisions raise the barrier for market entry, which is a concern for industries that supply consumer goods.

Existing production sites have a vested interest in their facilities' competitive position. Investments in the producer's time and resources must address these issues:

- Improve the producer's competitive position.
- Provide an equal or greater return with less risk than the alternatives.
- Combined with competitor activities, address a government's responsibilities to community concerns.

GHG specifications

GHG is measured as a carbon dioxide equivalent (CO_2e), where chemicals or commodities released into the environment are converted to their CO_2e by a factor specific to that chemical or commodity. Resources for the conversion, are numerous and exhaustive.[4,5] Table 1 shows a few common fuels used in industry. Fuel use is the largest source of GHG emissions.

Unburned fuel in the form of methane (CH_4), nitrous oxides (N_2O), and other contaminants associated with low-combustion efficiency contribute to a fuel's GHG production.

Poor combustion is the primary reason solid fuels (i.e., coal, coke, and waste products) produce three times the CO_2e impact of natural gas, in addition to emitting elevated levels of sulfur and nitrogen oxides (NO_x). Maximizing the heating potential of any fuel reduces fuel use and CO_2e production. But plant fuel gases containing liquefied petroleum gas (LPG) can have

20% more than the CO_2e of natural gas, in addition to the loss in value compared to the finished LPG product. While a project's focus may lie in the reduction of greenhouse gases, economic justification will remain the driver for implementation.[6]

The next largest GHG emissions issue can be the selection and use of process refrigerants.

CO_2e OF COMMERCIAL FUELS USED IN INDUSTRY AND TRANSPORTATION

Table 1

	Kg of CO_2/MMbtu	Natural gas basis
Natural gas	52.9	1.00
Propane	63.1	1.19
N-butane	65.0	1.23
Regular unleaded	70.9	1.34
Jet fuel	70.9	1.34
No. 2 heating oil	73.2	1.38
No. 6 heating oil	78.8	1.49
Bituminous coal	93.5	1.77
Anthracite coal	103.6	1.96
Petroleum coke	113.7	2.15
Waste tires	112.8	2.13

Table 2 lists the most common refrigerants and their properties, including values of CO_2e as kilograms of CO_2/kg of refrigerant, normal boiling point, and safety classification.[7,8] Although the refrigeration system is process-specific, the refrigerant selection is typically based on the process requirements and safety of personnel and property surrounding the equipment.

Table 2 compares the price ratio of a nominal quantity of different refrigerants to R744 (CO_2). Although the service capabilities are different, engineered refrigerants are high-cost compared to a commodity application. Refrigeration systems are estimated to have an inventory loss of 10-50%/year of normal operations.[9]

The equipment CO_2e is a percentage of the total refrigerant inventory. Although direct refrigerant substitution is typically cost-prohibitive, and the power requirements for a process service with different refrigerants can vary, system replacements provide the opportunity to factor the refrigerant cost into the evaluation of different refrigeration systems.

Where possible, system specifications should be reviewed and purchasing decisions made for outside, common-process operations to incorporate process safety with lower refrigerant costs.

Plant fuel gas

Because components in the fuel gas system have a higher value as finished products they are justified for removal with operating changes or investment. Priority should be given to management of hydrogen because of its higher value as chemical feed, even with a CO_2e of zero. Hydrogen is typically present in the plant fuel system only from cracked light ends production.

Properly configured production sites have a cascading route for all hydrogen bleed or vent gas streams that contain a 70% or greater concentration of hydrogen. Hydrogen production is costly, and the byproduct stream is eventually a high-volume CO_2 exhaust to the environment. Hydrogen plants can be the highest source of GHG emissions from a typical refinery.

Fig. 1 shows hydrogen and the other components of typical plant fuel gas, including LPG. Hydrogen has displayed a heightened pricing differential to natural gas throughout the past business cycle.[10] Hydrogen price estimates are based on a natural gas feed, steam methane reforming expenses, and a nominal return on operations. Actual prices may vary due to regional valuations and logistics, but the difference noted across all periods can justify operating changes, and investment over half the period.

Fuel gas containing olefins, amine mist, and other reactive compounds can produce sludge that reduces the capacity of fired equipment. An accumulation of sludge will restrict the fuel gas line flow, foul and misalign burner flame patterns, reduce burner capacity, and increase both maintenance and GHG emissions. Combined with scheduled and unscheduled maintenance, light hydrocarbon recovery is a priority for increasing product yields, equipment reliability, and GHG reduction.

Flare gas

Most large production sites are using flare gas recovery systems to meet emission requirements. Originally designed to scrub flare gases for sulfur compounds before rerouting to fuel gas, the gas stream is typically high in LPG from leaking tower relief or pressure control values. An exception would be a coker unit drum blowdown system or other intermittent wet gas stream that is predominantly hydrogen, methane, and nitrogen.

Although both systems need removal from the flare, LPG-rich streams should be routed separately to light ends separation for product recovery. The rate and composition of the LPG-rich streams are typically more consistent due to the stream source.

Flare gas recovery systems are also typically operating at capacity as maintenance or a down period is needed to remedy the source of leaks. Repeat maintenance items require a higher specification for modification or replacement before repairing.

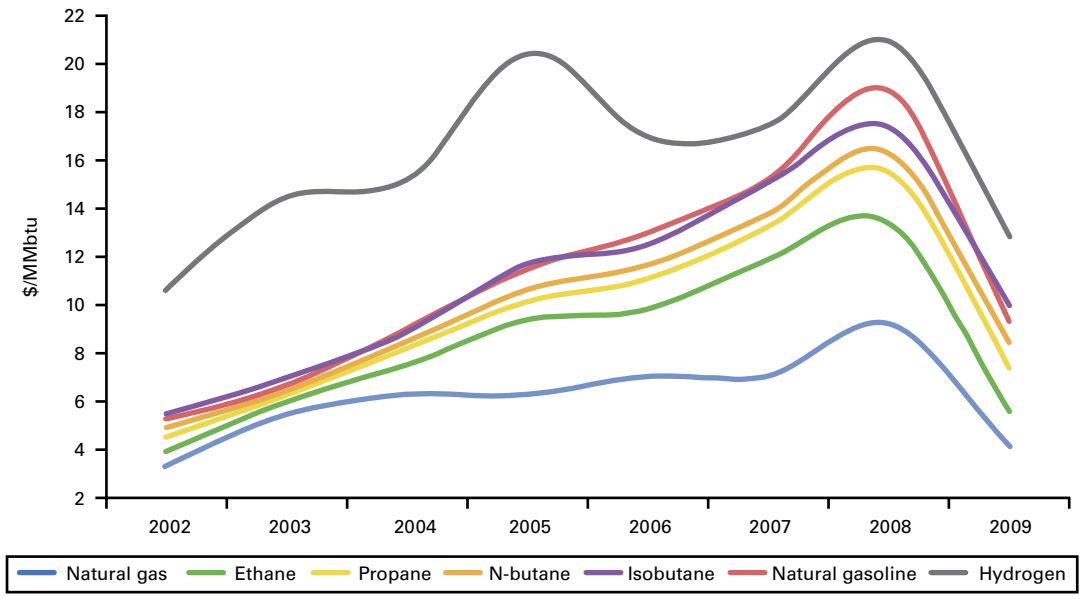
Boilers, process heaters

In many installations, fired equipment has evolved into a combination of complex technologies that support responsive air-fuel control with feedback on carbon monoxide (CO) emissions, air and process preheat, NO_x reduction, and a complete emissions-monitoring recorder.

Advanced NO_x reduction technologies that were developed on the West Coast to meet strict clean air initiatives are now expanding eastward. This technology features a combination of ultralow NO_x burners with stack-gas exhaust recycling and real-time emissions reporting to the regulatory agencies. The combination of firing controls and gas recycling needed to maintain design emission capabilities typically

US GULF COAST PRICES OF PLANT FUEL GASES

Fig. 1



Source: Price data from Platts

reduces the fired heater capacity.

Because process heaters typically operate at a lower combustion efficiency when at maximum capacity, the equipment revisions needed to reduce NO_x emissions also limit processing flexibility. Permitting for new construction often requires retrofitting fired equipment to reduce or offset a site's NO_x emissions. The opportunity for increased firing efficiency and firing capacity is in balance with requirements for lower NO_x production. Engineered equipment specifications and supplier competence with the existing control systems are a priority for flexible, long-term, reliable operations.

A utility offset is the use of heat recovery systems on existing exhaust stacks or process streams currently routed to the environment or process coolers, respectively. All the principles of thermal pinch with cost considerations for pumping and equipment purchases should be compared. Many high-temperature tower operations allow for overhead duty reductions of 30-50% with interstage tower pumparound duties. High-temperature product streams are also a source for steam generation or additional feed preheat.

Large distillation operations have feed or bottoms heating from fired heaters or steam condensers. Fired heaters have limits on their duty and are typically part of the overall site emissions permit.

Attempts to increase the tower bottoms' temperature to increase product purity or yield of heavier components can be limited. Converting the reboiler to feed heating or adding feed preheat exchange against the bottoms' stream can improve product yields with equivalent or lower GHG emissions rates and a savings in fuel use.

The investment is negligible in comparison to feed or reboiler heater replacement and the possible repermitting requirements. Reboiler duty and associated GHG emissions reductions of 7-10% have been achieved by revising existing configurations.

Catalyst selection

Catalyst improvements continue to prove their worth with reduced operating conditions, higher product selectivity, increased product yields, and extended operating periods between regeneration or replacement. Even the catalyst materials continue to evolve into recyclable products for reuse or sale, resulting in less material being sent to the landfill.

Some of the most impressive improvements have occurred in the alkylation and cracking zeolite combinations. Long known for their qualities of high activity from a large surface-to-mass and reactive-metal content, operations that were once elevated-temperature, vapor phase with catalyst coking tendencies are now moderate-temperature, liquid phase reactions.

Because these technologies no longer require fired feed heaters, chrome-molybdenum reactor metallurgies, and repeated start-ups and shutdowns for reactor switchover or regeneration, there is a marked reduction in product losses. Additional benefits of these technologies include less energy consumption, lower operating costs, and the elimination of the associated GHG emissions. Existing and competing technology licensors provide the options, and alternative catalyst suppliers are typically available.

The marketplace is growing increasingly crowded with a wide variety of catalyst alternatives that provide dramatic increases in desulfurization, denitrification, dearomatization, and other properties required for cleaner-burning fuel. Although these catalysts are more expensive, their activity, yields, and extended performance provide reduced preheat and start-up/shutdowns for changeout. Catalyst advances justify their installation and operational investments.

Equipment selection

Equipment selected for replacements, modification, or repair must be engineered to the correct specifications to reduce maintenance under anticipated operating conditions. Production maintenance strives for a planned schedule based on equipment monitoring to provide the preventive activities and minor repairs necessary to continue operations that are safe and adhere to environmental rules.

Repeated equipment repair indicates inadequately engineered parts or altered process conditions. Rotating equipment specifications under the American Petroleum Institute provide a baseline for long-term performance, and additional qualifications may be warranted.[11]

Although equipment decisions are case by case, motor drives, pumps, compressors, and gear-system efficiency generally improve with lower revolutions per minute (rpm) basis friction. Motor efficiency rating is also essential, especially in small motor sizing. Equipment costs are typically the reverse—lower with higher operating rpm and lower efficiency.

Also, oversized, high-efficiency motors operating at a reduced load can—and frequently do—operate as efficiently as smaller, less efficient motors operating at design capacity. The higher-efficiency motors are expected to operate more reliably. Steam turbines, typically smaller sizes or operating at reduced load, can have a fraction of the operating efficiency of a comparable electric motor drive.

Backup service aside, continuous low-pressure, steam turbine driver use should be avoided, and all turbine operations should strive for operation at full capacity.

Intermediate and low-pressure steam turbine drivers can lose efficiency at a rate of more than 0.7:1 at reduced rates. For example, a 30% reduction in driver capacity can cause a 20% loss in efficiency. Equipment selection for reliability, efficiency, and cost consists of an engineering analysis of different applications for anticipated operations over the equipment life cycle. The outcome of any analysis can differ as the basis for a long reliable or short-term life expectancy.

Varying the drive speed can add efficiency to specific equipment services, but justifying an investment solely on an efficiency basis is difficult unless there are extended periods of underutilization.

Reviewing the market period to date may shift production profitability to product yields instead of increased charge rates with alternative charge stocks. Higher efficiency mechanical operations deserve a review in an underutilized production market scenario.

Fixed equipment, such as exchanger configurations, have design options like bell heads that can reduce purchase costs and leaks and still provide access for cleaning and inspection. Unused vessel flanges, specified as part of standard configurations, provide more leakage points and require monitoring. Improvements such as heater insulation, sealed box closures, roof seals, and optimized heat distribution provide incremental operation and maintenance savings. Numerous areas, ranging from rotating equipment seals to gasket materials, affect product losses, equipment reliability, and operating costs. Advances in equipment technology provide justifiable alternatives.

Production configurations (the flow of a process between equipment) become more complex as a production site ages. Piping or out-of-service equipment left in place and complex stream routings introduce materials and stress into operating equipment outside of the design considerations. The cost of unused lines and equipment left in place is difficult to quantify in product loss, repeat repairs, personnel exposure, and future consequences. Timely removal is always advisable.

COMMERCIAL REFRIGERANTS USED IN THE PROCESS INDUSTRY

Table 2

ASHRAE number	$KgCO_2$ / kg	NBP[1] (oF.)	Safety class[2]	Price ratio
R717 (ammonia)	0	-28	B2	3
R728 (nitrogen)	0	-320	A1	3
R744 (CO_2)	1	-109	A1	1
R290 (propane)	3	-44	A3	4
R600 (N-butane)	4	31	A3	5
R600a (I-butane)	8	11	A3	6
401A	18	-30	A1	199
401B	15	-32	A1	201
401C	21	-23	A1	204
402A	1,680	-57	A1	227
402B	1,064	-53	A1	362
407C	1,526	-47	A1	213
409A	0	-32	A1	225

[1]Normal boiling point. [2]Toxicity and flammability classification. Letter refers to toxicity upon exposure (A < 400 weight ppm > B), where B is toxic to exposed personnel. Number refers to flammability, where 3 is the most flammable.

Start-up, shutdown

Up-to-date procedures guide safe and environmentally secure operations. But continuous improvements in operations performance have reduced the experience personnel have with start-ups and shutdowns.

Training, timed shortly before a planned start-up, is warranted on large investments with high operating temperatures and pressures, light-ends compression, or other technologies with an extended vent or flaring period. New, revised, and existing production units are implementing procedures that strive to eliminate flaring during start-ups. Planning and creative procedures are essential to incorporate all the site-specific implications.

Production start-up activities begin with planning in the engineering and construction or maintenance phase. Proper planning can reduce start-up time by 25-50% by eliminating rework and unplanned repairs. No set procedure directly applies to all sites because each site has configuration details that must be individually addressed. Operating procedures offer an area for continuous improvement.

Many technologies create a high level of equipment wear during start-up and shutdown. High-temperature/high-pressure reactor circuits, gasification, fluid cracking, and coking, for example, sustain the majority of the vessel and associated piping stress during the expansion and contraction cycle of a start up or shutdown. Extended operations between production interruptions can extend the operating life of the affected equipment.

GHG recovery, sale

Plant operators have a broad menu of possibilities for the recovery and sale of GHGs, each with its own set of considerations. Here are examples:

• LPG in flare and plant fuel gas. In the context of maintenance issues with light ends venting and leaks, LPG in fuel gas seems to continually evolve. The challenge lies in justifying, economically, the changes needed for LPG recovery.

From operational and maintenance standpoints, these justifications include higher operating pressures, peak condenser capacities, and improved product purities. Higher returns also typically result from a minor reprioritization of feeds to saturate and unsaturated gas plants and replacement of natural gas with selected plant gas feed to a hydrogen plant.

Investments worth considering range from increasing existing equipment capacities to installing gas liquids recovery technology that is stream and component-specific. Many regions have an opportunity to capitalize on economy-of-scale operations by combining common product streams throughout adjacent production sites.

• Refrigerants. When refrigeration systems are not in use or are underutilized and service can be consolidated into fewer operating units, units should be deinventoried. Refrigerant handling is equipment-specific, but replacing the refrigerant with another inert material may extend the service life of the equipment if use is seasonal.

• CO_2 recovery. Aside from combustion flue gases, many production technologies produce a pure CO_2 stream as a byproduct. Hydrogen, ammonia, and certain methanol technologies (from partial oxidation or steam methane reforming followed by a gas separation section) along with certain ethylene oxide technologies provide a stream at ambient condition and, sometimes, elevated pressure. Sources of the highest purity, ambient temperature, and elevated pressure are priorities for cost-effective collection, treating, and transfer for sale.

Road and rail transfers are typically as a liquid, and pipeline transfers are a high-pressure vapor. Production site priorities usually do not include CO_2 recovery operations, so considerations for specialist firms, transfer, or end-user commercials should be evaluated.

HOW CO_2e VALUES AFFECT GAS, COAL Table 3

CO_2e $/ton*	Natural gas $/MMbtu	Coal $/ton
5	0.28	18.33
10	0.56	36.67
20	1.13	73.33
40	2.25	146.67

*As traded in Europe.

Recovery of a byproduct or marketable side stream product typically requires an innovative fit into an aged infrastructure. Most production sites are celebrating 40, 50, or more years of operation across a constrained plot plan. Investment and operating costs to recover GHG for product sales may not be as clear-cut or as feasible as they first appear.

• CO_2 markets. CO_2 markets can be far from large generation sites, requiring expensive transportation options to be factored into recovery costs. Enhanced oil recovery opportunities develop as reservoirs age and new or low-cost reservoir replacement opportunities dwindle.

CO_2 injection in specific sites has extended operations by more than a decade, and the volume required is difficult to assess. Due to the risk and high expense associated with alternative energy sources, CO_2 injection for the recovery of known oil and gas deposits continues to justify investments.

Small markets for purity CO_2 exist everywhere, such as for use as propellant, cleaner, storage agent, water treatment, and additive to agricultural products.

Investment in the operations to reproduce plant-based products continues to grow, spurred, in part, by attractive incentives. The economics for production of renewable fuels becomes more favorable as the price increases for oil products.

Government and industry

Reduction of GHG emissions depends ultimately on a combination of actions undertaken by the government and industry.

Congress is debating legislation that would place a value on CO_2e and set a cash value on the GHG emissions associated with a production site that exceeded a certain cap. When a value is placed on GHG emissions, the cost of the fuel generating that emission can rise by 50-100%.

Table 3 illustrates this point by converting a CO_2e price to units of the fuel purchased.

For industry, long-term decision-making is as important as it is challenging. Projects based on short decision times often result in less-than-desirable outcomes, increased investments, more complex operations and reduced production margins. Successful projects avoid situations that create additional, unnecessary costs for doing business or that force a choice between the best of worse scenarios.

To remain viable in an increasingly competitive market, production operations—either stand-alone or as a unit of a diversified business—must continue to increase product yields and reduce operating costs. Even unique and specialized product lines rapidly find they are just another commodity in a global market.

Given these realities, government and business both must embrace a common goal of increasing production efficiency.

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Salazar to end federal oil and gas RIK program

Nick Snow
Washington Editor

US Interior Sec. Ken Salazar beat a US House committee to the punch and announced plans to eliminate the US Minerals Management Service's royalty-in-kind (RIK) program on Sept. 16.

His announcement came during his opening statement to the House Natural Resources Committee in the first day of hearings on a sweeping federal minerals reform bill that its chairman, Nick J. Rahall (D-W.Va.), introduced on Sept 8. The measure includes a provision ending the RIK program.

"The royalty-in-kind program has been a blemish, in my view, on this department. It is time for us to end it," said Salazar. "It was set up at a time when people felt the department could

US Interior Secretary Ken Salazar, second from left, and three other top US Department of the Interior officials listen as House Natural Resources Committee members respond during a Sept. 16 hearing to his announcement that he will end the US Minerals Management Service's oil and gas royalty-in-kind program. Joining Salazar were, from left, Wilma A. Lewis, assistant Interior secretary for land and minerals management; US Bureau of Land Management Director Robert V. Abbey; and MMS Director S. Elizabeth Birnbaum. Photo from DOI.

make more money from selling oil and gas on the open market than in taking royalties. It was created by administrative order, and I intend to end it."

He told reporters following the hearing that it will take about a year to shut the program down because several of its components operate under contracts. "We expect to issue the order in the coming weeks," he said.

MMS Director S. Elizabeth Birnbaum and BLM Director Robert V. Abbey will work with Wilma A. Lewis, assistant interior secretary for land and minerals management, in making the transition from the RIK program to a more transparent and accountable royalty collection operation, Salazar told the committee.

"Bravo, bravo, bravo," Rahall said after Salazar finished his opening statement. "I have called for its elimination for years because it has so many problems."

The program drew especially heavy fire in September 2008 after an investigation by the Department of the Interior's inspector general found federal RIK employees in Denver were paid for outside work, abused drugs and alcohol, and solicited sex.

Different conclusions

Rep. Cynthia Lummus (R-Wyo.) noted that Salazar's predecessor as interior secretary, Dirk A. Kempthorne, formed an independent committee chaired by former Sens. J. Robert Kerrey (D-Neb.) and Jake Garn (R-Utah) which investigated the government's minerals royalty programs and reached different conclusions. One of those was that the RIK program should be scrapped onshore but retained offshore because of significantly bigger takeaway volumes, she said.

Salazar said he was acquainted with the committee's work and would consider its recommendations.

American Petroleum Institute President Jack N. Gerard said the RIK program collected $6.6 billion in oil and gas deliveries during fiscal 2008 and is one of the federal government's largest sources of nontax revenue. "Terminating this straightforward method of handling royalty payments runs the risk of raising administrative costs and adding additional layers of paperwork required to determine the value of oil and gas production," he said.

Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) apparently wasn't surprised, since the Government Accountability Office issued two reports before the hearing calling for major federal royalty management reforms. "GAO's rebuke of the way [DOI] collects royalties is just the latest red flag that the American people are not getting a fair return for the oil and gas resources they own," he said. "We'll be taking a careful look at the administration's proposals to overhaul the flawed royalty management program."

Salazar told the committee that phasing out the RIK program is part of a broader effort to improve minerals royalty collections within DOI. He said Lewis was leading a two-track department-wide minerals royalty policy review of possible administrative and legislative actions. "There's a lot we can do to simplify the collection of federal royalties," the secretary said.

In his written statement, he said the administration has not had an opportunity to fully analyze Rahall's bill, which also includes a provision combining the US Bureau of Land Management and MMS into a single Office of Federal Energy and Minerals Leasing.

Administrative actions

Many of the bill's provisions can be achieved through administrative actions, Salazar told the committee. "For example, I am developing options to improve the coordination between [MMS and BLM] in onshore and offshore leasing and revenue management policies related to domestic energy production, both conventional and renewable, from federal lands," he said. "I intend to bring needed coordination and strategic guidance to the department's energy development programs and to its implementation of significant reforms, including recommendations

from the reports of the GAO and the Office of the Inspector General."

Republican committee members criticized Rahall's bill and Salazar's actions since becoming interior secretary. "In your time at [DOI], you have essentially blocked energy development across-the-board," Rep. Michael Coffman, a freshman from Colorado, told Salazar. "We can't drill onshore, we can't drill offshore, we can't develop oil shale, we can't develop uranium deposits, and you haven't issued any new solar permits."

Salazar disagreed, citing continued oil and gas lease sales at BLM and MMS and revised oil shale technology assessment programs.

Another GOP freshman, Bill Cassidy from Louisiana, suggested that Rahall's bill creates contradictions in calling for more expeditious oil and gas production while increasing the potential for bureaucratic delays.

"There is room for us to improve," Salazar responded. "Technologies such as horizontal drilling create opportunities today that were not available 30 years ago. We're also aware that several private landowners and oil and gas producers are taking approaches which may be more efficient than the federal government's. We'd like to look into these."

When Robert J. Wittman (R-Va.) asked about the status of a lease sale scheduled off Virginia's coast in 2011 as part of the MMS's 2007-12 OCS plan, Salazar said that DOI was looking at it but added that there hasn't been new information about Atlantic US offshore resources for decades. "Virginia has the opportunity to be the first new leasing area on the East Coast, not just for conventional but also renewable resources," Wittman said.

"I think one area where you can expect bipartisan support there is natural gas," Salazar replied. "There are indications that there may be substantial amounts out there." Responding to a question about Atlantic OCS leasing in general from Doug Lamborn (R-Colo.), ranking minority member of the committee's Energy and Mineral Subcommittee, the secretary said that more current information is necessary because "what's out there could turn out to be a big nothing." ✦

Extended OCS comment period produces 350,000 comments

Nick Snow
Washington Editor

The US government received more than 350,000 public comments on possible Outer Continental Shelf resource development strategies during the 6-month comment period that expired Sept. 21, US Interior Secretary Ken Salazar said on Sept. 22.

Many of the comments came from public meetings he hosted in New Jersey, Louisiana, Alaska, and California, he said. "I heard broad agreement that we must confront our dangerous dependence on foreign oil, build a clean energy future, and make use of the limited resources we have while protecting our land, water, and wildlife," he said.

Salazar said the US Minerals Management Service is reviewing all of the comments, which will take several weeks. Once that is complete, it will initiate environmental analysis and what he termed "public scoping opportunities" associated with the 5-Year Plan for oil and gas development on the OCS.

"The offshore energy program we are developing must address our nation's energy security challenges, deliver a fair return to the taxpayers who own the resources, and account for the views of local communities, states, and tribal nations," the secretary said.

It also must take several key considerations into account, including ocean areas critical to military training and the national defense; other economic benefits of the oceans including fishing, tourism, and subsistence uses; environmental considerations; existing oil and gas infrastructure; interest from the oil and gas industry; and the availability of seismic and scientific data, he said.

"I am confident that we will be able to expand our nation's offshore energy portfolio by focusing on development in the right way in the right places," Salazar said.

Move aggressively

Meanwhile, oil and gas industry groups urged MMS to move ahead aggressively on developing more OCS energy resources the 6-month public comment period on a draft proposed 5-year OCS plan expired.

"In about a week's time, we will mark the 1-year anniversary of the end of the moratoria for new oil and natural gas leasing in federal waters off our Atlantic and Pacific coasts," noted American Petroleum Institute Pres. Jack N. Gerard. "Despite the public's clear desire for more domestic energy development and the industry's years of experience operating offshore in an environmentally sensitive way, this administration repeatedly has slow-pedaled this plan which would benefit all Americans, especially in these tough economic times."

