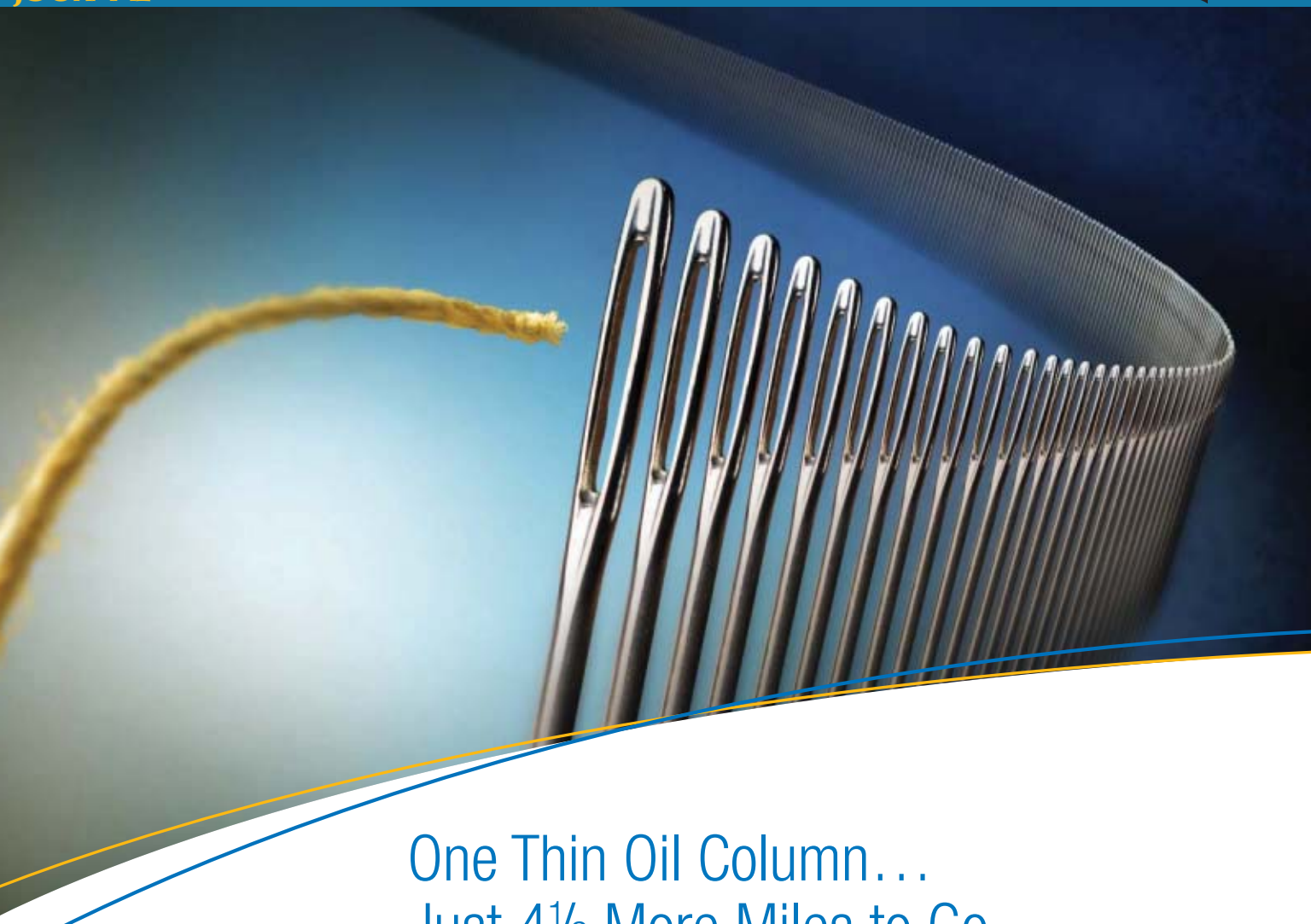

One Thin Oil Column…
Just 4½ More Miles to Go.

Extended reach. Precise placement.

Objective:	Geosteer highly complex, extended reach, lateral branch along ultra-thin oil column to 23,720 ft (7,230 m), including a flat 135° azimuthal turn at horizontal, precisely navigating relative to the oil-water contact.
Environment:	Sognefjord sandstone with hard calcite stringers, Troll Field, North Sea.
Technology:	Baker Hughes INTEQ AutoTrak™ X-treme™ RCLS with integrated MWD/LWD and CoPilot™ real-time drilling optimization.
Answers:	Increased recoverable reserves by accessing complex oil reservoir while precisely navigating 15,984 ft (4,872 m) horizontal step out within 18 inches of oil-water contact for a measured depth of 4.5 miles, delivering 100% ROP improvement.

Read the full case history and find out more about how the AutoTrak service can advance your reservoir performance at www.bakerhughes.com/autotrak.

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These are electronic directories that reside on your PC desktop for easy access and use (sorry no Macs). The directory information is searchable and printable, and there are links available to company web sites. The directories use unique software that enable the information to be displayed much like a print directory. Contact information at your fingerprints, but not exportable to spreadsheet or database.

For most companies the

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Key personnel with phone and email
Company operating & finance descriptions
Company Links to websites

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Engineers, Contractors & Service Co's
Equipment Manufacturers & Suppliers
Trade Associations & Regulatory Agencies

- Gas Utility Industry – Worldwide
- Electric Utility Industry - Worldwide
- Pipeline Industry - Worldwide
- Refining & Gas Processing Industry - Worldwide
- Petrochemical Industry - Worldwide
- Liquid Terminals Industry - Worldwide
- Drilling & Well Servicing Industry - Worldwide

- United States & Canada E&P
- 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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Pipeline Report

Study: Waxman-Markey bill costly to US refiners
Oil, gas supply trends point to tight spots, higher prices
Weyburn CO_2 injection modifications finalized
H_2, N_2 assist compliance with new environmental regs

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OIL&GAS JOURNAL®

Nov. 23, 2009
Volume 107.44

PIPELINE REPORT

REGULAR FEATURES

COVER

A work crew lowers in pipe on the Midcontinent Express Pipeline constructed by Kinder Morgan Energy Partners LP for its joint venture with Energy Transfer Partners LP. Work on the pipeline included laying the 42-in. OD pipe shown here between Delhi, La., and Transco Station 85 in Butler, Ala. The entire 500-mile pipeline extends from Bennington, Okla., to Station 85, connecting production from the Barnett shale, Bossier sands, and other plays in the region to the eastern US. Oil & Gas Journal's special Pipeline Report, which begins on p. 58, focuses on potential environmental threats pipelines face once in service and advances in pigging technology. Photo from Willbros USA Inc. by Lindy King.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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

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

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

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

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

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Audience Development Manager Tommie Grigg, tommieg@pennwell.com

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OGJ Newsletter

Nov. 23, 2009

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General Interest — Quick Takes

EPA publishes regs on oil-spill rule amendments

The US Environmental Protection Agency published a final regulation on Nov. 10 that amends certain requirements for facilities subject to its Oil Spill Prevention, Control, and Countermeasure (SPCC) rule.

EPA said the amendments clarify regulatory requirements, tailor requirements to particular industry sectors, and streamline certain requirements for a facility owner or operator subject to the rule. The action completes the SPCC action, which was proposed on Oct. 15, 2007; finalized on Dec. 5, 2008; and for which the agency received public comments on Feb. 3, 2009.

The amendments do not remove any regulatory requirement for owners and operators of facilities in operation before Aug. 16, 2002, to develop, implement, and maintain an SPCC plan in accordance with regulations which were in effect at that time, EPA said. Such facilities continue to be required to maintain their plans during the interim until the applicable date for revising and implementing their plans under the new amendments.

More information about the SPCC rule is available online at www.epa.gov/emergencies/content/spcc/index.htm.

Tight market alters European utilities' spending

The economic crisis is forcing European utilities to defer or cancel investments in facilities, renewables, and energy efficiency and to divest assets, according to Cap Gemini SA, Paris, in its annual European Energy Markets Observatory (EEMO).

Lower prices and drops of 5% in electric power consumption and 8% in natural gas consumption in this year's first half have depleted utilities' 'war chests,' said Colette Lewiner, in charge of the EEMO report.

Germany's E.On AG reduced its 2009-11 investment to €30 billion from €36 billion. Italy's Enel SPA intends to reduce its 2009-13 investment to €32 billion from €44 billion. Investments by Spain's Iberdrola SA are down to €4.5 billion from an initial €13 billion, while the newly merged Gas Natural and Union Fenosa will cut investments to €11-13 billion from €31 billion.

This is a marked change from 2008 when aggregate utilities investments reached a record €120 billion. But debt also increased: the combined debt of the 10 largest European companies rose by 11.3% between 2006 and 2008 to €213 billion.

CSB to investigate Puerto Rico tank farm fire

The US Chemical Safety Board will fully investigate an Oct. 23 tank explosion and fire at Caribbean Petroleum Refining in Puerto Rico that damaged homes and businesses more than a mile away, the board said Nov. 17.

It said that at 12:23 a.m. on Oct. 23, a large vapor cloud ignited at the facility near San Juan that includes a refinery that was shut down in 2000 and a tank farm that is still in operation. CSB sent investigators to the site that day who have conducted interviews, requested hundreds of pages of documents, and catalogued key pieces of evidence, it said.

A tank was being filled with gasoline from a ship docked in San Juan's harbor when the accident occurred, according to CSB. It said that investigators have determined that a likely cause was the tank's being accidentally overfilled. Gasoline then leaked undetected and spread across the facility, creating a vapor cloud 2,000 ft in diameter until it reached an ignition source in the facility's northwest section, it said.

It said that its investigators found that the tank's liquid level could not be determined on the evening of the incident because the facility's computerized level monitoring system was not fully operational and operators used a mechanical gauge on the tank's exterior wall instead. "Therefore, as the gasoline level in the tank rose and eventually overflowed, employees located in the facility's control room were unaware of the emergency," CSB said.

"The filling of a tank without a functioning monitoring system is the type of activity the CSB will be examining very closely," said Jeffrey Wanko, the investigator-in-charge. "The CSB's investigation will examine operations particular to Caribbean Petroleum, but will also look at the regulations and best practices surrounding the industry as a whole in an effort to improve safety practices at similar facilities." ✦

Exploration & Development — Quick Takes

Ivanhoe to acquire stake in PSA in Mongolia

Ivanhoe Energy Inc. said its Asian subsidiary plans to acquire interest in a production-sharing agreement (PSA) held by PanAsian Petroleum Inc., which holds exploration and production rights to a large block in central Mongolia.

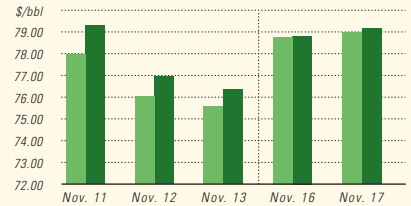
Ivanhoe's Sunwing Energy Ltd. plans to acquire interest in PanAsian's Mongolian interests for up to 3 million shares of Ivanhoe common stock. Transaction terms do not involve any cash payment to PanAsian.

A private company based in Alberta, PanAsian has a PSA with the Petroleum Authority of Mongolia. The contract provides PanAsian with the exclusive right to explore, develop, and produce oil or gas within Block XVI in Mongolia's Nyalga basin.

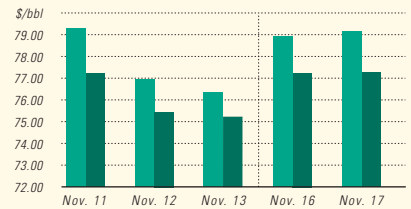
The structure of the merger is such that the holder of the PSA, PanAsian Energy, and its wholly owned Mongolian subsidiary, Shaman LLC, remain unaltered.

Industry Scoreboard

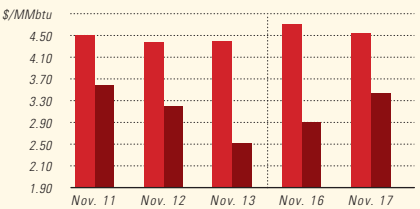
IPE BRENT / NYMEX LIGHT SWEET CRUDE



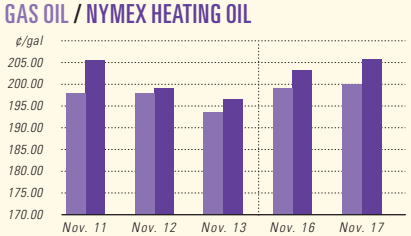
WTI CUSHING / BRENT SPOT



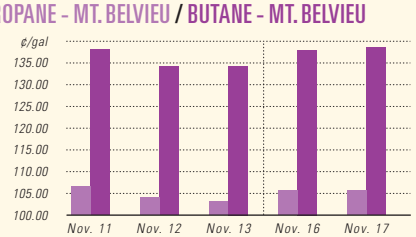
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



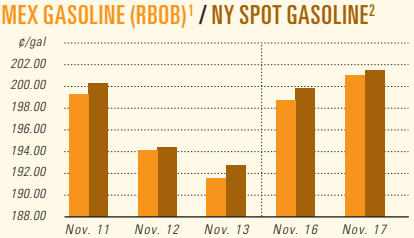
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

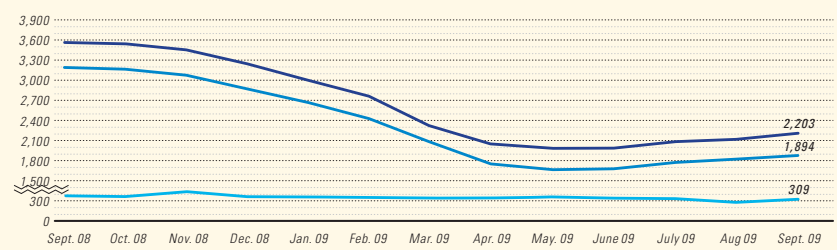
US INDUSTRY SCOREBOARD — 11/23

Latest week 11/6	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	8,917	9,003	–1.0	9,025	9,002	0.3
Distillate	3,559	4,127	–13.8	3,594	3,968	–9.4
Jet fuel	1,364	1,421	–4.0	1,410	1,561	–9.7
Residual	577	584	–1.2	542	617	–12.2
Other products	4,246	4,448	–4.5	4,086	4,422	–7.6
TOTAL DEMAND	18,663	19,583	–4.7	18,657	19,570	–4.7
Supply, 1,000 b/d						
Crude production	5,406	4,733	14.2	5,268	4,934	6.8
NGL production[2]	2,055	1,905	7.9	2,013	2,093	–3.8
Crude imports	8,593	10,061	–14.6	9,148	9,784	–6.5
Product imports	2,513	3,084	–18.5	2,759	3,142	–12.2
Other supply[3]	1,515	1,769	–14.4	1,667	1,577	5.7
TOTAL SUPPLY	20,082	21,552	–6.8	20,855	21,530	–3.1
Refining, 1,000 b/d						
Crude runs to stills	14,341	14,564	–1.5	14,459	14,676	–1.5
Input to crude stills	14,641	15,055	–2.7	14,806	15,046	–1.6
% utilization	82.9	85.4	—	83.9	85.5	—

Latest week 11/6	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	337,676	335,914	1,762	311,949	25,727	8.2
Motor gasoline	210,837	208,277	2,560	198,095	12,742	6.4
Distillate	167,725	167,376	349	128,351	39,374	30.7
Jet fuel–kerosine	44,652	45,183	–531	36,835	7,817	21.2
Residual	36,023	35,054	969	38,976	–2,953	–7.6
Stock cover (days)[4]			Change, %		Change, %	
Crude	24.1	23.8	1.3	21.3	13.1	
Motor gasoline	23.6	23.1	2.2	21.9	7.8	
Distillate	47.1	47.0	0.2	32.2	46.3	
Propane	52.1	55.6	–6.3	48.5	7.4	
Futures prices[5] **11/13**			Change		Change	%
Light sweet crude ($/bbl)	78.21	79.04	–0.83	64.31	13.90	21.6
Natural gas, $/MMbtu	4.48	4.77	–0.29	7.01	–2.53	–36.1

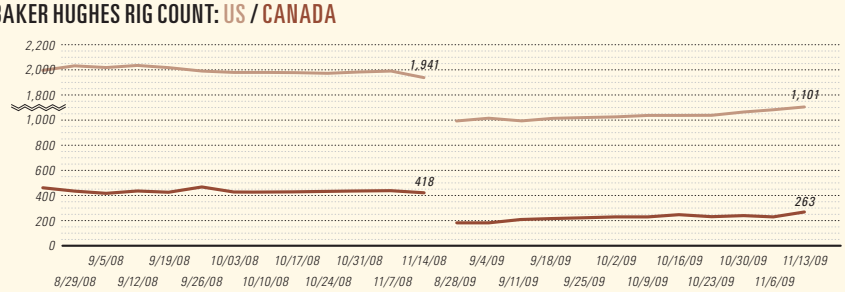
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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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Now, with our successful acquisition of NATCO, Cameron brings the complementary businesses of two well-known names, NATCO and Petreco, together as Cameron's Process Systems. By combining NATCO's portfolio of process technologies, advanced products and in-house manufacturing capabilities with Petreco's custom solutions and global reach, we now offer the full continuum of processing solutions and best-in-class project delivery. In addition to giving customers more choices and greater efficiencies, the acquisition advances our expertise in emerging technologies including subsea processing. From concept to completion, Cameron is the processing industry's Total Solutions Provider. To find out more, visit us at www.CameronAcquiresNATCO.com

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PanAsian has invested $4 million in the acquisition and development of Block XVI, which covers 16,839 sq km and contains four subbasins. The target is light oil, Ivanhoe said.

A Russian driller initially explored part of the block in the 1950s, and the area was included in a regional appraisal conducted by BP International for the Mongolian government in 1990.

Devon to accelerate Haynesville shale drilling

Devon Energy Corp. plans to accelerate drilling in its southern Haynesville shale play based upon results from a well in San Augustine County, Tex.

Kardell 1H achieved an average continuous 24-hr flow rate of 30.7 MMcfd of gas equivalent through a $^{37}/_{64}$-in. choke. Flowing pressure was 6,824 psi.

The well was drilled to 18,350 ft TMD, including a horizontal lateral section of 4,500 ft. Devon operates the well with 48% working interest. Crimson Exploration Inc. owns the rest.

David A. Hager, Devon executive vice-president, exploration and production, said the company plans a five-rig program in 2010 in this southern play area.

Devon holds 570,000 net acres in the greater Haynesville trend of east Texas and north Louisiana. Previously, Devon drilled eight horizontal Haynesville wells around Carthage, Tex.

Appraisal well completed in Bo Rang B field

Carnarvon Petroleum Ltd., Perth, and its joint venture partner Pan Orient Energy Corp., Calgary, completed testing the BR-3D1 appraisal well in Bo Rang B oil field in Thailand and declared the field commercial. Pan Orient serves as project operator.

The well is the first horizontal appraisal in the field and flowed at 700 b/d of oil from a fractured volcanic reservoir target at a depth of 446 m.

Carnarvon said this is a significant increase in the flow rate from the nearby BR-2ST1 sidetrack Bo Rang B discovery well, which had a cased-hole completion and flowed at only 35 b/d.

The JV points to the success of horizontal drilling and highlights the shallow zone potential within the Bo Rang and nearby L44-W sectors of the L44 permit.