Gerard said new oil and gas development could create thousands of jobs, add more than $1 trillion to government coffers, strengthen US energy security, and encourage a domestic economic recovery. "It's time to end the delays. The administration now has comments in hand. It knows that oil and natural gas will be integral to the nation's economy for decades to come. It must act now to ensure that America has the energy it needs today, and in

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Delivering 'human impact statements'

US House Natural Resources Committee members found plenty on which to disagree as they began 2 days of hearings on Chairman Nick J. Rahall's (D-W.Va.) federal minerals management reform bill on Sept 16. They probably would have agreed with Interior Secretary Ken Salazar, who was there to testify, that Rep. Rob Bishop (R-Utah) was the most passionate during his allotted 5 min for questions.

Bishop had a lot on his mind. He started with questions about contacts between the National Parks Service and the National Parks and Conservation Association. He reiterated his criticism of Salazar's Feb. 6 order to cancel 77 oil and gas leases in eastern Utah that the US Bureau of Land Management auctioned in December.

Then he asked Salazar to turn around so he could see a man and a woman standing together near the press table. Jeremy and Amber Harrison had come from Vernal, Utah, to present 150 "human impact statements" about the lease cancellations to Deputy Interior Secretary David J. Hayes the day before, Bishop explained.

He said Hayes' office notified them that the appointment had been cancelled and that the DOI official would not be able to see them at all that week. So Bishop brought them to the hearing.

'They're individuals'

"These aren't oil and gas producers or special interest groups. They are individuals who were directly affected by your decision," he told Salazar.

"What happened to those 77 lease parcels you're so passionate about is that the [US Bureau of Land Management] did not conduct proper consultations about them. Those are taking place now, and several of them may be offered in the future," the secretary responded.

But he also essentially apologized to the Harrisons. "Periodically, the federal government acts without considering the trouble individuals like them take to express their views in person," he said during the hearing. He met with the couple in the hallway afterward and told them they could meet with someone at DOI that afternoon.

Downturn's cause

OGJ also spoke with the Harrisons, who own and operate an oil hauling truck. They said unlike previous downturns that had been caused by companies canceling major projects, this one occurred because of an official's decision in Washington.

Salazar's move came after a consultant completed an extraction industry impact study for Uintah County in November 2008 to attract more oil field service firms, Amber Harrison said. "As soon as his decision was publicized, companies started to pull out instead," she noted.

Unemployment in the county has climbed to 8% now from around 1% a year ago, she added.

Salazar kept his word. The Harrisons met that afternoon with Hayes and BLM Director Robert V. Abbey. "It went well. It was a little easier to get our points across to Mr. Hayes one-on-one" and Abbey seemed very willing to listen, Mrs. Harrison told OGJ by telephone on Sept 21. ✦

the future," he said on Sept. 21.

In comments submitted to MMS on Sept. 15, Independent Petroleum Association of American Pres. Barry Russell warned: "As our nation's energy demand continues to increase, a failure to provide needed access to the OCS will increase domestic energy prices, slow US economic growth, and create hardships for consumers."

"The next 5-Year Plan will define the shape and scope of domestic offshore energy development. It is essential that MMS develop a leasing program that provides maximum flexibility for our nation to address its energy needs," Russell said.

Prompt review

National Ocean Industries Association Pres. Tom Fry urged US Interior Secretary Ken Salazar to review the comments promptly and analyze all OCS planning areas now that the 6-month comment period extension the secretary imposed on Feb. 10 has expired.

"Today's volatile energy prices and supplies have created many problems for ordinary Americans. In part, this is because the government has denied access to energy resources owned by the American people," Fry said on Sept. 21. "The energy resources on the OCS are vital to the nation's economic prosperity, and safety records show that they can be produced in an environmentally responsible manner."

Jenny Fordham, energy markets and government affairs director at the Natural Gas Supply Association, said the draft proposed plan (DPP) was a step in the right direction "and industry supports a robust plan as a foundation to our future domestic energy supply." She said, "MMS should not delay the 5-Year Plan process, but should move forward quickly after the close of the comment period to develop the proposed plan and complete the necessary environmental work."

In comments submitted to Renee Orr, MMS's 5-Year Plan program director on Sept. 21, Fordham said NGSA

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was pleased that MMS added areas not included in previous 5-year OCS plans to this one's DPP, including lease sales in the eastern Gulf of Mexico "which is known to contain vast resources of natural gas." The industry association supports the proposal of 31 lease sales with no restrictions, such as buffer zones, and encourages MMS to prioritize the schedule of lease sales to be held in those areas known to have the highest resource potential, she said.

The federal government locked up OCS areas believed to contain 18 billion bbl of oil and 77 tcf of gas for more than 20 years, Doug Morris, API's upstream and industry operations group director, noted in comments that API submitted to MMS on Sept. 21.

'May be conservative'

"These resource estimates may be conservative since the areas in question are largely unexplored," Morris said. "But if given access to them, the industry could use today's highly sophisticated technology to locate and tap new domestic resources in an environmentally responsible manner as it has in other areas for decades."

Past decisions to restrict OCS acreage available for exploration compelled the oil and gas industry to "pick over the bones" in search of commercial hydrocarbon quantities, Morris said. He cited expenditures of $2.2 billion for leases in 1996-97, with only 6% of the tracts eventually producing oil and gas and the remainder returned to the government. "Over 50% of the leases were eventually resold in subsequent sales for an additional $6.2 billion as the industry continued to search for the 'needle in the haystack' in a limited geographic area using new exploration technologies," he said.

Morris conceded that successive exploration over some of the same areas led to new discoveries because new geologic concepts were tested, aided by the evolution of exploration and production technologies. "Nevertheless, over the period that moratoria restricted access to as much as 80% of the OCS, other opportunities for discovery went unexplored and untested," he said.

Access to areas where technologies and concepts can be tested, and where lessons learned from exploration elsewhere in the world can be applied, will increase the likelihood that new domestic offshore oil and gas resources will be discovered and domestic energy security improved, Morris said. "We will continue to rely on oil and gas in the long term, so we need to make decisions now that provide us with the resource in the long term," he said.

Include all areas

In IPAA's comments, Russell urged MMS to keep all areas, including the eastern Gulf of Mexico, Alaska, and the entire Atlantic and Pacific OCS under consideration during the planning process's next phase. Doing so would mean that "essential preparatory work will have been completed enabling that area to be offered for leasing more quickly should Congress mandate a sale," he said.

Russell also suggested that MMS use area-wide lease sales wherever possible, and focused leasing for places where it is not. "Area-wide leasing allows IPAA members, the smaller independent companies, to actively acquire, explore, and produce low-risk fields. It also encourages innovative exploration strategies and is consistent with maintaining financially sound geophysical contracting and processing industries," he said.

Fordham said in NGSA's comment that the association also was encouraged by MMS's including areas previously off-limits in the DPP. NGSA and API separately expressed in their submissions to MMS their opposition to the idea of coastal buffer zones and support for sharing new federal OCS oil and gas revenues with states directly feeling the impacts of development.

Morris and Fordham each noted that in August 2008, when MMS requested comments as then-Interior Secretary Dirk A. Kempthorne accelerated the OCS planning process to produce a 5-Year Plan for the 2010-15 period, some 60% of the responses said that the agency should initiate a "new program to provide some level of expanded access to domestic sources of oil and natural gas." It was a significant indication that the general public understood the importance of developing more domestic oil and gas supplies, the API and NGSA officials separately said. ✦

Tighter OTC derivative oversight needed, House panel told

Nick Snow
Washington Editor

Regulation of over-the-counter derivatives is essential as the US government tries to prevent market manipulation, the chiefs of two key financial regulatory commissions told the US House Agriculture Committee on Sept. 22.

Noting that a year has passed since the domestic financial system nearly collapsed as several major investments through complicated financial instruments went sour, US Commodity Futures Trading Commission Chairman Gary G. Gensler and US Securities and Exchange Commission Chairwoman Mary C. Schapiro each said the lack of OTC derivative market regulation was only one of several serious weaknesses in US financial regulation.

But it was a significant weakness and it should be corrected, they continued. "It is critical that we work together to enact legislation that will bring greater transparency and oversight to the OTC derivatives market," Schapiro said in

her opening statement. "The derivatives market has grown enormously since the late 1990s to approximately $450 trillion of outstanding nominal amount in June 2009."

Gensler said comprehensive OTC derivate market reform will require two complementary regimes: one for derivatives dealers and one for the markets themselves. "This regulatory framework must cover both standardized and customized swaps. It should include all the different products, such as interest rate swaps, currency swaps, commodity swaps, equity swaps, and credit default swaps, as well as all of the derivative products that may be developed in the future," he said.

"We should eliminate exclusions and exemptions from regulation for OTC derivatives. Congress should extend the regulatory regimes of the Commodity Exchange Act and the federal securities laws to fully cover OTC swaps in all commodities," Gensler said, adding, "I believe that the law must cover the entire marketplace, without exception."

Impetus for reform

Congressional and other critics of the current system have contended that speculators used financial swaps and other instruments during 2008's first half to drive oil prices to a record peak after moving their money from a crumbling domestic real estate investment arena. The US Department of the Treasury sent legislative language to Congress on Aug. 11 that would institute regulation of all OTC derivatives. Oil and gas as well as other industries have argued that regulating commodities too strictly could reduce their ability to hedge prices and drive their operating costs higher.

"Public gas systems depend upon both the physical commodity markets as well as the markets in OTC derivatives to meet the natural gas needs of their consumers," David Schryver, executive vice-president of the American Public Gas Association, told the House Agriculture Committee Sept. 17 at an earlier commodities market reform hearing. "By using both markets, these public gas systems are able to purchase firm deliveries of gas from a diverse set of suppliers while hedging the risk of future market price fluctuations."

Proposals to require all standardized OTC derivatives to be cleared (which Gensler said he supports on Sept. 22) would make it much harder for municipal and other public gas systems to use these gas supply strategies, Schryver continued.

Many APGA members with very high credit worth are not required to post collateral for an agreed-upon number of transactions under the current system, he explained. Mandated clearing of all OTC transactions would require them to post an initial margin for all transactions and to meet potential margin calls whenever required on little notice, putting a significant financial burden on the systems and the communities and customers they serve, Schryver said.

He and other witnesses said at the Sept. 17 hearing that while they recognize the need to impose position limits and other restrictions to prevent excessive commodities speculation, exemptions also will be needed in many cases for market participants which are trying to control their fuel or feedstock costs.

Unaffordable costs

"Our primary concern with the Treasury Department's proposal is that it would require most of our transactions to be cleared since our natural gas trades would be considered 'standardized,'" said Glenn English, president of the National Rural Electrical Cooperatives Association. Emphasizing that the group does not want to hedge in an unregulated market and wants derivatives trading to transparent and free of manipulation, he said that most rural electrical co-ops would be able to continue hedging if all derivatives contracts must be cleared.

"Commodity markets were created for the benefit of physical hedgers, and they must continue to remain accessible to them," said Richard B. Hurst, senior vice-president and general counsel for Delta Air Lines Inc., who also testified on the American Air Transport Association's behalf. "In a trade where at least one party is a legitimate physical hedger in a commodity, the committee should consider provisions that would enable these transactions to occur with little additional financial burden on the parties involved."

Jon Hixson, federal government relations director at Cargill Inc., said the food and agricultural service company's businesses include risk management products for bakeries, restaurants, and heating oil suppliers.

"Under the Treasury Department's proposal, it is highly likely that Cargill would be forced to greatly reduce, if not eliminate, offering our customers these risk management solutions…. In addition, we would expect prudent hedging to decline significantly in those situations where Cargill, like other end-users, manages its own commodity, interest rate, and foreign exchange risks due to the imposition of mandatory margining and the drain on working capital," he indicated.

But Gensler, at the Sept. 22 hearing, said CFTC should have authority to set aggregate position limits across all markets and trading persons on traders of OTC derivatives which perform or affect a significant price discovery function in markets that the commission oversees. "This will ensure that traders cannot evade position limits by moving to a related exchange or market," he told the committee. "Exemptions to position limits should be limited and well defined."

More transparent

Moving standardized OTC trades onto regulated exchanges and trade executive facilities would make markets more efficient and transparent, Gensler said. "Exchanges greatly improve the functioning of the existing securities and futures markets. We should bring the same transparency and efficiency to the OTC swaps markets," he said.

Schapiro said Congress should consider modifying the Treasury Department's proposal so that securities-related OTC derivatives are regulated like securities, and commodity and other non-securities-related OTC derivatives are treated like futures.

"At the core of this approach is that similar products should be regulated similarly, or equivalently, if possible," Schapiro explained. Oil and gas swap contracts or other commodity-related OTC derivatives would be regulated in a manner similar to the underlying oil and gas or other futures, she said.

Meanwhile, US Sen. Maria E. Cantwell (D-Wash.) introduced a bill on Sept. 17 that she said would make it easier for CFTC to investigate and punish alleged commodities market manipulation. The measure, which was cosposored by Sen. Bill Nelson (D-Fla.), would replace the requirement for the commodities regulator to prove "specific intent" to do harm with the same "reckless conduct" standard which the SEC has used for 75 years, and the Federal Energy Regulatory Commission and Federal Trade Commission recently adopted, she said.

"When bad actors like Enron and Amaranth Advisors manipulate commodities prices, Americans end up footing the bill, paying more for commodities like oil, gasoline, heating oil, food, and natural gas," Cantwell said. "Unfortunately, regulators lack the tools to protect us from market manipulation in critical commodity futures markets. Through this tough new language, we can establish a clear, bright line against illegal market manipulation and can empower regulators to effectively enforce and deter market manipulation." ✦

House panel told leasing bill would hurt development

Nick Snow
Washington Editor

A bill that aims to make federal oil and gas leasing more effective and efficient would have the opposite effect instead, two oil and gas industry officials told the US House Natural Resources Committee on Sept. 17.

"We believe that it is important to develop policies that provide more access to federal lands and remove barriers that delay the development of these resources," said Doug Morris, group director for upstream and industry operations at the American Petroleum Institute. "We should not be erecting additional obstacles to development which, unfortunately, would be the unintended consequence of this legislation."

Alex B. Campbell, vice-president of Denver independent Enduring Resources LLC and a board member of the Independent Petroleum Association of Mountain States, said HR 3534, which committee chairman Nick J. Rahall (D-W.Va.) introduced on Sept. 8, would create delays with new layers of bureaucracy and regulations.

The measure also would institute policies that would make markets less efficient and leasing less transparent, significantly increase oil and gas production costs on federal lands, and fundamentally change the US public lands' multiple use concept to an approach that would further restrict renewable as well as conventional energy development, he warned.

Morris said API and its members are concerned about Rahall's bill because it would create more layers of bureaucracy that could slow leasing down. "For example, it has the potential to interfere with the [US Outer Continental Shelf] 5-Year Leasing Plan process that has worked well for 30 years," he said.

Several components

"This process includes three separate public comment periods, two separate draft proposals, development of an environmental impact statement, and the final proposal. Even after the [Interior] secretary approves a final program, there is a lengthy public comment period for each lease sale that includes consultation with stakeholders at several stages and additional environmental analysis," Morris said.

Unfortunately, HR 3534 would create new regional planning councils, which apparently mirror many activities already being performed as part of MMS's development process for each 5-year OCS plan, he continued. "Furthermore, these councils have the potential to interfere with OCS development since leasing cannot occur if regional plans do not identify an area as being suitable for oil and gas leasing," the API official said. "By vesting this authority within regional councils, the bill could very well put areas effectively under moratoria for years to come."

He also questioned provisions in the bill eliminating the US Minerals Management Service's royalty-in-kind program (which US Interior Secretary Ken Salazar said he would phase out when he appeared before the committee on Sept. 16) and categorical exclusions from auditing requirements authorized under the 2005 Energy Policy Act.

"Problems with the management of these programs, whether perceived or actual, can and should be addressed by the Interior Department," said Morris. "Elimination of programs that have so much potential to increase efficiency is both unnecessary and unwise."

He and Campbell separately questioned the bill's diligent development requirements. "This provision displays a lack of understanding of the oil and gas exploration and production business," the Denver independent said. "Vast differences in geology, topography, reservoir characteristics, composition of the resource, environmental considerations, market conditions,

transportation of the resource to market, and many other factors make each oil and gas lease unique."

Acquiring capital

The business's financial aspect also is critical in determining when, where, and how a property is developed, he continued. Acquiring the necessary capital to develop properties is a never-ending activity for upstream independents, he explained.

Observers from outside the oil and gas industry sometimes confuse non-producing and inactive wells, Morris said. "Even if a well isn't producing, companies may be committing significant amounts of money for geophysical studies and other evaluations," he said.

When House Natural Resources Committee member Michael Coffman (R-Colo.) asked if lease protests were common, Campbell said that all the tracts which the federal government sold last year in Utah attracted protests. "I have one Utah lease, the Rock House project south of the already existing Natural Buttes field, where I've spent $30 million since 2004 while it has been tied up in litigation," he said.

The bill contains a provision that would require producers to notify not just surface landholders directly involved in split estate situations but also possibly adjacent surface land owners, he indicated. "This provision would create serious title uncertainty risks. While oil and gas producers are accustomed to evaluating the geologic and engineering risks of drilling a well, they are not willing to invest millions of dollars to purchase a lease or drill a well in the face of clouds on the title," he said.

In an interview after the hearing, Campbell said he was aware of the US Bureau of Land Management's effort to have producers provide surface landholders' names when proposing tracts for possible inclusion in future federal lease sales. He conceded that it would be additional work to look up the information, but added that most producers try to develop a good working relationship with surface landholders before applying for drilling permits.

Typical cost

"A typical well in Utah will cost me $3-4 million for leasing, surface preparations, drilling, completion, fracturing, and connection to a pipeline," he told the committee. "If I have to choose between leasing a private property and one on federal land with too many restrictions, I'll choose the private property."

Other hearing witnesses said the bill attempts to address problems that need to be corrected. Danielle Brian, executive director of the Project on Government Oversight, said that HR 3534 attempts to end a requirement for federal auditors and other compliance and enforcement personnel to report to officials whose responsibilities also include leasing and development, "and who may be more inclined to make the royalty management program look successful rather than be successful."

The bill also would end heavy reliance on compliance reviews instead of audits and try to get MMS to improve its computer system so it could identify instances where producers fail to report revenue or royalties at all, she noted.

Stephen B. Smith, the mayor of Pinedale, Wyo., said that while the measure does not fully address socioeconomic impacts from a major energy development such as the Jonah natural gas field near his community, it would require federal lessees to use best management practices. "The use of best available technologies should be required for all energy development on federal lands," he said.

"Producers in our area are currently moving in that direction, using some natural gas-burning engines for drilling and introducing a liquid gathering system on the Pinedale anticline," he continued. "These are two examples of voluntary and proactive steps taken by some operators. We hope they will continue." ✦

Indonesia awards exploration rights for blocks

Eric Watkins
Oil Diplomacy Editor

Indonesia has awarded five oil and natural gas blocks to several companies, aiming to increase oil and gas reserves and to lift dwindling production.

"The companies will drill three exploration wells. We believe those areas have hydrocarbon potential," said Evita Legowo, director general oil and gas at the ministry of energy. A total investment of $91.5 million has been committed for the projects in the first 3 years.

Indonesia awarded exploration rights to Talisman Energy Inc. for Andaman III block off North Sumatra, while Indonesia's state-owned PT Pertamina and Malaysia's Petronas won exploration rights to West Glagah Kambuna, off North Sumatra.

A consortium comprised of Niko Resources and Black Gold Energy won rights to the three remaining blocks: Halmahera Kofiau, off South Halmahera; East Bula, off of Seram; and West Papua IV, off of Papua.

Indonesia has been offering exploration rights and financial incentives for oil fields in a bid to stem a steady decline in production, but this year's efforts have not been entirely successful.

Officials said Indonesia failed to attract enough investors to develop all the blocks offered in this year's first quarter due to the global economic slowdown and concerns over revisions to the cost

recovery mechanism.

Of the 16 oil and gas blocks offered between December 2008 and April of this year, only five blocks won developers, according to the final results of the bidding process announced Sept. 11 in Jakarta.

Should the situation persist, the government will be in serious trouble due to its inability to meet oil production targets amid soaring demand that has already made Indonesia a net importer of oil and oil products.

"This is very bad, but this is the fact. If the situation remains like this, my objective to maintain national oil production at about one million b/d cannot be achieved," said Legowo.

Legowo cited two main factors hampering investors' interests in bidding for the blocks: the global liquidity crisis and the government's plan to revise the cost recovery mechanism.

Indonesia has turned into a net oil importer in recent years as production has dropped due to the failure to tap new fields fast enough. Indonesia also is Asia's largest importer of oil products, with Pertamina's nine refineries able to supply less than 70% of domestic oil product consumption.

Due the lack of refining capacity, a Pertamina official earlier this month said the state firm expects the country's gasoline imports to more than double from existing levels by 2017.

The official, who spoke on condition of anonymity, warned that annual domestic gasoline consumption would climb to 192.7 million bbl in 2017, from a forecast 123.8 million bbl in 2009.

He said Indonesia's refineries can only produce 68.5 million bbl/year of gasoline, so imports would have to rise to 124.2 million bbl in 2017, from 55.3 million bbl in 2009.

"If Indonesia wants to cut gasoline imports, it must build new refineries as quickly as it can," the official said.

Meanwhile, Pertamina said it expects to import about 5.6 million bbl of gasoline and 3.6 million bbl of diesel in October, down slightly from the figures for September.

The state firm earlier said it planned to import 5.8 million bbl of gasoline, and 3-4 million bbl of diesel in September in an effort to boost supplies for the Muslima holidays of Ramadan and Eid al-Fitr.

Eid al-Fitr, which marks the end of Ramadan, takes place from Sept. 21-22.

Agustiawan also said the company currently has 20.9 days of gasoline stocks and 25 days of diesel stocks.

"We will secure domestic oil products supply, especially during Ramadan and Eid al-Fitr," said Karen Agustiawan, Pertamina's president director, who added that "Gasoline and diesel imports are expected to be normal in October." ✦

Gazprom launches new stretch of Kaliningrad gas line

Eric Watkins
Oil Diplomacy Editor

Russia's state-owned natural gas monopoly OAO Gazprom, meeting the demand of the Russian government, has completed the construction of the second stretch of the 139-km Minsk-Vilnius-Kaunas-Kaliningrad gas pipeline.

"The Russian government tasked Gazprom with guaranteeing the supply of 2.5 billion cu m of gas to the Kaliningrad region in 2010," said Gazprom Deputy Chief Executive Officer Valery Golubev.

"The existence of the two-stretch pipeline and a compressor station, which will be commissioned near Vilnius next year, allows us to say that the set goal will be achieved," Golubev said.

The pipeline expansion is part of a Russian government action plan aimed at increasing supplies to Kaliningrad—a Russian enclave between Lithuania and Poland.

Besides the pipeline, the plan also calls for the upgrading of gas metering stations and for construction of a compressor station near Vilnius and an underground gas storage facility at Kaliningrad.

"The new gas pipeline will also increase the reliability of gas supplies to Lithuania, open up new prospects for more intensive development of gas-distribution networks in the republic, and increase gas deliveries to Lithuanian consumers," Golubev said.

Pipeline 'essential'

Viktoras Valentukevicius, head of Lithuania's gas company Lietuvos Dujos, 38.9% owned by Gazprom, said the pipeline was essential for his country.

"Natural gas will become a key energy resource for our country for decades. This line is very important for Lithuania as a guarantee of stable energy supplies from Russia," said Valentukevicius.

In December, Lithuania will close its Soviet-era reactor in Ignalina, which will transform the country from a net energy exporter to an energy importer.

Since Lithuania has no direct link to Europe's electric power grid, it has no choice but to import more energy from Russia—a matter that leaves many Lithuanians apprehensive, especially given Russia's recent decision to cut off supplies to other countries in the region.

"Vilnius should not forget that the Kremlin is using Gazprom not only as [an] economic [tool], but also a very efficient political tool," said Raimundas Lopata, director of the International Relations and Political Science Institute in Vilnius.

While acknowledging the con-

cerns of Lithuanians about the reliability of Russia as a supplier, analyst IHS Global Insight felt the new line represents a step in the right direction for the country's energy security.

"The additional gas supplies that can be delivered via the new string of the Minsk-Vilnius-Kaunas-Kaliningrad pipeline will be a net benefit to Lithuania, even if the Baltic state is not yet entirely convinced," IHS Global Insight said.

LNG to Lithuania

Meanwhile, Golubev said Gazprom is prepared to supply LNG to Lithuania if a regasification terminal is built at the Baltic Sea port of Klaipeda.

"We regard this project as a very interesting, promising direction. It is needed now. We have discussed this issue and we believe that it is very good that countries are building such terminals," said Golubev, who added that Gazprom believes it is necessary to build a gas pipeline link to Klaipeda.

In September, Lithuania and the US agreed that the US Trade and Development Agency (USTDA) would provide an $800,000 grant to conduct a feasibility study for an LNG import terminal in Lithuania.

The study will determine the possibility of building a terminal with a capacity of 1.5-2 billion cu m of LNG and will evaluate three potential sites, including one offshore.

According to current plans, the terminal will be 80% state owned, with the remaining 20% to be held by AB Achema, a private producer of nitrogen fertilizers and chemical products.

According to a statement by a Lithuanian economy ministry official, construction of the terminal could start 3-4 years after the completion of the feasibility study, which is expected in 2010.

Lithuania's Energy Minister Arvydas Sekmokas recently said his country is looking for a strategic investor in the terminal from a foreign country "rich in natural gas." ✦

Discovery off Sierra Leone may set up 700-mile play

Alan Petzet
OGJ Chief Editor-Exploration

The 45 ft of net hydrocarbon pay cut by an Anadarko Petroleum Corp.-operated deepwater exploratory well off remote Sierra Leone was only part of a "tremendous amount" of reservoir-quality rock the well penetrated, company officials said.

Anadarko and partners were still logging the Venus well Sept. 16, had not yet seen analyses of hydrocarbons recovered to surface by a modular formation dynamics test (MDT) tool, and were still receiving 3D seismic shot off Liberia to the east. The discovery is a technical success and could be highly commercial, they said.

It also appears to set up an exploration play that stretches 700 miles or more to the east along the coasts of Sierra Leone, Liberia, Ivory Coast, and western Ghana where giant Jubilee field and others have been discovered.

Anchoring a conference call on Venus that formed the basis for this article were Anadarko's Al Walker, chief operating officer; Bob Daniels, senior vice-president, worldwide exploration; and Frank Patterson, vice-president, exploration.

Stacked fan-channel complex

All information from the well "is very positive for the exploration effort in the Liberian and Ivorian basins," including fan systems, petroleum system, thermal maturity, and migration, said Daniels. The well proved the fan systems get better coming off the craton.

In the Venus well Anadarko saw good reservoir quality in numerous sands and shows in numerous sands. Nine wells previously were drilled on the shelf off Sierra Leone, and Venus validated the geological parameters of the depositional model that are going to help the company and its partners set up the rest of the play, they said.

After the group drilled to the originally prognosed 5,000 m, the well was still in fans and seeing hydrocarbon shows and the group elected to continue to the final TD of 18,500 ft.

Venus findings

The well found a combination stacked channel and fan complex, and both facies can be productive, Anadarko said.

One source rock encountered in the Venus well is immediately adjacent to reservoirs, and the area could contain other source rocks not yet penetrated, the company said.

A lot of data are still to be collected to determine where to drill the next well at Venus, but a dip rate of 2-7° indicates that areal extent of the reservoirs could be quite large. Areal extent, still to be determined, will become clearer after well and log data are tied with existing 3D seismic data.

Anadarko didn't reveal the geothermal gradient but said it shows that the kitchen is kicking out large amounts of hydrocarbons.

The drillsite is not at each zone's optimal location on the prospect. Rather, the well is in the best position to obtain as much data as possible on the multiple targets in the stratigraphic section to be penetrated, Anadarko said.

Play elements

Anadarko's goal is to drill opportunities to discover more than 150 million to more than 1 billion gross barrels of oil equivalent, and it sees multiple such features on all of the 10 blocks in which it participates off the four West African countries.

Anadarko was able to obtain a majority of the best acreage off the four countries and had done enough preparatory work to know what acreage to pursue and which to avoid. Even so, it might show interest in a few more blocks, and Venus has substantially de-risked the acreage, the company said.

After completing work at Venus, the rig will drill the South Grand Lahou prospect off Ivory Coast in the western part of the Ivorian basin. The South Grand Lahou fan system looks like giant Jubilee oil and gas field off Ghana

Liberia to gather ultradeepwater seismic

Liberia plans to announce an ultradeepwater licensing round after it acquires 15,000 km of 2D seismic, gravity, and magnetic data.

National Oil Co. of Liberia (NOCAL) has let a $16 million contract to TGS-NOPEC Geophysical Co. to collect the data in as much as 4,000 m of water, Dr. Fodee Kromah, president and chief executive officer of NOCAL told OGJ in an exclusive interview.

TGS will start the work later this year provided there is enough industry interest. Offshore Liberia has attracted significant industry attention due to recently announced discoveries in the Gulf of Guinea and Sierra Leone.

Earlier this month, NOCAL opened its third petroleum bidding round covering five blocks, which will close on Nov. 30. A ceremony to open bids for blocks LB-1, LB-2, LB-3, LB-4, and LB-5, is set for Dec. 1. NOCAL is offering production sharing contracts that expected to be signed by June 2010.

Kromah told OGJ that despite the downturn and global recession, he was confident that Liberia would attract interest in its blocks, which each span 3,000 sq km and lie in as much as 3,000 m of water.

Liberia is not an oil and gas producer. "We planned this round before hearing of Anadarko's discovery off Sierra Leone and there is a lot of interest," he said. "Liberia and Sierra Leone are in the same basin."

Kromah added that no date could yet be given for the deepwater licensing round until it had received the information from TGS-NOPEC.

did before it was drilled, Anadarko said.

The rig will then move to drill the Windjammer prospect off Mozambique (OGJ Online, June 25, 2009).

Venus preliminaries

Anadarko plans to drill two to five wells in 2010 in the Gulf of Guinea Cretaceous Trend.

Venus B-1, the first deepwater test in the Sierra Leone-Liberian basin, went to 18,500 ft in 5,900 ft of water on Block SL 6/07 about 55 miles from Liberian waters.

Venus is one of more than 30 prospects and leads Anadarko has identified on its West Africa acreage position. That includes interests in nearly 8 million acres on 10 blocks off the four countries. Anadarko operates seven of the blocks and the majority of the prospects with 40% average working interest.

"With Jubilee (off Ghana) on the east and Venus on the west, we have established bookends spanning approximately 1,100 km (700 miles) across two of the most exciting and highly prospective basins in the world," said Daniels.

Sierra Leone and Liberia have no oil or gas production. Venus is near the northwestern end of a 3,700 sq km 3D seismic survey on blocks SL 6/07 and SL-7 off Sierra Leone. That survey adjoins a 6,000 sq km 3D seismic survey on Blocks LB-15, LB-16, and LB-17 off Liberia. Seismic shooting is under way on Block LB-10 off Liberia.

Venus is also 850 miles south of oil and gas discoveries in the Atlantic off Nouakchott, Mauritania (see map, OGJ, Oct. 23, 2006, p. 38).

Interests in Venus are Anadarko 40%, Woodside Energy Ltd. and Repsol YPF SA 25% each, and Tullow Oil PLC 10%. ✦

Repsol YPF confirms large gas find off Venezuela

Repsol YPF SA confirmed earlier reports that it has made a giant natural gas discovery off Venezuela.

The company, in an exploration partnership with Italy's Eni SPA, said the Perla-1 well could hold 7-8 tcf of gas in place and said that further tests would be needed to determine the discovery's exact size.

The gas was discovered on a 924 sq km exploration block called Cardon IV, which the Spanish firm began exploring in 2006 along with Venezuela's state-owned Petroleos de Venezuela SA (PDVSA).

The block was one of three that drew bids in the October 2005 Rafael Urdaneta Phase A license round in the eastern Gulf of Venezuela. Three more blocks drew bids in Phase B in November 2005.

Repsol YPF and Eni would have stakes of 32.5% each in future production, while PDVSA would get 35%.

Earlier, the Spanish daily El Pais newspaper quoted Venezuela's President Hugo Chavez as saying that 1.5-2 tcf of the 7-8 tcf could be recoverable—a figure that Repsol YPF could not confirm. Repsol said the areal extent could be as large as 33 sq km.

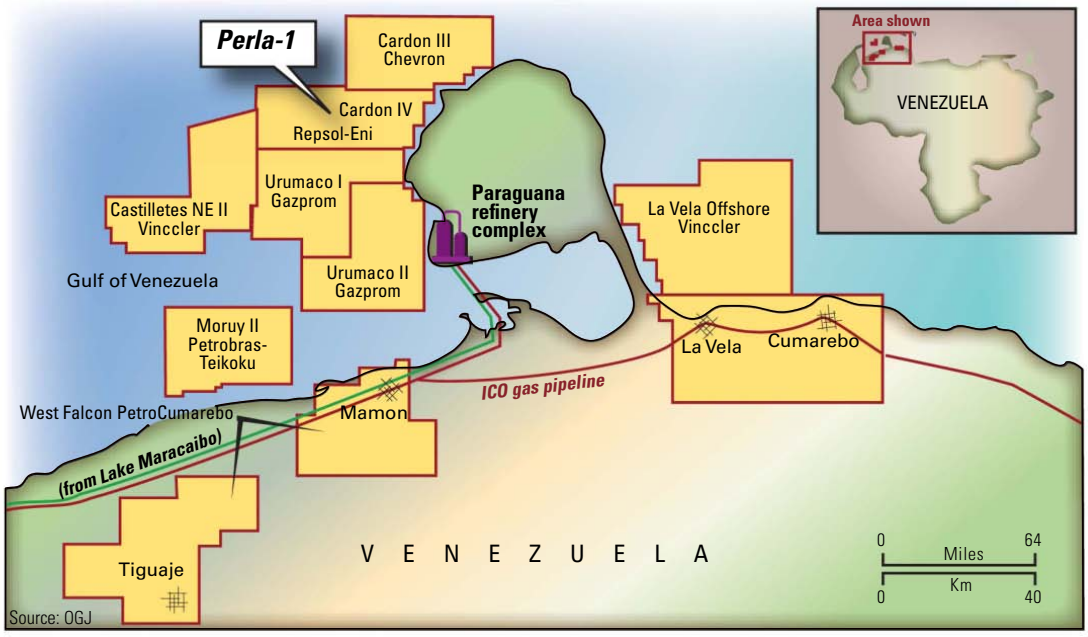
In any case, Chavez saw the find as boosting Venezuela into the top tier of world gas producers, saying, "At the rate the certified scientific discoveries are going, Venezuela's gas reserves will place it among the top five in the world."

Chavez was in Spain as part of a state tour of European and Asian countries, which has included Iran, Turkmenistan, and Russia, where several agreements were signed for the developments of Venezuela's Orinoco heavy oil belt.

Regarding Perla, Repsol also de-

REPSOL-ENI'S PERLA GAS DISCOVERY OFF VENEZUELA

Fig. 1



clined to give the formation or depth or to say whether the gas contains liquids. It said the discovery is the company's largest ever and the largest nonassociated gas find in Venezuela.

Perla is about 30 km northwest of PDVSA's Paraguana Peninsula refinery complex, the world's largest. Gas for the complex comes from Lake Maracaibo and from eastern Venezuela the new Interconexion Centro Occidente pipeline.

Perla, 130 miles northeast of Maracaibo city, is also 180 miles east of Chevron-operated Riohacha, Ballena, and Chuchupa dry gas fields in the Caribbean as far as 32 km off Colombia's Guajira Peninsula (see map, OGJ, July 22, 1974, p. 28). Those reservoirs are at about 6,000 ft. ✦

Mississippi

Mainland Resources Inc., Houston, and American Exploration Corp., Calgary, plan to explore for gas in deep Jurassic Haynesville shale on 13,500 net acres northeast of Natchez in Jefferson County, Miss.

Haynesville shale has similar attributes and is eight times thicker in the project area than in northwestern Louisiana based on engineering analysis of data from a Chevron well drilled on the acreage in the 1980s.

The companies have remapped the entire project area with reprocessed seismic data.

Mainland Resources has participated in the drilling and completion of two Haynesville shale wells in DeSoto Parish, La., and expects to complete a third well in a few months.

Mainland Resources will be operator and pay 80% of initial well costs to earn a 51% working interest in the total project area. It was not clear when drilling might start.

Griffin & Griffin Exploration LLC, Jackson, Miss., plans drilling to further develop Belmont Lake oil and gas field in Wilkinson County, Miss.

The field, on 142 acres in the Mississippi River flood plain, averages 130 b/d of 29° gravity oil from two vertical wells on gas lift from Oligocene Frio to a tank battery above flood stage. The river tends to flood between January and May, but the wells can produce when submerged.

The first new well could spud as soon as Sept. 21, 2009, said 8% working interest holder Cheetah Oil & Gas Ltd., Nanaimo, BC.

One or two development wells, including a horizontal well, in the north half of the field and an exploration well in the south half could hike production, Cheetah said. Cumulative production is more than 30,000 bbl.

Texas

Gulf Coast

Texon Petroleum Ltd., Brisbane, will run production casing at the fourth well on its Leighton prospect in McMullen County, Tex., after the well had oil and gas shows in Cretaceous Olmos. TD is 9,000 ft.

Wireline logs at Tyler Ranch-3 indicate similar reservoir properties to the Peeler-1, Tyler Ranch-1, and Tyler Ranch-2 wells.

Texon contracted a larger rig to drill Tyler Ranch-4 in early October to target Olmos at 8,500 ft and Eagle Ford shale at 11,000 ft. Working interests are Texon 70% and Global Petroleum Ltd. and Excellong Inc. 15% each.

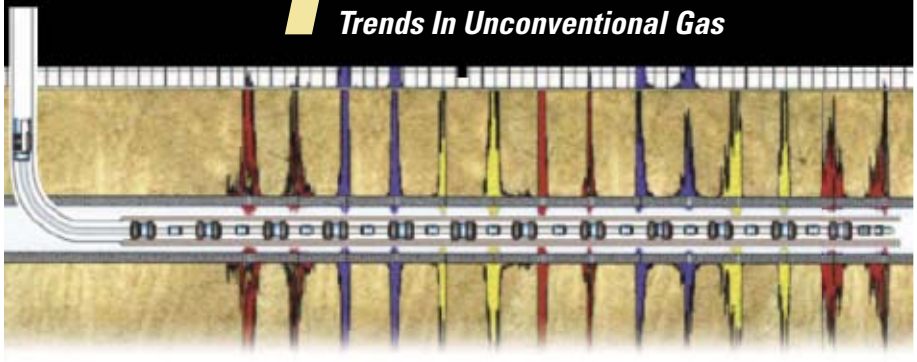
Texon holds 1,280 acres at Leighton and a 100% working interest in 1,434 acres at Mosman, 4 km southwest, and is seeking partners for the first Mosman well as early as first quarter 2010 to test Olmos and Eagle Ford.

GAS SHALE—1

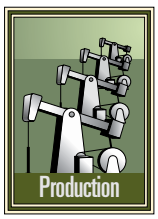
Seven plays dominate North America activity

Scott Stevens
Vello Kuuskraa
Advanced Resources International Inc.
Arlington, Va.

Special Report
Trends In Unconventional Gas



Seven shale plays dominate today's North America natural gas potential reserves additions and production increases.



Contrary to prior expectations of gas strategists and forecasts of gloom,[1] today North America is awash in natural gas supply. While reduced demand (–1.6 bcfd) and the new Rockies Express pipeline (0.9 bcfd) have been partly responsible, gas shale development undoubtedly has been the single most important factor.

During the past 5 years, gas shale production grew to more than 8 bcfd from 2 bcfd (Fig. 1). For some time now, shale and other unconventional reservoirs have helped stabilize US gas production, offsetting long-term production declines from conventional sources. Then, in recent years, the shale growth accelerated markedly, helping to push up overall US gas production into growth territory for the first time in a decade (Fig. 2).

The gas shale transition began with the Barnett shale in North Texas, followed by the Fayetteville in Arkansas and the Woodford in Oklahoma, and then was accelerated by the gas shales in the Haynesville and the Marcellus in the US and the Horn River and Montney in Canada (Fig. 3). Expectations are that these seven shale plays (the "Magnificent Seven") will dominate future natural gas reserves additions and production increases.

Building on the lessons learned from US and Canadian gas shales, various companies are starting to pursue overseas gas shale exploration in prospective areas such as Europe, Australia, India, and other countries.

From a resource once relegated to small independent producers, today majors, large independents and national companies are pursuing the play. How did this transition come about and where is it headed?

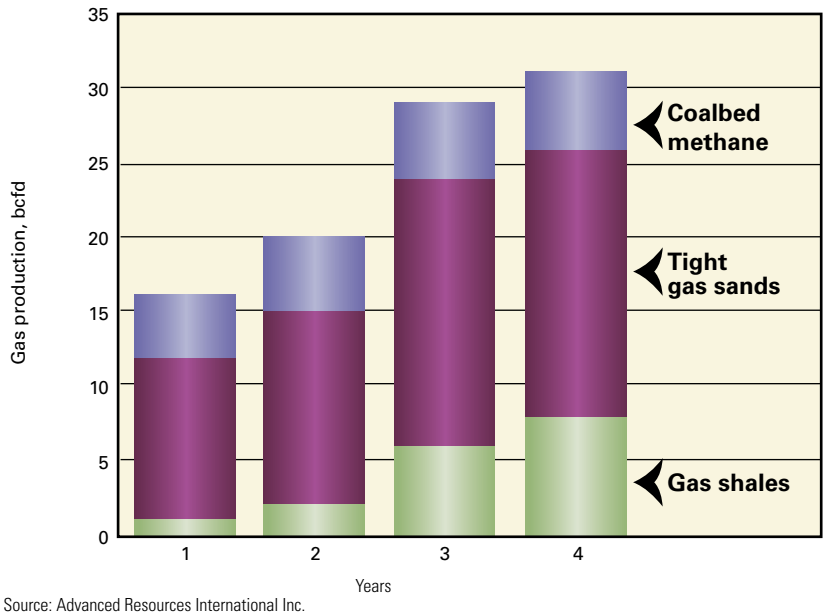
This three-part series on gas shale development begins with a look at the established and emerging North American shale basins and plays. The next two parts will examine the evolving technological and environmental considerations for optimally producing shale reservoirs as well as the potential for developing emerging gas shale plays in North America and elsewhere.

Shallow, deep shales

The Section 29 nonconventional fuels tax credit in the 1980s helped develop and boost the economics of the marginally productive organic-

US UNCONVENTIONAL GAS PRODUCTION

Fig. 1



Source: Advanced Resources International Inc.

rich gas shales such as Appalachia's Devonian Ohio shale and Michigan basin's Antrim shale.

Companies developed these shallow (500-2,500 ft deep) shale plays with conventional vertical wells and small hydraulic stimulations. Production was modest, generally about 100 Mcfd/well but long-lasting with reserves in the 0.25 bcf/well range. Fortunately, capital costs also were low.

These shallow, low-maturity, clay-rich shale reservoirs store gas mainly from methane adsorption, with only a small porosity gas component. Today, these shallow shales produce about 1 bcfd.

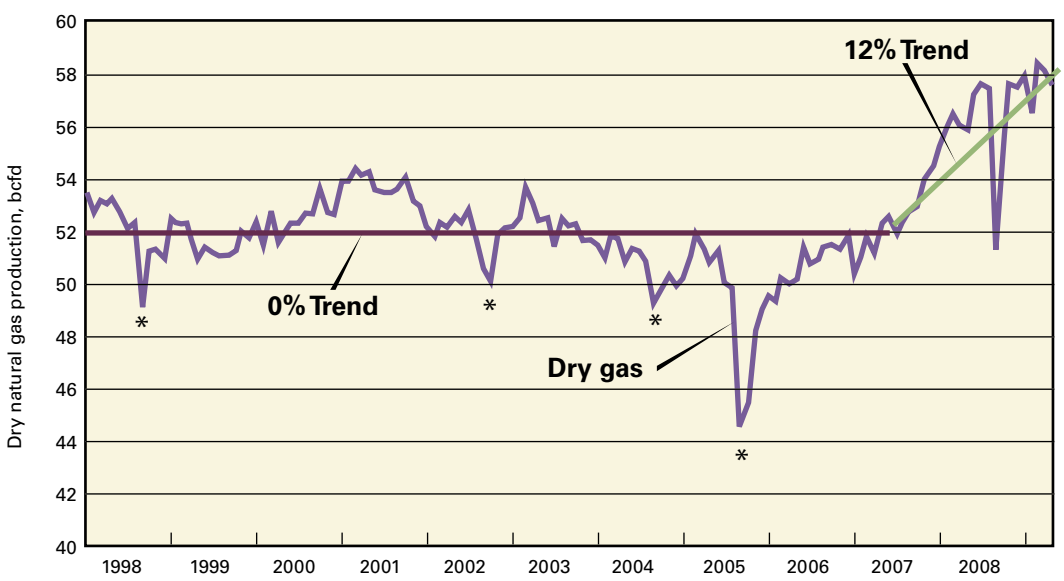
Modern deep shale development began about 1995 with emergence of the Barnett shale play in the Fort Worth basin, North Texas (Fig. 4). Long known for its gas-rich deposit, the Barnett at 8,000 ft pushed the depth envelope for favorable flow capacity.

Mitchell Energy & Development Corp.'s innovative large slick-water fracs outperformed earlier small gel fracs but their vertical wells still recovered just a small percent of the gas in place.[2] The first US Geological Survey assessment placed technical recovery from the Barnett Shale at just 3.4 tcf.[3]

Devon Energy Corp. acquired Mitchell in 2000 and recognized it could create more reservoir flow paths with a cased 4,000-ft horizontal well stimulated with large slick-water fracs containing several million pounds of sand proppant and pumped in 8-12 stages. Recovery increased manyfold compared with earlier vertical wells. As horizontal drilling and fracturing technology advanced, Barnett core area wells have improved to an average 2.5 bcfe/well. Current production from the entire play is almost 5 bcfed from more than 12,000 vertical and horizontal wells.

US GAS PRODUCTIVE CAPACITY

Fig. 2



Source: DOE-EIA Short Term Energy Outlook, August 2009

The Barnett's core area sweet spot has favorable depth, thickness, thermal maturity, pressure gradient, and a hard underlying sandstone that acts as a hydraulic fracture stress barrier, focusing energy within the shale reservoir. With access to new well performance and geologic data, an updated USGS resource assessment placed technical gas recovery from the Barnett at 26 tcf.[4]

At yearend 2008, however, cumulative production was 5 tcf with an additional 20 tcf of booked proved reserves, thus ultimate gas recovery needs an upward revision.

Advanced Resources puts the remaining undeveloped recoverable resource from the Barnett at 15-40 tcf, depending on gas prices. This gas play still has room to run.

Barnett lessons learned

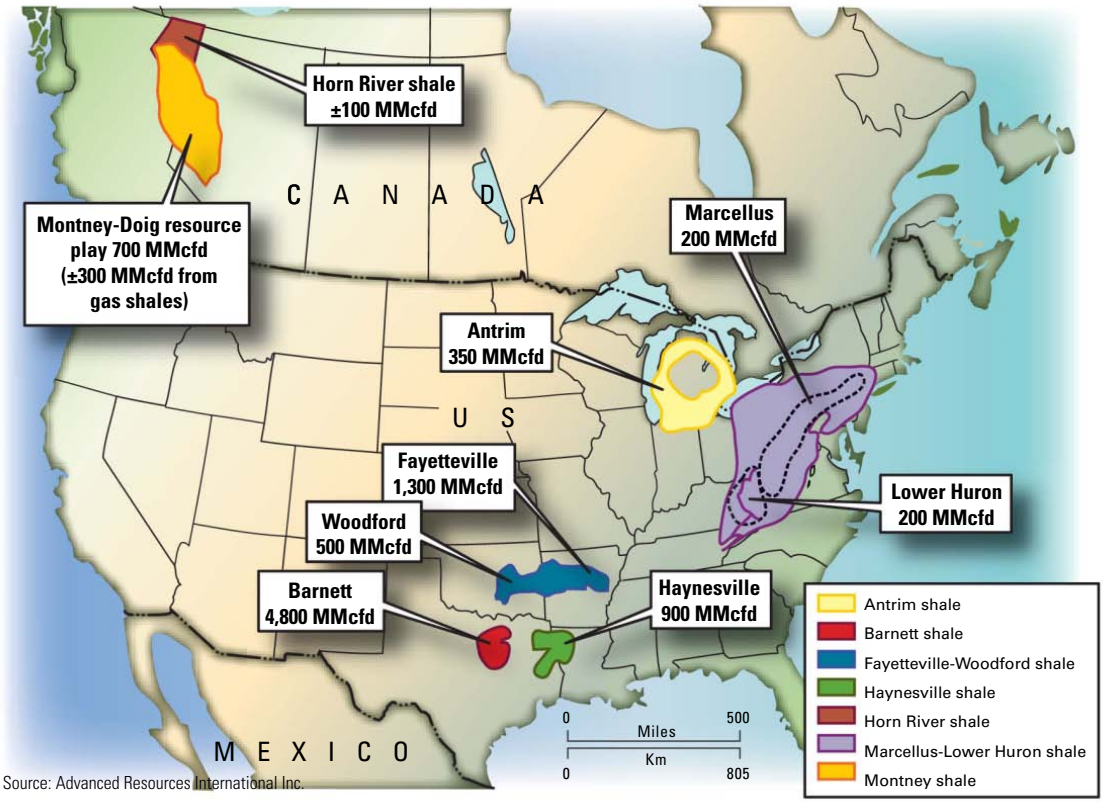
A series of factors spurred the explosive growth of high-quality shale plays beyond the Barnett, as documented by internal studies performed recently by Advanced Resources, to be discussed in the second article.

The factors include a greater geologic understanding, advances in drilling and completions, and access to land and infrastructure.

Although the Barnett shale was an acknowledged deep horizontal shale success, doubts lingered over whether it was merely a one-of-a-kind geologic setting, such as the still-unmatched San Juan fairway coalbed methane play in New Mexico. Not until 2006, following Southwestern Energy Co.'s Fayetteville and Newfield Enegy Co.'s Woodford shale production breakthroughs, were the doubters finally silenced and the new shale exploration and development paradigm confirmed.

As it turned out, shale plays do not have to be Barnett look-alikes; their geologic settings can be remarkably varied.

MID-2009 GAS SHALE PRODUCTION Fig. 3



Source: Advanced Resources International Inc.

For instance, reservoir depth can range from 3,000 ft in the Fayetteville to more than 14,000 ft in the Haynesville.

The key geologic precursors for deep shales turned out to be different than for the shallow shale plays. Modest but adequate porosity (6-12%) is essential for gas storage. Unusual mineralogy, low in ductile clays and high in brittle quartz, feldspar, and carbonate components, helps promote frac effectiveness.

The shale needs adequate thermal maturity (R_o >1.0%) to avoid unfavorable relative permeability from liquid hydrocarbons in the reservoir. Higher thermal maturity also promotes shrinkage of the total organic carbon (TOC), leading to higher effective permeability and often a fully gas-charged system. The shale needs an adequate TOC (2-5%) for gas storage by adsorption.

An equally important factor, requiring 3D seismic, is the avoidance of geohazards, such as water-bearing karsts and faults.

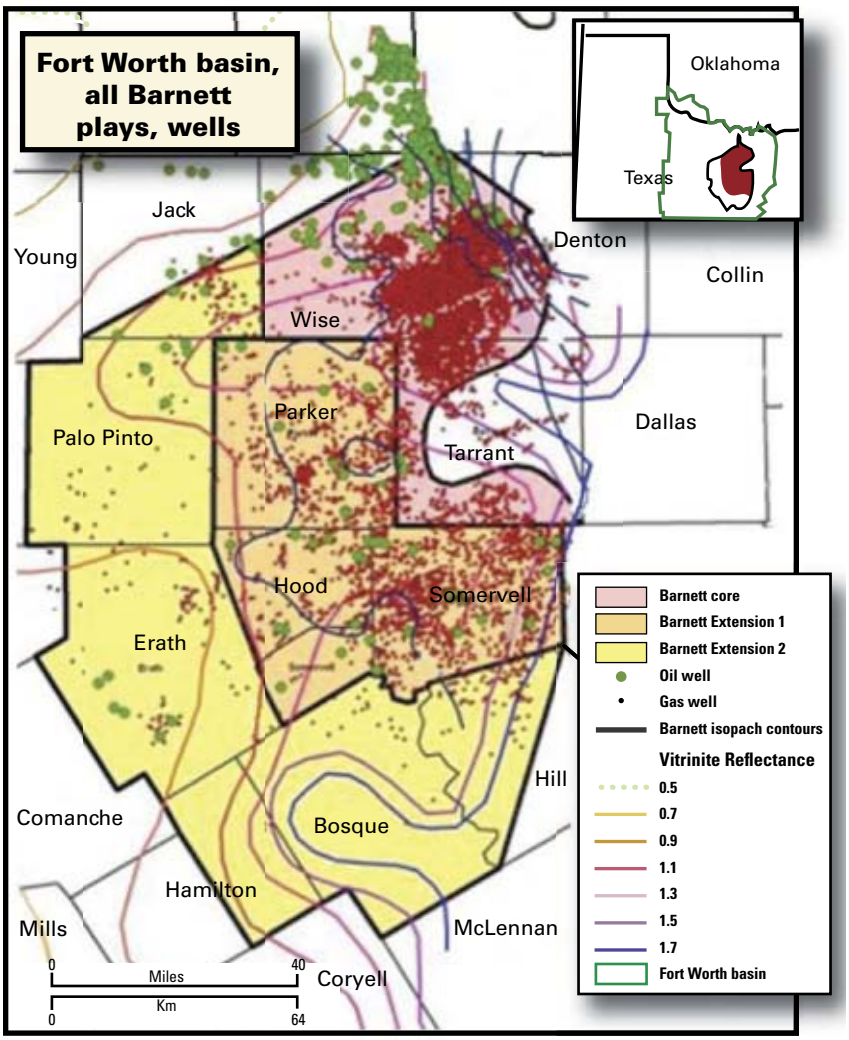
Natural fracturing turned out to be somewhat less important than initially assumed. Even with permeabilities in the nanodarcy range, artificial stimulation could create the resevoir's flow capacity.