The JV is now planning to drill three more horizontal appraisals targeting the Bo Rang B field before yearend.

Nine multiwell drill pad locations are under environmental review by the Thai authorities. Approval is anticipated in January.

Petrobras extends Marimba to the north

Petroleo Brasileiro SA (Petrobras) says it has extended Marimba oil field to the north in the Campos basin off Brazil.

The 3-MA-32A exploratory well detected presence of 29° gravity oil in a 30 m of pay with good porosity and permeability. Water depth is 400 m.

Petrobras estimates recoverable oil in the extension at 25 million bbl, which would increase Marimba's recoverable volume by 27%.

It said the discovery resulted from revision of the area's geological model and use of new seismic interpretation methods.

The state-owned company said it will place the well on production through the nearby P-8 platform by next August. ✦

Drilling & Production — *Quick Takes*

Haynesville buried-array seismic work set

El Paso Corp. let contract to MicroSeismic Inc. for a buried-array seismic monitoring program in its Haynesville shale development program south of Shreveport, La.

The buried array, to be installed before yearend, will provide microseismic monitoring, mapping, and analysis for hydraulic fracturing of El Paso wells. It will be the sixth such system the contractor has installed in the Haynesville shale play.

El Paso has five rigs drilling in the Haynesville play and expects to be producing more than 125 MMcfd of gas equivalent from the shale by December.

In October it said it had 250-300 Haynesville locations on 40,000 net acres, 30,000 in Louisiana. At the time it had 13 Haynesville wells on production with two being completed.

Partners report high Bakken shale test rates

Brigham Exploration Co., Austin, and US Energy Corp., Riverton, Wyo., reported high initial production rates from their first three completions in a six-well program in the Williston basin's Bakken shale oil play.

The latest completion, Brigham Lee 16-21 No. 1H Bakken, flowed on a 24-hr test at 1,341 b/d of oil and 1.22 Mcfd of natural gas after a 28-stage frac job. US Energy said oil sales would begin immediately, with gas sales starting in 90-120 days following connection to a gathering system.

Wells in the program, all operated by Brigham, are drilled about 10,000 ft vertically and 10,000 ft horizontally, targeting middle Bakken strata.

The Lee well is in the Rough Rider area of Williams County, ND, 5 miles south of BCD Farms 16-21 No. 1H and 8 miles northwest of the Brad Olson 9-16 No. 1H, both earlier completions in the Brigham-US Energy program.

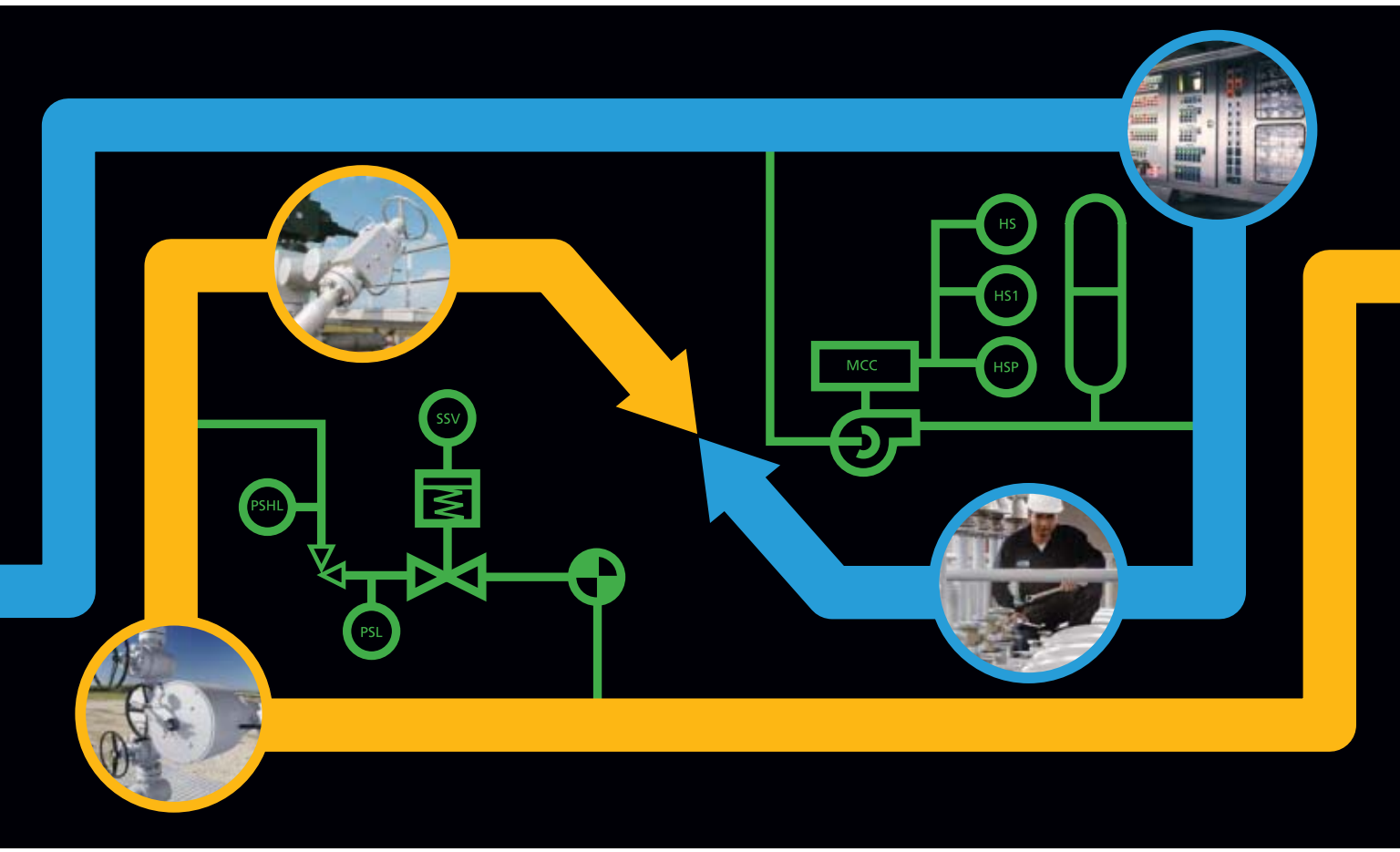
The BCD Farms well, also stimulated with a 28-stage frac job, produced 1,553 b/d of oil and 1.34 MMcfd of gas during an early 24-hr flowback period, Brigham said.

The Brad Olson well, 13 miles southeast of the Farms location, tested 2,112 boe/d of oil and gas.

US Energy said Brigham had finished drilling a fourth well, Strand 16-9 No. 1H, and run a sleeve with 26 swell packers into the hole and was preparing for completion. The other two wells, Williston 25-36 No. 1H and State 36-1 No. 1H, are still being drilled.

The companies' interests in the wells vary. Brigham's interests increase after payout.

Bud Brigham, chairman, president, and chief executive officer, said early results confirm his company's interpretation of a continuous Bakken reservoir across the core Rough Rider area. The company holds 100,000 acres in the area and sees potential for three Bakken wells for each 1,280-acre spacing unit.



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Suncor revives Firebag oil sands expansion

Suncor Energy Inc. will resume investment in the 50%-complete third stage of its Firebag in situ development in the oil sands of Alberta.

The company has approved capital spending of $5.5 billion (Can.) in 2010, including $900 million for the next step in Firebag expansion and $50 million for the fourth stage. With other projects, the "growth capital" part of Suncor's investment plans for next year totals $1.5 billion.

The company suspended work on the Firebag third stage early this year, along with plans for expanded upgrading capacity for its mining operations. Resumption of the upgrading investment is not part of the 2010 capital budget.

Noting "some improvement" in crude prices and the overall economy, Suncor Pres. and Chief Executive Officer Rick George called the budget "a conservative capital strategy" that Suncor can support from free cash flow at "midcycle" crude prices.

The third and fourth Firebag stages are to have production capacities of 68,000 b/d each from steam-assisted gravity drainage. Production from the third stage is to start in the second quarter of 2011 and from the fourth stage in the fourth quarter of 2012.

Total production from the first two stages, which started up in 2004 and 2006, averaged 54.3 million b/d in July-September.

Production from those stages is recoverying from cap of 42,000 b/d imposed in 2007 by Alberta regulators in response to excessive sulfur emissions from the Firebag operation. The cap was lifted in the third quarter of 2008.

Suncor is completing a sulfur plant, expected to cost $400 million, able to handle emissions from all six planned Firebag stages. ✦

Processing — *Quick Takes*

ConocoPhillips delays refinery upgrade

ConocoPhillips has confirmed plans to delay the upgrade of its 260,000-b/d Wilhelmshaven refinery in Germany.

"This is the right project for Wilhelmshaven—but not now," said Willie Chiang, senior vice-president, refining, marketing, and transportation. "We will reevaluate this investment opportunity as market conditions warrant."

ConocoPhillips had planned to add a coker, hydrocracker, and hydrogen units to the refinery, which it acquired in 2006 from Louis Dreyfus Refining & Marketing Ltd.

ConocoPhillips Chairman and Chief Executive Officer Jim Mulva last month said delay of the project was possible (OGJ, Nov. 16, 2009, p. 68).

Valero to shut Paulsboro FCCU until early 2010

Unscheduled maintenance on the scrubber at the Valero Energy Corp.'s Paulsboro, NJ, refinery's 55,000-b/d fluid catalytic cracking unit will force its shut down later this month, according to a company news release. The unit will remain down until the maintenance is completed, estimated at mid-January.

During the FCCU shutdown, Valero will also bring down the remainder of the refinery for maintenance, it said. The entire plant will be shut down for about 3 weeks during the longer FCC outage.

Valero said staffing at the plant will not be affected, and production units will be restored to service once the maintenance is complete. Nor will the outage affect a previously scheduled turnaround at the company's Delaware City refinery.

Vietnam's Dung Quat refinery to shut for repairs

Petrovietnam, apparently at the urging of state officials, reported it will shut down the 148,000 b/d Dung Quat refinery for 10-14 days for maintenance in December.

The facility, which began operating in February, has experienced several stoppages in the past year due to technical problems. In mid-August, it was shut down for 6 weeks due to a technical fault in a cracking unit.

"There was a problem at the RFCC unit and repairs should take about 20 days, which means the plant will resume operation by Sept. 9 or 10," said a Petrovietnam official, who declined to be identified (OGJ Online, Sept. 4, 2009).

At the time, officials said the plant would go back online at the end of September, and would begin running at full capacity by Oct. 20.

On Oct. 30, reports said the refinery had operated at full capacity in the first full week after the shutdown, and that Vietnam's crude exports were expected to fall after the unit's successful restart.

However, reports in local media now say the unit's crude oil floating storage and offloading vessel has broken down.

As a result, the Phap luat Thanh pho Ho Chi Minh newspaper Nov. 13 said the state appraisal council, which reported the breakdown to Prime Minister Nguyen Tan Dung, asked Petrovietnam to take "drastic measures" to deal with the issue.

The council's request came just days after Vietnam's Minister of Industry and Trade Vu Huy Hoang said general contractor Technip would hand the Dung Quat facility over to Petrovietnam in January at the latest.

The refinery was due to become fully operational by yearend, or 2 months behind schedule, Hoang said on Nov. 10.

On Nov. 7, Petrovietnam's subsidiary Binh Son Petrochemical & Refinery Co. signed a $4.8 million, 1-year contract with the Marine Oil & Gas Maintenance Co., Oil & Gas Technology Co., and Malaysia's OSS for maintenance of the refinery's single-point mooring structure.

Since starting up in February, the Dung Quat refinery has bought 1.2 million tons of oil pumped from the the Bach Ho (White Tiger) oil field, which lies off the southern coastal province of Ba Ria-Vung Tau. During that time, the $3.054 billion facility has produced 800,000 tons of products.

The Vietnamese government, aiming to reduce the country's trade deficit, has been hoping that production at Dung Quat would help to reduce, or even halt the import of petroleum products during the remainder of 2009. The country's trade deficit is forecast to run at $11.5-12.5 billion this year, compared with $17.516 billion in 2008. ✦

Final leg of Rockies Express line enters service

The final 195 miles of the Rockies Express-East pipeline was completed Nov. 12, entering service between the Lebanon Hub in Warren County, Ohio, and Clarington in Monroe County, Ohio.

The entire 1,679-mile Rockies Express Pipeline, extending from northwestern Colorado to eastern Ohio, is now operational and available for full firm shipper nominations, Kinder Morgan Energy Partners LP said.

Long-term, binding firm commitments have been secured for virtually all of the pipeline's 1.8 bcfd capacity.

The Rockies Express line began service into Lebanon on June 28, opening the first direct route between the Rockies producing region and historically higher priced natural gas markets in Ohio and the US Northeast.

Shippers on the line took advantage of the new capacity almost immediately, moving gas away from the markets they had been serving in the Midwest to higher-priced markets. Regional price differentials shifted in response to the changes in gas flows.

Bentek Energy says completion of the final leg of line to Clarington and additional interconnections with the Northeast market will likely have similar effects (OGJ, Sept 7, 2009, p. 50).

Kinder Morgan owns 50% of the line, which it constructed and operates. Sempra Pipelines & Storage, a unit of Sempra, and ConocoPhillips each own a 25% stake.

Russians close to approval of ESPO oil line tariff

Russia's Federal Tariff Service said it expects to approve the tariff for oil transportation through the East Siberia–Pacific Ocean (ESPO) pipeline in late November or early December.

FTS head Sergei Novikov said the tariff should be introduced from Jan. 1, and would be a through rate for eastbound oil exports, with two or three zones for oil exports.

Novikov's remarks concerning three zones as well as their price structures largely reiterate a proposal made earlier this month by Russia's state-owned OAO Transneft.

Last week a Transneft spokesman said the firm wants the ESPO line to be divided into the eastern, western, and central export tariff zones, with $34/tonne charged for oil transported via the eastern zone, $48/tonne via the western zone, and $42/tonne via the central zone (OGJ Online, Nov. 9, 2009).

Meanwhile, Russian authorities last week announced that all of the onshore and offshore facilities for oil exports have been finished at the Port of Kozmino—the planned terminus of the ESPO pipeline, now under construction (OGJ Online, Nov. 12, 2009).

CNOOC, PetroChina to buy more LNG from Qatar

Qatar's state-owned Qatargas Operating Co. Ltd. boosted its exports of LNG to China by signing supply agreements with China National Offshore Oil Co. (CNOOC) and PetroChina International Co. Ltd. The agreements were announced at the official opening of Qatargas' representative office in Beijing, which was attended by Abdullah Al-Attiyah, Qatar's deputy prime minister as well as minister of energy and industry, and Qatargas Chief Executive Officer Faisal M. Al Suwaidi.

Qatargas signed a memorandum of understanding with CNOOC for long-term supplies of LNG to China in addition to amounts already agreed by the two sides.

Under terms of the MOU, Qatargas intends to supply a further 3 million tonnes/year of LNG to CNOOC commencing in 2013. In addition to the base volume, Qatargas and CNOOC said they will "contemplate the sale and purchase of an additional 2 million tpy of LNG."

These volumes combined with an existing long-term supply commitment of 2 million tpy of LNG agreed under a 2008 sales agreement will potentially take the total volume of the Qatari LNG to be supplied to CNOOC to 7 million tpy.

According to analyst IHS Global Insight, "CNOOC, the largest offshore oil and gas developer of China's [NOCs], is planning a significant expansion of LNG import and storage capacity, which Qatar with its huge liquefaction projects can help to fill."

In addition to the CNOOC agreement, Qatargas also signed an MOU with PetroChina for 2 million tpy of LNG to China.

Besides the 3 million tpy already to be supplied from Qatargas to PetroChina, the new MOU will increase the total amount of LNG deliveries to 5 million tpy.

Qatargas said the initial supply of 3 million tonnes of LNG is expected to commence with the start-up of Qatargas 4's Train 7, while the additional 2 million tonnes of LNG under the new MOU is expected to start in "the first half of the next decade."

In October, CNOOC received its first cargo of LNG from Qatar, 216,000 cu m of gas at the Dapeng LNG terminal in Shenzhen under the long-term supply agreement signed between CNOOC and Qatargas last June (OGJ Online, Oct. 20, 2009).

PEP lets contract for Veracruz pipeline project

Petroleos Mexicanos subsidiary Pemex Exploration & Production (PEP) has awarded Copavisa the tender for construction of various pipelines in its Veracruz project. Copavisa presented a winning bid of $8.77 million for the project, which will last for 2 years.

Pemex's Veracruz project, the second-largest producer of nonassociated gas in Mexico after the Burgos project, also produces some oil and associated gas.

News of the award follows a recent announcement by Pemex that at least 90 of its oil and gas wells in Veracruz and Tabasco states were shut down due to flooding. Production dropped by more than 56%, falling to 26,280 b/d from 60,000 b/d, according to Pemex executive Fernando Flores Rivera, whose office controls 241 wells in the area. ✦

Correction

In the story, "EOG sees reserve hike in Barnett Combo play," initial production was incorrectly stated as 6,000 b/d. Production should be 600 b/d (OGJ Online, Nov. 6, 2009).

Letters

Gas-lift valve testing

This letter refers to an article by Zotan Turzo and Gabor Takacs entitled "CFD techniques determine gas-lift valve behavior" (OGJ, June 8, 2009, p. 46).

The article stated: "Mainly based on the systematic work performed at TUALP [Tulsa University artificial lift projects], API published the first edition of Gas Lift Valve Performance Testing (API RP11V2) in 1995."

The statement is not entirely correct. The testing techniques adopted by American Petroleum Institute for the Recommended Practice (RP) 11V2 had been performed for many years prior to TUALP by Teledyne Merla. I am the chairman of RP 11V2 and former employee of Teledyne Merla. I am quite familiar with the time line and development of the testing techniques adopted by API.

While TUALP did practice one of the testing methods prior to the publication of the API document, the test method they practiced was not developed by them. In addition, the API document included two additional test requirements that, to my knowledge, were never practiced at TUALP; namely, the Loadrate test and the Flow Coefficient test. Both of these additional tests are critical to the proper testing of a gas-lift valve.

I would like to ensure proper credit is given not only to Teledyne Merla but also to the members of the API committee who worked very hard and for a great deal of time to write this document.

Kenneth L. Decker
Chairman, API RP11V2
Decker Technology Inc.
Stone Mountain, Ga.

Calendar

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

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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.

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DECEMBER

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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.

International Petroleum Technology Conference (IPTC), Doha, +971 4 390 3540, e-mail: iptc@iptcnet.org, website: www.iptcnet.org/2009. 7-9.

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.

Global Floating LNG Summit, London, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.global-flngsummit.com. 20-21.

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.

✦Microsoft Global Energy Forum, Houston, (206) 829-1376, website: http://microsoft.crgevents.com/gef2010/microsoft_gef/ 21.

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,

Calendar

+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. 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.Photovoltaicsworldevent.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, Manama, +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.

Purvin & Gertz 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.

Offshore West Africa Conference & Exhibition, Accra, Ghana, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshore-westafrica.com. 9-11.

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.

Oil and Gas Africa Exhibition & Conference, Cape Town, SA, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: events@fairconsultants.com, website: www.fairconsultants.com. 16-18.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 16-18.