Horizontal drilling coupled with large slick-water hydraulic fracturing, employing ever-increasing lateral length and proppant loads, often guided by real-time seismic monitoring, provides much more effective (5-10 times) flow capacity than traditional vertical wells.

Today, deep shale drillers all employ essentially the same Barnett-style well drilling and completion design: ±4,000-ft long laterals stimulated by multimillion-lb slick-water fracs in a dozen stages. Armed with these new techniques, deep shale development is spreading rapidly to the Marcellus, Haynesville, and Horn River shales. Advancements continue, including simultaneous fracturing of closely spaced

BARNETT GAS SHALE PLAY

Fig. 4



Barnett shale recoverable resources

	Cumulative recovery, tcf	Proved reserves, tcf	Remaining recoverable, tcf	Total, tcf
Core area	3.7	12	11	27
Extension area 1	1.5	8	12	21
Extension area 2	0.1	1	9	10
Total	**5.3**	**20**	**33**	**58**

Source: Advanced Resources International Inc.

wells (600-800 ft apart) to contain the injected energy and more intensively shatter the shale reservoir.[5]

Access, infrastructure

Companies generally can develop shale plays located in the US Midcontinent and East, where most land is owned privately, with minimal political wrangling. The fact that shale developments can cover entire counties means that royalties are spread among thousands of individual landowners, often aligning them with operators.

On the other hand, development of eastern gas shales has raised concerns among environmental organizations and the general public, slowing or stopping development.

At both the state and federal levels, pressure exists for more active regulatory oversight of shale gas development. Particular areas of concern are frac water sourcing and disposal, along with the perceived effect of fracturing operations on ground water.

The third article in this series on gas shales will further explore the critical geologic, well completion, and environmental issues important for more optimally developing these unconventional gas resources.

New shale operators.

A new breed of shale operators—mostly mid to large-cap independents—emboldened by the improved geologic understanding and production technologies, has leased millions of shale-prospective acres. Most have tacked adeptly through the recent economic turbulence, bolstered by price hedging and supportive capital markets.

Hedging and financial inflows have enabled operators to hold and develop their best shale acreage in spite of (and indeed exacerbating) the collapse of spot gas prices.

In another industry step change, during the past year majors such as BG Group, BP PLC, ExxonMobil Corp., Shell Canada Ltd., and StatoilHydro have entered shale plays in a significant way through leasing and acquisition.

These include BP's purchase of Chesapeake's Woodford shale properties for $1.75 billion, as well as the company's $1.9 billion deal for 25% of Chesapeake's Fayetteville shale position.

Shell acquired Duvernay Oil Corp. for $5.9 billion, including extensive Montney shale leases in Canada.

Statoil farmed into Chesapeake's Marcellus shale position for $3.3 billion.

BG Group acquired an interest in Exco Resources Inc.'s Haynesville shale acreage for $1.55 billion.

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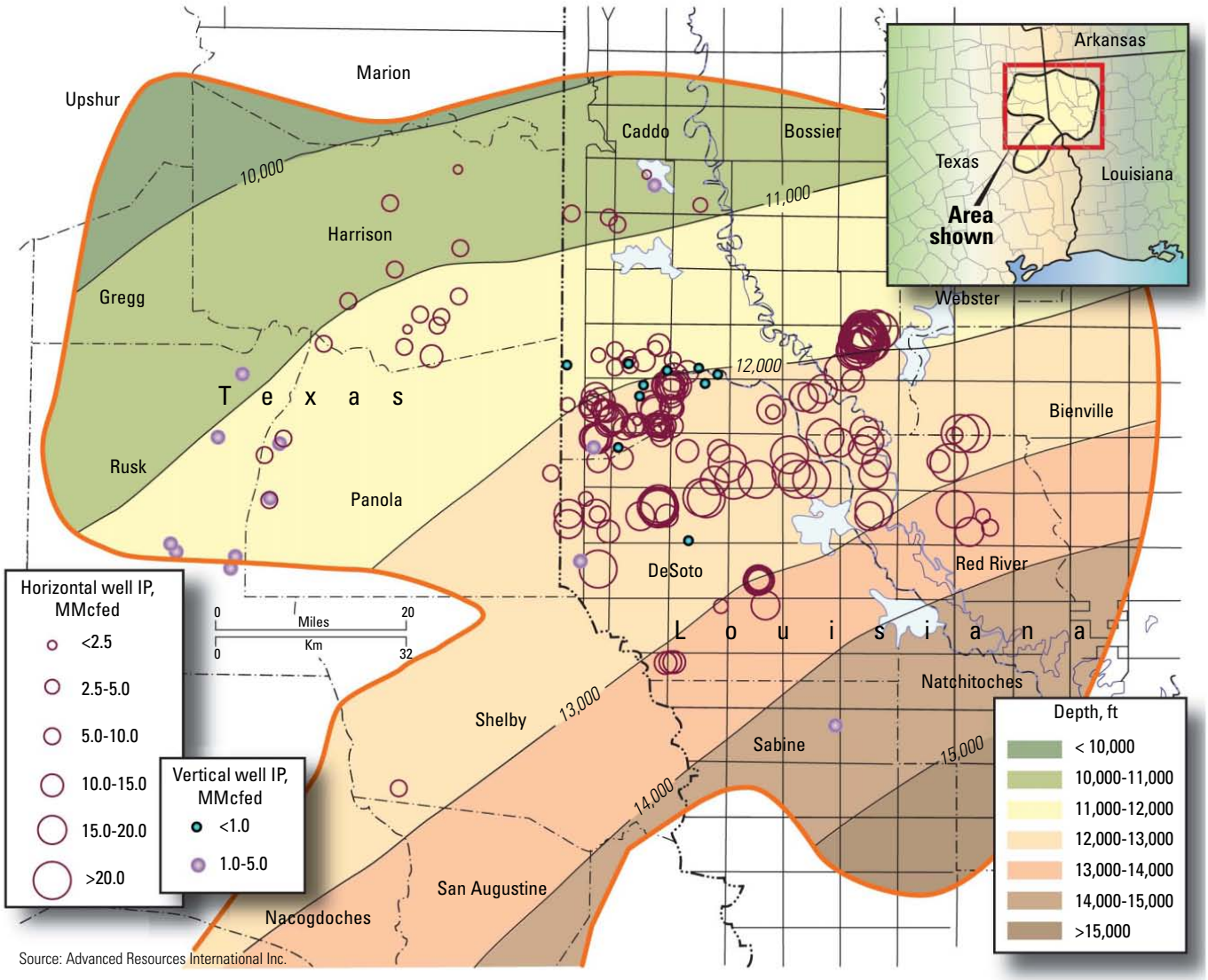
HAYNESVILLE SHALE IP RATES

Fig. 5



Source: Advanced Resources International Inc.

Others have taken the leasing approach in the Marcellus (Marathon Oil Co.), Eagleford (ConocoPhillips), and Horn River plays (ExxonMobil).

The Magnificent Seven

Including the Barnett, seven high-quality new deep gas shale plays are under development in North America: five in the US and two in Canada.

The high-quality core areas of these plays can have low overall full-cycle "break-even" costs of $4-5/Mcf, while the less favorable outer areas tend to have much higher costs. Advances in well drilling and completion technology would help lower the costs of developing the outer areas of these gas shale plays.

Fayetteville (Arkansas)

The eastern Arkoma basin's Fayetteville shale is a Mississippian Barnett-equivalent that extends across central Arkansas. It was the second deep shale to be commercialized. This discovery helped convince industry that the Barnett was not unique and that shale plays need not be geologic Barnett clones. This widened and intensified the global deep shale hunt.

The Fayetteville is shallower than the Barnett (3,000-5,000 ft deep vs. the Barnett's 6,000-8,000 ft) as well as thermally more mature (2.5% R_o vs. the Barnett's 1-1.5%). Carbonate collapse zones (karsts), which plague portions of the Barnett, are not present but water-bearing faults can occur.

The lower Fayetteville is the main completion target, as it is the most quartz-rich, high in total organic content, fairly porous, and gas-saturated zone.

Four shale-experienced operators dominate the Fayetteville shale play and production has increased rapidly to 1.3 bcfed today.

Southwestern Energy Co., with near-

ly a million net acres including much of the play's core area, recently attained the 1-bcfed benchmark. Others include Chesapeake-BP, XTO Energy Inc., and Petrohawk Enegy Corp.

Southwestern envisioned the play in 2002, drilled its first two vertical wells in 2003 to confirm reservoir quality, and eventually tested 33 pilots across its acreage to evaluate geologic quality and optimize well design.

Development started with vertical wells but soon switched to horizontals employing 2,500-ft laterals that were stimulated with crosslink gel fracs.

By 2007, Southwestern evolved its completion to longer laterals with slickwater fracs, both of which significantly improved gas production.

Recent wells are positioned using 3D seismic and typically employ 4,000+ ft laterals stimulated with a dozen or more frac stages.

Today, wells cost about $2.9 million (all-in), produce at initial rates of 3.0 MMcfd (30-day rate), and are expected to recover about 3.0 bcf/well in the core area. Active development continues despite low gas prices.

Woodford (Oklahoma)

The western Arkoma basin hosts the Mississippian-age Woodford shale play, which currently produces about 0.5 bcfed. Newfield Exploration Co. began to develop the play in 2006 and its early success helped bolster the global acceptance of deep shale as an exploration target.

The Woodford has some of the longest shale laterals drilled, up to 10,000 ft in the reservoir, thanks to enlightened state well-spacing regulations. Overall development, costs however, tend to be relatively high in the Woodford and low gas prices have severely curtailed drilling this year.

Production likely will plateau or even decline until gas prices recover. Newfield, the largest shale operator in the play, currently produces 240 MMcfed but has recently begun to release many of its rigs.

A geologically distinct emerging Woodford shale play occurs in the deep Anadarko basin. This "Cana" play has Haynesville-like 13,000-ft depths and is highly overpressured. Leading operators include Devon and Cimerex Energy Co. While the play is not yet proven, early well tests are encouraging.

Marcellus (Appalachia)

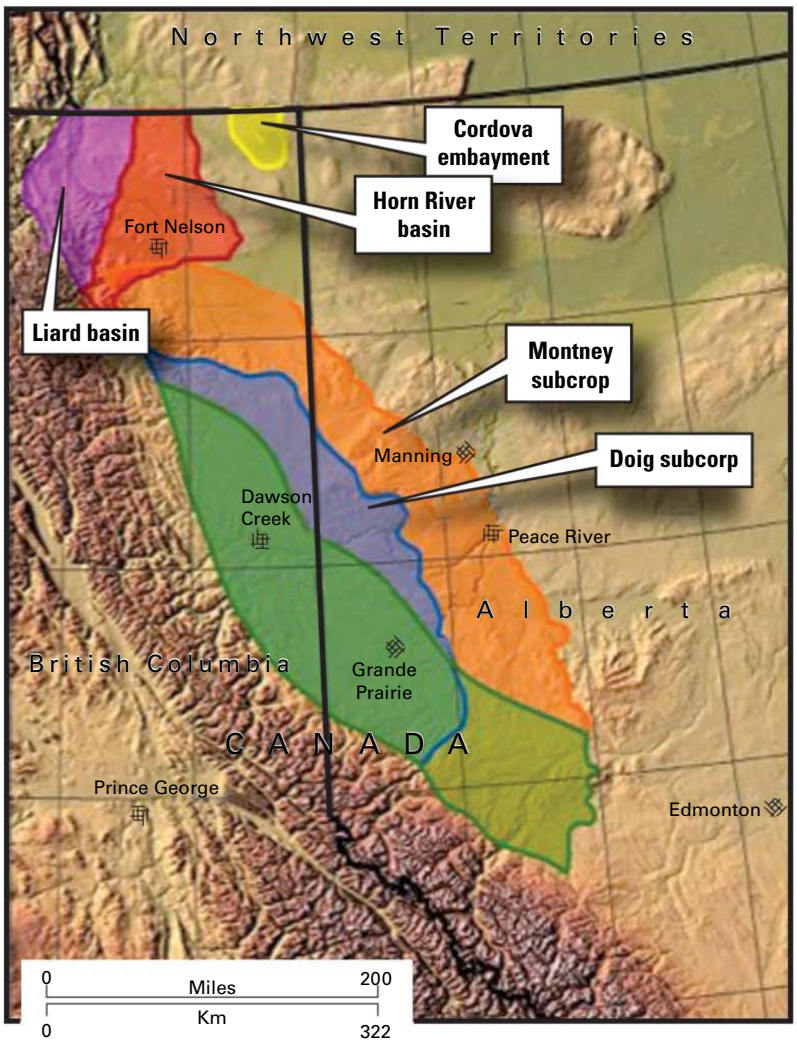
The Devonian Marcellus shale had been productive for decades in this region but in shallow settings. Then, starting about 5 years ago, success in the Barnett spurred operators to test the deeper portions of the Marcellus (5,000-9,000 ft depth) for the first time.

Recent geologic resource studies have helped quantify the potential of this huge shale target, which stretches from Kentucky to New York.

The USGS defined thickness, depth, and other reservoir parameters in 2002, conservatively estimating that the play had 1.9 tcf of recoverable resources.[6] Academic and industry studies have since raised that estimate to as high as 500 tcf.

ARI's internal study of the play (using a database of more than 500 wells) puts recovery in the 100-200 tcf

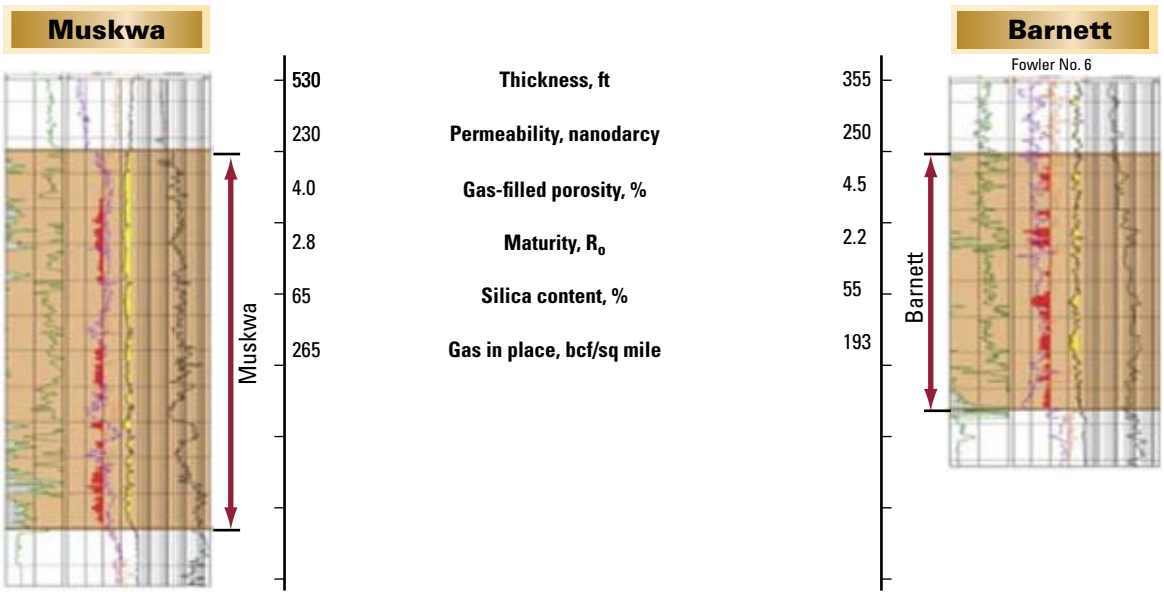
WESTERN CANADA GAS SHALE BASINS Fig. 6



Source: Advanced Resources International Inc.

HORN RIVER MUSKWA, BARNETT SHALE COMPARISON

Fig. 7



Source: Modified from EOG Resources, 2008

range, depending on gas prices, out of more than 1,600 tcf total gas-in-place resource.

Two Marcellus sweet spots have emerged. Southwestern Pennsylvania has fairly thick shale (100-150 ft) with high TOC. Marginally mature (R_o ~1%), this area produces wet gas that requires surface separation facilities.

Early-mover Range Resources Corp. has drilled 46 horizontal Marcellus wells, mostly in Washington County near Pittsburgh. Recent wells have an average 7 MMcfed initial potential, with one as high as 26 MMcfed (24-hr rates).

Range estimates recovery at about 4.4 bcfe/well, with a horizontal well estimated to cost $3.5 million (all-in).

The company estimates its total potentially recoverable resource from the Marcellus at 15-22 tcfe.

CNX Gas Corp. also reports good results in southwestern Pennsylvania, where it has drilled eight horizontal wells (6,000-ft vertical depth, 3,000-ft laterals) costing about $3.5 million, with initial potentials of up to 4.1 MMcfed.

Vertical wells also have been successful in the Marcellus. Atlas Energy Resources LLC has drilled more than 160 vertical Marcellus wells, with recent completions reported at 1.4 bcfe/well and costing just slightly more than $1 million/well. The company has increased its estimate of potentially recoverable resources on its acreage to about 9 tcfe.

Although companies likely will develop the Marcellus mainly with horizontal wells, verticals still will play a role.

A second sweet spot is developing in northeast Pennsylvania and south-central New York, where the Marcellus is exceptionally thick (200-400 ft). Cabot Oil & Gas Corp. has tested several wells here with initial potential's up to 9 MMcfed.

Ultra Oil & Gas Inc. has tested five horizontal wells, each coming in at more than 5.3 MMcfed (24-hr rates). Talisman Energy Inc., Chief Oil & Gas LLC, and Epsilon Energy Ltd. also report high-rate wells in this area. Other operators include Chesapeake, Southwestern, and Range.

Overall, Marcellus shale production currently is at about 200 MMcfed. Production is growing more slowly than in other shale plays because of rugged topography, a shortage of appropriate drilling rigs, environmental and regulatory hurdles, and the sheer size of the acreage, which must first be properly evaluated.

With its low finding and development costs, however, the vast Marcellus play may eventually reach or exceed Barnett Shale production rates.

Haynesville (Louisiana/Texas)

In late 2007, the "buzz" was that the massive Hayneville shale play in the Louisiana Salt basin of northern Louisiana and East Texas could eventually outshine even the Barnett shale.

The Haynesville shale is a Jurassic shale, much younger than the Mississippian Barnett, Fayetteville, and Woodford plays. It is also deeper (10,000-15,000+ ft), breaking the rules on where successful shale plays could go.

With decent levels of porosity (8-12%) in the eastern portion of the play area, the Haynesville is rich in brittle carbonates and quartz, particularly in its basal section.

The play's substantial depth, extreme

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U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
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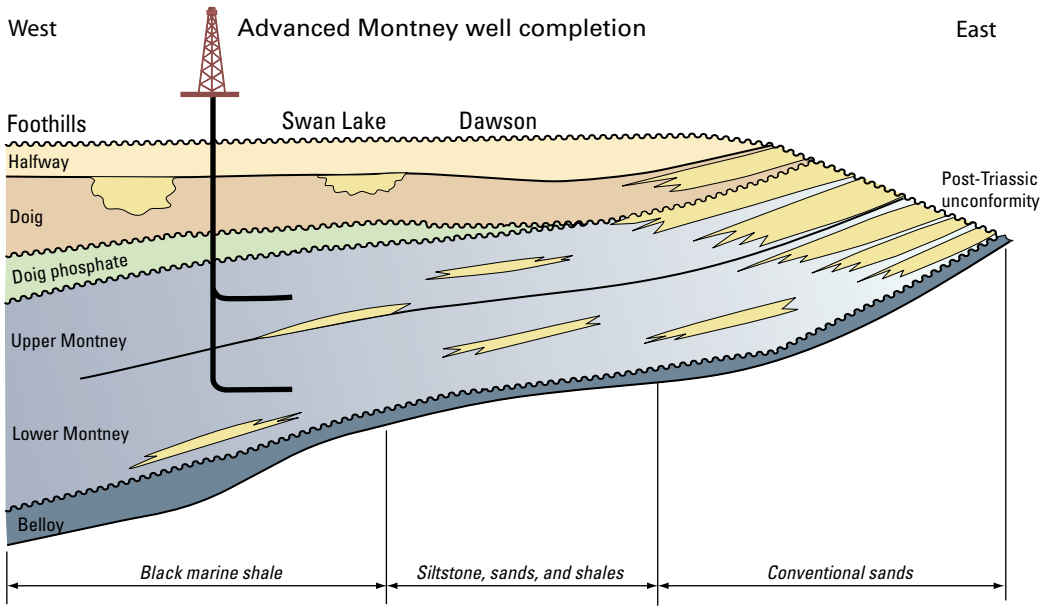
MONTNEY-DOIG RESOURCE PLAYS

Fig. 8



overpressuring (up to 0.85 psi/ft), huge size (>1,000 tcf of gas in place), and rich resource concentration (>200 bcf/sq mile) place the Haynesville in rarefied company.[7] But amazingly, there could be further upside: the overlying Bossier shale offers a secondary gas-charged completion target.

The primary challenge for the Haynesville is the high-pressure, high-temperature drilling environment and high resulting well costs of $10+ million. In addition, due to sharp initial year declines, long-term production and per-well reserves remain uncertain.

Companies still are defining the Haynesville's sweet spot. They have drilled excellent wells in portions of DeSoto, Caddo, Red River, and Bossier parishes, northern Louisiana, clustering around the 12-13,000 ft depth interval (Fig. 5). Core area wells frequently have an initial potential in excess of 20 MMcfed (24-hr rate).

Depending on decline rates these wells might be capable of producing 6-8 bcfe or more. Well costs are high but expected to drop with operational efficiencies such as pad drilling. Core area wells look attractive even at $4/MMbtu Henry Hub gas price.

The East Texas and extreme northern Louisiana portions of the Haynesville play are shallower (10-12,000 ft) and thicker (up to 400 ft). Reservoir quality, notably gas-filled porosity and brittle mineral content, however, appears lower. Wells typically have an initial potential below 10 MMcfed and will require higher gas prices to be economic.

Early thinking was that fracturing would require costly synthetic silicon carbide proppant for resisting the Haynesville's high pressures and temperatures. Most operators, however, have found low-cost resin-coated sand proppant to be adequate.

Haynesville shale operators include early-movers Chesapeake, EnCana Corp., Petrohawk, and Exco Resources, all with large core area positions.

Two dozen other operators are testing the horizons below their legacy gas fields, which produce from the Cotton Valley, and are acquiring undeveloped acreage.

Production, currently more than 1 bcfed, is growing much faster than in the Marcellus. Eventually production could approach Barnett production.

In a possible harbinger of deals to come, BG Group recently agreed to pay Exco $1.55 billion for a 50% share of certain upstream and midstream Haynesville assets in Louisiana. Numerous other operators are positioning to establish a stake in one of North America's largest and lowest-cost gas plays.

Horn River basin

A sequence of geologically attractive gas shales exist in the Horn River basin, in northeast British Columbia, with the Late Devonian Muskwa shale the most prominent. Often the Muskwa, Otter Park, and Horn River sequences are grouped within the broader Horn River terminology (Fig. 6).

The Horn River basin has an areal extent of about 5,000 sq miles. The Muskwa-Horn River shale within this basin is 300-500 ft thick in the heart of the play, thinning to 100-150 ft to the south near the Peace River arch.

Gas-filled porosity ranges 1-9%, with 3-4% typical.

Thermal maturity is high (R_o = 2-4%), reflecting a dry gas setting. There is potential for elevated CO_2 in the more thermally mature areas.

At a representative 8,000 ft depth, the formation is overpressured with a 0.6 psi/ft reservoir pressure gradient.

The Muskwa shale is organically rich, with an average 3% organic carbon content.

Fig. 7 shows a side-by-side compari-

son of the Horn River basin Muskwa and Fort Worth basin Barnett shale wells. EOG Resources Inc. drilled both wells in geologically favorable settings.

The figure shows that the Muskwa shale is thicker and more mature, providing higher gas concentration. The Muskwa shale has a higher silica content of 65% vs. 55% for the Barnett shale, causing the Muskwa shale to be more brittle and favorable for hydraulic fracturing. The Muskwa and Barnett shale have similar permeabilities and gas-filled porosities.

Seven major companies, led by EnCana and Apache Corp., hold significant lease positions in the Horn River gas shale play.

Horizontal well drilling has had positive results, with initial rates of 3-10 MMcfd. Operators, however, are still testing and optimizing their drilling and well completion strategies.

Market outlets and high transportation costs are a concern, as is gaining year-round access to drilling sites. Two new regional pipelines are under development to bring gas to markets. A 24-in. line is due in service mid-2009 and a larger 36-in. line is due in service by mid-2011.

Other innovative market options include sending gas to the oil sands area in northern Alberta as well as to coastal Kitimat, BC, for export as LNG.

Montney shale

The Montney resource play represents a complex geological sequence that varies from conventional gas (and oil) along the eastern edge of the basin, to a combination tight gas and gas shale play in the center, and to a classical black massive gas shale complex along the western edge (Fig. 8).

The closest geological analog may be the complex Bossier sand and shale play on the Texas and Louisiana border.

The Montney resource covers a massive area, more than 35,000 sq miles, with geologic and reservoir properties changing dramatically from the eastern to the western portion of the play area.

The Mid to Lower Triassic-age deposit contains sandstones on the shallower (3,000 ft) eastern boundary of the play, grading to siltstone and shale in the deeper (8,000 ft) western boundary of the play.

In the western Montney play area, near Dawson Creek, the gas shale is thick, thermally mature with high organic content. In the northern portions of the area, north of Fort St. John, the Montney Shale has higher clay content and decreased silica, reducing the brittleness of the formation and its favorability for creating reservoir permeability and flow capacity with hydraulic stimulation.

While companies have drilled considerably in the eastern and central portions of the Montney resource play, they only have drilled lightly the western gas shale play. Early horizontal well performance in the geologically favorable portions of the area, however, has been attractive with initial 30-day gas rates of 5 MMcfd and relatively modest declines for gas shale wells.

A large number of operators hold leases in the heart of the Upper and Lower Montney gas resource play, led by EnCana (with about a million acres), Shell (after its purchase of Duvernay Oil in mid-2008), plus Talisman, Murphy Oil Corp., and ARC Energy Trust. ✦

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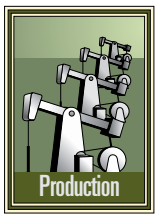
Understanding process key to shale gas development

Mark Parker
Halliburton,
Tyler, Tex.



Making hydrocarbon production from shales a profitable venture requires a process for driving down overall costs. It is clear from experience in these tight, widely varying resource plays that companies achieve an advantage through many efficiencies reached during the entire exploration and development process.

The starting point is critical to the success of this process. Because shale varies greatly, what works in one reservoir or well probably will not be as effective in the next. Failure to understand the difference leads to expensive miscalculations and prolonged well development.

Each shale well and reservoir requires a high degree of understanding to reach its full economic potential. This is especially important when exploring new shale formations for which knowledge is a key factor in the speed and efficiency of bringing on production.

Lessens learned in exploiting the Barnett shale in north-central Texas, have helped form processes for evaluating and developing the Haynesville shale to the east of the Barnett and the emerging Eagle Pass shale south of the Barnett.

Need to know

The need to know cannot be emphasized strongly enough. Reservoir knowledge guides a multitude of choices that can make or break a shale well, including critical steps in designing optimal fracture treatments.

Understanding the reservoir in these complex unconventional resources entails a rigorous grasp of rock properties, fracture geometry, fluid interactions, evaluation processes, microseismic surveys, tracers, and production logs. It also requires sharing this information across disciplines so that insights are leveraged as effectively as possible.

Collaboration among geoscientists and engineers is central to improving shale exploitation. Having a single strategy for the entire well rather than a series of discrete operations enables everyone on the asset team to make decisions with full knowledge of how actions affect total well objectives.

Specialized processes for shale analysis and stimulation design facilitate this effort. For instance, Halliburton's ShaleEval shale formation evaluation service forms expert shale teams that integrate geology and engineering in a process that examines fluids, the fracture treatment, formation evaluations, and candidate selection.

The process also uses shale-specific systems to identify mineralogy and integrate wireline log data and laboratory core analysis to help define shale characteristics. The information guides fracture treatment design by helping identify targets, which is critical to well performance in shale reservoirs. These systems are components of a life-cycle-based approach to developing shale reserves that Halliburton uses to integrate asset management from the first look at reservoir potential through development stages and decline.

Ultimately, this knowledge sharing facilitates a holistic view of the reservoir throughout its development, which brings with it the various insights needed to create shared efficiencies and synergies.

Formation description

Companies can acquire reservoir information with basic logging suites. Their primary purpose is exploration and calculation of reservoir fluids. But new analysis and presentation techniques provide a comprehensive formation description that is routinely verified and calibrated with core analysis.

A variety of logs provides highly

practical information about shale. For example, formation lithology is identified with natural gamma ray tools to measure elevated uranium signals that are common indicators of shales rich in organic matter and total organic carbon (TOC). When they also exhibit sufficient porosity, these shales typically are productive.

Information also comes from resistivity measurements that indicate fluid saturation and permeability in the shale. Low permeability and high clay content can be an early indictor that the shale may not respond well to treatment.

Density logs and dual count neutron logs indicate shale porosity and the associated reservoir capacity for storing fluids. Acoustic logs, which record the velocity of compressional and shear waves through the formation, are used to generate stress data, which help predict the behavior of hydraulic fracturing treatments that are critical to shale production.

Images of the formation acquired with electrical borehole imaging tools provide views of the sedimentary sequences in the wellbore. This information is used to plan optimal horizontal well trajectories in shales, guide sidewall-coring points and identify pressure dependent leak-off points from small fractures.

Magnetic resonance logging provides data on the fluids in the pore spaces as well as other formation parameters such as pore size, calculated permeability and presence of clays. In shale wells, these data cover the long, continuous intervals at reservoir conditions with less expense than conventional core data.

Building on the Barnett

Much of what is known about the mysteries of shale rests on lessons learned in developing commercial production out of the Barnett shale in north-central Texas. In pioneering this resource play, companies have applied innovative new technologies and methods subjected to almost daily changes.

But successful techniques hammered out in the Barnett are not easily transferred to new and emerging shale plays. Experience proves that methodology is the most important constant in shale development, not discrete techniques. Using a process that starts with reservoir knowledge is key for selecting the most appropriate techniques and achieving the highest efficiencies.

Shales from various plays have different properties (Fig. 1).

To the east of the Barnett, the Haynesville shale straddles the borders between Texas, Louisiana, and Arkansas in one of the oldest productive regions in the US.

While the Haynesville is also a tight-gas shale, the comparison of its relatively ductile rock with the Barnett shale is one of peanut butter to peanut brittle. Understandably, wells in these two shales are not completed in the same way. Fig. 1 shows various shale samples.

First drilled in 2005, the reservoir is deep at about 10,500-14,000 ft and hot with bottomhole temperatures as high as 380° F. Bottomhole pressures can exceed 12,000 psi and treating pressures climb to 15,000 psi. Its laminated shales include soft ductile intervals that can cause proppant embedment and fines problems.

There is vigorous discussion about how best to produce this resource and a correspondingly diverse set of production successes and failures. That has resulted in a competitive learning curve in this promising play as operators seek to exploit it economically.

Haynesville treatments

Reservoir knowledge is proving to be the best starting point for unraveling the Haynesville shale. A Halliburton study of modeled stimulations to test various treatment strategies has further defined fundamental differences in rock character and reservoir conditions compared with the Barnett shale.

The study reviews the design processes and technologies recommended to achieve the best production results.[1] Its results are not indicative of any one particular well or set of reservoir characteristics.

Simulations conducted in the study indicate that formation brittleness is a valuable guide to identifying fracture initiation points. Perforating and fracturing from these intervals are critical to successful stimulation.

The study also shows that low-viscosity fluid systems do not provide adequate proppant transport and suspension to achieve long-term productivity in this formation. The Haynesville, however has successful simulations with

Fracturing wells completed in the Haynesworth shale requires considerable horsepower (Fig. 2).

crosslinked gel fracture treatments containing high-conductivity proppants.

The successes were attributed to better wellbore-to-fracture communication established by proppant distribution throughout the created fracture height and length.

Fluid systems

In simulating a variety of treatment designs, the Haynesville shale study model consisted of a typical 4,000-ft lateral section broken into stages of about 300-400 ft. Within the stages were 3-4 perforation sets of 2-4 ft in length with a perforation density of 6 shots/ft.

To simplify the simulation, the study evaluated a single fracture created in a horizontal wellbore. It selected fluid systems based on rock properties.

The Haynesville shale is a generally ductile formation with relatively low Young's modulus and Poisson's ratio. Identification of brittle areas is important because these are the best targets for fracture initiation. But there are concerns too. These areas have significant lime content that can cause fines problems if acid is applied.

Clays are also present and can result in fines and swelling damage in response to water-based fluids.

The study also simulated multiple treatment designs to address treatments in the Haynesville shale that vary from high-rate, treated-water fractures, hybrids of treated water and linear gel, and hybrids of linear gel to crosslinked gels.

Water fractures with low proppant concentrations and large water volumes provide minimal conductivity damage and low costs. Linear-gel systems have good friction-reduction properties, similar to the water fractures with friction reducer.

Crosslinked-gel fracturing fluid systems allow treatment at lower pump rates, with smaller fluid volumes and provide the ability to place high-conductivity proppants. Placing high-conductivity proppants is not attempted with low-viscosity fluids because of the poor proppant transport and narrow fracture widths.

The fluid efficiency and excellent proppant transport of crosslinked systems can maximize formation surface-area contact and communication with the wellbore to achieve the benefits of the long, horizontal sections with spaced fractures communicating with the wellbore.

High-viscosity fluids help establish a dominant fracture to accept larger high-strength proppants (20/40 mesh). In addition, more effective proppant transport provides a longer effective fracture with direct communication at the wellbore.

Fig. 2 shows a typical fracturing spread on a Haynesville well.

Proppant options

High temperatures and pressures make proppant selection in the Haynesville important for short and long-term production. Cleanup and early production following fracturing are the immediate issues. But over time as reservoir pressure depletes, the increasingly stressful environment becomes the greater consideration.

Fracture conductivity may be the most important parameter for long-term production of the Haynesville shale. Initial closure stress on the proppant in the fracture may start at more than 6,000 psi. As production continues, the stress increases and can exceed 12,000 psi.

For water-frac treatments, conductivity issues include initial conductivity, two-phase flow (gas and water), proppant crushing and fines, and proppant embedment in the fracture face.

For linear-gel treatments, conductiv-

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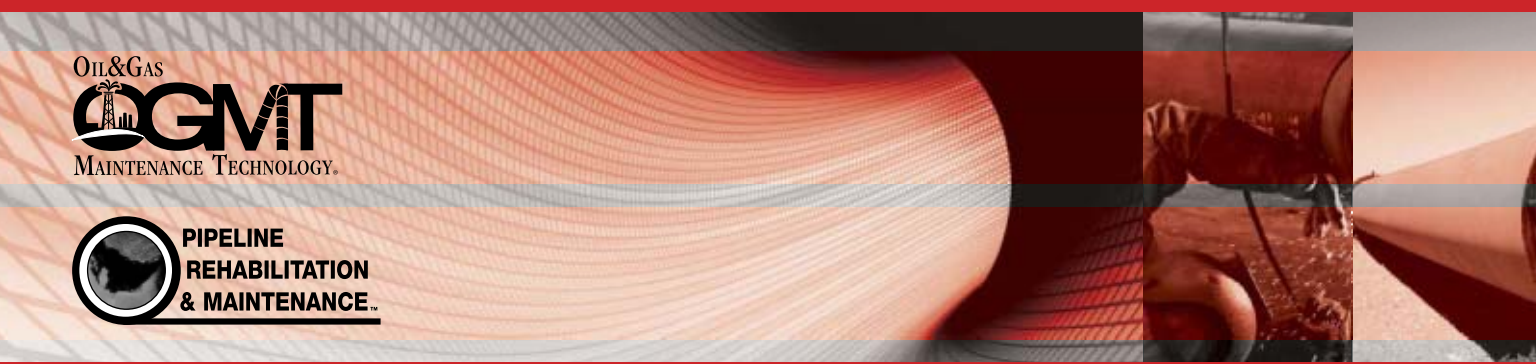

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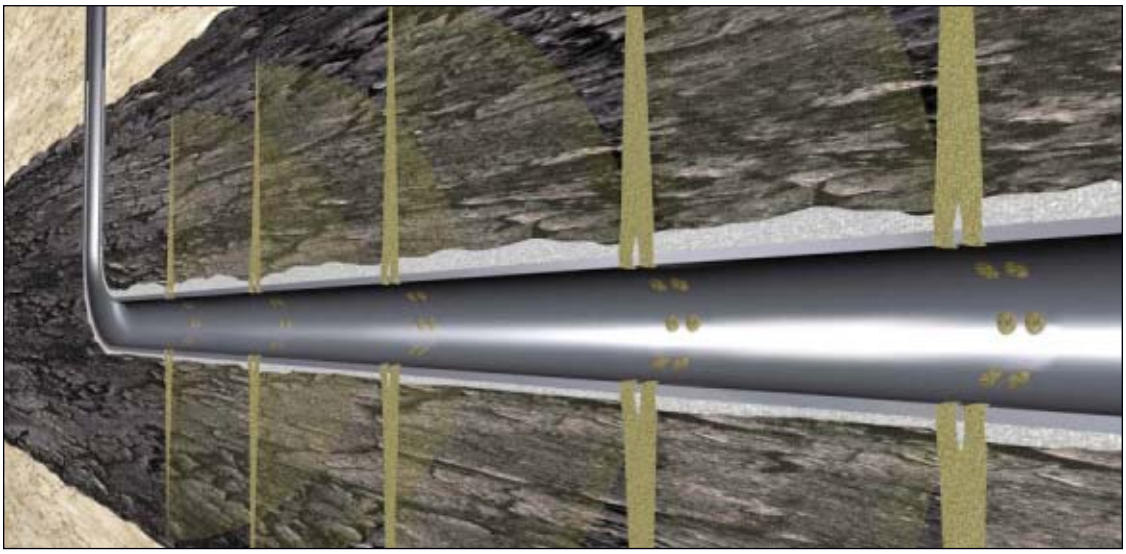
ity concerns include the same list, with the addition of a polymer filter cake. Crosslinked-gel treatments add concerns about the yield stress of residual polymer in the fracture. Gel breakers can address both the polymer filter cake and residual-gel issues.

Embedment is another issue. Proppants embedded into the ductile shale by formation pressure leads to decreased fracture width and the resulting lower conductivity. Brinell hardness numbers (BHN) can be used to infer embedment. Table 1 from a Halliburton internal report shows BHNs for different formations, including several shale plays.

Shale formations have a great amount of variation. The Barnett is very hard with a BHN of 80, while the Marcellus BHN is a much softer 32. The Haynesville shale, with a BHN of 18, has one of the lowest values seen for low-permeability stimulation targets, indicating the most potential embedment.

These extreme variations from hard to very ductile formations are a strong indicator of the pronounced differences between shales and the scope of techniques that might be applied. What works in one play may not work as well in another and not at all in a third.

The study considered proppant conductivity for proppants for Haynesville shale stimulation treatments at simulated reservoir conditions of temperature and stress and proppant concentration of 1 lb/sq ft. Results of the simulations clearly show that man-made proppants are the most appropriate proppant based on conductivity. While this does not consider effects that reduce the conductivity of all proppants, it does show the relative performance of the proppants to guide selection.



Haynesville well completions typically maximize reservoir exposure while eliminating communication between fractures with a reliable annular seal (Fig. 3).

BRINELL HARDNESS NUMBERS Table 1

Formation	Brinell hardness
Woodford	43
Marcellus	32
Haynesville	18
Bossier	12
Barnett	80
Carthage lime	82
Ohio sandstone	34
Alabama coal	15
Floyd	25

The study shows the practical importance of petrophysical information in designing effective fracture stimulations of the Haynesville formation. Organic content, ductility and brittleness, clay content, and a host of other characteristics are fundamental to targeting the treatment and to the design of fluid and proppant systems.

A typical Haynesville well, designed to produce at high rates and low cost, maximizes reservoir exposure while eliminating communication between fractures with a reliable annular seal (Fig. 3).

Eagle Ford

South of the Barnett in the emerging Eagle Ford shale. Early operators are in the process of understanding a formation that recently was an obstacle rather than an objective.

Stretching across a broad swath of Texas from northeast to southwest, its potential is equally huge. But the play is very young and largely confined to three southwest counties: McMullen, LaSalle, and DeWitt. In these counties it lies at depths to about 12,000 ft.

The likely source rock for the Austin chalk formation above it, the Eagle Ford shale exhibits an altogether new range and different scope of shale characteristics, and challenges from the Barnett and Haynesville shales.

One of the most topical issues at this stage in the Eagle Ford is drilling through the depleted zones above it. Companies are drilling mile-long multilaterals in it, but the temperatures and pressures do not appear to be too demanding.

Still, the differences are being carefully considered, from variations in fluid compatibilities to changes in drilling and completion strategies. And within the Eagle Ford, operators are quietly noting the variations that exist within its boundaries, where shale depth, thickness and mineralogy can change dramatically over short distances.

As the resource play picks up momentum, the knowledge that is being collected now will be a major factor

in how efficiently it is developed. The ability of early operators to achieve the efficiencies and effectiveness of an integrated process driven by this reservoir knowledge will determine the pace and the success of the Eagle Ford resource play.

Start at the beginning

The effort under way to understand the Eagle Ford is the hallmark of success in gas shales. Clearly, this emerging play varies from the Haynesville shale, which is markedly different from the Barnett and other shales around the world.

The only way to approach economic development of these resources is by first understanding their unique characteristics. That knowledge guides a holistic approach that builds efficiencies during the life of the asset. ✦

Reference

1. Parker, M., "Haynesville Shale: Hydraulic Fracture Stimulation Approach," Paper No. 0913, International Coalbed and Shale Gas Symposium, Tuscaloosa, Ala., May 20-21, 2009.

The author

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La. refinery converts control system without shutdown

Ryan M. Schulz
Marathon Petroleum Co. LLC
Garyville, La.

Adam R. Joiner
Honeywell Process Solutions
Baton Rouge

Marathon Oil Corp. has installed new process-control equipment and systems at its Garyville, La., refinery.

Migration to the new control system required close cooperation with its primary automation contractor, Honeywell Process Solutions. The refinery staff collaborated with Honeywell's site support specialists to formulate and execute a plan for migration to the next-generation Experion Process Knowledge System without taking the refinery's process units off-line.

The project, described in this article, will provide a blueprint for future site migrations.

Based on a presentation to the NPRA Annual Meeting, San Antonio, Mar. 22-24, 2009.

Marathon Oil has extensive refining, marketing, and transportation resources concentrated primarily in the US Midwest, upper Great Plains, Gulf Coast, and Southeast. Located to serve major markets, Marathon's operations include a seven-plant refining network with more than 1 million b/d of crude oil refining capacity.

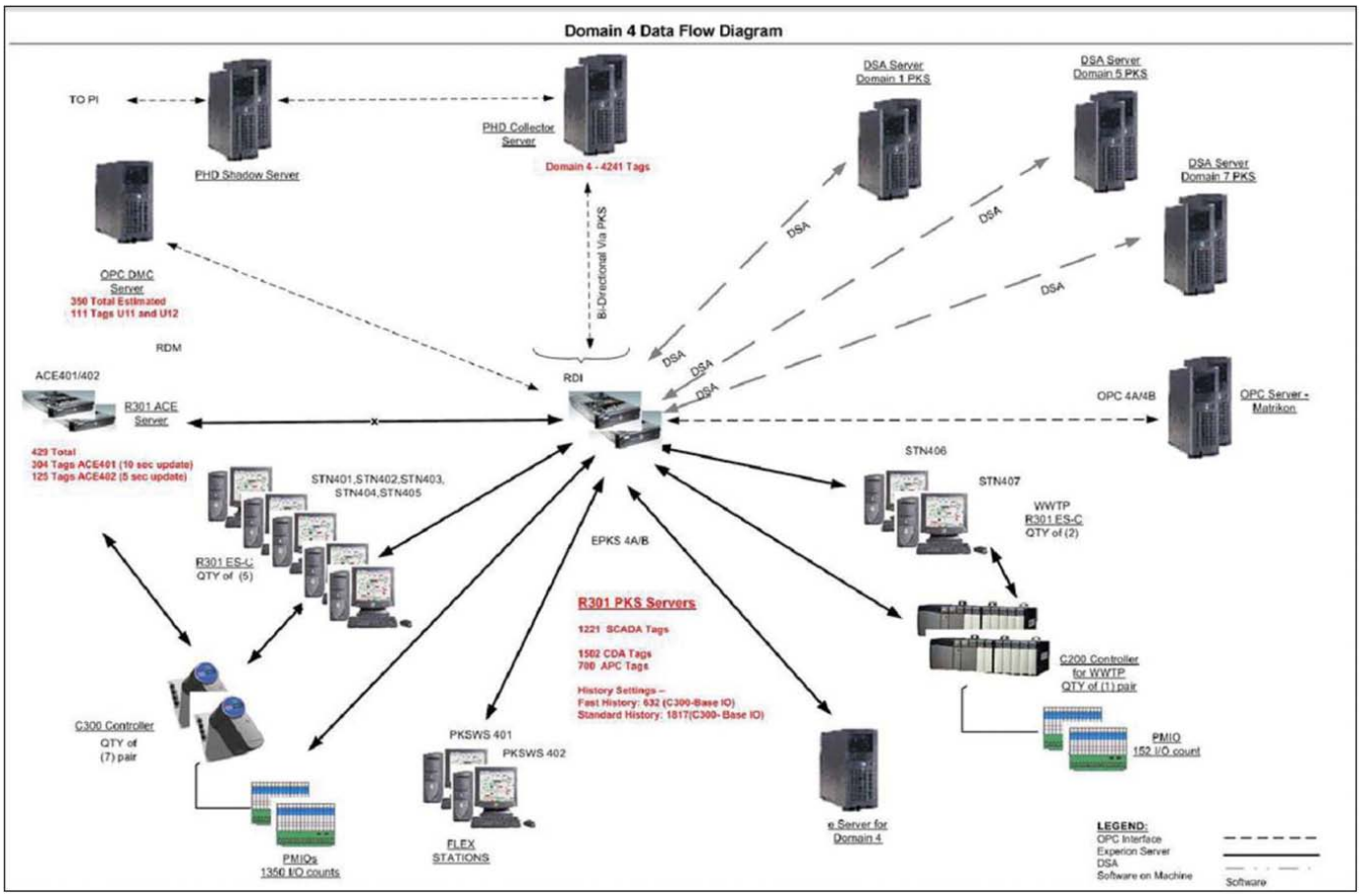
The company's Louisiana refining division operation is located along the Mississippi River in southeastern Louisiana near Garyville (Fig. 1).

Migration requirements

At Garyville, a collection of complex refining operations converts 256,000 b/d crude oil into products such as gasoline and No. 1 and 2 fuel oils. Sulfur, asphalt, propane-propylene, isobutane, kerosene and coke are manufactured as secondary products.

As do other oil refining operations, Marathon requires automation solutions

Marathon Oil's refinery at Garyville, La., is the last grassroots refinery built in the US (Fig. 1; photo from Marathon Oil).



The detailed design process incorporated data flows for the entire control system architecture (Fig. 2).

to increase the reliability, efficiency—and profitability—of its production assets. The refinery's legacy Honeywell TDC2000 distributed control system was originally installed in 1978.

As part of a plant expansion, the human-machine interface platform had been upgraded to the TotalPlant Solution platform with Global User Station capabilities. The aging data highway system no longer provided reliable day-to-day operation. Spare parts and support were also becoming scarce.

In addition, the legacy DCS did not provide the most current advanced control capabilities enabling the refinery to increase throughput, reduce costs and improve regulatory compliance, and answer customer demands for better product quality and faster delivery.

Marathon's initial attempt to migrate to Experion PKS for control of a crude unit was hampered by a lack of coordination among project participants, as well as insufficient computing capacity to handle demanding process-control functions. Through various trials, the refinery migrated its first TDC2000 Data Hiway to an Experion R200 system in 2004.

A subsequent migration project began in early 2007, when Marathon decided to convert a second Data Hiway to an Experion Version R301 system. This project encompassed a diesel hydrotreater, gas-oil hydrotreater and reformer, and a naphtha hydrotreater.

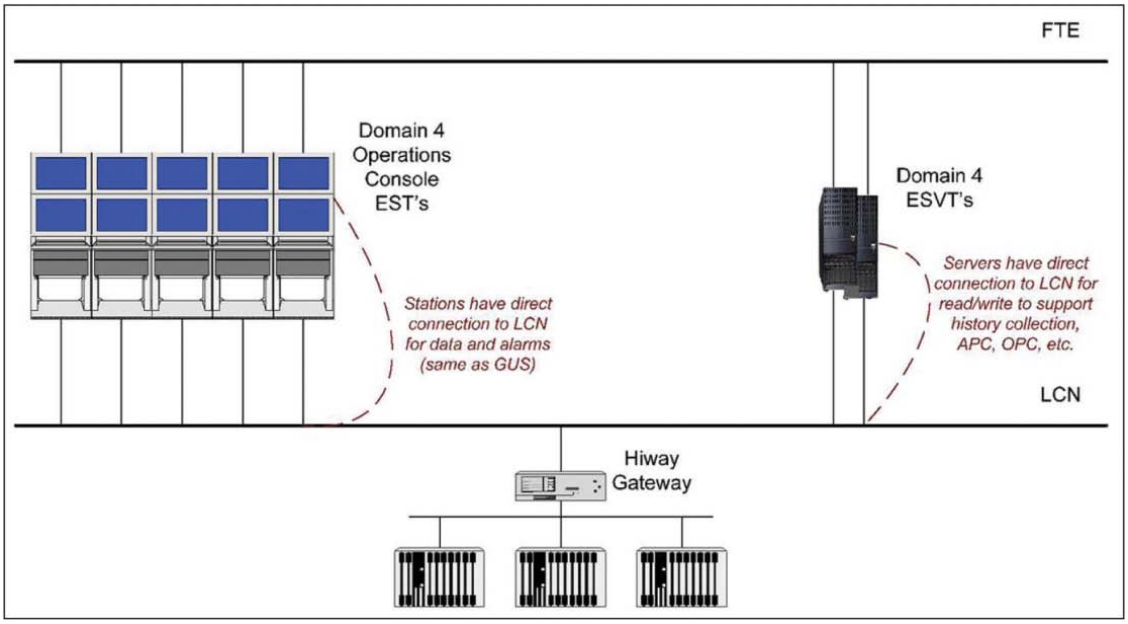
The work entailed moving about 1,400 control wire pairs to new marshalling panels, field termination assemblies, and process manager input/output modules, as well as migrating all advanced process-control functions to the new Experion platform.

For this migration, Marathon and Honeywell established a collaborative strategy based on common goal: To meet and exceed all end-user expectations and design requirements for implementation of a state-of-the-art automation architecture.

Keys

During normal operations, refineries are reluctant to schedule shutdowns for non-critical maintenance or replacement of field equipment. Therefore, control system migrations are typically executed via a "hot cutover," which involves moving one control loop at a time to the new system, while the unit operates in order to eliminate production losses.

A hot cutover also provides immediate feedback that the instrumentation is connected and working properly and is viewed as having overall lower risks to operations.



Phase 1 provided operator stations with direct connections to the local control network (Fig. 3).

Marathon realized it would require help from the local Honeywell field office, in Baton Rouge, to perform the hot cutover to Experion. Key to the project was the ability to convert the legacy system to new technology one step at a time. Both existing and new equipment would have to operate simultaneously, without interrupting normal control functions or upsetting the process, until the cutover was complete. It was also essential that the cutover be transparent to unit operators.

From Marathon's perspective, project success hinged on close cooperation between all participants to formulate and execute a migration plan providing access to modern control technology without having to replace all of its legacy hardware and software assets. The project also required migration guidance to help the refinery develop a long-range automation plan to keep pace with future needs.

Marathon wanted project team members to work hand-in-hand to use the company's existing control system, with its large amount of proprietary programming, to maximize the daily production while minimizing production costs. Being able to migrate all Marathon's large investment in both hardware and software to a new Honeywell platform yields large cost savings. This included steps for migrating and supporting existing control system nodes, such as controllers, HMIs, and supervisory computing nodes.

Honeywell was designated as control system integrator for the migration project, overseeing design, procurement, installation, training, and support for the new automation solution. A software provider, ProSys, handled HMI graphics and advanced controls. Marathon's process-control group coordinated design review and testing, site preparations, field wiring preparation and termination, etc.