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, Turkey, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 16-18.

Electric Light & Power Executive Conference, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.elpconference.com. 21-22.

NPRA Annual Meeting, Phoenix, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 21-23.

GPA Annual Convention, Austin, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.GPAglobal.org. 21-24.

AIChE Spring National Meeting & Global Congress on Process Safety, San Antonio, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 21-25.

Howard Weil Energy Conference, New Orleans, (504) 582-2500, website: www.howardweil.com/energy-conference.aspx. 21-25.

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. 21-26.

Middle East Downstream Week & 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. 22-25.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Singapore, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 23-24.

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-24.

Middle East Refining Conference & 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. 23-24.

Base Oils and Lubricants in Russia and CIS & Annual Meeting, Moscow, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 23-25.

SPE Intelligent Energy Conference and Exhibition, Utrecht, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.intelligentenergyevent.com/conferenceOGJ. 23-25.

Utility Products Conference & Exposition, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.utilityproductsexpo.com. 23-25.

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'Genned' by the wind

Sam Fletcher
Senior Writer

What fluctuates faster than crude prices in a nervous market? Apparently the RPMs of wind turbines powered by the whims of Mother Nature.

For 90 min. on Nov. 8, an unusually strong wind set Spain's wind turbines to spinning like pinwheels, generating 53% of that country's electricity needs. Unfortunately, that power peak occurred on a Sunday between 4:30 a.m. and 6 a.m., when Spain's power demands are minimal. According to a Nov. 10 report in the Wall Street Journal, "Spain had never gotten more than 43% of its juice from wind power before. It suddenly had so much wind power, it had to export some electricity."

Spread over the remaining 22½ hr of that blustery day, power from windfarms dropped to 39% of the country's electricity needs—yet still far above Spain's annual average of 12% and the 2% of US electricity generated by wind in 2008.

The extreme variability of wind and solar power has for years kept those renewable resources on the perimeter of the market for sustainable energy. Wind is especially vulnerable since—as the Spanish incident demonstrated—it often generates the most power when it's least needed. Moreover, Spain's 18 Gw of installed turbines produced little more than 11 Gw of electricity—a production rate of about 60%. "That means that in the absolute best-case scenario, two out of every five gigawatts of wind power are essentially sitting idle," WSJ said.

The paper quoted Luis Atienza, chairman and chief executive officer of Red Electrica de Espana, as saying, "The risk that on these very windy mornings there isn't enough demand to offload all the wind production, a risk that will increase in step with installed wind capacity, should be alleviated by increasing energy storage capacity and export capacity. Furthermore, it would be convenient to shift part of the electricity demand to those off-peak hours. In that sense, electric cars, since they can recharge overnight, seem destined to facilitate the integration of more renewables into the electricity system."

Although long a leader in wind power, Spain still hasn't managed "to clean up its economy and meet all of its obligations under the Kyoto Protocol; the country has one of the worst compliance records in Europe," WSJ reported.

The day after generating a record amount of power by wind, Spain agreed to buy Poland's excess greenhouse-gas emissions permits for $37 million.

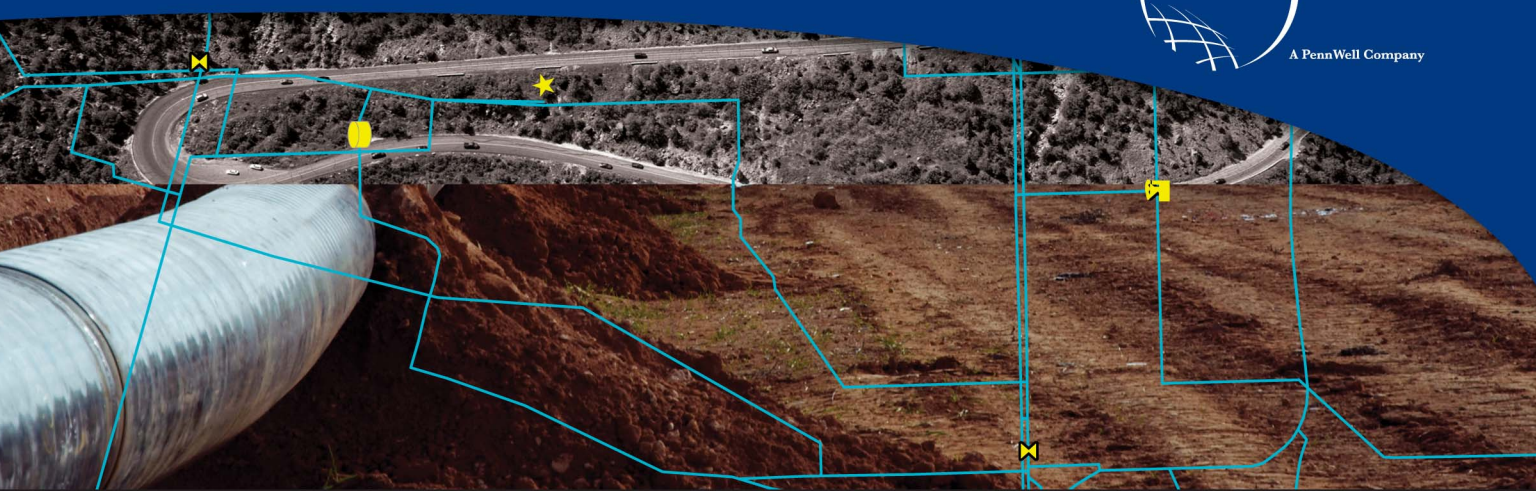
Corn ethanol withers

Besides being hard on oil producers and refiners, the last couple of years have been economic hell for corn ethanol. Just 18 months ago, Raymond James & Associates Inc. was tracking five producers of corn ethanol. Since then, the brokerage's analysts reported, "US BioEnergy was acquired by VeraSun, and not long thereafter (November 2008), VeraSun—the largest US ethanol producer at the time—filed for Chapter 11. It was followed into bankruptcy court in short order by Aventine (March 2009) and Pacific Ethanol (May 2009). Ironically, the smallest of the group, BioFuel Energy, has survived the longest. It's still in business, albeit trading around $1/share and facing a heavy debt burden. This list, by the way, does not include the numerous bankruptcies and liquidations of smaller ethanol producers, including farmer co-ops."

Nevertheless, plants owned by bankrupt ethanol companies are still operating—"run either by their original owners or acquirers (e.g., Valero bought most of VeraSun's plants for about 30% of replacement cost)," said analysts in Raymond James' Houston office. "But it's safe to say that this is hardly a conducive environment for investment in the industry. Given the overcapacity (within the context of depressed gasoline demand), along with corn prices that are still lofty (though no longer egregiously high), ethanol cash margins were near zero (turning negative in some weeks) for much of the first half of 2009."

Crude's recent escalation to $80/bbl helped restore ethanol margins to "decent levels" of 30-40¢/gal, but that's "still slim" compared with their heady 60¢/gal levels in the 2006-07 boom. "This needs to be seen alongside the fact that capital for new capacity remains practically frozen. After all, if banks are still uncertain about lending to, say, solar farms, how likely are they to finance new ethanol plants?" analysts said.

Corn farmers in key political swing states still reap ethanol subsidies. But analysts said corn ethanol no longer is seen as a "game-changing" solution to the imbalance between oil supply and demand. ✦



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Editorial

Interior's damaging overhaul

US Interior Sec. Ken Salazar often portrays his approach to oil and gas leasing as repair of damage inflicted by the administration of George W. Bush. He thus adopts his own administration's tiresome penchant for blame-shifting. More important than that, however, is the damage he is inflicting, with a growing record of resistance to the development of oil and gas resources, on national energy interests.

Since confirmation of his nomination last Jan. 20, Salazar has fallen into a pattern: He identifies an issue, blames the Bush administration for mishandling it, then implements change, often sweeping, that discourages oil and gas work.

Lease withdrawals

Less than a month after taking office, for example, he withdrew 77 leases offered to producers late in the Bush administration near national parks and other sensitive areas. The offerings had been challenged in court, as such developments often are, and made subject to a temporary restraining order. For a new interior secretary, the litigation was a problem. But effectively starting over was heavy-handed. Later, a study team recommended leasing 17 of the parcels, deferring 52, and withdrawing 8. It also recommended increasing "coordination and collaboration" in leasing decisions.

The outcome of this response to what Salazar repeatedly disparaged as a "rush" to lease the land: fewer acres available for oil and gas development and more bureaucracy.

Soon after that move, Salazar rescinded a Bush administration program for oil shale leases. He objected to the ability of holders of research-and-development leases to expand their acreage and secure a low royalty rate for successful projects. Oil shale researchers said they'd need lease expansion and royalty limits to move development to commercial scale. Salazar instead has moved to limit acreage, leave royalties uncertain, and impose new administrative steps. The combined effect: Discourage oil shale development, which already faces technical problems and substandard economics.

In March, the secretary again showed his leanings on oil and gas leasing by praising enactment of the Omnibus Public Lands Management Act of 2009, which added 2 million acres to the untouchable wilderness system and subjected 26 million acres to a new, thick layer of activity-repellant bureaucracy. More recently, he ended the royalty-in-kind program, a move that will revive disputes between leaseholders and the federal government over valuation of produced oil and gas. An inspector general's report found problems with the department's administration of the program, so the secretary—ever ready to swing the saber—killed it. And the burden on producers grows.

The latest setback to oil and gas activity on federal acreage came hidden in, of all things, the announcement of a federal offshore lease sale. "Continued development in appropriate areas of the Outer Continental Shelf, such as in the areas we will offer in the Gulf of Mexico, is a key component of our efforts to reduce our country's dependence on foreign oil," Salazar said, obviously playing to two unlike-minded audiences at once.

Sale 213 will offer 6,800 unleased blocks covering more than 35.9 million acres in 3-3,400 m of water. The numbers sound substantial. At least this is leasing. But lease values have shrunk. Initial terms of leases involving water depths of 400-800 m will drop from 8 years to 5 years. Those with water depths of 800-1,600 m will fall to 7 years from 10 years. Spudding of an exploratory well on a lease reinstates the larger value.

"This new approach to lease terms will better ensure that taxpayer resources are being developed in a timely manner," Salazar said. The ludicrous presumption is that he knows better than the producers he regulates, whose money is at risk, when and where drilling should occur. Now producers interested in new onshore leases must wonder what changes await.

Overhaul unnecessary

Federal oil and gas leasing didn't need this overhaul. Where allowed to work, the system offered reasonable consistency and generally encouraged exploration and development.

Salazar's changes erode those advantages. They address administrative problems with stiffened regulation that will discourage work essential to future oil and gas supplies. They do not, therefore, represent improvement. ✦

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Study: Waxman-Markey bill costly to US refiners

Larry Goldstein
Ben Montalbano
Lucian Pugliaresi
Pravin S. Sheth
Energy Policy Research Foundation Inc.
Washington, DC

Economic consequences to the US refining industry of the American Clean Energy and Security Act (ACES), H.R. 2454, also known as the Waxman-Markey (W-M) energy and climate bill, are profound, according to an evaluation by Energy Policy Research Foundation Inc. The legislation calls for controlling emissions of greenhouse gasses (GHGs) by placing a price on them. The bill passed the House of Representatives on June 26, 2009, and companion legislation is under discussion in the US Senate.

Under the W-M bill, manufacturers (refiners) and importers of transportation and other fuels derived from crude oil would be required to purchase allowances to account for the carbon dioxide emitted into the atmosphere as a result of combustion of these fuels beginning in 2012, 2 years before any free allowances are distributed. Allowances could be bought and sold under the legislation's cap-and-trade program.

US refiners would responsible for approximately 45% of all emissions covered by the W-M bill, which would regulate 86% of all US emissions by 2016. US refiners, but not importers, would have to purchase allowances for stationary source emissions (emissions released at the refinery). US refiners would receive some free allowances beginning in 2014 and ending in 2026 to assist in transitioning to a higher cost operating environment, but these allowances are small compared to the total obligations under the program (Table 1).

This article is adapted from a report available on EPRINC's web site at http://www.eprinc.org/pdf/refiningindustry-waxmanmarkey.pdf.

Rising costs

The cap-and-trade program as outlined in the W-M legislation will require the US refining industry to adjust to a new set of cost structures and a new regulatory program. This program will not be applied in a vacuum but within the structure of an industry already facing rising competition from foreign refiners and a rising mandate to increase sales of biofuels.

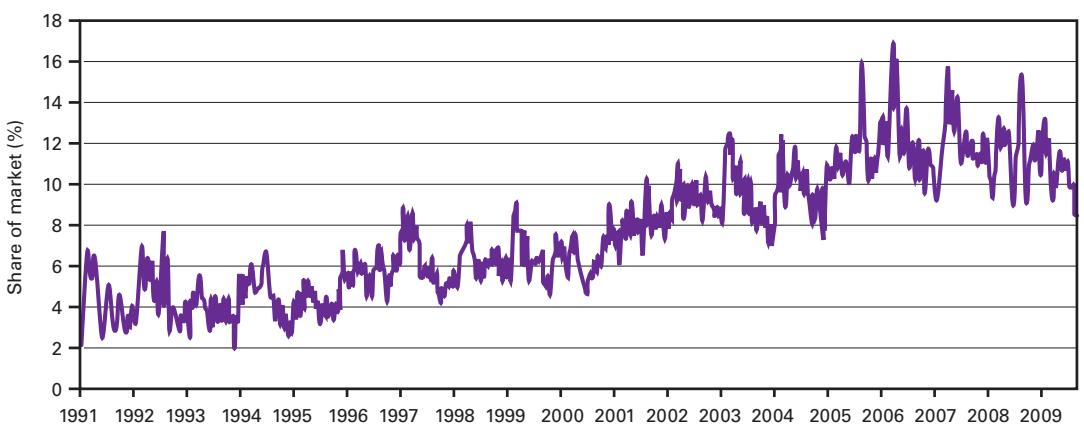
The US possesses 20% of the world's refining capacity (17.5 million b/d of the world's 86 million b/d of capacity) and is the world's largest consumer of oil, making it one of the most important markets in determining product trade flows.

In recent years the US has imported 10-12% of its gasoline and gasoline blending components (1 million b/d), an increase from approximately 6% in 2000. Imports' share of supply has held steady as gasoline demand has declined over the past 2 years and as the supply of ethanol has tripled in under 5 years. Ethanol production was barely over 200,000 b/d in 2004 and has averaged 672,000 b/d through the first 8 months of 2009.

Gasoline imports are and will

IMPORTS' SHARE OF US GASOLINE SUPPLY*

Fig. 1

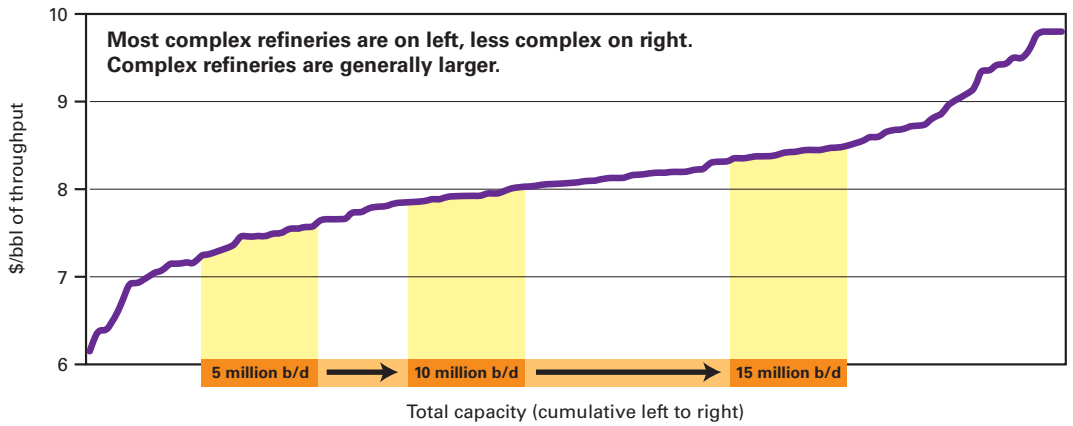


*Total gasoline imports as share of finished motor gasoline product supplied.
Source: EPRINC calculations from Energy Information Administration data

be a firmly integrated part of US petroleum supply. The US imports the majority of its gasoline from Canada, the Virgin Islands, and Europe, where the dieselization of passenger cars has left refiners with surplus gasoline.[1] Fig. 1 shows gasoline imports' share of US gasoline supply.

US REFINERS' EFFECTIVE COST OF PRODUCTION—2015-30*

Fig. 2



*Some lubricant and small niche refineries have been excluded.
Source: EPRINC calculations

Because refineries vary widely in complexity, product mix, and access to markets, no single production function (or supply curve) can fully capture the cost of producing the entire slate of refined products for the US economy. However, it is possible to approximate the cost of alternative regulatory programs (e.g., biofuels mandates, tax treatment, cap-and-trade legislation) on the entire refining sector by standardizing different segments of the industry to a common product slate and then evaluating the relative cost of producing the standard product slate across all units.

While such a calculation may not yield a precise competitive metric for an individual unit, this approach does permit an estimate of the average cost of alternative regulatory programs and what those programs are likely to do to the cost of producing the standard product slate for the entire economy. Estimating this shift in the cost of producing the product slate is essential for estimating how much of the rising cost can be passed through to consumers as well as subsequent adjustments (losses) in market share to foreign refineries.

Fig. 2 shows EPRINC's estimate of the cost of production for the entire US processing fleet for 2015-30 under the Energy Information Administration's Annual Energy Outlook 2009 reference scenario—prior to any capacity reductions resulting from rising costs from pending legislative and regulatory programs (blend wall, removal of Section 199 from the tax code, and cap-and-trade legislation) or as a result of competitive pressures from emerging and expected growth in world refining capacity likely to take place in the period.

In this "business as usual" scenario the US production function remains relatively stable with real operating costs reflecting the EIA forecast for modestly rising feedstock prices. This scenario also assumes no substantial capacity expansion as the US faces essentially flat demand for transportation fuels for the forecast period. In EIA's reference case, liquid fuels consumption remains virtually flat throughout the forecast period, rising at 0.1%/year, and fuel prices rise at 2.6%/year.[2]

The EPRINC estimate heading into the 2015-30 timeframe has operating costs (fixed and variable) of approximately $6/bbl, rising to over $9/bbl depending on complexity, without any major commitments to capacity expansion. The 50 most complex US refineries account for 10 million b/d of capacity, meaning nearly 60% of total US refining capacity is found in 40% of its refineries.

According to EIA's Financial Reporting System, operating costs shown in

EMISSION ALLOWANCES UNDER WAXMAN-MARKEY BILL*

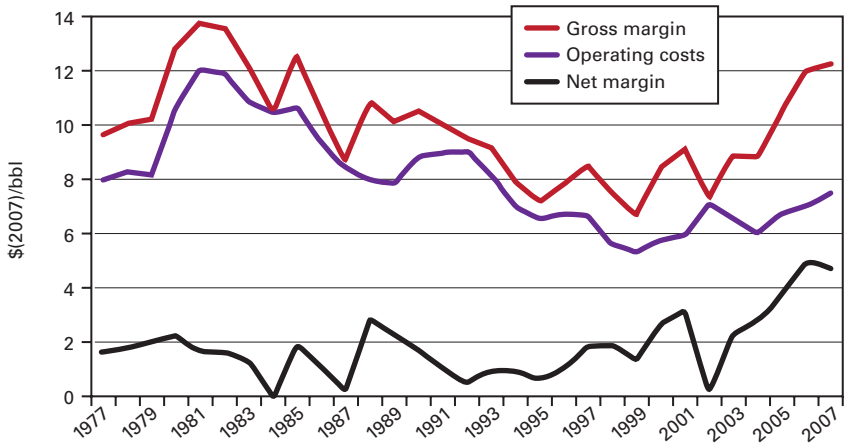
Table 1

Year	Total CO_2 emissions permitted for US economy	US refiners' emissions stationary (source)	US refiners' emissions (product combustion)	Refiners' total emission compliance obligation	Emission allowances provided at no cost	Net emission allowance purchase requirement
	Million tonnes/year of CO_2					
2015	5,003	256	2,029	2,285	100	2,185
2020	5,056	250	1,980	2,230	101	2,129
2025	4,294	248	1,964	2,212	86	2,126
2030	3,533	249	1,973	2,222	0	2,222

*Actual emissions for the entire US will be higher as ACES covers only 86% of the US economy. Does not include allowances allotted to small business refiners, 0.25% of the free allowance pool. All estimates are prior to trade flow adjustments from higher cost of US refinery operations under the Waxman-Markey bill
Source: HR 2454, EPA Data, EIA W-M Basic Case Projected Refinery Crude Throughputs, and EPRINC Calculations.

US PRODUCT MARGINS AND COSTS*

Fig. 3



*Per barrel of product sold for EIA Financial Reporting System companies.
Source: EIA

LOSSES FROM PRODUCT AND STATIONARY ALLOWANCE COSTS WITH...

Table 2

	Low foreign supply case	Medium foreign supply	High foreign supply case
	Capacity at risk of closure (Million b/d, except job losses)		
...CO_2 cost of $15/ton			
Product emission costs - 90% passthrough	0.80	1.50	2.4
Stationary emission costs	0.75	1.50	2.25
Total capacity losses	1.55	3	4.65
Total job losses	80,000	160,000	240,000
...CO_2 cost of $30/ton			
Product emission costs - 90% passthrough	1.3	2.3	3.0
Stationary emission costs	2.1	4.2	5.0
Total capacity losses	**3.4**	**6.5**	**8.0**
Total job losses	**180,000**	**275,000**	**350,000-400,000**

Fig. 3 have remained relatively steady in recent years, within their historical range of $6-8/bbl, and are consistent with EPRINC's estimates in Fig. 2. Net margins were strong during the refining "golden era" from 2004 to 2007, but more recent data, shown in Fig. 4, suggest net margins have likely returned to their historical level around $2/bbl.

Fig. 4 below shows gross margins for refined products accounting for 85% of the barrel. Gross margins have returned to their historical levels near $10/bbl after several years at or over $15/bbl beginning in 2004. Composite margins shown in Fig. 4 do not include bottom-of-the-barrel products, which generally sell below crude cost.

Regulatory cost

The industry is likely to face a range of cost pressures in the coming years from both existing regulatory programs and new legislation. EPRINC has estimated the cost of the following regulatory and legislative initiatives and divided the cost outcomes into two categories: 1. costs faced by US refiners but not by many foreign suppliers, and 2. costs faced by both US and foreign suppliers.

With regard to cost of operations borne by US refiners alone, the cost of acquiring allowances for stationary emissions of GHGs at the refinery site, and adjustments in tax rates (such as removal of Section 199 in the US tax code) are the most prominent. Although refined products entering the US from some foreign sources may have a cost penalty from CO_2 control costs from stationary emissions, a large volume of processing capacity now in place abroad as well as new capacity scheduled to come on line will be free of a higher cost structure from carbon controls of stationary source emissions and will also not be subject to the higher proposed cost tax structure faced by US refiners.

In some cases, national governments may decide to participate in an international agreement to reduce GHGs but may select control strategies that do not raise the cost of industrial operations and instead focus on strategies to promote efficiency and reduce consumption by end-users, as the European Union is attempting. The potential for widely differing cost structures for refining in international markets is especially important in the near to medium term.

EPRINC has identified substantial foreign refining capacity with open access to the US market that faces neither stationary emission costs for controlling GHGs nor corporate tax levels which would raise their cost structure to levels comparable to the cost structure of US refiners. Fig. 5 shows IEA's forecast for worldwide refining capacity additions expected to come online between 2009 and 2014. The IEA forecast does not include three 400,000 b/d projects in Saudi Arabia which now appear to be moving forward and are all scheduled to start up by 2014, although the completion of any one refinery cannot be guaranteed. China is set to be the largest source of new capacity.

Depending upon the cost of allowances and whether Section 199 provisions are repealed, the incremental cost of operating the US refining fleet will rise by $1-2/bbl in 2015 as a result of Section 199's repeal and stationary emission costs.

The cost imposed on refiners for their stationary emissions is 75¢/bbl, based on the typical amount of refinery emissions per barrel of throughput (0.05 tons/bbl) and the average price of CO_2 allowances in the Environmental Protection Agency's core scenario for 2015 ($15/ton of CO_2 equivalent)

to $1.50/bbl in the same scenario without international offsets. EPA further estimates that real carbon prices would rise at a rate of approximately 5% per annum.

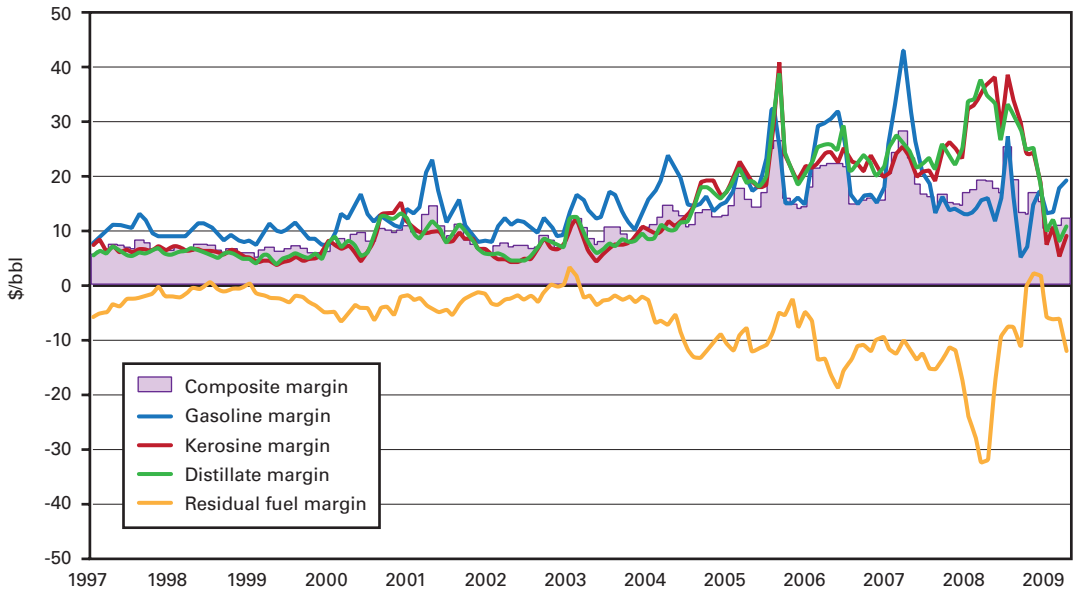
The repeal of the Section 199 manufacturers' tax credit will add about 25¢/bbl to production costs with refinery runs at an annual average of 15 million b/d. Section 199 was enacted to provide all US manufacturers, not only oil refiners, with a tax treatment that is more competitive with foreign manufacturers. The proposed repeal of the credit would affect only oil refiners and oil and gas companies; it would remain in place for all other domestic industries.[3]

The new $1-2/bbl cost does not include product allowance costs which are also imposed on imports. It represents an increase in operating costs of 12.5-25% for a refinery with operating costs of $8/bbl and would wipe out 50-100% of net margins for a refiner earning $2/bbl should the refiner be unable to pass this cost to consumers. Inclusion of free allowances granted between 2014 and 2026 lowers the cost to 75¢-$1.50/bbl. Pass-through of such costs to consumers will be difficult because imported fuels will not be subject to them. After 2015 operating costs will rise further as allowance prices become more costly. It is also worth noting that in EIA's analysis of W-M, basic case allowance prices are 70-130% higher than those in EPA's "core" scenario during 2015-30.

Allowances distributed to refineries will provide some financial relief, but "free" allowances cover less than half of all stationary emissions.

GROSS MARGINS BY PRODUCT

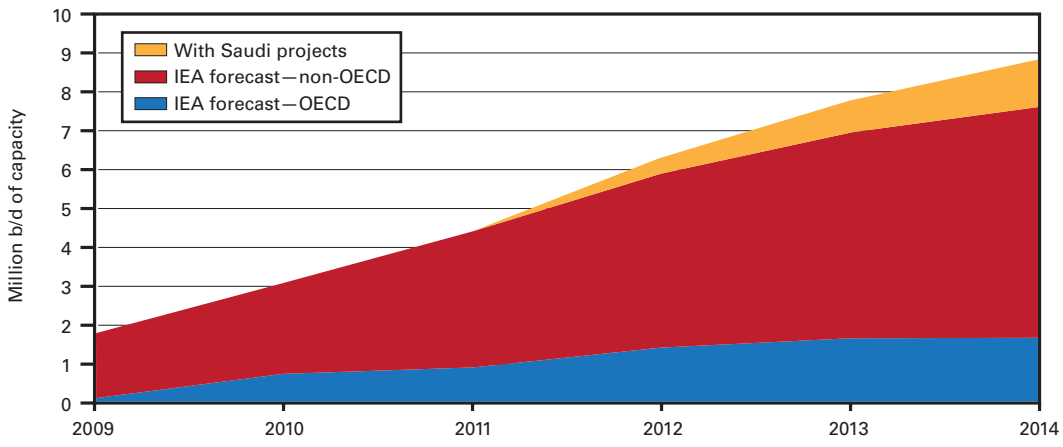
Fig. 4



Source: EPRINC calculations from EIA data

PROJECTED REFINING CAPACIY ADDITIONS

Fig. 5



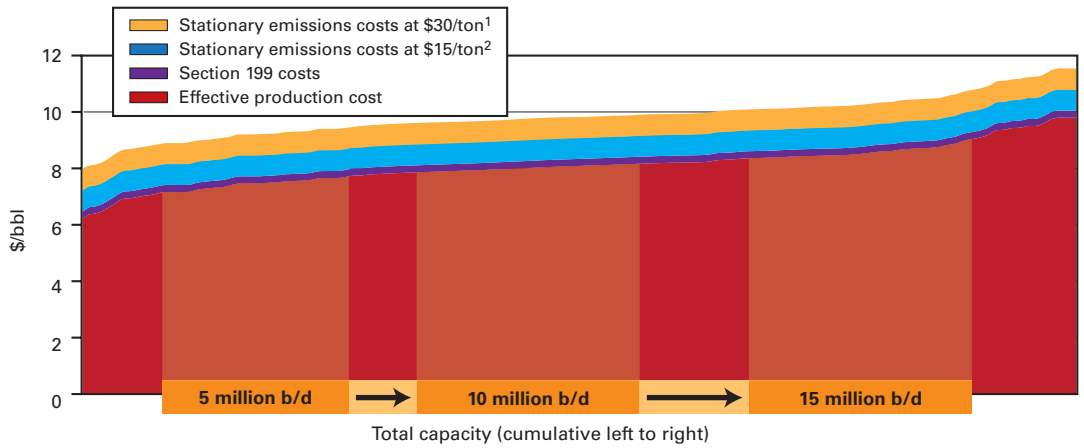
Source: EIA Medium-Term Oil Market Report; EPRINC data and calculations

Allowance purchases

US refiners and product importers must purchase allowances for the emissions released from consumption of the fuels they produce or import. W-M assumes that domestic refiners will be able to pass through 100% of these costs to consumers and will therefore be protected from trade flow risks. However, pass-through of increases in taxes and feedstock prices is often less than 100%.[4]

OPERATING COSTS WITH STATIONARY EMISSIONS, SEC. 199 REPEAL

Fig. 6



[1]Average EPA scenario for 2015—no international offsets. [2]Average EPA core scenario for 2015.
Source: EPRINC

Although pass-through has at times been 100%, and sometimes greater, in an environment of excess worldwide capacity 100% pass-through is unlikely. Foreign refiners selling in the US market will likely find opportunities to spread allowance costs (paid by importers) among the portion of their product slate not subject to such costs.

Because the scale of product allowances is so large, over $30 billion/year at $15/ton of CO_2 for 15 million b/d of product sales, sub-100% pass-through of product allowance costs will pose a huge risk to refiner profitability and will likely force many to idle or close capacity.

Even at a rather optimistic pass-through rate of 90% and an allowance price of $15/ton, refiners must absorb 60¢/bbl of product (30% of a $2/bbl net margin). At $30/ton, a price closer to EIA estimates of allowance prices, 90% pass-through would force refiner to absorb $1.20/bbl, over half of a typical refiner's net margin.

Likely adjustments

EPRINC evaluated the extent to which the W-M legislation would raise operating costs and the likely adjustments that would take place both to domestic operating capacity and to direct and indirect employment throughout the refining sector. The major conclusions of EPRINC's report are that with enactment of the W-M legislation:

- The market environment will be characterized by Rising Regulatory Costs and Excess Capacity Abroad

The GHG provisions, i.e., the required purchase of stationary source and combustion allowances under W-M, will take place in an environment in which the US refining industry must simultaneously adjust to:

1. Rising costs of production from recently enacted environmental and regulatory requirements.

2. Rising competition from foreign competitors as 7.6-8.8 million b/d of new refining capacity comes online by 2015-80% of which will be built outside the Organization for Economic Cooperation and Development. Based on EIA's projected estimate of world petroleum demand through 2015, there is likely to be as much as 18 million b/d of excess crude distillation capacity worldwide.

3. Flat or declining demand for transportation fuels in the US market.

The emergence of major new centers of global refining combined with rising production costs for domestic operations due to environmental regulations, rising taxes, and biofuel mandates will further shrink margins and place 2.5 million b/d of the current 17.5 million b/d of domestic operable capacity at high risk of permanent closure early in the 2015-30 forecast period, even without any accounting for the increased costs associated with allowance purchases beginning in 2012 as called for in the W-M legislation.

- Stationary-source allowance costs alone will idle additional US capacity.

The GHG allowance costs associated with stationary emissions, a cost not placed on imported fuels, represent a large increase in refiners' cost of production. This cost alone will put the profitability of many refiners at risk. Full pass-through of such costs is unlikely considering the amount of excess worldwide capacity.

Constraints on pass-through for stationary emission costs alone will erase 25-50% of a typical refinery's net margins in the program's first few years, inclusive of free allowances allotted to refiners. As shown in Fig. 7a, some capacity will be idled or permanently shut down. The volume of lost capacity is highly dependent upon the availability of foreign capacity, but much of this capacity is coming online now, and even under the most optimistic case, US capacity losses will be substantial: 750,000-2.25 million b/d with allowance prices at just $15/ton. At an allowance cost of $30/ton of CO_2, capacity losses rise to 2.1-6.3 million b/d.

- Pass-through of product emission allowance costs is unlikely at a $15/ton allowance cost.

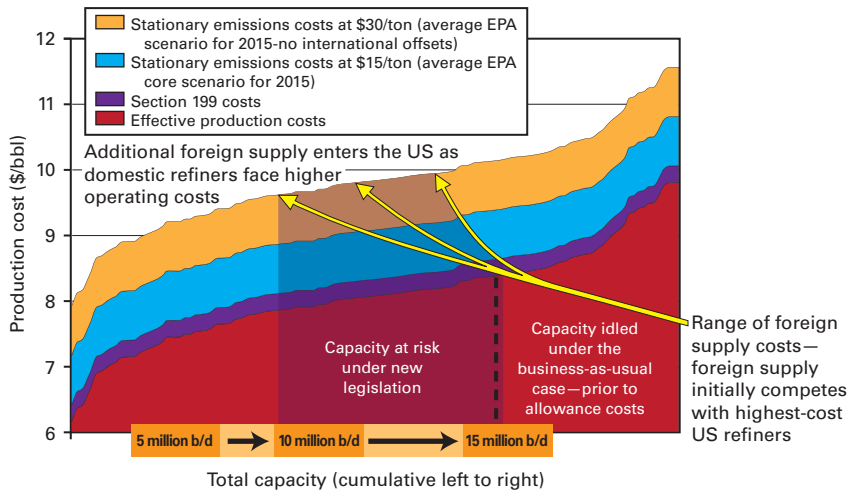
Full pass-through of product emission costs will also be unlikely. EPRINC has identified sustained periods when refiners have been limited to passing through increases in feedstock prices and taxes to as low as 50-75%. In a market environment of substan-

US CAPACITY AT CLOSURE RISK FROM COST INCREASES FROM...

Fig. 7

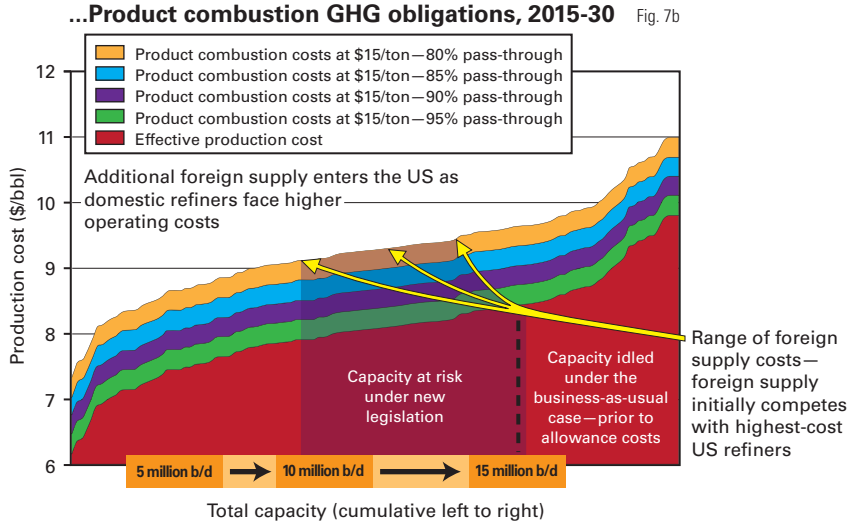
...Stationary-source GHG obligations, 2015-30

Fig. 7a



...Product combustion GHG obligations, 2015-30

Fig. 7b



Source: EPRINC

tial excess capacity (both in the US and abroad) opportunities for 100% pass-through will be rare as lower-cost refiners seek to shift costs among the product slate to maintain operating capacity. The scale of GHG allowance costs for product emissions is so large that a pass-through rate of 80% or even 90% will force a large segment of the industry to idle capacity.

Failure to achieve full pass-through of product allowance costs will place large segments of the industry at risk of closure—in addition to capacity threatened by stationary emission costs. As shown in Fig. 7b and Table 2, the range of potential capacity losses relating solely to product emission costs would be 800,000-2.4 million b/d at 90% pass-through even under the more optimistic scenario of an allowance cost of $15/ton of CO_2.