New technology

Marathon Oil relied on Honeywell's strategy of continual technology evolution to extend its existing automaton assets while upgrading legacy controls—the 30-years of hardware, field wiring, control programs, and engineering software and existing automation—to the latest Experion PKS technology. Built on a secure DCS architecture, Experion is an open system designed to improve plant operations, reduce incidents, improve decision-making, and enhance work flows.

Unlike traditional plant automation systems, Experion integrates the entire scope of production, equally addressing the needs of operations, maintenance, engineering, and business. It provides the operator with more than just the minimal knowledge he or she may need to make decisions to run the refinery, addressing alarm management, boundary management, and operations management to improve operational reliability.

Experion also allows operators to monitor the performance of critical plant processes and equipment and reduce process downtime and unplanned maintenance expenses.

Implementation of Experion provides a user friendly, Windows-based HMI delivering plant-wide process information such as pressures, temperatures, and flow information used to control the processes and improve monitoring of process history, trends, and averages. The system's graphical interface connects operators directly to the process and allows information to be easily accessed from anywhere in the plant. As a result, operators can react quickly and safely to changing situations.

Design, installation

Marathon's "design for performance" methodology was intended to ensure a proven, robust control system. Whether it was the I/O, controllers in the field, or the computer station operator interface, the project team evaluated each system component to determine its ability to perform under extreme conditions.

The detailed design process incorpo-

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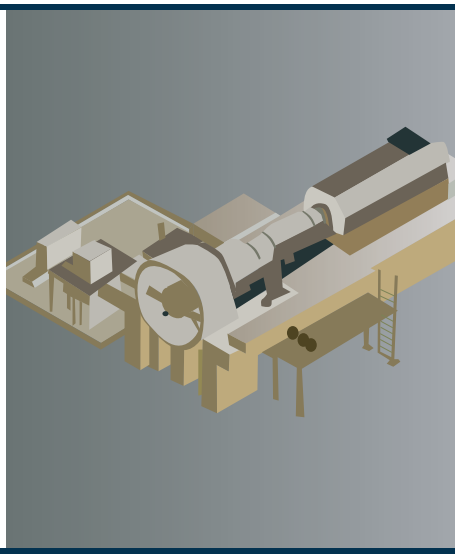

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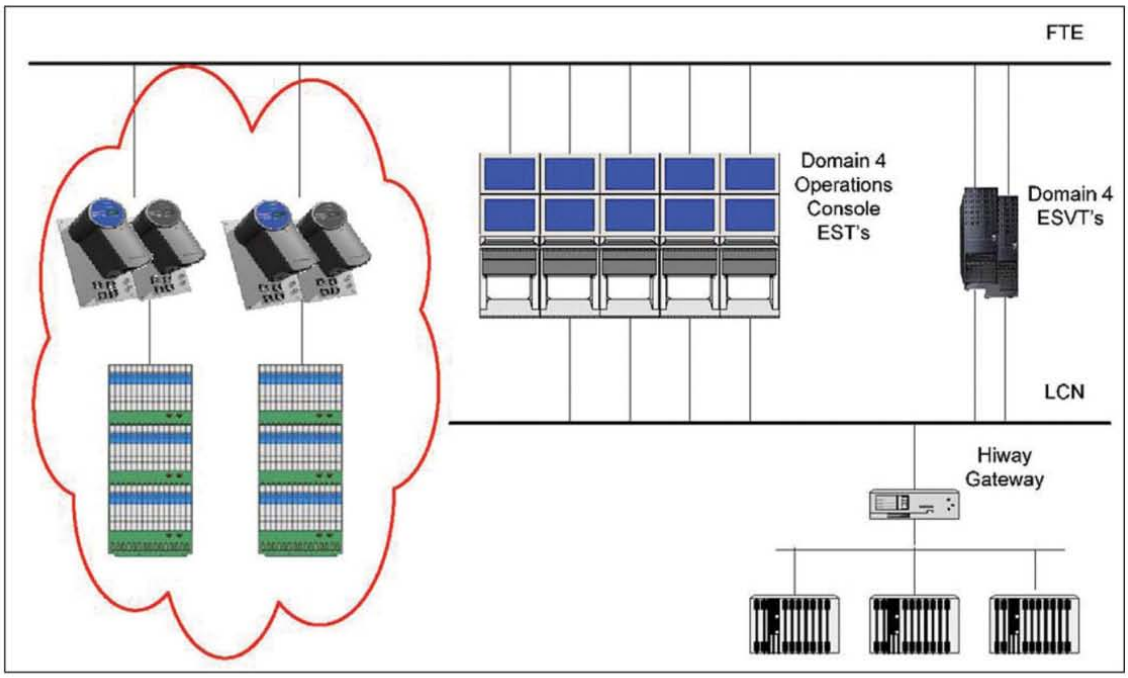
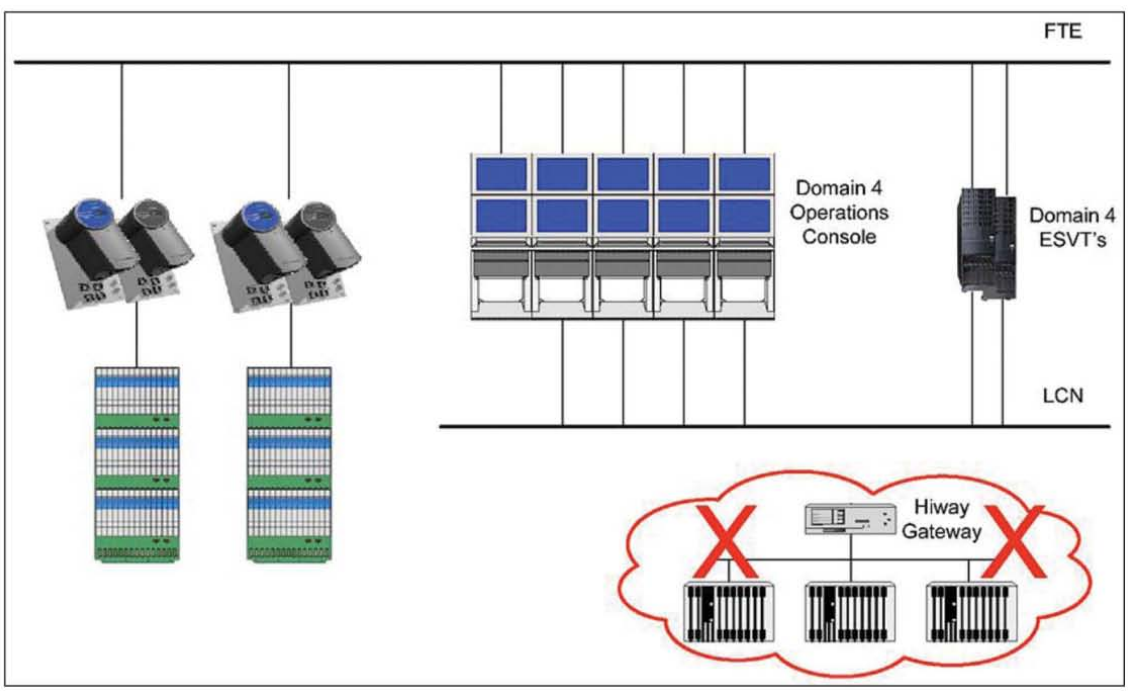


Phase 2 involved addition of new Experion hardware (Fig. 4).



The final control system architecture reflected an improvement over the initial migration effort (Fig. 5).

rated data flows for the entire control system, which included seven Honeywell redundant C300 controllers, one redundant C200 controller, two ACE nodes, OPC servers, process data historian interfaces, seven operator consoles, two engineering work stations, and redundant Experion system servers. The system configuration allowed new control hardware and cabinetry to be installed in the refinery's existing infrastructure.

As part of the design process, engineers looked at the maximum data-demand case that could be experienced during a process emergency, start-up, or shutdown. They also considered all aspects of the controller data load, including input/output processor (IOP) scan rates, control module execution, peer-to-peer subscription (PPS) rates, PPS for advanced application controller nodes, console station update rates, and subscribed data objects (SDOs) from controllers to operator stations. Their goal was to reduce unnecessary peer-to-peer communications among Experion C300 controllers, while ensuring a minimum of 50% free CPU under normal conditions.

Fig. 2 illustrates how the load on controllers was distributed so as to avoid the "focus effect," a situation in which all the data requesters ask for the same piece of information for a single data provider, causing the data provider to publish the same information to many different users. The system architecture allows efficient communication to operators and applications, as well as communications to and from controllers for process history, multi-variable control, alarm management, asset management systems, and other server applications.

In terms of HMI graphics performance, the project team defined reasonable limits for the number of parameters on each display, ensuring operators are not overwhelmed by the amount of data on their HMI panels. Parameters are updated no faster than necessary, and displays come up quickly and are uncluttered. Operators can also utilize standard shapes optimized for performance.

During electrical and instrumentation installation, new multi-conductor instrument wiring cables were run from the field junction box to the marshalling panel. The system was configured with field termination assemblies installed in separate cabinets, providing a standard 20% unassigned I/O spare capacity. Cables were prewired to the MP and FTAs, and terminations and tag labeling were reviewed during system analysis and testing.

For the control system conversion, all wire cutover was completed in the field at the junction box. Technicians reviewed each loop carefully to ensure that wires could be removed and moved while maintaining safe control of process operations.

Testing

Before shipping equipment to the refinery site and proceeding with the hot cutover, the project team tested the reliability and performance of the new plant automation technology to gain acceptance from operations personnel.

For example, the factory acceptance test involved 3 weeks of integrated testing at Honeywell's Baton Rouge facility. Project team members tested the configuration and redundancy of all hardware and reviewed configurations of all process points. They also verified graphic layouts, and all data and functionality of the objects on the graphics were accurate. This process provided an opportunity for operators to interact with the control system and provide specific feedback based on their experiences.

The project team also conducted tests simulating normal and abnormal load on the system in order to verify its performance under different operating scenarios. This included detailed trending to monitor system components throughout various levels of system loading. This simulates normal operating conditions and extreme abnormal operating conditions to ensure the system would perform under an extreme situation in which the data requests are at an extreme or abnormal level.

Results, future

Marathon's project team met its schedule for completing the 2007 control system migration, resulting in the hot cutover of 1,400 wire pairs during a 6-week period.

Phase I of the project, implemented in August 2007, provided operator stations with direct connections to the local control network for data and alarms. In addition, it provided servers with direct connection to the LCN for read/write to support history collection, advanced process control, data from third-party systems located in the field (Fig. 3).

Phase II, the addition of the new Experion hardware, was completed in November 2007. Cutover was accomplished ahead of schedule and with no disruptions to the process (Fig. 4).

The refinery hydrotreater units have now operated reliably on Experion technology for more than 2 years, including turnarounds, shutdowns, and start-ups (Fig. 5).

Operators now have a direct link to the process through a range of preconfigured standard and custom-built displays. They are better able to react to changing situations because operating, alarm, and system displays are dynamic and better represent the actual process infrastructure. The control system's familiar Windows environment further improves efficiency through ease of navigation among process displays and other applications.

In terms of performance, the open automation architecture allows multiple Experion systems, installed on different operating units, to communicate, exchange data, and work together seamlessly. Plant personnel can connect directly to information and control networks, providing full and immediate access to critical data across the enterprise.

Based upon the success of its control system migrations, Marathon is undertaking further modernization projects. Another Data Hiway migration was completed in late 2008, and an ongoing $3.2 billion expansion at the refinery will use Experion C300 controllers and C-Series I/O.

This expansion will increase plant capacity to 425,000 b/d, making it among the largest refineries in the US. Two additional Data Hiway migrations to Experion are planned for 2010 and 2011. ✦

The authors

Ryan M. Schulz (rmschulz@marathonoil.com) was lead process control engineer for Marathon Petroleum Co. LLC for the Garyville, La., DCS upgrade projects that occurred 2007-08. He has worked in the refining industry for 8 years, starting in 2001 at ExxonMobil's Baton Rouge refinery before joining Marathon's refinery in Garyville in 2006. Schulz received his bachelor's in chemical engineering from Auburn University and an MBA from Louisiana State University.

Adam Joiner (Adam.Joiner@honeywell.com) is a lead project engineer for Honeywell International Inc. Process Solutions' South Region operations' office in Baton Rouge. He works with local project management and coordinates technical aspects, project deliverables, and customer interface associated with each HPS project. Joiner has 9 years' industry experience in several positions with Honeywell. He worked at the Geismar, La., plant and was then hired at the Baton Rouge plant. After 5 years at the Baton Rouge plant, he joined Honeywell HPS. In the past 3 years he has led some 16 projects in the oil and gas refining, pulp and paper, and chemicals in the Louisiana area. Joiner holds a bachelor's in electrical engineering from Louisiana State University.

CYBER SECURITY—1

Effective defense requires thorough risk assessment

Tim Shaw
Cyber SECurity Consulting
Monkton, Md.

Protecting a pipeline system from cyber attack requires placing independent barriers and protections (technical countermeasures) around its supervisory control and data acquisition system in an effort to keep communication paths secure.

The first part of this series, presented here, describes a risk assessment for cyber attack before detailing a number of potential attack avenues requiring attention as part of a vulnerability assessment. Part 2 (next week) will detail application of a particular approach to vulnerability assessment.[1]

Background

Pipelines and associated facilities have come to the attention of terrorist and extremist organizations outside of the US (including some in the UK and Canada).[2,3] These organizations have mounted successful attacks on such facilities. The US has experienced incidents of vandalism and blackmail threats against pipeline facilities.[4,5]

In one instance a blackmailer positioned what appeared to be explosives on the Trans Alaska Pipeline System and sent a photo of this to the respective pipeline executives demanding money.[6] Accidental pipeline incidents have also resulted in deaths and damage in the US and made headlines.

The US government (as well as those of Canada and the UK) maintains an incident database and has determined pipelines are attractive potential targets for future terrorist activities.[7] Pipeline operators no longer have the option of implementing a comprehensive security program. Such a program is now essentially a mandate, even if the US Transportation Safety Administration Pipeline Security Division still officially classifies them as voluntary.

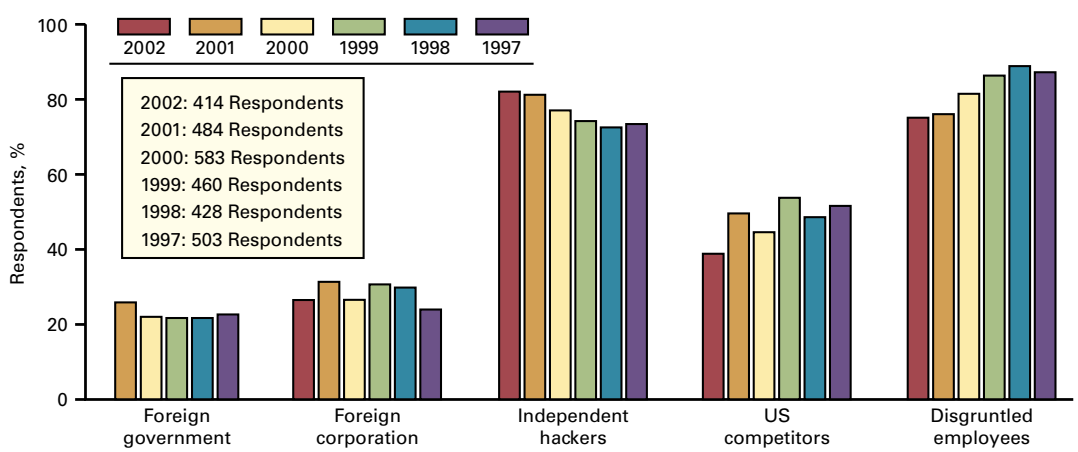
Even if it were not being strongly encouraged by various governmental agencies, a pipeline company would normally want to perform a risk assessment as part of good business practices and of establishing a legal basis for proving it has given serious attention to corporate governance, risk management, and compliance issues.

This article will not specifically address physical attacks on cyber assets, but providing a suitable level of physical security and protection for such assets is essential. If physical security isn't addressed, it may be pointless to worry about cyber security.

The International Standards Organization has a standard derived from a solicitation of IT management best practices—ISO-17799—which has been heavily drawn upon by the North American Electricity Reliability Council in creating Critical Infrastructure Protection standards (CIP-002 through CIP-009) for the electric utility industry. The International Society of Automation uses some of the same standard's

LIKELY CYBER ATTACK SOURCES

Fig. 1



Source: Computer Security Institute

recommendations in its SP99 Industrial Cyber Security standards work.

Both instances require an operator to define, establish, monitor, and protect both a physical security perimeter around critical cyber assets and an electronic security perimeter around those same assets. This article will not specifically address aspects of the physical security perimeter but will assume it is being addressed as part of an overall security program including cyber security.

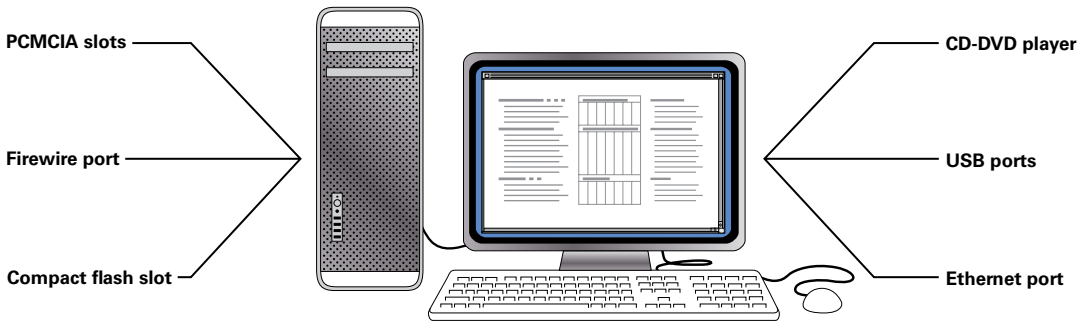
NERC CIP standards are available at the NERC web site and offer good suggestions regarding physical security.

A risk assessment is a structured procedure used to identify and rate the likelihood and consequences of various credible threat scenarios. Threat scenarios take (credible) threat agents and examine realistic ways in which they could exploit vulnerabilities to attack a vital asset. These include scenarios addressing physical attacks on facilities (such as trying to blow up a portion of a pipeline) or scenarios addressing cyber attacks on critical systems (like getting a malware infection into the supervisory control and data acquisition system computers).

Going through these exercises helps sort out credible threat agents, how these threat agents could attack vital assets, and, if such attacks were successful, what would be the consequences. Most organizations do not have enough detailed information to perform such analysis in any quantitative manner. But it is usually possible to make a qualitative assessment of risks and consequences.

Interfaces allowing manual delivery to a PC

Fig. 2



Risk assessment

A cyber security risk assessment is predicated on the presumption an intentional, hostile attack will be made and will attempt to generate the maximum possible damage through compromising the automation systems. Risk analysis involves enumerating and evaluating the following basic elements of the risk equation:

- Threat agents that might realistically stage attacks.
- Assets likely to be subject to such attacks.
- Vulnerabilities enabling an attack to be successful.
- Consequences of a successful attack.

Understanding that risk and consequences are related, but not the same thing, is important in making a risk assessment. Risk attempts to combine the likelihood of an event with the consequences of an event. If an event has dire consequences but is extremely unlikely to occur, the risk is low. If an event is very likely to occur but has minimal consequences, the risk again is low.

Accounting and insurance underwriting treat risk as a financial calculation. In the industrial automation world, including pipelines, since people can die or be seriously injured, and there can be environmental harm, risk is much more difficult to quantify.

The accompanying equation provides a simple description of risk (see box below).

People tend to focus on consequences and not likelihood. Asteroids do strike the earth, and when they do, the consequences are dire. Yet we make no provisions for asteroid insurance because the likelihood of one hitting us is so close to zero the resulting risk is essentially zero.

Acting to alter either component of the equation—likelihood and consequences—can reduce risk. If you can't reduce the likelihood, then you try to reduce the consequences. If you can't alter the consequences, you try to reduce the likelihood.

In financial terms, risk is generally stated as a financial loss experienced as the result of a successful attack; an amount that is usually annualized to reflect the probable time span during which such an attack is likely to occur. Annualized exposure is then used to justify the amount of funding invested in reducing the risk.

A strictly financial risk analysis, however, can't easily accommodate issues not conveniently expressible in dollars, such as loss of life or effects on the national economy and security. It also has difficulty determining the time span over which an event becomes likely to occur.

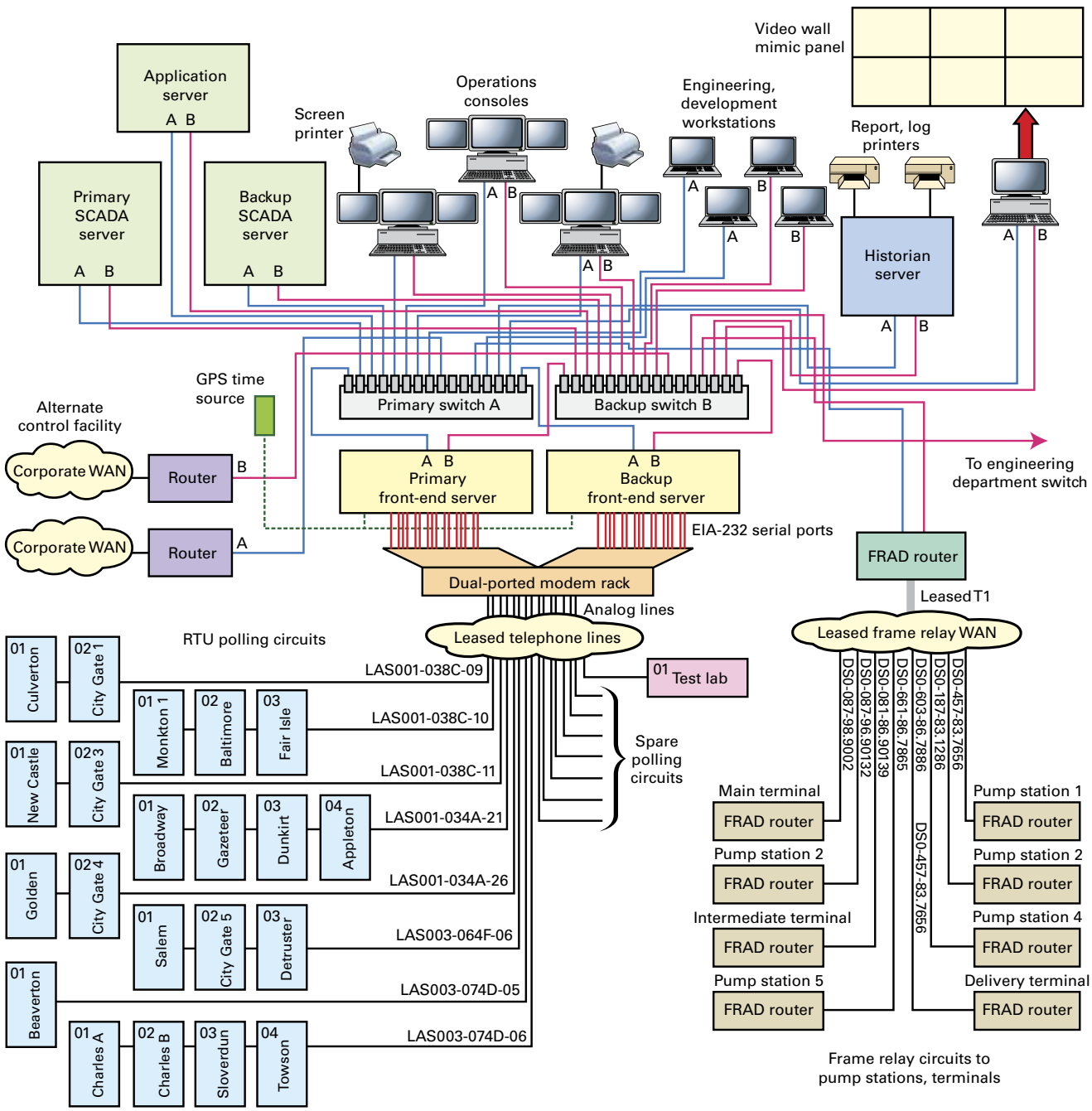
A qualitative assessment can address

Equation

Risk ≈ Likelihood of an event * consequences of an event. (1)
Where: Likelihood ≈ Number of threats * target attractiveness * number of vulnerabilities

SCADA SYSTEM BLOCK DIAGRAM*

Fig. 3



*IP networking extends SCADA LAN to field sites, automation systems.

nonfinancial issues. The likelihood of an event is not always easy to define in quantitative terms. The more attractive assets are as a target, and the greater the number of vulnerabilities in a security perimeter, the more likely an attack is to occur.

Threats

The US government has already determined pipelines are attractive targets for terrorism and that credible threat agents exist who would be prepared to attack both pipelines and related facilities. The only parameter in the presented equation the operator can manage is the number of vulnerabilities in both the physical and cyber defense perimeters that would enable a successful attack.