- Pass-through of product emission allowance costs is unlikely at a $30/ton allowance cost.

In a scenario where allowance costs reach $30/ton with 90% pass-through of product emission costs, total capacity losses could rise to as much as 8 million b/d, and job losses could approach 400,000.

- In the 2015-2030 forecast period evaluated by EPRINC, gasoline prices could rise by an average of 20-40¢/gal under the carbon costs calculated by the EPA.

Gasoline, and all other petroleum-based transportation fuels, could rise by over $1/gal under some CO_2 allowance cost forecasts by the EIA.

- Carbon leakage remains a severe trade risk to the US refining industry.

The purpose of the W-M bill is to curtail GHG emissions, but the cap-and-trade program poses severe risks to the structure of the US refining industry, and instead of reducing GHGs as intended the legislation will replace domestically produced fuels with imported fuels. In addition, the hundreds of products made from petroleum would see price increases as refiner operating costs rise.

The W-M bill and its companion legislation in the Senate, the Boxer-Kerry climate bill, specifically exclude petroleum refiners from receiving free emission allowances set aside for trade-vulnerable industries. However, in the European Union's Emission Trading System (EU ETS), the world's only functioning GHG cap-and-trade system, the refining industry has been designated as a trade-vulnerable industry under the program's "carbon leak" criteria, and a review is under way to determine what amount of additional free allowances the industry will be allotted to cover its stationary emissions. Refiners operating under the EU ETS are not responsible for their products' emissions.

A complex tariff structure could be implemented to rebalance costs to reflect the cost of their carbon content in all products imported by the US, but implementing such a complex tariff raises many technical, legal, and trade risks. Also, some countries may even adhere to international agreements on carbon controls but do so in a manner that that does not alter costs of production at major industrial facilities. ✦

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The authors

Larry Goldstein is a Trustee of EPRINC and director of special projects and previously was president. He has extensive advisory relationships with energy companies, research institutes, and government agencies. He has testified before numerous congressional committees and regulatory bodies and has been appointed to the National Petroleum Council (NPC) by every secretary of energy. He was a founder and president of the PIRA Energy Group, an energy consulting firm that is currently retained by nearly 400 companies.

Ben Montalbano (benm@eprinc.org) is a senior research analyst at EPRINC. He is a recent graduate of the University of Colorado at Boulder, where he studied economics. Montalbano joined EPRINC in January 2008 and earlier provided research support to the foundation during his college years, covering world energy markets and oil and gas production developments. He speaks Russian, and in addition to his research efforts in the oil and gas market, he has worked in the information technology industry.

Lucian (Lou) Pugliaresi (loup@eprinc.org) has been president of EPRINC since February 2007 and managed the transfer of its forerunner, Petroleum Industry Research Foundation Inc. (PIRINC), from New York to Washington, DC. He served on the board of trustees of PIRINC before assuming the presidency. Since leaving government service in 1989, Pugliaresi worked as a consultant on a wide range of domestic and international petroleum issues. His government service included posts at the National Security Council at the White House; Departments of State, Energy, and the Interior; and the Environmental Protection Agency.

Pravin S. Sheth is a refinery and chemical engineering consultant to EPRINC and an independent consultant. Pravin has over 28 years of experience in the refining industry in the areas of operations, technology development, asset support, technical training, and technical service. He worked in the industry from 1980 through 2007, serving as lead asset support engineer responsible for providing technical support to ExxonMobil's worldwide FCC units and, before that, as complex operation supervisor with Gulf-Chevron at the Philadelphia refinery. Pravin has a master's degree in chemical engineering from the University of Missouri at Rolla.

NPRA outlines problems in EPA's proposed GHG rule

Nick Snow
Washington Editor

A proposed greenhouse-gas tailoring rule for large industrial facilities could cause more problems than it solves, a National Petrochemical & Refiners Association official told the US Environmental Protection Agency on Nov. 18.

NPRA Environmental Affairs Director David Friedman said in his prepared testimony that the organization and its members consider the proposal unnecessary and a violation of the federal Clean Air Act's statutory authority.

In the first of two public hearings on the proposal, Friedman said the proposal: is not a relief rule and does not account for all sources of greenhouse gases; does not adequate address costs and benefits; will not preclude states from issuing permits for smaller facilities; and would create regulatory uncertainty in other ways.

Under the proposed rule, refineries and other large industrial plants that emit at least 25,000 tons/year of greenhouse gases (GHGs) would be required to obtain construction and operating permits. EPA estimates that the program would cover nearly 70% of total US GHG emissions from stationary sources.

"NPRA believes there is a straightforward way to avoid the fundamentally flawed legal position that EPA puts forward in the tailoring rule while obtaining 95% of the [GHG] reduction benefits projected for the Section 302 light-duty vehicle rule," Friedman said.

The agency should delay its promulgation of the light-duty rule while the National Highway Traffic Safety Administration finalizes its portion early next year, he suggested. "This result would avoid reliance on EPA's erroneous conclusion that PSD [prevention of significant deterioration under the CAA's New Source Review] is automatically triggered for all sources upon the effective date of the Section 202 rule," he said.

'Troubling precedent'

Friedman noted that the CAA "stipulates unequivocally" that the threshold to issue permits for major stationary sources is 250,000 tons/year, and that EPA lacks legal authority to categorically exempt sources that exceed the law's major source threshold from permitting requirements. "Taking such action would create a troubling precedent for other agency actions in the future," he warned.

EPA's streamlining techniques outlined in the proposed tailoring rule also are not consistent with long-standing federal policies outlined in CAA's PSD and Title V programs, which would create regulatory uncertainty, according to Friedman. It also is not clear how regulating GHGs would be implemented in the context of other CAA requirements and air pollution regulatory

frameworks such as those required to meet the National Ambient Air Quality Standards, per-ton fees for permits, and state PSD program approvals, he said.

"Therefore, altogether, the proposal highlights the perils of forcing [GHG] regulations into the [CAA]. You shouldn't try to fit a square peg in a round hole," he maintained.

The proposal also is not a relief rule, Friedman indicated. With 300-400 PSD applications annually already under the CAA, the proposed tailoring rule's overall effect would be to increase PSD enforcement nearly 40-fold to more than 13,000 facilities without a proper assessment of costs and benefits of such a regulatory expansion, he said.

He cited EPA estimates that it costs $125,000 and takes 866 hr for a plant's owner or operator to complete a PSD permit application. "That means the cost to industry for the more than 13,000 facilities to file PSD permits will be more than $1.6 billion," Friedman said.

'Kicking the can'

"In addition, it is not as if smaller GHG sources will be exempted from these significant filing cost increases," he continued. "EPA makes clear in the proposed rulemaking that it intends to eventually phase smaller sources into the permitting process. Huge costs will reach smaller facilities, just a few years after our facilities pay these costs."

The proposed program does not save $54 billion, as its cost/benefit analysis calculates, but merely delays the $54 billion which the US economy would have to pay to comply with a PSD program, Friedman said. "We are simply kicking the can down the road and paying later," he observed.

The proposed tailoring rule also would create regulatory uncertainty since several states' GHG permitting thresholds are less than the EPA proposal's 250,000 tons/year, he said. Its preamble discussion also does not answer how EPA could achieve a transition for states with fully approved PSD and Title V permit programs, he added.

"The adjustments for the new applicability thresholds under the tailoring rule could be delayed as the states have to go through the notice and comment rulemaking in order to incorporate new federal requirements and policies into state programs and raise their permitting thresholds to match the federal program," Friedman said. "Instead of streamlining the permitting program, these factors will mean that the tailoring rule will provide only an additional level of uncertainty for facilities operating throughout the nation."

Timing also is an issue, he pointed out. The proposal, along with the tailpipe rule, the endangerment rule, and the GHG reporting rule, are among the most important and far-reach rules which EPA has addressed in the past few years, he said, adding that they also are complex and interrelated.

"Industry's efforts to extend comment periods on these rules have been uniformly rejected," Friedman said. "We strongly believe that it is more important that these rules be done right and not that they fit into an artificial deadline. These rules are too important to be rushed only to find flaws and unintended consequences. We are only seeking these short comment extensions in order to produce a useful and meaningful end product that benefits both industry and society as a whole." ✦

IPAMS chides Congresswoman for letter about fracing

Nick Snow
Washington Editor

The Independent Petroleum Association of Mountain States has asked US Rep. Diana DeGette (D-Colo.) to stop spreading misinformation in a letter to other members of Congress about hydraulic fracturing in an apparent effort to pass a bill she and Rep. Maurice Hinchey (D-NY) introduced on June 9.

"When we met with you in late September, you told us that your intent for the legislation was to produce a scientific study so that regulators have the data they need to ensure fracing remains a safe activity while still enabling development of American natural gas and oil," IPAMS Pres. George Solich told DeGette in a Nov. 12 letter that the association released on Nov. 16.

DeGette and Hinchey's bill, HR 2766, would move hydraulic fracturing regulatory enforcement from states to the federal government under the Safe Drinking Water Act (SDWA). "While we were puzzled that you would introduce a bill that would add an onerous and expensive layer of regulation onto a safe procedure, we took away the message that you were not going to actively advance your bill at this time," said Solich, who also is chief executive of Cordilera Energy Partners III LLC in Denver.

He said IPAMS was surprised to discover that DeGette sent a 'Dear Colleague' letter to other members of Congress on Nov. 4 seeking more cosponsors for her bill and citing a New York Times editorial, which Solich said was written "with a clear agenda but devoid of factual accuracy." His letter listed three statements based on the editorial in DeGette's letter that he said were inaccurate.

Citing a statement that fracing "has been implicated in a growing number of water pollution cases across the country" and that "the safety of the nation's water supply should not have to rely on luck or the public relations talents of the oil and gas industry," Solich said that the Colorado Department of Public Health and Environment and other states' regulators have issued statements about the lack of any drink-

ing water contamination cases connected with the technology.

60-year safety record

"The 60-year safety record of fracing has nothing to do with our public relations, but rather with our engineering talents. That record continues to this day," Solich maintained. "The incidents being blamed on fracing by environmental groups and a media mainly uninterested in trying to understand complex regulatory issues have not been attributed to fracing."

Solich said DeGette also erred in stating that the bill would bring fracing enforcement authority back to the US Environmental Protection Agency (which has never had it) and force producers and well service companies to disclose chemicals used in fracing fluids (which Colorado and five other states already require).

"Rather than impose the EPA and federal regulation over states' rights on the issue, Congress could step back and support efforts by the Interstate Oil & Gas Compact Commission and the Groundwater Protection Council, both bodies of state regulators, to encourage effective state regulation of fracing and natural gas and oil development," Solich suggested.

Finally, said Solich, DeGette disregards existing oil and gas industry regulations that are extensive and costly when she asks why producers and service companies should fear additional federal regulation if fracing is as safe as they say. IPAMS estimates that federally regulating fracing under the SDWA's underground injection program would add about $100,000 to the cost of drilling each well, he noted.

"We continue to be confused about the inaccurate information from your office on fracing, even though we and many other members of our industry have tried to explain the process," Solich told DeGette. "We feel that the rhetoric coming from groups with a clear agenda to stop responsible natural gas and oil development is affecting the legislation." ✦

Salazar: Businesses, entrepreneurs critical to energy future

Nick Snow
Washington Editor

Businesses and entrepreneurs will need to play a critical part if the US is to create a cleaner energy economy, US Interior Sec. Ken Salazar told a North Dakota audience.

He said the Department of the Interior can develop rules for clean energy development on public lands; identify appropriate sites for conventional and renewable energy production; and enforce rules, make decisions based on sound science and the public interest, and follow the law and high ethics standards.

"The rest, though, is up to you and

Shorter lease terms proposed for central gulf sale

Nick Snow
Washington Editor

The US Minerals Management Service's next Central Gulf of Mexico lease sale on Mar. 17, 2010, will include a shorter initial lease term for blocks in 400-1,600 m of water, US Interior Secretary Ken Salazar said on Nov. 13.

Tracts lying in 400-800 m of water will change from an 8-year term to a 5-year initial term, which would extend to 8 years once drilling of an exploratory well begins, Salazar said. Blocks in 800-1,600 m of water will change from a 10-year to a 7-year initial lease term, which would extend to 10 years once an exploratory well is drilled, he continued.

"This new approach to lease terms will better ensure that taxpayer resources are being developed in a timely manner," Salazar said. Several Democrats in Congress have pushed for diligent development requirements in federal oil and gas leases, commonly called "use-it-or-lose-it" provisions.

American Petroleum Institute Pres. Jack N. Gerard immediately criticized the move, calling it "one more impediment to the development of the oil and natural gas industry necessary for the American economy to prosper."

Gerard said API wrote to Salazar on Nov. 10 to remind him that the administration of President Barack Obama has set up a series of roadblocks to discourage the investment necessary to increase domestic energy supplies, create well-paying US jobs, and provide additional government revenues at a time when they are desperately needed.

"The shortening of lease terms does nothing to guarantee more discoveries but rather takes away from companies the flexibility necessary to operate in an extremely challenging and risky environment," Gerard said.

Salazar said the lease sale would offer nearly 36 million acres that potentially could produce up to 1.3 billion bbl of crude oil and 5.4 tcf of gas off Louisiana, Mississippi, and Alabama. The acreage is in water 3-230 miles offshore in 10-11,200 ft of water. It includes acreage in the 181 South area, he added.

Terms and conditions for the lease sale are contained in the proposed notice of sale information at the MMS's web site at www.gomr.mms.gov/homepg/lsesale/213/cgom213.htm.

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Cantwell's basic question

US Sen. Maria E. Cantwell (D-Wash.) probably recognized that the bill she introduced on Nov. 10 with Ronald L. Wyden (D-Ore.) and Bernard Sanders (I-Vt.) has little chance of being considered. Congress appears unlikely to let state regulators and attorneys general consider regulating over-the-counter financial derivatives trading as a form of gambling.

Cantwell wanted to make a point. "The derivatives market has done so much damage to our economy and is nothing more than a very high-stakes casino—except that casinos have to abide by regulations," she said.

"Even in Las Vegas at the blackjack tables, both the house and the player have to have capital behind their bets," she said, adding, "But we allow Wall Street to continue to operate in the dark and without capital to back up bets on derivatives. We remain at risk of further harm until we have the tools to stop abusive speculative practices."

Congress exempted derivatives traders from state gambling regulations when it passed the Commodity Futures Modernization Act in 2000. Cantwell's proposal would reveal this provision.

Much bigger now

The derivatives market has grown from $80 trillion, when CFMA went into effect, to more than $600 trillion now, Cantwell said. The lack of any regulations at the federal level meant that the 2000 law made it open season for rampant derivatives speculation that culminated in the economic collapse of 2008, she said.

Cantwell noted that Senate Banking Committee Chairman Christopher J. Dodd (D-Conn.) mentioned OTC derivatives when he unveiled his sweeping federal financial regulatory reform proposal the same day.

"Our ultimate goal is a strong, uniform set of federal regulations," she said, adding, "Congress must take a strong stand to prevent the kinds of abuses that have cost American workers and taxpayers so much."

Basic question

Cantwell's demand for tighter derivative regulations has grown more urgent as Congress considers instituting a carbon cap-and-trade program as part of global climate-change legislation. "The fact that the derivative market still has loopholes means we shouldn't start a carbon market too quickly," she said at a Nov. 10 Senate Finance Committee hearing on House and Senate climate-change bills.

Cap-and-trade proponents argue that the US Commodity Futures Trading Commission successfully regulated sulfur dioxide as a commodity under its acid rain program in the 1990s. Witnesses at the Finance Committee hearing said that cap-and-trade would be much bigger and not as focused.

"We're talking about a huge amount of the energy economy which would be put into these securities," said Kenneth P. Green, a resident scholar at the American Enterprise Institute for Public Policy Research.

Cantwell keeps raising an apparently basic question about cap-and-trade and probably will keep asking it until she gets satisfactory answers. ✦

the people who work for you," Salazar said at the 2009 Great Plains Energy Expo and Showcase in Bismarck.

He said DOI is committed to helping the nation build a comprehensive energy strategy that includes development of oil, gas, and coal resources "in the right way, and in the right places."

Some critics, he said, "want you to believe the Obama administration is 'anti-this' or 'anti-that.' The truth is we are developing on all fronts—but responsibly."

2009 lease sales

Salazar noted that the Bureau of Land Management has held 29 onshore oil and gas lease sales so far in 2009 while the Minerals Management Service has held two offshore lease auctions. "Together, these sales offered more than 55 million acres for oil and gas development and generated more than $931 million in revenues," he said.

He said the US will rely on coal for decades and urged US companies to export to countries like China and India technologies that promote carbon capture and sequestration (CCS). DOI "wants to be a full partner in this job-creating effort and will look to scale up [CCS] on the public lands that we manage with large-scale demonstration projects."

He said the US Geological Survey next year will begin a national assessment of carbon dioxide storage capacity in oil and gas reservoirs and saline formations.

The need to diversify US energy beyond traditional sources has required DOI to change the way it does business, the secretary said. "Not only are we proceeding with oil, gas, and coal but also, for the first time ever, we are allowing environmentally responsible energy projects on public lands that can help power President Obama's vision for our clean energy future," he said.

DOI is creating the first framework for offshore renewable energy development; working with the Federal Energy Regulatory Commission to cut red tape that created confusion for such projects; and awarding the first exploratory

leases for wind energy off New Jersey and Delaware, Salazar said.

The department also is creating renewable energy coordination offices in western states to help swiftly complete reviews for solar, wind, geothermal, and biomass projects on public land, he said. It has set aside 1,000 sq miles of public land in 24 "Solar Energy Study Areas," which are being evaluated for possible development. And it has invested $41 million through the administration's economic recovery plan to facilitate a rapid and responsible move to large-scale energy production from renewable resources on public lands.

"We believe that of the solar and wind projects currently proposed, more than 5,300 Mw of new capacity could be ready for construction by the end of 2010," Salazar said. ✦

Bingaman joins Barrasso in CCS bill to offer R&D prize

Nick Snow
Washington Editor

Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) has joined US Sen. John A. Barrasso (R-Wyo.) in proposing a government prize to encourage scientific research and development of carbon capture and storage technology.

The two federal lawmakers introduced S. 2774, the Carbon Dioxide Capture Technology Act, on Nov. 12 to establish a CCS awards system for scientists and researchers.

Historically, prizes have been used to encourage all types of technological development, said Barrasso, who introduced a similar bill in 2008. Charles A. Lindberg was competing for the Orteig Prize when he flew the Spirit of St. Louis nonstop from New York to Paris in 1927, he noted.

"The bill taps into American ingenuity and innovation," Barrasso explained. "It recognizes the need to develop the technological solutions needed to address climate change. It makes sense that we explore alternative approaches for removing and permanently sequestering excess carbon dioxide. With financial awards, we can encourage the extraordinary breakthroughs needed to tackle this problem."

Bingaman added, "If we could capture carbon dioxide emitted by low-concentration sources, or even the atmosphere, it would be a major step toward a cleaner energy future." Bingaman—who is cosponsoring the legislation for the first time—concluded: "A federal prize to inspire inventive solutions to this technical challenge could help us get there quicker."

Under the bill, Barrasso said, a program would be established under a federal commission within the US Department of Energy. Climate scientists, physicists, chemists, engineers, business managers, and economists would serve on the commission as presidential appointees.

Awards would go to public and private entities which design technology to remove and permanent sequester CO_2 directly from the atmosphere, Barrasso said.

The US would share the intellectual property rights with the inventor once the technology was developed, he noted. ✦

OPEC: World oil demand to rise slightly in 2010

Eric Watkins
Oil Diplomacy Editor

The Organization of Petroleum Exporting Countries reported that the world's economic recovery will drive global oil demand to 85.07 million b/d in 2010, an increase of 0.9%.

In its latest monthly report, OPEC forecast that the world economy will grow 2.9% in 2010 after a contraction of 1.1% this year, with the majority of growth coming from emerging Asian economies including China and India.

OPEC forecasts that oil demand next year would grow 3.7% in China and 3.34% in the Middle East, while falling 1.25% in Western Europe. Meanwhile, it said world oil demand in 2009 was expected to drop 1.63% year-on-year to 84.31 million b/d.

In its report, OPEC also said world oil demand was unlikely to return to precrisis levels in the near future, warning that sustained increase in oil prices could erode crude demand amid a shaky global economic recovery.

Key points of the OPEC report include:

- OPEC's reference basket surged $5.50/bbl, or 8%, in October to reach $72.67/bbl. The bullish sentiment in the market was strengthened by upward adjustments to world oil demand following revision to GDP numbers by the IMF. US dollar depreciation and rising equity prices also contributed to the upward price trend along with counterseasonal draws in US gasoline inventories. The basket stood at $76.50/bbl on Nov. 10. Recent market volatility suggests that crude prices are likely to remain in the high $70s in the near future with price direction continuing to be impacted by economic data and US dollar fluctuations.
- The world economy continues its recovery and is now forecast to grow

by 2.9% in 2010 after a contraction of 1.1% in 2009. Most of the growth is expected to come from the emerging Asian economies. China is forecast to grow by 8% and 8.5% in 2009 and 2010 respectively, unchanged from last month. Fueled by the unprecedented fiscal and monetary stimulus, OECD output is expected to show positive growth in the third quarter. Still, it remains to be seen when private consumption expenditures will pick up sufficiently as government support fades. All major OECD regions are projected to return to growth in 2010 with the US forecast to grow at 1.4%, the Eurozone at 0.5% and Japan at 1.1%.

• Most of the signs are aiming toward higher world oil demand growth in 2010; however, downward risk factors highlight the need for caution. World oil demand is forecast to grow by 0.8 million b/d in 2010 following a 1.4 million b/d contraction in 2009, although the potential weak economic recovery may dampen potential demand growth in the coming year. US oil demand remains the major factor driving 2009 demand growth. Despite the improved performance in late summer, recent data indicates a contraction in demand in October.

• Non-OPEC supply is forecast to increase by 360,000 b/d in 2010 to reach 51.2 million b/d. Brazil, Azerbaijan, Kazakhstan, Canada, and the US are seen to be the main contributors to next year's growth, while Mexico, UK, and Norway are foreseen to experience the largest declines. OPEC natural gas liquids and unconventional oil are projected to reach 5.3 million b/d in 2010, indicating a significant growth of 540,000 b/d over the current year. In 2009, non-OPEC supply is estimated to increase by 410,000 b/d, representing a minor upward revision from the previous assessment. In October, OPEC crude production averaged 28.99 million b/d, around 40,000 b/d higher than the previous month.

• Product market sentiment improved slightly in October due to product stock draws in the US, increasing freight movements, and relatively higher demand from industrial sectors. However, rising crude costs have overwhelmed positive developments in product prices and exerted pressure on refining margins, especially in the Atlantic Basin. While a cold winter may provide support for product markets and encourage refiners to increase runs in the coming months, excessive levels of distillate stocks could further constrain refinery operations, impacting crude stock movements.

• US commercial oil stocks dropped by 19.4 million bbl in October to stand at 1,089 million bbl, the largest draw since December 2007. Gasoline and distillate inventories accounted for almost half of the draw. Despite this draw, the overhang with the 5-year average remains considerable at around 70 million bbl. Crude oil inventories dropped 1.7 million bbl, narrowing the overhang to 22 million bbl. Although distillates fell 4.3 million bbl, the overhang remains large. In September, Japan total commercial oil stocks moved against the seasonal trend, falling 11 million bbl with preliminary data indicating a further decline of 9 million bbl in October.

• Demand for OPEC crude in 2009 was revised up 70,000 b/d to now stand at 28.7 million b/d, representing a decline of 2.3 million b/d from last year. In 2010, demand for OPEC crude is expected to average 28.5 million b/d, following an upward adjustment of 110,000 b/d. This indicates a drop of 0.2 million b/d compared to the previous year. ✦

GOP members ask DOI to improve categorical exclusions

Nick Snow
Washington Editor

Four US House Republicans urged US Interior Secretary Ken Salazar to improve, instead of jettison, categorical exclusions in response to a recent Government Accountability Office report.

"We are deeply concerned about a common practice of the Departments of the Interior and Justice of settling lawsuits filed without forcefully defending authorized agency actions," said Doc Hastings (Wash.), ranking minority member of the House Natural Resources Committee, and three other GOP members of the committee in a Nov. 5 letter to Salazar.

"Specifically, a current lawsuit is challenging the use of categorical exclusions, a valuable tool provided by Congress to the land management agencies to improve the government process of approving energy production while at the same time ensuring protection of the environment," they said, adding, "We are worried that an out-of-court settlement by this department would eliminate or severely limit the use of categorical exclusions and further prohibit the production of US oil and natural gas."

Doug Lamborn (Colo.), ranking minority member of the committee's Energy and Minerals Subcommittee; Rob Bishop (Utah), ranking minority member of the committee's National Parks Subcommitte; and Cynthia M. Lummus (Wyo.), a committee member, also signed the letter.

They noted that under Section 390 of the Energy Policy Act of 2005, Congress directed the US Bureau of Land Management to use categorical exclusions to expedite energy supply growth by limiting redundant analysis and unnecessary red tape.

'Scalpel, not sledgehammer'

"While we support the department's efforts to develop new guidance to address the few issues of consistency

identified by GAO in the use of these categorical exclusions, we are concerned that the [US] Department of the Interior is prepared to use a sledgehammer where a scalpel would suffice," the four Republican lawmakers said.

They noted that in its report, GAO recommended that errors it identified be cleared up with resided guidance implementation guidelines and better oversight from state BLM offices.

"The report found many examples where BLM failed to use categorical exclusions or applied additional restrictions, highlighting the cautious and overly conservative use of categorical exclusions by BLM," they continued. "Categorical exclusions are not discretionary, yet GAO didn't attempt to quantify the one major use of BLM's implementation of Section 390: the frequent violation of the law when categorical exclusions were not used for projects that met the criteria mandated by Congress."

DOI should not need to be reminded that the Section 390 categorical exclusions are statutory, not administrative, the four House Republicans said in their letter. "There is nothing in the statutory language that even mentions extraordinary circumstances; rather, the language is straightforward in mandating the use of categorical exclusions when the conditions in the statute are met," they indicated. The law does not give the Obama administration or DOI discretion to decide which provisions will be followed, they added.

They also noted that it is important to recognize that categorical exclusions are one of EPACT's biggest success stories. "[Their] use in energy permitting has been accompanied by more time available for field staff to conduct environmental inspections and to address the backlog of [drilling permit applications]," the federal lawmakers said. "Field personnel recognize and appreciate having categorical exclusions in their management toolkit as it allows them to efficiently process permits in a timely manner while making educated, common sense field decisions." ✦

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Brunei assures Japan

Japan's oil and gas industry got a bit of assurance from Brunei after learning it will receive stable long-term supplies of LNG from the sultanate.

The reassurance came after some considerable effort by the Japanese government, including Prime Minister Yukio Hatoyama who made a personal request of his counterpart from Brunei, Sultan Hassanal Bolkiah.

"I seek your cooperation in the supply of LNG and the development of our friendly bilateral ties," Hatoyama told Bolkiah on the sidelines of a recent Asia-Pacific summit.

Bolkiah replied, "We've had a good relationship in the past two decades on the supply of LNG, and there will be no problems with supply in the future."

It was the second time in as many weeks that Japanese officials pressed a member of the Bolkiah family for reassurances of Brunei's willingness to keep up the supplies of LNG.

Repeating requests

On Nov. 5, Japan's Foreign Minister Katsuya Okada met with Prince Mohamed Bolkiah, Brunei's Minister of Foreign Affairs and Trade, then in Japan on affairs of state.

"To Japan, Brunei is an important provider of LNG," said Okada, who also noted the importance of stable LNG provision, based on a long-term relationship of mutual trust between the two countries.

In response, Bolkiah said, "The relationship between Japan and Brunei in the energy field is a favorable one, and we hope to build a relationship that is beneficial for both countries."

The importance of these reassurances cannot be overstated, especially since Japan has virtually no energy resources of its own and must rely heavily on imports to meet its oil and gas needs.

As for LNG, Japan imports 60 million tonnes/year from countries led by Indonesia, Malaysia, and Australia. Due to recent problems, it has had with Indonesia, however, Japan has redoubled it efforts to diversify its sources of energy.

JBIC threatens

Underscoring those difficulties, Japan Bank for International Cooperation earlier this month threatened to withdraw its commitment to finance the construction of an LNG plant in Central Sulawesi if Jakarta insists that the LNG produced there is for domestic consumption only.

A consortium of Pertamina, Medco Energi Internasional, and Mitsubishi established PT Donggi Senoro LNG to build the $1.6 billion LNG plant, which will use gas from fields owned by Pertamina and Medco.

Mitsubishi joined the consortium with a majority share of 51%, and JBIC later agreed to finance the project hoping that the gas could be exported to Japan—a hope that has been dashed repeatedly by Indonesian government officials.

Indeed, the project's viability fell into a state of complete uncertainty in June when Indonesia's Vice-President Jusuf Kalla said that gas from the Senoro and Matindok fields intended to supply the Donggi LNG plant had to be sold domestically and not abroad.

Clearly, Brunei's reassurances are timely. ✦

COMPANY NEWS

Devon to divest noncore assets; focus on N. America

Devon Energy Corp., Oklahoma City, plans to divest its Gulf of Mexico and international assets in a move toward focusing on high-growth US and Canadian onshore assets, the company reported Nov. 16.

The strategy, according to Devon Chairman and Chief Executive Officer J. Larry Nichols, will enable the company "to emerge with an even stronger balance sheet and one of the lowest overall cost structures" among its peers.

In other recent company news:

• Cameron International Corp. will be required to divest assets used in the production and sale of oil refining desalters before it proceeds with its $980 million acquisition of Natco Group Inc., the US Department of Justice said on Nov. 17.

• Qatar Petroleum International signed a series of agreements to acquire two Singapore chemical joint ventures from Royal Dutch Shell PLC. The agreements were signed with Shell Eastern Petroleum Pte. Ltd. Terms of the transactions were not discussed.

• Perenco strengthened its position in Gabon with the acquisition of Marathon Oil Corp.'s wholly owned subsidiary Marathon Oil Gabon Ltd., which holds a 56.25% working interest in three offshore production fields. The effective date of the transaction is Jan. 1 with completion anticipated during the fourth quarter.

• Occidental Petroleum Corp., Mubadala Development Co., and the National Oil & Gas Authority of Bahrain (NOGA) have formed a joint operating company to further develop Bahrain field.

• Indonesia's state-owned PT Pertamina, aiming for an 11% boost in oil production, expects to increase capital expenditure to $4.15 billion in 2010—a 77% increase over spending in 2009, according to a company official.

Devon's divestiture plan

Devon expects to open data rooms and start the divestiture process in first-quarter 2010. It expects to complete the process by yearend 2010.

The divestitures are expected to generate aftertax proceeds of $4.5-7.5 billion. The company expects the repositioning to be highly accretive to earnings, cash flow, production, and reserves beginning in 2011.

Devon has 3,500 wells in the Barnett shale gas play, and it also has acreage in the Haynesville shale. Internationally, the company has assets in Azerbaijan, Brazil, China, and Russia.

Based on estimated yearend 2009

PERSONNEL MOVES AND PROMOTIONS

Ivanhoe Energy Canada appoints president, CEO

Ivanhoe Energy Inc., Calgary, has appointed **David Dyck** as president and chief executive officer of its Canadian subsidiary, Ivanhoe Energy Canada Inc.

Dyck will lead the company in the development of the Tamarack heavy-oil project in Alberta's Athabasca oil sands, including the application of Ivanhoe's proprietary heavy-to-light heavy-oil upgrading technology.

The Tamarack team is on schedule to complete front-end engineering and design for the 20,000-b/d Tamarack project by yearend, the company said.

As executive director and chief executive officer of LeaRidge Capital since 2007, Dyck provided financial advisory services to a number of North American companies in the energy and service sectors.

During 2000-07, Dyck was senior vice-president, finance, and chief financial officer with Western Oil Sands, Calgary. He was a member of the company's senior executive team and a director of four offshore subsidiaries.

Other moves

Noble Energy Inc. reported that **Kenneth M. Fisher** joined the company as senior vice-president and chief financial officer.

Fisher has more than 25 years of experience with financial and operating organizations that have been involved with complex energy and capital-intensive businesses. Most recently, Fisher served as executive vice-president of finance for upstream Americas at Royal Dutch Shell PLC.

Prior to his most recent position with Shell, Fisher served as director of strategy and business development for Shell in The Hague, executive vice-president of strategy and portfolio for their global downstream business in London, and as chief financial officer for Shell Oil Products US.

Before joining Shell, Fisher held positions of increasing responsibility with General Electric Co., including vice-President and chief financial officer of the Aircraft Engines Services division and a Singapore-based position as director of finance and business development of GE's Asia Pacific plastics business.

Fisher succeeds **Chris Tong**, who retired.

Dominion has appointed **Andrew Cochran** as chief executive officer.

proved reserves, Devon's Gulf of Mexico and international properties comprise 7% of Devon's proved reserves of 2.8 billion boe.

If the anticipated sale had occurred in 2009, Devon's estimated yearend 2009 proved reserves would have been 2.6 billion boe.

Oil and natural gas liquids account for 43% of companywide estimated proved reserves at yearend 2009. Pro forma for the divestiture of the Gulf of Mexico and international assets, oil and NGL will account for 41% of the total.

Regarding international assets, Devon primarily is involved off Brazil and off China.

Devon currently is developing the Polvo project in the Campos basin in 300 ft of water on Brazil's Block BM-C-8. Production started in 2007. Devon holds interest in 10 blocks off Brazil covering 1.4 million acres.

The company has joined exploration efforts with Petroleo Brasileiro SA (Petrobras) on five of these blocks.

Off China, Devon's oil production is from the Panyu development in the Pearl River Mouth basin in the South China Sea on Block 15/34.

In addition to Panyu, Devon holds 100% interest in four exploration blocks off China. In aggregate, Devon's Chinese acreage covers 7.9 million net acres.

Cameron-Natco deal

DOJ's antitrust division said the Cameron-Natco deal as originally proposed would substantially reduce US refinery desalter manufacturing competition, resulting in higher prices and lower quality, service, and innovation. Cameron and Natco are, respectively, the No. 1 and No. 2 US refinery desalter suppliers, it said.

The divestiture also would remedy harm caused by Cameron's 2005 acquisition of certain assets from Howe Baker Engineers Ltd., DOJ said in a civil action it filed in US District Court for the District of Columbia. DOJ said it also filed a proposed settlement which, if approved by the court, would resolve the lawsuit's competitive concerns.

Cameron and Natco, a recent entrant into the desalter market, are each other's closest competitors for a significant set of US refining customers, DOJ said.

According to the complaint, Cameron's $8.25 million purchase of the Howe Baker assets in 2005 reduced from two to one the number of US sellers of refinery desalters. Under the proposed settlement, Cameron would divest the desalter and dehydrator assets from that purchase (the EDGE business) and all related tangible and intangible assets.

It also would divest a nonexclusive license to certain Natco technology related to refinery desalters, which uses dual technology transformers. This dual technology license may be used worldwide for the development, production, sale, and service of refinery desalters using this technology, DOJ said.

QPI's Singapore ventures

Completion of the transactions are expected in December in what QPI calls its first downstream acquisition abroad.

Shell will sell its existing shareholdings in two companies to a new joint

Cochran will work with the existing management team to strengthen the company's financial position following the investment by BlueGold Global Fund LP, which was completed in September.

Cochran most recently served as business development director at Salamander Energy PLC and was a founder of the company. He previously was new ventures manager at Endeavour International Corp. and before that was exploration advisor at Anadarko Petroleum Corp.

The Center for Strategic and International Studies (CSIS) Energy and National Security Program announced the creation of a new senior energy advisory council comprised of former high government officials and industry representatives.

James Schlesinger, former Secretary of Energy, Defense, and former director of the Central Intelligence Agency, will be the chairman. The council will guide the CSIS Energy and National Security Program's research priorities and program planning.

Other council members include **Samuel Bodman**, former Secretary of Energy, **Abdallah Jum'ah**, former Saudi Aramco chief executive officer, **Luis Giusti**, former chairman and chief executive officer of Petroleos de Venezuela SA and current CSIS senior advisor; and **Peter Robertson**, former vice-chairman of Chevron Corp.

Range Resources Corp. has appointed **Joseph H. Frantz** as vice-president of engineering for the Marcellus shale division in Pittsburgh.

Frantz brings more than 26 years of petroleum engineering experience with Texaco Inc., SA Holditch & Associates, and Schlumberger. He led Schlumberger's shale evaluation team for various emerging shale formations, including the Barnett, Fayetteville, and Marcellus.

Frantz has extensive experience working in the Appalachian basin, and he has performed studies on topics ranging from reservoir simulations to hydraulic fracture optimization.

Colombia's Ecopetrol SA has appointed **Hector Manosalva Rojas** as vice-president, production, and **Alvaro Castaneda Caro** as vice-president, transportation.

Rojas joined Ecopetrol in 1986 and has held a number of positions, including head of the division of planning, production manager in Putumayo, and director of corporate social responsibility. He most recently served as production manager of the central region for the office of the vice-president of production.

Caro has been working with the office of the vice-president of transportation for the past 20 years.

venture called QPI and Shell Petrochemicals (Singapore) Pte. Ltd.

Through the new venture, QPI and Shell will hold 50% of Petrochemical Corp. of Singapore Pte. Ltd. (PCS) and 30% of The Polyolefin Co. (Singapore) Pte. Ltd. (TPC).

The other shareholders in PCS and TPC are Japanese consortiums led by Sumitomo Chemical Co. Ltd.

PCS owns and operates two naphtha steam crackers totaling 1.9 million tonnes/year of olefins production capacity and is an anchor olefins supplier for the Singapore Petrochemical Complex on Jurong Island.

TPC owns and operates 260,000 tpy of low-density polyethylene capacity in three plants and 600,000 tpy of polypropylene capacity in five plants. These plants receive feedstock from PCS.

The latest joint venture agreement is part of a wider strategic cooperation. QPI and Shell, together with PetroChina, are progressing with joint preliminary studies to assess the viability of building a refinery and petrochemical complex in China.

Shell continues to develop with QPI proposals for a petrochemicals complex in Qatar.