Viable threat agents aside from terrorists also need to be considered when performing a risk analysis. The full list

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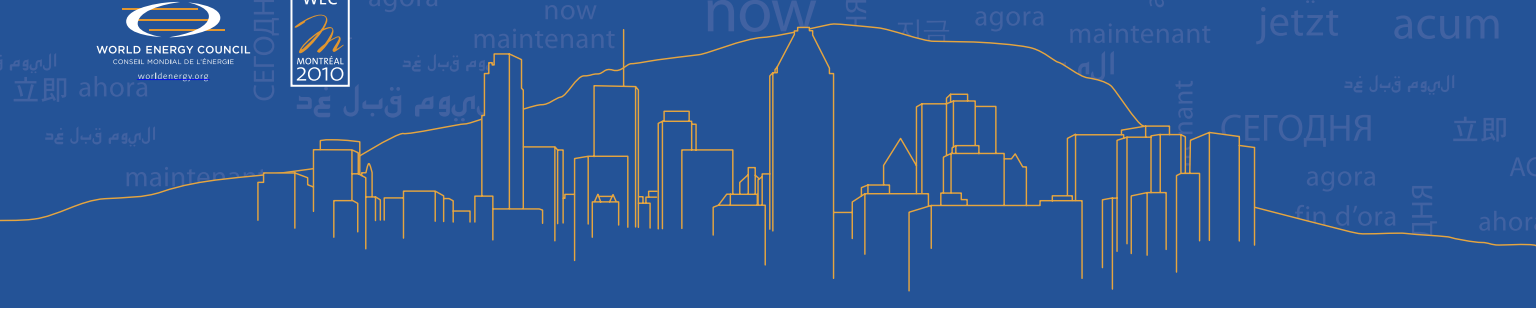

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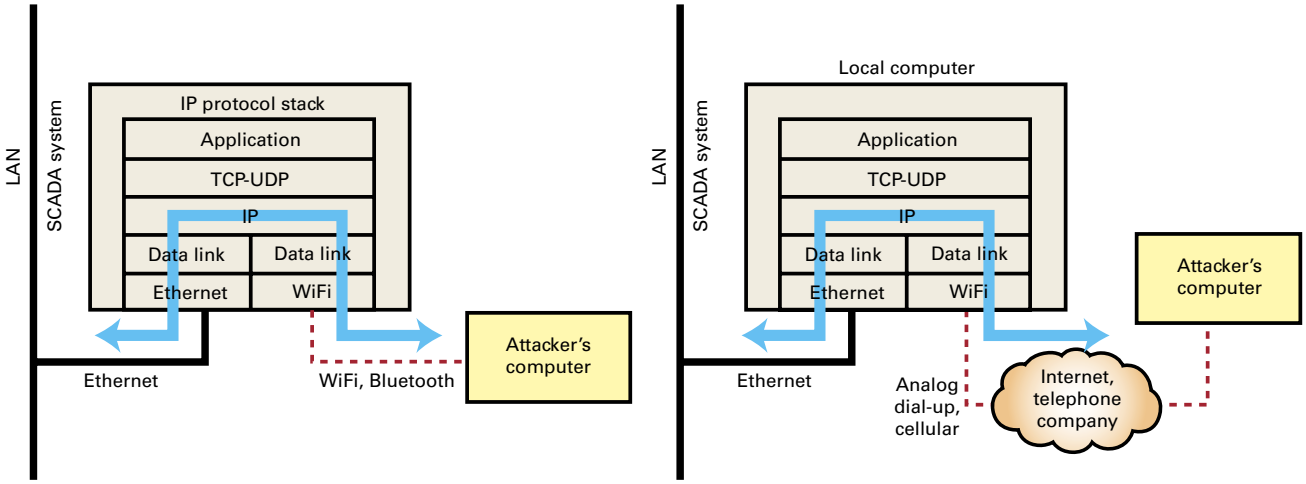
BRIDGING ONTO A CRITICAL LAN VIA ALTERNATE COMMUNICATION INTERFACES

Fig. 4



of potential cyber attack threat agents includes:

- Malware (malicious software such as viruses and worms).
- Human error (mistakes, poorly trained insiders, poor procedures, etc).
- Insiders (disaffected or angry employees, contractors, etc).
- Former insiders (terminated employees, contractors, etc.).
- Outsiders (hired hacker groups, terrorists, criminal groups, etc.).

Terrorist groups either have, or can hire, the technical expertise to stage a cyber assault, if they so choose. One could argue physically protecting a long-distance pipeline is nearly impossible, and thus a physical attack is more likely than a cyber attack. But as the government makes it harder for terrorists to enter the country or operate inside the country, a cyber attack may become more probable.

Environmental activists are also included among the threatening outsiders and have staged attacks and made threats against pipeline operators.[8] Organized crime (both inside and outside the US) has found cyber crime pays well, but there is no clear and obvious motivation for those groups to target pipelines, except possibly for extortion and blackmail.

The huge range of already existing and deployed malware and the constant introduction of new malware require cyber risk analysis include it as a credible and probable threat agent. Human error often plays a part in cyber attacks. Many malware infections are delivered accidentally by uninformed or careless employees. Many successful hacker attacks on systems are enabled by employees using simple, easy-to-guess passwords. Poorly trained employees might also fall for social engineering tricks and reveal confidential information enabling a successful attack.

Employee training and education are a critical element of cyber security because human error frequently defeats expensive technical protective measures. Well developed and clearly explained policies and procedures are key components in an overall cyber security program.

Whether a given pipeline organization has current or former employees, contractors, or consultants with the needed skills and a desire to cause harm or a monetary incentive to do so is a question each organization must answer itself. But according to the US Federal Bureau of Investigation, insider-initiated incidents of intentional industrial sabotage have been increasing steadily during the past 10 years. Mergers, downsizing, reorganizing, and outsourcing have led to growing disaffection among both hourly and salaried workers.

Fig. 1 shows cyber crime statistics gathered by the Computer Security Institute over a 6-year interval. Disgruntled employees are a major factor in these statistics.

This article classifies a cyber asset as:

- A computer or intelligent device containing a microprocessor and some form of communications interface.
- A local or wide-area communications infrastructure and associated components.
- Software (including operating system, networking, and application programs), data, and configuration information contained by a computer or intelligent device.
- Information-documentation about any of the above (regardless of format) that would, if accessed by a threat agent, expose or create exploitable vulnerabilities.

Making critical information (such as user account information) or critical documentation (network Ethernet-MAC, IP addresses, etc.) available to a computer-knowledgeable attacker, would make his efforts to penetrate critical systems both easier and more likely to succeed.

Evaluating the consequences of a given cyber asset being disabled, disrupted, damaged, altered, revealed, or otherwise made unavailable will allow

further differentiation of these assets. If the consequences are unacceptable, the asset is critical.

All-encompassing security is an unrealistic and potentially hugely expensive goal. Cyber security should therefore focus primarily on protecting critical cyber assets.

Communications interfaces

In addition to developing an inventory of cyber assets, the beginning of a risk-assessment process should also diagram communications' interfaces, showing all interconnections between and among assets. This documentation, however, would itself be a cyber asset and would need to be treated as confidential information.

Table 1 shows examples of the types of things falling into each of the four cyber asset categories.

Creating a communications interconnection diagram is an essential step in risk assessment because to launch a cyber attack, the attacker must have some communications mechanism providing him access to your cyber assets. Such a communications path could be a telephone circuit, a wireless network connection, a local area network Ethernet connection, or even a connection created through an existing connection to another network (such as the internet).

One of the most basic and ubiquitous communication mechanisms usually goes unnoticed when addressing communications access: the manual transfer of files from one computer to another. Portable electronic devices and removable storage media provide literally dozens of ways in which malware can be delivered to a target system. Identification of communication access points therefore ought to include CD and DVD drives, USB, Firewire (IEEE-1394), PCMCIA and Ethernet ports, and memory stick slots (Compact Flash, SD, miniSD, microSD, and smartCards).

Many seemingly innocuous devices with a USB connection—digital cameras, digital video recorders, MP3 players, and many color printers—actually contain integral file systems and storage that can deliver malware to a target system (Fig. 2). They could, of course, also be used to carry away sensitive and confidential files copied from a critical system. Installing a certain major vendor's printer driver or just accessing an infected printer over a local area network has led to viruses being spread to computer systems; the Funlove virus for example.

A good starting point for a communications interconnection diagram is to create an up-to-date, detailed system block diagram for the SCADA system monitoring and operating the pipeline. This diagram should show all key components, as well as all of the communications interfaces between and among these components.

Fig. 3 is an example of a representative SCADA system block diagram, with the level of detail typical of the level

Cyber assets

Table 1

Category	Cyber assets examples
Computer, microprocessor-based device with communications interface	• SCADA host computer (primary and backup) • Alternate site SCADA system • Test-Training SCADA system • SCADA system servers • SCADA application processors, servers • SCADA system operator consoles, workstations • SCADA system engineering workstations • Computer-driven map board • Computer-driven alarm, annunciation system • Computer-driven pager, e-mail server • Computer-driven video display panels • Remote terminal units • Smart analyzers, instrumentation • GPS time source
Local, wide-area communication infrastructure	• Ethernet switches, LAN components • Routers, gateways, hubs • Leased telecommunication services • Corporate WAN components • Analog phone lines • Dial-up phone lines • Wireless networking equipment • Cellular communications equipment • Microwave, radio systems • Voice communications equipment • Serial communications circuits • Dedicated interfaces to partners, vendors, regulators, etc. • Communications diagnostic-testing equipment
Software, data, configuration information	• Computer operating systems • SCADA system software • SCADA system utilities software • SCADA systems configuration software • Operator console software • RTU I/O, SCADA database configuration files • RTU program-logic-calculation configuration files • RTU polling configuration files • Parameter alarm-setpoint configuration files • Operator console graphic definition files • Calculation, statistics configuration files • Report, log configuration files • Recent, historical trending configuration files • Modeling software • Simulation software • Advanced application software • Forecasting software • Leak detection, survivability software • Batch tracking, scheduling software • Product metering, accounting software • Product metering, accounting configuration files • Pipeline-modeling data, software • Tank farm, pipeline inventory data • Tank strapping tables
Sensitive documentation, information	• System networking information • System interconnection diagrams • Operator, user manuals • Vendor documentation • User account information • Backup, cold-start procedures • Company personnel information

CONSEQUENCE RANKING MATRIX

Table 2

Criteria	Qualitative consequence ranking			
	Severe	Moderate	Low	Minimal
Injury, death	One or more deaths	Life-threatening injuries, loss of limbs	Serious injuries that will mostly heal	Minor injuries
Environmental damage	Major release, contamination	Minor release, contamination	Fully containable	Within allowable limits
Financial loss	>$1 million	<$600,000	<$200,000	<$10,000
Facility damage	Complete loss	Major damage	Minor damage	Easily repaired
Regulatory violations	Large fines, definite legal prosecution	Minimal fines, possible legal action	Minor infraction, no legal action	Warning only
Energy supply	Extended fuel, power shortage	Moderate fuel, power shortage	Minor fuel, power shortage	Nothing serious
Outage duration	Months	Weeks	Days	Hours

of what might be found on most such drawings. Such a diagram usually shows interconnections between and among local system components and at least the SCADA system end of interconnections to other systems and networks. But it usually won't indicate what is at the other end of a wide area network interconnection (e.g., the corporate WAN leading to the Internet).

Another important communications interface often unnoticed and undocumented consists of alternative communication interfaces installed in computers attached to critical local area networks. Most new laptop PCs come with integral Ethernet interfaces, and most will also have a built-in analog telephone modem, integral WiFi, and frequently even an integral Bluetooth wireless adapter. The same can be true of desktop PCs.

These alternate communication interfaces can make a simultaneous communication connection, offering a path through the PC to the local network connected via the Ethernet port. It is important to note the presence of these interfaces when constructing a system network interconnection diagram.

Pretty much all PCs today, when interfaced to a local area network (LAN), will be using one of the variations of Ethernet and will be running an IP protocol stack on top, causing TCP-IP networking to be used between and among local computers.

The strength of IP-based networking lies in establishing a connection, regardless of the number of intermediate computers. Inside IP-networked PCs is a layer of communications software (the IP layer) that will route message traffic if it arrives at the PC on one communications connection but is not actually addressed to that particular PC. In such instances IP will look for another available communications connection and send the message off on that alternate path (Fig. 4).

If a PC is connected to a critical LAN, such as the SCADA system's LAN, and has an enabled wireless adapter, then an attacker could connect to its wireless interface and pass through the PC onto the SCADA's LAN. The same can be true for a PC with an active telephone dial-up or cellular-based connection to the Internet, while also connected via Ethernet to the SCADA LAN.

Both scenarios offer a communications path an attacker could use. It is also important to identify any computers with dual Ethernet adapters connected, via these two different Ethernet adapters, to a critical LAN and a nonsecure LAN, as the same kind of routing function can occur. An example might be a PC connected to the SCADA LAN and also to a site business LAN including an Internet connection.

This is not the same as having two Ethernet adapters for the purpose of network redundancy. The example SCADA system block diagram Fig. 3 incorporates redundant LAN switches and Ethernet interfaces, to improve system reliability and availability not with two different networks, but one replicated (redundant) network.

If Ethernet switches are used to create the local LAN(s) connecting all SCADA system components, and there are unassigned ports on those switches, such a block diagram may not show if those ports are active or disabled. An insider who can access such a switch, however, can use a free port to connect to the SCADA LAN, unless all such ports are disabled. If VLAN (virtual local area network) technology segments equipment into logical groups, this information should also be documented on such a drawing.

Such system block diagrams may, or may not, make it clear what type of communications connection technology is present for each connection. The drawing also may not clearly show what protocol support is in place on each such circuit shown. Knowing some of these details can help assess the risk of a possible cyber attack via a communications interface; the details of the interface showing the potential level of vulnerability.

Information about what the other end of each communications interface looks like, and to what the system at that other end may be connected (such as the Internet) will often be missing from a SCADA's block diagram. It is good policy to assume the other end of any communications circuit you do not fully control is not secure.

Vulnerability assessment

A risk assessment attempts to estab-

lish parameters for gauging the impact of a successful attack against a critical asset. The results (consequences) of a successful attack on a pipeline, or associated facility, be it physical or cyber in nature, can be organized into a manageable number of consequence categories. These can then be qualitatively ranked based on increasing level of seriousness, using a variety of topic-specific rating criteria.

Table 2 provides an example of a potential consequences-ranking matrix using seven criteria. The quantity and types of criteria, and their severity rankings, will vary from one pipeline organization to another, but the general need to create such a qualitative consequence matrix and make a business determination as to what level of consequences can and cannot be tolerated remains.

At this point in a risk-assessment process, the likelihood of a successful attack still must be addressed. Looking at cyber assets and considering attack scenarios in an attempt to answer the questions what would happen if this asset were made unavailable, and how could an attacker bring this about?

Answering the "How" part of the question requires an understanding of what (cyber) vulnerabilities exist and how they could be exploited by an attacker. Identifying the communications interfaces is key to making a vulnerability assessment because cyber attacks cannot occur without some form of communications channel between the attacker and critical cyber assets.

A commercially available assessment methodology and associated tools can formalize the process of making a vulnerability assessment. These methodologies can help gather relevant information about your systems and networks and help generate a vulnerability assessment based on these data.

Vulnerability assessment methods fall into two categories: active and passive. An active vulnerability assessment involves actually trying to break into one's own systems using hacker tools such as Metasploit, Nmap, and Nessus, a process called penetration (or pen) ≠testing.

The primary problem with making an active vulnerability assessment on an operating system is the real possibility of disabling the SCADA system being assessed. Active assessments are best done on either backup systems or on test-training-support systems. Such tools require expertise and it is best to hire experts to perform an active vulnerability assessment.

Passive vulnerability assessments evaluate the available communication paths into critical cyber assets, reviewing known computer and communication system vulnerabilities before applying approaches such as fault tree analysis or failure mode effect analysis to derive a scenario probability and severity estimate. The industrial automation sector uses a number of passive vulnerability assessment methodologies (some with software tools to help automate the process), including some developed by end-user organizations.

The Idaho National Laboratory has established a national SCADA test bed for studying SCADA system vulnerabilities and has published various articles and papers providing guidance in this area. The American Petroleum Institute, in conjunction with the Process Control Systems Forum, has a working group on defining SCADA cyber security self-assessment methodologies. IBM offers the IBM Internet Security Systems ISS-X program and consulting services.

The US Department of Energy's Office of Energy Assurance offers a well written and comprehensive do-it-yourself guide to Vulnerability Assessment Methodology,[9] specifically developed for the electric power industry, but highly SCADA-oriented. It addresses a comprehensive range of vulnerabilities, both physical and cyber. ✦

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Company operating & finance descriptions
Company Links to websites

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Equipment Manufacturers & Suppliers
Trade Associations & Regulatory Agencies

- Gas Utility Industry – Worldwide
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- Texas E&P
- Houston & Gulf Coast E&P
- Mid Continent & Eastern US E&P
- Rocky Mountain & Western US E&P
- Offshore E&P
- International E&P (outside North America)

Directory Numbers (latest counts)

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

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Services / Suppliers

Global Tubing,

Dayton, Tex., has appointed Pete Sinner manager, North American sales. Sinner has 30 years of experience introducing new technology and product developments to the market for several energy companies, including NOWSCO/NOWCAM, Santrol, and Maverick Solutions. He also served as coiled tubing champion for Quality Tubing for 12 years.

Skinner

Sinner is a member of the Intervention and Coiled Tubing Association/International Coiled Tubing Association and Society of Petroleum Engineers and has played an active role in the Coiled Tubing Consortium and other technical organizations. He has a BS in business from Louisiana State University and an MBA in marketing from the University of Colorado at Denver.

Global Tubing is a worldwide provider of coiled tubing products and related services for the oil and gas industry.

Boots & Coots Inc.,

Houston, has agreed to purchase Halliburton Co.'s external abrasive jet cutting systems. Following the acquisition, the abrasive jet cutting systems will be strategically positioned worldwide. Halliburton developed the system in 1991 to assist firefighting crews in Kuwait in battling more than 700 fires left after the Iraq invasion. Positioned on a burning well, the external abrasive jet cutter utilizes sand and water to abrade the wellhead or surface equipment, thus allowing the well to flow in a vertical direction, making it possible to extinguish the fire with water. Boots & Coots has worked in conjunction with Halliburton for several years coordinating the jet cutter in emergency response efforts in the U.S. and abroad.

Boots & Coots provides a suite of integrated pressure control services to onshore and offshore oil and gas exploration companies around the world, including well intervention services such as hydraulic workovers and snubbing jobs. Boots & Coots also provides high-pressure, high-temperature rental tools through its equipment services segment.

Seahawk Drilling Inc.,

Houston, has appointed William C. (Kurt) Hoffman senior vice-president and COO. Hoffman is a 27-year veteran of the oil field services industry. Previously, he served as vice-president, worldwide marketing, at Noble Corp., where he also was vice-president, Western Hemisphere operations, during 2000-2004. Prior to that, he held several management positions with Triton Engineering Services, including president and vice-president, international operations. Hoffman started his career in the drilling industry with Zapata Offshore Co.

Seahawk, recently spun off from Houston-based offshore drilling giant Pride International Inc., owns a fleet of 20 mat-supported jack ups in the U.S. and Mexico. Seahawk has the second largest fleet of jack ups in the Gulf of Mexico.

Equipment / Software / Literature

New cable lockout system for oil field valves

This new safety cable lockout system eliminates the requirement of chains and incorporates the features of the hasp right into the cable lock.

The firm says its product is suited for isolation of various types of oil field valves. The cable lock is lightweight, easy to use, adjustable, and Occupation Safety & Health Adminstration (1910.147) compliant. The system allows as many as six operators to have individual control without compromising company safety standards, the firm says.

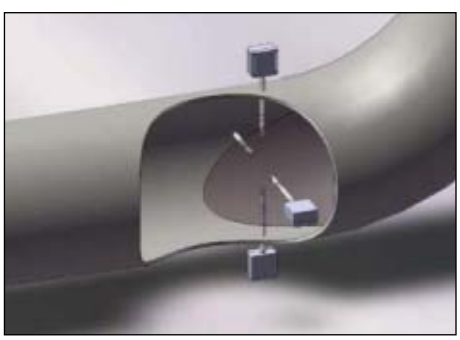
Made from high impact UV resistant polypropylene plastic, the cable lock promises to withstand corrosion and extreme weather conditions.

The system consists of a base and cover screwed together and accommodates a flexible, looped 6 ft PVC coated multi-stranded galvanized cable.

Source: **LOCKOUT TECH,** 80 Huntington St., Suite 616, Huntington Beach, CA 92648

New refinery flowmeter

The new Multi-Trak Model 670S flowmeter measures mass flow rates in large refinery ducts or stacks that have nonuniform velocity profiles, high turndown requirements, dirty gas streams, wide temperature ranges, and fast velocity and temperature changes.



The unit dynamically compensates for changes in the flow profile by using as many as four independent mass flow sensing points to measure the instantaneous average gas mass flow velocity. The 670S's user friendly microprocessor-based human machine interface (HMI) controls all functions of the system. The HMI is used to collect, visualize, and store flow data, as well as set up the individual sensor points, thus allowing the entire system to be easily configured in the field.

Source: **Sierra Instruments,** 5 Harris Court, Bldg. L, Monterey, CA 93940.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	9-11 2009	9-4 2009	9-11 2009	9-4 2009	9-11 2009	9-4 2009	*9-12 2008
	1,000 b/d						
Total motor gasoline	675	978	26	7	701	985	977
Mo. gas. blending comp.	523	799	23	0	546	799	635
Distillate	129	221	18	14	147	235	131
Residual	217	367	50	29	267	396	258
Jet fuel-kerosine	42	45	43	48	85	93	79
Propane-propylene	93	169	4	4	97	173	168
Other	472	(164)	33	42	505	(122)	612
Total products	**2,151**	**2,415**	**197**	**144**	**2,348**	**2,559**	**2,860**
Total crude	**7,920**	**8,064**	**983**	**1,031**	**8,903**	**9,095**	**8,510**
Total imports	**10,071**	**10,479**	**1,180**	**1,175**	**11,251**	**11,654**	**11,370**

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

Purvin & Gertz LNG netbacks—Sept. 18, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	5.74	3.72	4.94	3.61	4.28	4.87
Everett	2.67	1.41	2.33	1.55	1.21	2.94
Isle of Grain	2.69	1.44	2.11	1.47	1.24	2.14
Lake Charles	0.95	0.10	0.81	0.26	0.25	1.52
Sodegaura	4.90	7.10	5.16	6.81	6.10	4.01
Zeebrugge	5.11	3.33	4.47	3.27	3.64	4.53

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,701	54,061	35,390	12,591	71,767	14,377	4,302
PADD 2	78,313	50,231	25,302	7,808	33,582	1,088	30,457
PADD 3	171,618	71,174	39,151	15,488	47,490	13,942	33,968
PADD 4	14,966	5,870	1,855	498	3,419	223	[1]1,844
PADD 5	53,155	26,364	21,193	8,767	11,535	4,272	—
Sept. 11, 2009	**332,753**	**207,700**	**122,891**	**45,152**	**167,793**	**33,902**	**70,571**
Aug. 4, 2009	**337,482**	**207,153**	**122,648**	**45,341**	**165,556**	**33,583**	**70,718**
Sept. 12, 2008[2]	**291,706**	**184,634**	**95,359**	**39,084**	**129,625**	**35,980**	**55,526**

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

Refinery report—Sept. 11, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,254	1,248	2,361	77	430	82	53
PADD 2	3,356	3,338	2,076	234	896	49	244
PADD 3	7,602	7,442	2,809	699	2,173	287	696
PADD 4	576	579	333	31	187	14	[1] 62
PADD 5	2,552	2,442	1,453	379	474	98	—
Sept. 11, 2009	**15,340**	**15,049**	**9,032**	**1,420**	**4,160**	**530**	**1,055**
Sept. 4, 2009	**15,385**	**15,105**	**9,240**	**1,448**	**4,143**	**600**	**1,102**
Sept. 12, 2008[2]	**13,632**	**13,237**	**8,326**	**1,323**	**3,800**	**452**	**956**
	17,644 Operable capacity		**86.9 utilization rate**				

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

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

OGJ crack spread

	*9-18-09	*9-19-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	74.27	116.90	–42.62	–36.5
Brent crude	66.49	92.42	–25.93	–28.1
Crack spread	7.78	24.47	–16.69	–68.2
FUTURES MARKET PRICES				
One month				
Product value	75.98	110.13	–34.15	–31.0
Light sweet crude	71.36	97.29	–25.93	–26.7
Crack spread	4.62	12.84	–8.22	–64.0
Six month				
Product value	80.29	109.65	–29.36	–26.8
Light sweet crude	73.72	97.46	–23.74	–24.4
Crack spread	8.21	12.19	–3.97	–32.6

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

OGJ GASOLINE PRICES

	Price ex tax 9-16-09	Pump price* 9-16-09	Pump price 9-17-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	205.4	251.9	368.8
Baltimore	210.8	252.7	372.7
Boston	212.9	254.8	369.1
Buffalo	205.9	266.8	363.9
Miami	219.2	270.8	365.7
Newark	211.1	243.7	358.7
New York	199.9	260.8	368.8
Norfolk	206.8	245.2	363.1
Philadelphia	211.1	261.8	371.1
Pittsburgh	212.0	262.7	367.7
Wash., DC	223.4	261.8	366.0
PAD I avg	210.8	257.6	366.9
Chicago	212.1	276.5	402.0
Cleveland	214.9	261.3	369.9
Des Moines	211.0	251.4	363.9
Detroit	217.1	276.5	373.5
Indianapolis	203.1	262.5	366.5
Kansas City	200.2	236.2	364.5
Louisville	218.4	259.3	375.9
Memphis	199.4	239.2	360.9
Milwaukee	212.0	263.3	372.9
Minn.-St. Paul	216.1	260.1	368.9
Oklahoma City	191.9	227.3	357.3
Omaha	188.0	233.3	365.9
St. Louis	195.3	231.3	361.5
Tulsa	188.9	224.3	355.8
Wichita	193.0	236.4	358.5
PAD II avg	204.1	249.3	367.9
Albuquerque	199.6	236.0	362.9
Birmingham	202.7	242.0	361.6
Dallas-Fort Worth	203.7	242.1	349.3
Houston	200.6	239.0	365.0
Little Rock	194.9	235.1	362.6
New Orleans	203.6	242.0	368.9
San Antonio	204.8	243.2	363.6
PAD III avg	201.4	239.9	362.0
Cheyenne	224.0	256.4	352.8
Denver	225.0	265.4	385.4
Salt Lake City	216.0	258.9	370.8
PAD IV avg	221.6	260.2	369.7
Los Angeles	239.3	306.4	377.8
Phoenix	229.8	267.2	359.3
Portland	245.0	288.4	363.7
San Diego	241.3	308.4	385.1
San Francisco	248.3	315.4	393.6
Seattle	247.4	303.3	370.0
PAD V avg	241.9	298.2	374.9
Week's avg.	**212.0**	**257.6**	**367.8**
Aug. avg.	**209.9**	**255.5**	**375.3**
July avg.	**205.6**	**251.2**	**405.7**
2009 to date	**177.3**	**222.9**	—
2008 to date	**310.1**	**354.0**	—

*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

	9-11-09 ¢/gal		9-11-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	177.55	New York Harbor	169.15
Gulf Coast	172.80	Gulf Coast	168.40
Los Angeles	203.55	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	180.73	ARA	172.81
Singapore	184.33	Singapore	181.19
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	192.30	New York Harbor	148.69
Gulf Coast	171.30	Gulf Coast	153.81
Los Angeles	215.55	Los Angeles	179.03
		ARA	155.61
		Singapore	161.68

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

BAKER HUGHES RIG COUNT

	9-18-09	9-19-08
Alabama	4	5
Alaska	8	11
Arkansas	42	59
California	20	47
Land	19	46
Offshore	1	1
Colorado	45	116
Florida	2	3
Illinois	1	0
Indiana	4	2
Kansas	23	10
Kentucky	9	12
Louisiana	147	191
N. Land	99	89
S. Inland waters	7	21
S. Land	16	25
Offshore	25	56
Maryland	0	0
Michigan	0	2
Mississippi	11	17
Montana	3	10
Nebraska	0	0
New Mexico	46	91
New York	2	7
North Dakota	46	73
Ohio	8	10
Oklahoma	69	211
Pennsylvania	55	27
South Dakota	0	1
Texas	382	947
Offshore	4	11
Inland waters	0	0
Dist. 1	19	27
Dist. 2	11	35
Dist. 3	41	59
Dist. 4	31	93
Dist. 5	69	185
Dist. 6	46	135
Dist. 7B	15	29
Dist. 7C	22	71
Dist. 8	61	130
Dist. 8A	14	29
Dist. 9	22	43
Dist. 10	27	100
Utah	16	42
West Virginia	20	28
Wyoming	37	83
Others—HI-1; NV-2; OR-1; TN-1; VA-5	10	13
Total US	**1,010**	**2,018**
Total Canada	**214**	**425**
Grand total	**1,224**	**2,443**
US Oil rigs	293	417
US Gas rigs	705	1,589
Total US offshore	32	74
Total US cum. avg. YTD	**1,084**	**1,868**