Perenco's Gabon position

Perenco's acquisition of Marathon's stakes in the Tchatamba Marin, Tchatamba South, and Tchatamba West fields will add about 15,000 bo/d gross production to the company's current 50,000 bo/d operated production in Gabon.

Perenco will now be the operator at these fields, from where production is processed on a single facility at Tchatamba Marin, with processed oil being transported through a pipeline to a nonoperated onshore facility.

Tchatamba Marin field, which lies 15 miles offshore and 100 miles southeast of Port Gentil, was discovered in 1995 and began production in early 1998. Tchatamba South and West fields were discovered in 1997 and came on stream in 1999 and 2000, respectively.

Bahrain field JV formed

The joint entity, Tatweer Petroleum-Bahrain Field Development Co., will serve as the operator for the field and will operate under the development and production-sharing agreement (DPSA) signed in April by all three partners.

Tatweer Petroleum, which will begin production and development activities immediately, will be comprised of workers from Bahrain Petroleum Co. (Bapco) as well as from Oxy and Mubadala. The venture also plans to hire additional local employees.

Ray R. Irani, Oxy chairman and chief executive officer, said, "Tatweer Petroleum further expands our presence in the region and is a key element of our growth strategy for the Middle East."

Mubadala Chief Executive Officer and Managing Director Khaldoon Khalifa Al Mubarak said, "This investment is aligned with [Mubadala's] ambition to include enhanced oil recovery projects as one of the key pillars of its investment strategy in the [Middle East and North Africa] region."

Abdul Hussain Bin Ali Mirza, minister of oil and gas affairs and NOGA chairman, noted, "The [DPSA] with Oxy and Mubadala represents a paradigm shift for the oil industry in Bahrain. The revitalization of one of the longest producing oil fields in the world is the cornerstone for fueling the economic diversification plans set by the political leadership in Bahrain and will bring added prosperity and opportunity to the whole nation."

Pertamina spending up

Pertamina Financial Director Frederick Siahaan said of the company's planned spending increase, "The increase in capital expenditures was made to meet the increasing number of new projects and preparations to build a number of refineries."

He said, "This is our prediction, but we still need approval from the shareholder meeting." Frederick noted that as much as $2.5 billion would be secured from loans, including $1 billion in dollar-denominated bonds and 1 trillion rupiah in rupiah-denominated bonds.

"We can only issue the bonds after the financial audit for 2009 is finished. Thus, this will perhaps be in March or April next year," said Frederick, who added that Pertamina plans to use two thirds of the planned expenditure for upstream activities.

Frederick also said Pertamina will also use $17-19 billion of the planned outlays to upgrade existing refineries at Plaju, Cilacap, Balikpapan, Dumai, and Balongan and to construct three new refineries in Cilacap, Banten Bay, and East Java.

According to Karen Agustiawan, Pertamina president director, the state firm expects to increase oil production to 193,900 b/d in 2010, up 10.93% over the projected 174,000 b/d for 2009. Karen said the Cepu block is expected to contribute significantly to next year's targeted oil production increase.

"We expect that the Cepu block will start its early production of 20,000 b/d by the beginning of 2010. Of this production, Pertamina expects to get 9,000 b/d," Karen said.

The announcements of increased spending coincided with other reports that Pertamina is looking to acquire a 25% participating interest in the Mahakam block before the expiry of Total E&P Indonesie's contract in 2017.

Karen said Pertamina already had submitted a request letter to the government to control a 25% participating interest in Mahakam block, East Kalimantan, but that the eventual target is 100% control.

"In 2027, we hope to control 100% participating interest and become the operator of Mahakam block. We have announced this to the government on Nov. 4," Karen said.

Karen said Pertamina also wants 100% control in the West Madura block, where the contract will expire in 2011. If 100% control is not possible, Karen said, "We hope to at least seize a 60% interest." ✦

Oil, gas supply trends point to tight spots, higher prices

Rafael Sandrea
IPC Petroleum Consultants Inc.
Broken Arrow, Okla.

At the beginning of the millennium oil prices were $27/bbl and essentially remained at this level through 2003. But soon afterwards they began a steep climb, reaching $99 in November 2007 and a record high of $145 in July 2008.

This finally created awareness among analysts that the world was struggling to sustain oil production and that it may not be possible to increase supply beyond a certain level. Indeed, crude oil output remained flat at around 71 million b/d from 2004 through 2008, and during this period the growing demand for petroleum liquids was satisfied mainly with additional natural gas liquids.

Global crude oil production has increased continuously from the 1900s until 1980, when demand dropped significantly during the last major world recession. Production hit a low of 53 million b/d in 1985, a huge 10 million b/d plunge from a high of 63 million b/d in 1979. It took 25 years for demand to return to its previous trend (Fig. 1, purple/square dots).

Astoundingly, over the last 30 years world crude oil production has increased just 8 million b/d in spite of the growth of offshore production—from 9 million b/d in 1980 to 25 million b/d in 2008—and the existence of a shut-in spare capacity of 10 million b/d from the 1980 recession—a total of 26 million b/d of available output. Onshore production in the mean time has remained flat, around 46 million b/d over the last 2 decades (Fig. 2).

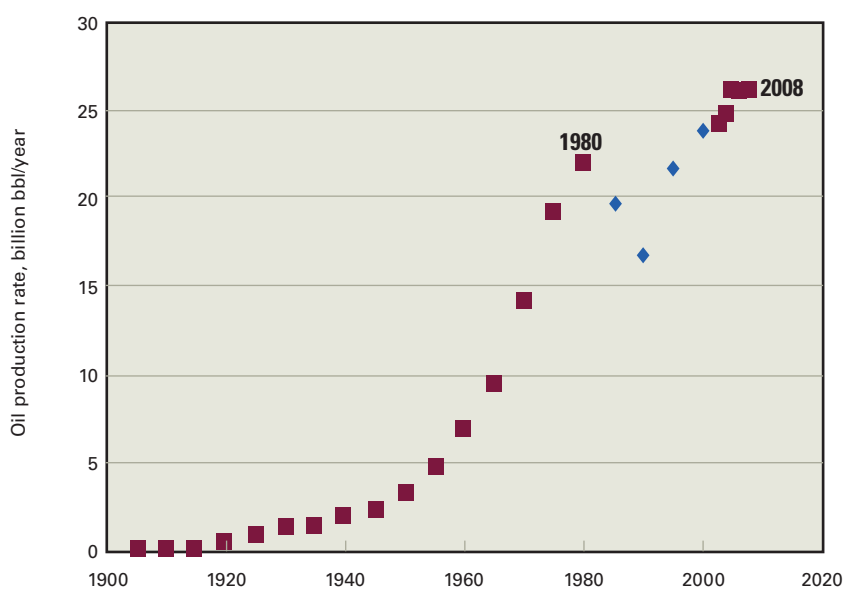
This disproportionately diminished net production increase of 8 million b/d over a 30-year period results from the perverse synergy that occurs between reserves depletion and production decline.

Global exploration and production trends for crude oil over the last 8 decades are disturbing (Table 1). Discoveries of new reserves grew from an average of 19 billion bbl/year in the 1930s to a peak of 55 billion bbl/year in the 1960s. Thereafter they have declined continuously, reaching 15 billion bbl/year in the 1990s and 10 billion bbl/year in this millennium.

New reserves markedly exceeded oil production (depletion of reserves) up through the 1970s. At the zenith of

GLOBAL CRUDE OIL PRODUCTION SINCE 1900

Fig. 1



GLOBAL OIL E&P TRENDS

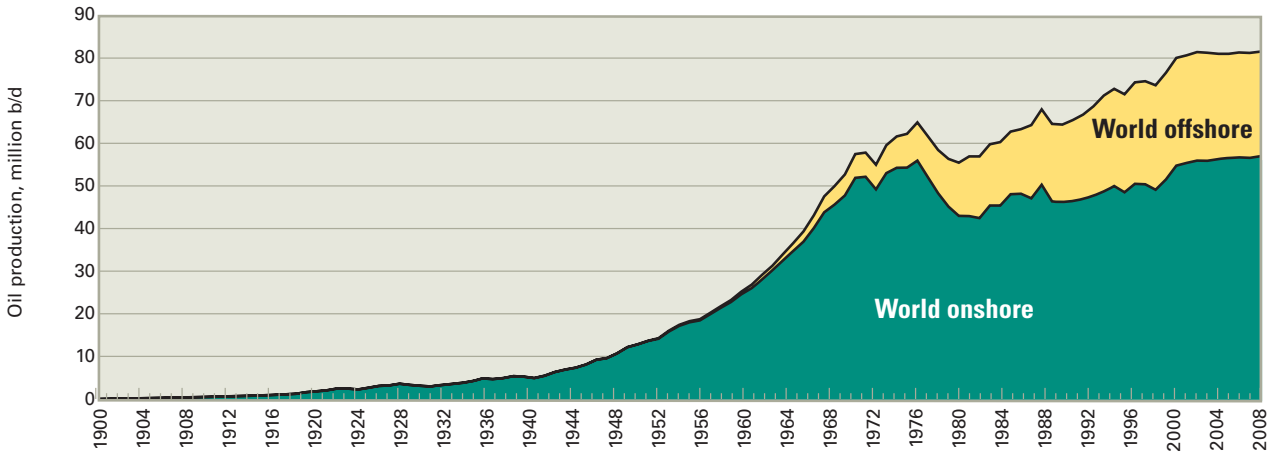
Table 1

	Discoveries	Production
	Billion bbl/year	
1930s	19	1.6
1940s	26	2.7
1950s	35	5.4
1960s	55	11
1970s	39	20
1980s	21	21
1990s	15	23
2000s	10	26

Sources: IHS; EIA

GLOBAL LAND-OFFSHORE OIL PRODUCTION

Fig. 2



exploration successes in the 1960s they were five times production, but from the 1980s to the present, the reserves/production relationship has become inverted—today's production rate is three times that of discoveries, 26 versus 10 billion bbl/year.

Reserves are the foundation of production potential. If the reserves base is being depleted, production capacity inevitably declines, and this clearly has been the situation since the 1980s.

These shortcomings of discoveries are not due to a lack of spending as some have suggested. Global E&P capex has increased fourfold in this millennium, to over $450 billion in 2008.

Crude oil supply

The logistic model has proved to aptly handle the upstream fundamentals of reserves growth/depletion and production growth/decline of oil and gas fields and their clusters as in the case of country analyses.

Fig. 3 shows the global outlook for crude oil production capacity through the end of the century using this model. Superimposed on the graph are the demand projections of the US Energy Information Administration through 2030. Supply and demand projections begin to decouple early on.

Table 2, based on EIA's forecasts, gives a breakdown of the different supply sources that make up the total petroleum liquids output. Crude oil is the most important source and accounts for 83% of the total.

The crude oil production potential of the reserves as estimated by the logistic model is also shown in the table. The crude oil outlooks of the IEA outpace production capacity in 2015 and 2030, with shortfalls of 1.7 million b/d and 12.7 million b/d, respectively.

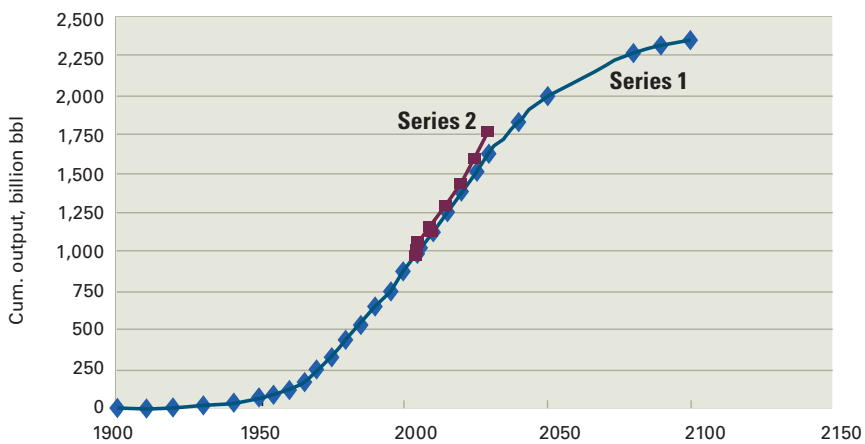
More outstandingly, however, the IEA's outlook shows continued growth in crude oil production while the logistic model indicates decline. It is also worth noting the importance of NGLs in the supply mix. NGL production would have to double by 2030, to 20 million b/d.

The IEA also provides a breakdown of expected oil outputs for the world's seven oil producing regions (Table 3). Production in four of the regions (North America, Europe, Asia-Pacific, and Latin America) is on the decline, leaving three regions (Middle East, Eurasia, and Africa) to provide the necessary volumes to meet demand by 2030.

With the Middle East region having the highest expectations, it would have to increase its current output by 67%. Africa and Eurasia would have to increase their present production by 27% and 25%, respectively. These assumptions of output growth are conditioned

GLOBAL CRUDE OIL OUTLOOK

Fig. 3



to timeliness and commitments to large capital investments, exploration successes and geopolitics.

Development costs are huge and spiraling.

In Kashagan, the largest oil field discovered in the last 20 years, these costs have recently jumped 22% to $38 billion, and the field is not set to go on stream until 2012.

Regarding exploration efforts, not only are we now discovering less reserves but the size of the new fields is much smaller. Over the last 10 years, the average new field size is 28 million bbl worldwide, and for the Middle East it is a paltry 54 million bbl. All of these factors point towards the complexities that lie ahead to meet a continual growing demand.

There is evidence that we are emerging from the current world recession. In 2010, GDP is expected to climb to 2.7% from a negative growth rate of 1.2% this year. As the global economy picks up, however, supply/demand will inevitably revert to the imbalances of the mid-2000s that brought on $145 oil. And that implies possibly three-digit oil prices lurking on the horizon.

Natural gas supply

Natural gas is considered the queen of the fossil fuels mainly because it is the cleanest of them all.

In a world that is in transit to a low-carbon economy this has led to an abnormally high increase in gas production as energy demand worldwide shifts towards this resource for electricity generation and natural gas vehicles. Gas demand in countries outside the Organisation for Economic Cooperation and Development group is now larger and growing faster than in the OECD countries.

Supply/demand has increased a sizzling 30% in the last 10 years, from just over 220 bcfd to 287 bcfd presently and, according to the latest demand models, is expected to further increase 50% to reach 337 bcfd by 2015 and 425 bcfd by 2030. The Big Three producers—Russia (63 bcfd), the US (51 bcfd), and Western Europe (28 bcfd)—are also the biggest consumers and together account for 50% of output and consumption worldwide.

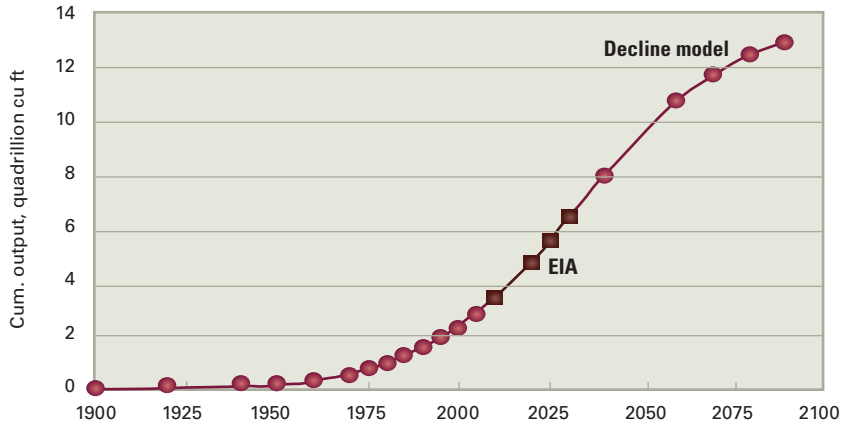
Exploration trends indicate that we have discovered abundant reserves of natural gas, particularly since the 1960s (Table 4). In fact, globally there is as much conventional natural gas reserves as there is oil—an estimated ultimate recovery of 14 quadrillion cu ft, or 2.4 trillion bbl of oil equivalent. The natural gas industry is relatively young and vigorous. Only 22% of the gas discovered has been produced in comparison with 46% for oil. Presently, production and discoveries are in balance at around 100 tcf/year.

The logistic model indicates that global natural gas production capacity would exceed demand over the next 25 years (Fig. 4). However, there are some tight spots of natural gas supply over the medium term.

The latest assessment of the IEA provides a breakdown of future natural gas outputs for the world's seven gas producing regions (Table 5). Production from North America and Western Europe, two of the largest consumers, will be on the decline, and the key to meeting a world demand of 425 bcfd by 2030 lies in the Middle East. Qatar and Iran would have to triple their current production level; Eurasia (largely Russia and Turkmenistan) would have

GLOBAL NATURAL GAS OUTLOOK

Fig. 4



GLOBAL LIQUIDS SUPPLY-DEMAND OUTLOOK

Table 2

	2007	2015	2030
	Million b/d		
Demand	84.3	94.4	106.4
Supply			
NGLs	10.4	14.5	19.8
Refinery gains	2.1	2.3	2.6
Unconventional	1.6	4.6	8.8
Crude oil	70.2	73.0	75.2
Crude oil potential*	70.2	71.3	62.5
Deficit	—	1.7	12.7

*Logistic model estimates.
Source: IEA08

GLOBAL OIL* SUPPLY BY REGION

Table 3

	2008	2030
	Million b/d	
North America	14.1	11.4↓
Europe	4.2	2.1↓
Eurasia	13.3	16.5♦♦
Asia-Pacific	8.1	5.1↓
Latin America	7.3	5.9↓
Middle East	25.8	43.2♦♦♦♦
Africa	10.8	13.8♦♦
Subtotal	84	98
Unconventional	2	8
Total	**86**	**106**

*Oil includes crude oil, NGLs, and refinery gains.
↓ = Output decline. ♦ = Degree of output growth.
Source: IEA08

GLOBAL GAS E&P TRENDS

Table 4

	Discoveries	Production
	Tcf/year	
1930s	23	2
1940s	46	5
1950s	86	13
1960s	244	29
1970s	290	43
1980s	100	58
1990s	129	79
2000s	100	97

Sources: IHS; EIA

GLOBAL GAS SUPPLY BY REGION

Table 5

	2006	2015	2030
	Bcf/day		
Eurasia	82	92	103♦
N. America	73	76	73↓
Asia-Pacific	37	50	62♦
Middle East	31	46	96♦♦♦♦
W. Europe	29	27	21↓
Africa	19	28	43♦♦
L. America	13	18	27♦♦
World	**284**	**337**	**425**

♦ = Degree of output growth. ↓ = Output decline.
Source: IEA08

to increase its current output by 30%; Asia-Pacific by 67%; while Africa and Latin America would have to double their current outputs.

These assumptions of output growth are also strongly subject to uncertainties in investment levels and geopolitics. By 2030 the Middle East and Eurasia together would control 50% of the world's natural gas output compared with 40% today. In fact, they would have to provide 50% of the increase (53 bcfd) in production required to meet global demand as early as 2015, that is in the next 5 years.

Contrary to the case of oil wherein reserves are dwindling, gas reserves are not an issue. Five regions have sufficient gas reserves to cope with the future production capacities called for but would require massive capital investments for their development.