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	9-18-09 Percent footage*	Rig count	9-19-08 Percent footage*
0-2,500	49	6.1	93	3.2
2,501-5,000	77	70.1	123	52.0
5,001-7,500	108	18.5	275	16.7
7,501-10,000	212	4.2	466	2.1
10,001-12,500	212	13.2	445	1.5
12,501-15,000	146	—	352	—
15,001-17,500	132	—	141	—
17,501-20,000	54	—	84	—
20,001-over	33	—	22	—
Total	**1,023**	**11.1**	**2,001**	**6.4**
INLAND	12		16	
LAND	977		1,970	
OFFSHORE	34		15	

*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]9-18-09	[2]9-19-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	670	647
California	655	656
Colorado	64	66
Florida	7	5
Illinois	29	27
Kansas	109	115
Louisiana	1,410	538
Michigan	18	18
Mississippi	62	60
Montana	90	86
New Mexico	160	158
North Dakota	190	188
Oklahoma	178	169
Texas	1,374	1,140
Utah	61	62
Wyoming	147	146
All others	66	73
Total	**5,311**	**4,175**

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

US CRUDE PRICES

	9-18-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	73.75
California-Kern River 13°	63.40
Lost Hills 30°	71.90
Wyoming Sweet	63.29
East Texas Sweet	68.00
West Texas Sour 34°	63.50
West Texas Intermediate	68.50
Oklahoma Sweet	68.50
Texas Upper Gulf Coast	61.50
Michigan Sour	60.50
Kansas Common	67.50
North Dakota Sweet	58.25

*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]	9-11-09
United Kingdom-Brent 38°	68.56
Russia-Urals 32°	68.11
Saudi Light 34°	66.33
Dubai Fateh 32°	68.07
Algeria Saharan 44°	68.61
Nigeria-Bonny Light 37°	70.20
Indonesia-Minas 34°	71.88
Venezuela-Tia Juana Light 31°	68.54
Mexico-Isthmus 33°	68.43
OPEC basket	68.35
Total OPEC[2]	67.69
Total non-OPEC[2]	67.98
Total world[2]	67.82
US imports[3]	67.23

[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]

	9-11-09	9-4-09	9-11-08	Change, %
	bcf			
Producing region	1,110	1,099	801	**38.6**
Consuming region east	1,876	1,831	1,764	**6.3**
Consuming region west	472	462	397	**18.9**
Total US	**3,458**	**3,392**	**2,962**	**16.7**
	June 09	**June 08**	**Change, %**	
Total US[2]	**2,752**	**2,171**	**26.8**	

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

Statistics

World oil balance

	2009 1st qtr.	2008 4th qtr.	2008 3rd qtr.	2008 2nd qtr.	2008 1st qtr.	2007 4th qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	19.06	19.53	19.19	20.04	20.31	20.90
Canada	2.19	2.26	2.28	2.19	2.31	2.38
Mexico	2.05	2.07	2.14	2.19	2.12	2.16
Japan	4.72	4.71	4.34	4.63	5.45	5.25
South Korea	2.34	2.14	2.10	2.11	2.35	2.31
France	2.02	2.04	1.95	1.95	2.01	2.02
Italy	1.55	1.62	1.64	1.64	1.66	1.75
United Kingdom	1.73	1.73	1.65	1.73	1.73	1.73
Germany	2.57	2.65	2.71	2.43	2.49	2.54
Other OECD Europe	7.05	7.40	7.59	7.32	7.44	7.62
Australia & New Zealand	1.08	1.12	1.10	1.11	1.10	1.15
Total OECD	**46.36**	**47.27**	**46.69**	**47.34**	**48.97**	**49.81**
NON-OECD						
China	7.55	7.56	8.10	7.89	7.86	7.61
FSU	4.11	4.38	4.35	4.31	4.30	4.35
Non-OECD Europe	0.77	0.80	0.80	0.79	0.79	0.81
Other Asia	9.09	8.76	8.96	9.61	9.52	9.29
Other non-OECD	15.31	15.55	16.40	16.03	15.12	15.96
Total non-OECD	**36.83**	**37.05**	**38.61**	**38.63**	**37.59**	**38.02**
TOTAL DEMAND	**83.19**	**84.32**	**85.30**	**85.97**	**86.56**	**87.83**
SUPPLY						
OECD						
US	8.78	8.46	8.18	8.75	8.67	8.58
Canada	3.39	3.40	3.40	3.22	3.38	3.40
Mexico	3.06	3.12	3.15	3.19	3.29	3.33
North Sea	4.40	4.37	4.06	4.31	4.44	4.57
Other OECD	1.55	1.60	1.60	1.58	1.53	1.57
Total OECD	**21.18**	**20.95**	**20.39**	**21.05**	**21.31**	**21.45**
NON–OECD						
FSU	12.60	12.46	12.42	12.60	12.59	12.65
China	3.92	3.99	3.97	4.00	3.94	3.87
Other non–OECD	12.50	12.38	12.32	12.15	12.22	12.12
Total non-OECD, non-OPEC	**29.02**	**28.83**	**28.71**	**28.75**	**28.75**	**28.64**
OPEC*	**33.23**	**35.16**	**36.18**	**35.84**	**35.72**	**36.15**
TOTAL SUPPLY	**83.43**	**84.94**	**85.28**	**85.64**	**85.78**	**86.24**
Stock change	**0.24**	**0.62**	**–0.02**	**–0.33**	**–0.78**	**–1.59**

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

OECD total net oil imports

	May 2009	Apr. 2009	Mar. 2009	May 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,342	–1,283	–1,339	–1,259	–83	6.6
US	9,581	10,073	10,636	11,109	–1,528	–13.8
Mexico	–1,039	–1,065	–1,102	–1,120	81	–7.2
France	1,798	1,641	2,025	1,720	78	4.5
Germany	2,146	2,273	2,440	2,049	97	4.7
Italy	1,532	1,481	1,441	1,441	91	6.3
Netherlands	937	1,060	820	1,005	–68	–6.8
Spain	1,330	1,376	1,463	1,496	–166	–11.1
Other importers	3,682	3,608	4,063	3,925	–243	–6.2
Norway	–1,912	–2,098	–2,413	–1,960	48	–2.4
United Kingdom	–85	–16	125	–112	27	–24.1
Total OECD Europe	**9,428**	**9,325**	**9,964**	**9,564**	**–136**	**–1.4**
Japan	3,973	4,089	4,374	4,681	–708	–15.1
South Korea	1,964	1,965	2,162	2,251	–287	–12.7
Other OECD	832	927	955	962	–130	–13.5
Total OECD	**23,397**	**24,031**	**25,650**	**26,188**	**–2,791**	**–10.7**

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

OECD* total gross imports from OPEC

	May 2009	Apr. 2009	Mar. 2009	May 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	339	386	369	375	–36	–9.6
US	4,471	4,754	5,215	5,913	–1,442	–24.4
Mexico	10	29	23	20	–10	–50.0
France	855	567	689	837	18	2.2
Germany	450	464	347	471	–21	–4.5
Italy	927	963	1,047	1,212	–285	–23.5
Netherlands	516	533	516	640	–124	–19.4
Spain	758	653	689	789	–31	–3.9
Other importers	1,021	1,036	1,090	1,243	–222	–17.9
United Kingdom	315	257	311	303	12	4.0
Total OECD Europe	**4,842**	**4,473**	**4,689**	**5,495**	**–653**	**–11.9**
Japan	3,503	3,629	3,806	4,105	–602	–14.7
South Korea	1,950	2,072	2,274	2,306	–356	–15.4
Other OECD	522	482	535	604	–82	–13.6
Total OECD	**15,637**	**15,825**	**16,911**	**18,818**	**–3,181**	**–16.9**

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

US petroleum imports from source country

	May 2009	Apr. 2009	Average YTD 2009	Average YTD 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	272	612	489	546	–57	–10.4
Angola	505	462	566	478	88	18.4
Kuwait	93	105	173	231	–58	–25.1
Nigeria	600	733	649	1,106	–457	–41.3
Saudi Arabia	1,079	1,021	1,109	1,543	–434	–28.1
Venezuela	1,341	891	1,168	1,160	8	0.7
Other OPEC	581	930	863	1,013	–150	–14.8
Total OPEC	**4,471**	**4,754**	**5,017**	**6,077**	**–1,060**	**–17.4**
Canada	2,206	2,281	2,395	2,539	–144	–5.7
Mexico	1,186	1,289	1,292	1,319	–27	–2.0
Norway	171	112	129	117	12	10.3
United Kingdom	250	424	261	211	50	23.7
Virgin Islands	313	290	313	341	–28	–8.2
Other non-OPEC	2,999	2,823	2,878	2,410	468	19.4
Total non-OPEC	**7,125**	**7,219**	**7,268**	**6,937**	**331**	**4.8**
TOTAL IMPORTS	**11,596**	**11,973**	**12,285**	**13,014**	**–729**	**–5.6**

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

Oil stocks in OECD countries*

	May 2009	Apr. 2009	Mar. 2009	May 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	176	173	178	177	–1	–0.6
Germany	281	279	278	277	4	1.4
Italy	133	132	131	136	–3	–2.2
United Kingdom	92	98	100	99	–7	–7.1
Other OECD Europe	720	723	724	685	35	5.1
Total OECD Europe	**1,402**	**1,405**	**1,411**	**1,374**	**28**	**2.0**
Canada	189	191	194	193	–4	–2.1
US	1,829	1,812	1,795	1,674	155	9.3
Japan	609	606	611	617	–8	–1.3
South Korea	149	152	155	146	3	2.1
Other OECD	112	114	110	106	6	5.7
Total OECD	**4,290**	**4,280**	**4,276**	**4,110**	**180**	**4.4**

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

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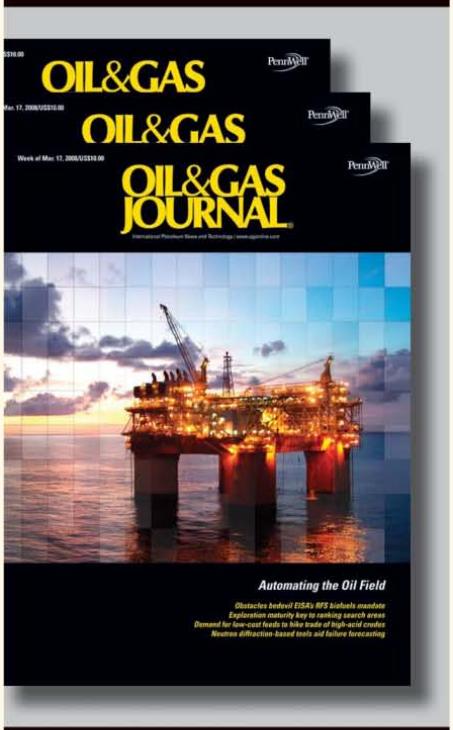

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RIK management, not concept, led to program's demise

The Editor's Perspective

by Bob Tippee, Editor

If the US government can't manage oil and gas royalties taken in kind, how can anyone expect it to handle a shady market for greenhouse-gas emission credits?

Interior Sec. Ken Salazar plans to kill the federal royalty-in-kind (RIK) program. A leasing reform bill in the House would do the same thing. That's bad news for oil and gas producers, for whom the program offers a clear advantage: It precludes fights over valuation. When the government takes its royalty in kind, few questions can arise over sticky issues such as valuation points and price proxies.

With RIK, the government receives its share of production and either sells or stores it. What can be simpler? With government, nothing's simple. Since its evolution from pilot programs in the late 1990s, the modern RIK program has never worked without doubts about management.

In 1996, Johnnie Burton, then director of the Minerals Management Service, requested an internal investigation of the RIK program, which MMS administers.

Results weren't cheery. The investigation uncovered weak controls and misbehavior by MMS employees. MMS's reputation suffered.

Now a Government Accountability Office study says MMS may be collecting too little royalty because of accounting lapses.

That the RIK program has problems is clear. But legitimacy of the concept isn't one of them. The decision to scrap the whole program is, therefore, regrettable. It will replace administrative problems at MMS with valuation disputes, which inevitably arise between leaseholders and royalty owners. When the royalty owner is the US government, those disputes become political. Oil and gas producers shouldn't welcome the change.

The decision, moreover, implies not only that the RIK program is broken but also that it can't be fixed. It says the government can't manage it.

Yet Congress soon might place a comparable mechanism in charge of a nebulous market for emissions credits. Instead of physical quantities of oil and gas at known locations, transactions under the proposed cap-and-trade system would involve rights to emit greenhouse gas worldwide. Values would depend largely on government decisions.

Against the politically charged complexity of that program, RIK administration would look like managerial child's play.

(Online Sept. 18, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Deloitte: Trade problems loom

Position limits being considered by the US Commodity Futures Trading Commission to eliminate "excessive" market speculation could create problems for companies trading energy commodities, said John England, managing partner for energy in Deloitte & Touche LLP's markets consulting practice. Proposed regulatory changes would affect hedge funds, banks, insurance, and other firms, said England. "It is important for most energy market participants to consider the potential impacts of these proposed rule changes on their ability to manage risk," he said.

To centrally regulate the OTC market, all transactions would be through monitored clearing exchanges. "Although it is expected that the exchanges would adapt by offering a greater variety of OTC products, it is unlikely that the products would cover all possible trading locations, product specs, and time frames," England said. "This could cause a decrease in the variety of instruments available today for laying off basis risk and may decrease the trading activity in high-risk, high-margin markets." He added, "If nonphysical transacting entities are limited in the volume of derivatives they can trade, the demand for these instruments may become low enough that it would not make economic sense for the exchanges to offer a wide variety, thus further limiting the ways that companies can manage or mitigate their basis risk."

England noted, "Typically in commodity markets, a decrease in liquidity results in higher bid-offer spreads and potentially higher costs to hedge in the market. This could have a large impact on both market participants (potentially unable to hedge adequately) and exchanges, as roughly one quarter of their revenue is derived from energy trading." A decrease in the variety of products offered in the US market could trigger a shift to other global exchanges and increase exposure to foreign currency and foreign governments, he said.

"The proposed rules could lead to an increase in margin call activity for derivatives normally traded directly with counterparties or through a broker on credit terms. Forcing transactions to clear on a more transparent clearing exchange rather than through OTC means would result in more cash being required to support deals and less ability to rely on credit," England said.

Problems in laying off risk could make it more onerous to value positions and risk exposure at less-liquid points. "In short, it could become much more difficult to price a large number of physical markets," said England.

Increased red tape

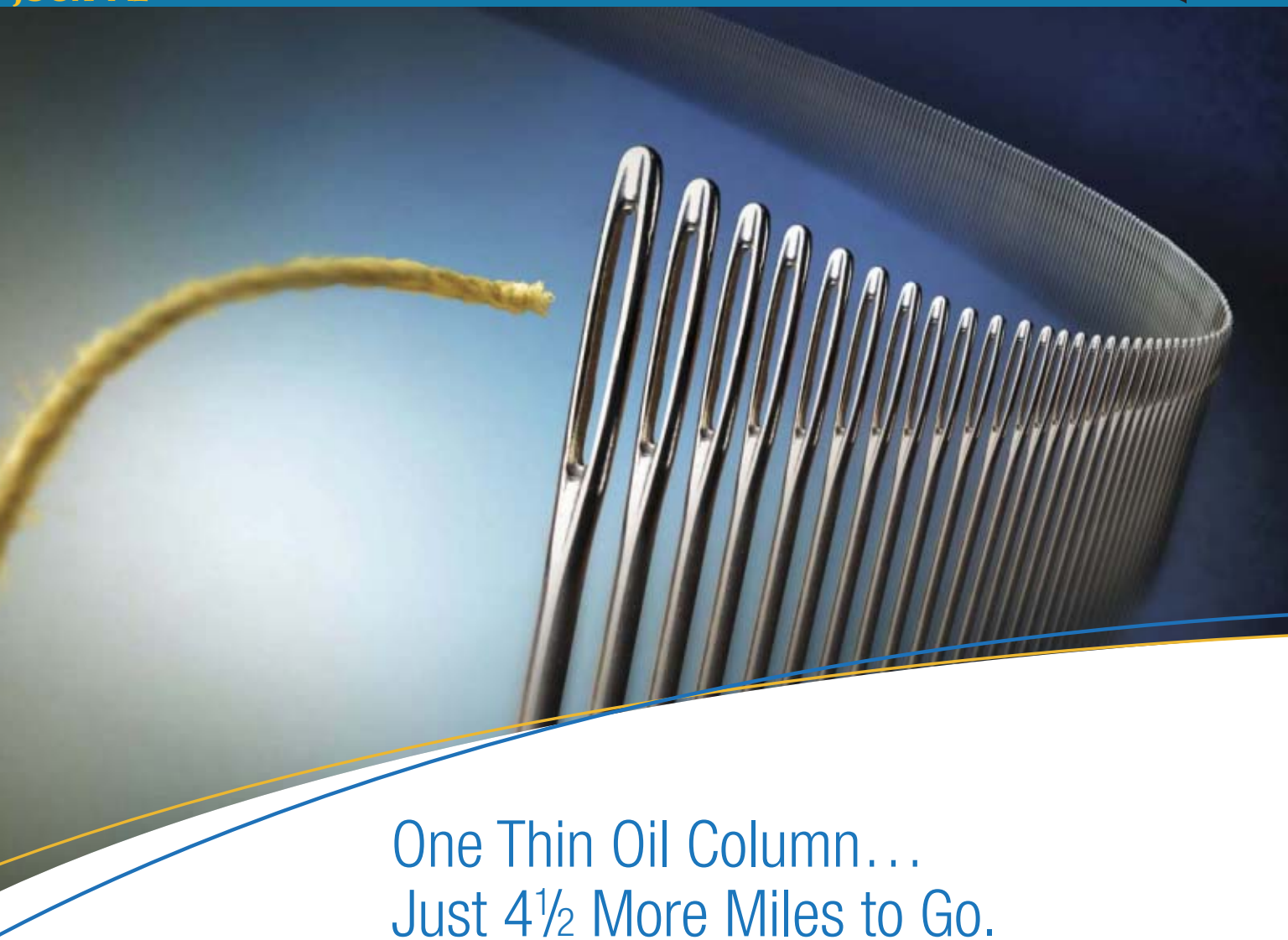
Information requirements and disclosure expectations are likely to be more frequent and more detailed under the new regulations. "Since the content of the reporting would come directly from existing trading systems where their financial positions are maintained, companies will need to determine whether these systems are reliable and support regular reporting," England said. "In some instances, these activities could lead to the need for significant investments in infrastructure (processes and systems), increasing costs and potentially squeezing razor-thin profit margins."

He said, "Should the proposed rules come into force, there is a high probability that the reporting requirements and expectations regarding transparency would rise in lockstep. Institutions transacting energy contracts on US exchanges would have to report to the CFTC on volumes in addition to the standards they are currently meeting. Regulatory oversight could expand into areas beyond the regulation of markets by treading into the regulation of speculative behavior, price movement, and price volatility. With an increase in reporting, this would heighten the risk of misreporting and subject entities to potential fines."

Regulators in both the US and UK are working to share information so as to more effectively track global market manipulation. If the US passes legislation to centralize regulation, it may also pursue an international agreement for regulatory standards in the major global markets, increasing the impact and reach of regulatory changes.

However, England said the global nature of energy markets makes it difficult for the CFTC to manage position limits. To be effective, the majority of exchanges worldwide would have to employ similar restrictions. If regulators and the International Organization of Securities Commissions are unable to spearhead a global response, "commercial transactions will naturally migrate to less onerous markets, again drying liquidity and potentially increasing transactional risk," he said.

(Online Sept. 21, 2009; author's e-mail: samf@ogjonline.com)



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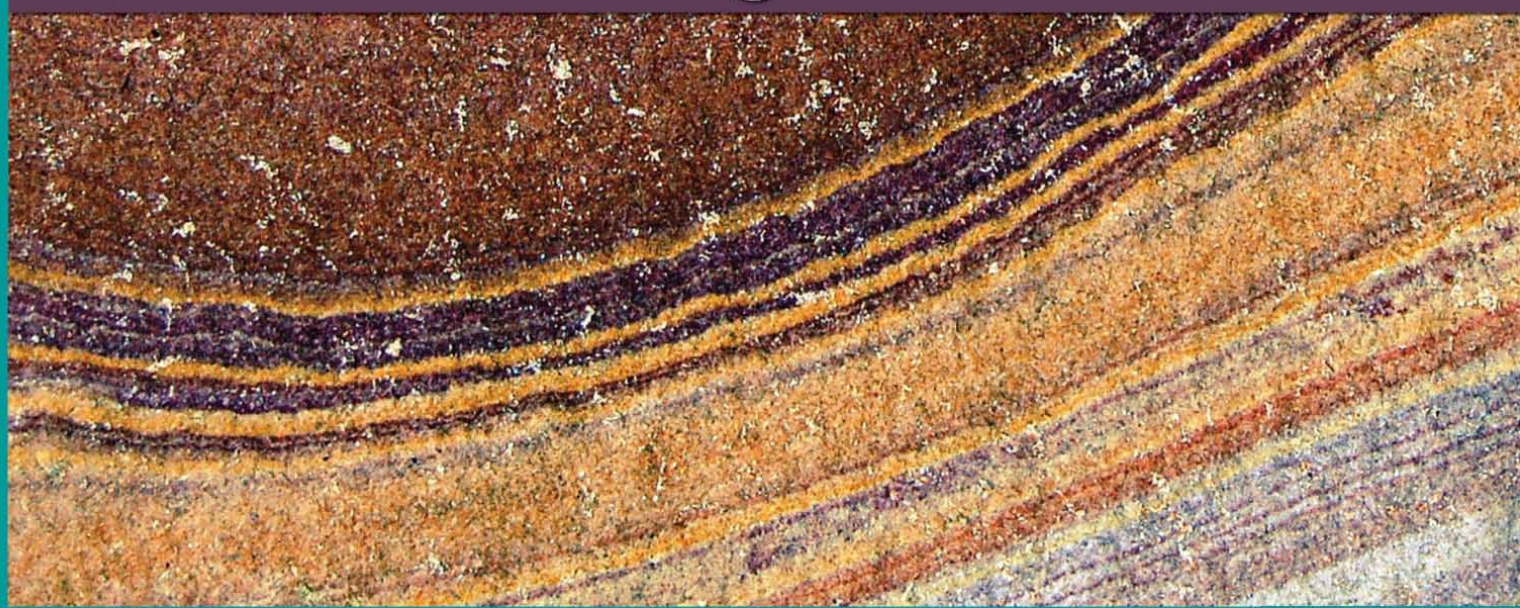

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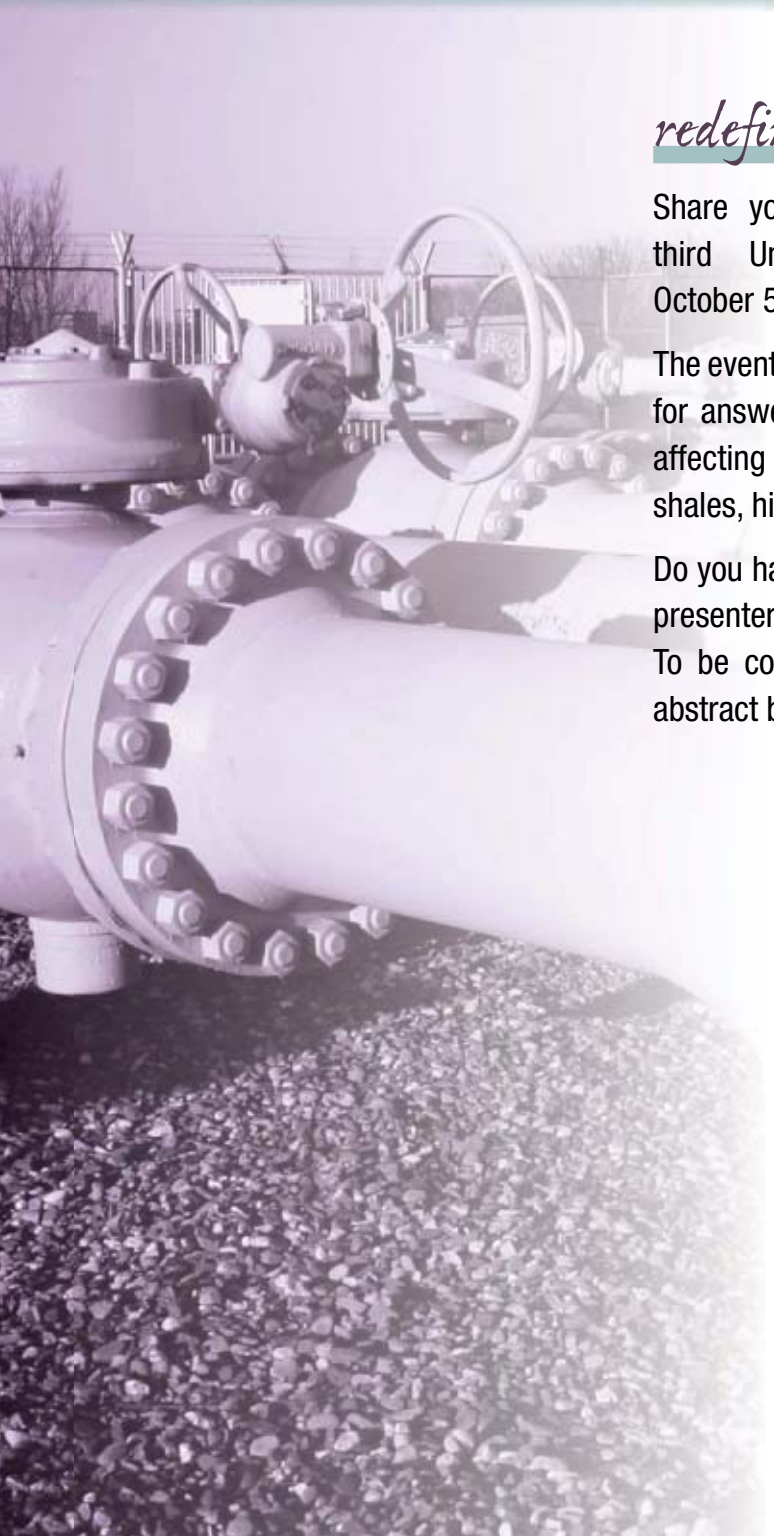

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