The world's largest gas field, North field-South Pars, shared by Qatar and Iran, presently produces less than 10% of its potential of 110 bcfd. Turkmenistan's Iolotan, the world's second largest, has a potential of 30 bcfd but is undeveloped and has special problems—high carbon dioxide content and high reservoir pressure.

The potentially massive gas reserves in the Yamal Peninsula of Russia are undeveloped. Shtokman, the world's sixth largest gas field, was discovered in 1989 and has a capacity of 11 bcfd but is yet to go on line. Yamal's development cost is currently estimated at $100 billion. Clearly, Russia/Eurasia needs investors with big pockets and the best technology.

Gas prices have historically lagged those of oil. Over the last 20 years gas prices have varied, on a thermal equivalent average annual basis, from 10% to 50% below those of oil. In the new global energy setting with impending supply/demand imbalances, it is almost safe to say that in the not too distant future gas prices will inevitably move towards more symmetry with those of oil.

Closing remarks

Global crude oil production has increased just 8 million b/d in the last 30 years and has remained flat at 71 million b/d since 2004.

There is evidence that we are emerging from the current world recession. As the global economy picks up, however, supply/demand of crude oil will inevitably revert to the imbalances of the mid-2000s that brought on $145 oil prices. And that implies possibly three-digit oil prices lurking on the horizon.

Although worldwide gas production capacity would exceed demand over the next 25 years, there are tight spots of supply over the medium term, not for a lack of reserves as in the case of oil but for a need of massive investments to develop existing reserves. The Middle East and Eurasia would have to provide 50% of the increases in production (53 bcfd) required to meet global demand as early as 2015.

Because of impending supply/demand imbalances, in the not too distant future gas prices will inevitably move towards more symmetry with those of oil. At present they are about one-half the price of oil. ✦

The author

Rafael Sandrea (sandrear@ipc66.net) is president of IPC Petroleum Consultants Inc., a Tulsa international petroleum consulting firm. He was formerly president and chief executive of ITS, a Caracas petroleum engineering firm he founded and directed for 30 years. He has a PhD in petroleum engineering from Penn State University.

Madagascar

Spectrum ASA, Oslo, will reprocess 6,000 line-km of seismic data off Madagascar under an agreement with state-owned OMNIS.

The surveys include data offshore the west, south, and east coasts and are located in the Morondava and Majunga basins, the Cap Ste.-Marie, and Ile Sainte-Marie areas, respectively.

Spectrum will produce new datasets for open blocks off the south and east coasts, and the west coast where a long line ties both awarded and open blocks.

Previous interpretation of the data suggests encouraging prospectivity for hydrocarbons, Spectrum said.

Pennsylvania

St. Mary Land & Exploration Co., Denver, is laying a temporary pipeline to test its first Marcellus shale gas well in Pennsylvania, where it holds 41,000 net acres in McKean and Potter counties.

The company has 70% working interest in the Potato Creek-1H and 3H horizontal wells in McKean County.

DRILLING MARKET FOCUS

Drilling outlook stabilizes as world economy rebounds

Paula Dittrick
Senior Staff Writer

The fundamental outlook for the global drilling market gained strength during October, driven by improving crude oil prices amid signs of an economic recovery throughout much of the world.

Schlumberger Ltd. Chief Executive Officer Andrew Gould said he was optimistic that oil producers might boost spending next year if they gain confidence that oil prices will stay around $80/bbl.

His comments came after the December 2009 contract for benchmark US light, sweet crude settled at $81.19/bbl on the New York Mercantile Exchange on Oct. 22, marking the first time in more than a year oil had settled higher than $80/bbl.

During an Oct. 23 conference call on Schlumberger's third-quarter financial results, Gould said he believes oil companies' 2010 budgets currently assume less than $70-75/bbl next year.

"The worst, provided the economy continues to show signs of recovery, is behind us," he said of the drilling downturn. Schlumberger's outlook for the rest of 2009 assumes continued modest recovery in North American gas drilling.

Most of the major oil companies have yet to discuss their 2010 spending plans. ConocoPhillips in early October said its 2010 capital expenditures will be $11 billion, down from $12.5 billion in 2009.

Rising utilization rates

Pritchard Capital Partners LLC suggests world jack up utilization "has likely troughed" and now appears to be stabilizing. Brian Uhlmer, Pritchard Capital director of research, said most

Pride International Inc.'s ultradeepwater drillship Pride Angola is drilling in 4,600 ft of water on Block 17/Rosa area off Angola for Total SA. The dynamically positioned drillship is equipped for drilling in 6,000 ft of water. Photo from Pride International.

A Petrobras subsidiary will use the Petrobras 10000 ultradeepwater drillship for work off Angola. Transocean Ltd. has a 10-year drilling contract as part of an agreement with the P&M Drilling International BV joint venture to acquire the drillship under a 20-year capital lease contract. Photo from Transocean.

markets reached bottom in the second or third quarter.

Based upon statistics from ODS-Petrodata Inc., Pritchard Capital estimated the jack up utilization for West Africa jumped to 82% in October after dipping to 55% in July. Utilization in the Gulf of Mexico and Mexico was 66% in July and gradually rebounded to 72% in October.

"We continue to believe the jack up market will be bifurcated, and drillers with high-spec, newer equipment will be first to have their rigs return to work and earn pricing power during the upcycle," Uhlmer said.

The supply of available independent-leg cantilever (IC) jack ups is lower than many believe, Pritchard Capital said. As of Oct. 19, analysts calculated 33 IC jack ups available in the world market.

Uhlmer believes most cold-stacked equipment never will go back to work. As of Oct. 19, he calculated 17 cold-stacked IC jack ups total belonging to Diamond Offshore Drilling Inc., Ensco International Inc., Hercules Offshore Inc., and Transocean Ltd.

"Over 68% of the global jack up fleet is over 20 years old, with just 17% of all jack ups under 10 years old," Uhlmer said. "As operators elect to drill to deeper depths, requiring higher hookload capacity and more complex mud pump and blowout preventer systems, we believe many drillers will elect to cold stack their older assets rather than refurbish the equipment to make it more competitive, further balancing the marketed supply."

Utilization roller coaster

Parker Drilling Co. Chairman, President, and Chief Executive Officer Robert L. Parker outlined his company's strategy for surviving the drilling downturn during a September 22 panel discussion at the IHS Herold energy conference in Greenwich, Conn.

Worldwide, Parker Drilling operates 29 land rigs and a fleet of barge rigs in the Gulf of Mexico. Within the last year, the contractor experienced an abrupt drop in demand for barge rigs.

"Out of 15 barge rigs, we operated 11 in early December 2008," Parker said, but that number dwindled at one point to only 2 barge rigs working. "Today, we have 6 barge rigs working. The whole industry is at 9 compared with 40 a year ago."

Meanwhile, Parker Drilling's Operations and Maintenance division experienced growing demand for its customized drilling packages in which the contractor operates customer-owned rigs.

The O&M division has a 2-year O&M contract with BP Exploration (Alaska) concerning a land-based rig designed to drill extended-reach wells in Liberty field. This involves the drilling from an existing island of an ultraextended reach well 10,000 ft deep with an 8-mile lateral.

Parker Drilling designed and constructed the rig, which arrived at its Alaska North Slope drilling site in July, Parker said.

The O&M division also has a front-end engineering design study and contracts with the consortium operating the Sakhalin-1 development off the east coast of Russia's Sakhalin Island.

The FEED study involves an offshore platform for Arkutun-Dagi oil field in 33-197 ft of water about 15 miles off Sakhalin Island (see map, OGJ, June 17, 2002, p. 42). Parker Drilling's O&M division designed and constructed Sakhalin-1's Yastreb extended-reach drilling rig, which reached 37,016 ft

laterally in the Z-11 well (OGJ, May 7, 2007, p. 9).

In addition, Parker Drilling project management division is supplying technical services for 18 rigs owned by Kuwait Drilling Co.

"This is a growing part of our company. We actually operate other companies' rigs for them," Parker said. "O&M is capital light because we don't have money invested in these rigs. It's a way to grow our net income without investments. It certainly helps us in times like today."

Deepwater markets

Contractors report a brisk business off Africa for both drillships and semisubmersibles.

The newbuild ultradeepwater drillship Petrobras 10000 has commenced operations off Angola under a 10-year drilling contract. Transocean Ltd. of Zug, Switzerland, has an agreement with the P&M Drilling International BV joint venture of Petroleo Brasileiro SA (Petrobras) and Mitsui to acquire the rig under a 20-year capital lease contract.

The Petrobras 10,000 features dual-activity drilling technology that allows for cost-saving parallel drilling operations. Built at a South Korean shipyard, the drillship has the capability of drilling in more that 10,000 ft of water.

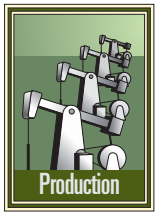
Petrobras aggressively plans to increase its rig capacity by chartering up to 28 ultradeepwater drilling units. The company has said it would like drillships, and possibly semis, built in Brazil for delivery during 2013-18.

Pride International Inc. said its deepwater semi, Pride South Pacific, has a 1-year contract by a subsidiary of Noble Energy Inc. for operations off West Africa. The contract is expected to commence during first-quarter 2010 in direct continuation of the rig's current contract commitment off West Africa. ✦

Multiple tasks finalize Weyburn CO_2 injection modifications

CO_2 INJECTION—Conclusion

Kenneth. J. Vargas
Falcon EDF Ltd.
Calgary



Modifications to the Weyburn CO_2 injection scheme required a detailed engineering approach followed by construction work carried out by multiple companies.

The first part of this two-part series (OGJ, Nov. 16, 2009, p. 43) on debottlenecking the Weyburn injection scheme described the design parameters; this concluding part covers the steps involved in the detailed design and construction.

P&IDs

Upon completion or near completion of the new process flow diagrams and material balances, as discussed in Part 1, the next step involved revision of the plant's existing piping and instrumentation drawings (P&IDs). The new P&IDs showed all new equipment such as the pumps, heat exchangers, and other skids.

During the preparation of the P&IDs, the detailed work also included the sizing of all secondary equipment and interconnecting piping and cable.

After completion and approval by Encana of the P&IDs, further detailed engineering followed.

Acoustical design

The detailed engineering required an acoustical analysis on each of the newly reconfigured reciprocating compressors. The analysis used an API 618 Design Approach 2 (M.2-M.4).

The pulsation analysis also looked at the existing pulsation bottles and orifice plates and found that the bottles were reusable but new orifice plates were needed.

The mechanical analysis recommended:

- Dynamic rigid supports on the first and second-stage suction piping.
- Third-stage suction bottle rigidly supported from a stiffened existing A-frame support.
- Rigid support for all scrubbers to maximize the mechanical natural frequency, which is a potential vibrations source.
- Adjustment of the discharge bottle support to maintain preload contact.

During start-up, a piping vibration survey was performed.

The injection pumps are in the two long buildings in the lower left. The pipe rack coming out of pump buildings goes towards the aerial compressor coolers. Two variable-frequency-drive buildings are to the right of the pump buildings. Two transformers are behind the VFD buildings. The Heatric exchangers' open skid is visible behind the pump-skid building (Fig. 1).

Interconnecting piping

Based on the P&IDs and the acoustical analysis, the design work created the detailed 3D piping models for fabricating all new spools and interconnecting piping.

The plant piping 3D layout for the restaged compressors, exchangers, and pumps identified the valves and instruments to make the turnaround piping installation and instrument replacement more efficient and easy.

After completion of the 3D piping design, the next step preformed a stress analysis on the piping with Caesar II software. This required importing the 3D Autocad model and analyzing all the new headers with the program.

The analysis passed all the stresses to which the piping would be exposed,

such as stresses caused by temperature, pressure, and hydro testing. All stresses were less than the ASME petroleum refinery code for pressure piping (B31.3) allowable stresses.

The initial design incorporated flexibility and expansion loops for avoiding potential stresses.

Each injection pump building houses two Reda pump skids (Fig. 2).

Electrical equipment

Concurrent with the detailed mechanical design, the work also included the electrical and instrumentation detailed design.

The detailed design work entailed frequent meetings of the civil, electrical, and mechanical groups for identifying interdisciplinary mismatches or changes. Produced were electrical single line, area classification, and junction box drawings

The scheme connected the Reda pump electrical motors via two 4,160-v to 480-v transformers from the 4,160-v main to four variable-frequency drives. Each train has two dedicated motors with the two motor variable frequency drives (VFDs) controlling the pump output via pressure on the pump suction or last stage K701 compressor discharge.

The control worked well, keeping the pump synchronized with the reciprocating compressors.

Fig. 1 shows the construction area.

Skids

Skid design started after completion of the basic design.

The pump building skid was the most complex and compact. It included the pump and motor, interconnecting piping, electrical hookup, instruments, lifting and transport provisions, maintenance access, and operations interface.

Fig. 2 shows the inside of the pump building.

The Heatric exchangers have an open skid design; however, running the piping was a challenge because of the high-pressure piping and inlet strainers. The exchangers require two strainers per stream, one in operation and the other on standby for use while cleaning and maintaining the other.

Fig. 2 of Part 1 (OGJ, Nov. 16, 2009, p. 45) shows the complexity of the strainers and heat exchanger open skid.

The VFD skids have minimal complexity except for the area classification of the transformer and process equipment as well as for the VFD spacing and enclosure requirements.

Civil engineering

The design included installing all equipment, skids, pipe rack, and supports on piles. The skid foundations consisted of I-beam channel and other structural steel.

Turnaround planning

The project called for developing a plan for the plant turnaround that involved tying in the piping and electrical equipment for the compressor recycle and pump upgrade.

Fig. 3 shows the turnaround schedule for the mechanical work to tie in compressors K701-1 and 2 after the installation of all equipment skids and interconnecting piping and wiring.

The electrical and instrumentation work was not included in the schedule. This was because the electrical instrument tie-ins were not on the critical path. The plan generated lists with the tasks to complete, one for electricians

CONSTRUCTION BREAKDOWN

Company	Work carried out
Carson Welding & Maintenance Ltd. (Weyburn)	Piping and mechanical field work: • Site work: Fencing, topsoil strip, trench, backfill compacting. • Foundation Structural: Drive finish piles, transformer concrete pad, pipe supports/racks & access platforms. • Piping: Spool fabrication per ISOs, manage pipe valves fittings delivery inventory, pipe equipment piping demolition, install new pipe, and install tie-ins and instruments in turnaround. • Equipment installation: Offload and set all equipment and skids, such as pump VFD HEX skids. • Instrument installation: In-line instrument installation only. • Insulation painting and testing: All piping, equipment instruments to be fully installed insulated and painted per company specifications. • Turnaround commissioning and start-up: Provide sufficient resources as required and authorized by EnCana for turnaround and start-up. • Clean up and move out: Site cleanup and environmental diligence for disposal of all debris/equipment.
Mainil Oil Field Services (Weyburn)	Lump-sum bid of two skid buildings containing two Reda 64 stage pumps each to encompass installation of all equipment instruments etc. Only wiring to be done by others.
CanWest Industrial Inc. (Calgary)	Lump-sum bid of two open skid containing two Heatric printed circuit heat exchangers to encompass installation of all equipment instruments, etc. Only instrument hookup to be done by others.
Magna Electric Corp. (Regina)	Installation of high-voltage tie-in of transformer to feed new pumps installation.
Industrial Electrical Weyburn Ltd. (IEW)	All pump and electrical equipment installation and wiring of all new skids. All electrical feeder cables to MCC-transformer and VFDs to motors.
Autopro-Authomation Consultants Ltd. (Calgary)	Programming and start-up of PLC to control new recycle gas expansion.

BLOWDOWN SEQUENCE

Table 1

Step	– Initial pressure – psi	kPa	– Final pressure – psi	kPa	Volume, cu ft	Inventory, lb Initial	Final	Released	Time required, min
1	1,241	8,557	900	6,205	210	6,342	5,420	922	2.4
2	1,045	7,200	600	4,137	233	6,243	4,800	1,443	4.8
3	600	4,137	350	2,413	497	6,209	4,215	1,994	11.4
4	350	2,413	290	2,000	768	4,836	4,188	648	6.4
							Total	**5,007**	**25.0**

and the other for instrument technicians.

The 3D mechanical drawings had labels showing the location of the instrument electrical tags. This enabled the construction technicians not familiar with the plant to plan their activities by physical location. These 3D drawings proved useful throughout the project.

Compressor blowdown

Fig. 4 is a simplified schematic of a single compression train to help visualize the blowdown procedure.

In the event of a plant emergency, the standard procedure requires blowing down the gas to the plant flare. This entails the closing of the inlet and outlet emergency shutdown valves and depressuring the piping and equipment to the flare.

The gas can form hydrates when it is blown down from high pressure as in the EnCana Weyburn injection system (15,300 kPa-g) and is water saturated or wet. In addition, it is extremely hazardous to try to contain this gas at high pressure. With any minute temperature change, the gas can expand and overpressure the piping or vessels.

Falcon performed the blowdown calculations to avoid hydrates or containing the gas for long periods.

Fig. 4 shows by means of a color schematic the piping and equipment steps involved in the blowdown. Note that during blowdown, the compressor cylinders act as check valves until their suction and discharge pressures equalize. The gas also can be heated before the blowdown valve (BV-1) to avoid hydrates.

HYDRATE TEMPERATURES

Table 3

Pressure kPa	psia	Hydrate temp. °C.	°F.
15,000	2,175	25	77
10,000	1,450	19	66
7,280	1,056	16	61
5,000	725	15	59
3,000	435	13	55
1,500	218	8	46
1,000	145	5	41
500	73	—	32

The following steps summarize the partial blowdown sequence of the two trains in parallel to a partial blowdown to 500 kPa (75 psi). It is possible to blow down one train while the other remains in operation.

- Step 1 involves activating a blowdown valve (BV-1) instantaneously for blowdown conditions. Regions blown down are the full discharge of the third stage of compression (cooler), the recycle line and valves, recycle and BP-2 to the third stage of compression, both Reda pumps, and all suction lines including the strainer and heat exchanger. The starting pressure of these regions is 8,412 kPa (1,220 psi) and the final pressure is 6,205 kPa (900 psi).
- Step 2 opens the valves BP-1A (Reda pump bypasses) and blows down the combined region from the check valve to ESD-2 on the Reda pump outlet

and the remaining inventory from Step 1. One should note that the pump discharge pressure is 15,275 kPa (2,215 psia) and upon mixing with the inventory left from Step 1, the equalized pressure will be 7,205 kPa (1,045 psia). Next blown down are the combined inventories from 7,205 kPa (1,045 psia) to 4,135 kPa (600 psia).

BLOWDOWN STEP TEMPERATURES, PRESSURES

Table 2

Step	Initial pressure psi	Initial pressure kPa	Initial temp. °F.	Initial temp. °C.	Final pressure psi	Final pressure kPa	Final temp. °F.	Final temp. °C.
1	1,241	8,557	93	34	900	6,205	75	24
2	1,045	7,200	79	26	600	4,137	44	6.5*
3	600	4,137	45	7	350	2,413	12	–11*
4	350	2,413	12	–11	290	2,000	1	–17*

*The final temperatures are less than the hydrate temperature. To elevate the temperature with the TIC in the third-stage discharge segment, one needs to open the recycle valve or blowdown valve BP-2 until the temperature is greater than hydrate temperature and then continue recycling and blowing down using the compression to heat the blowdown gas.

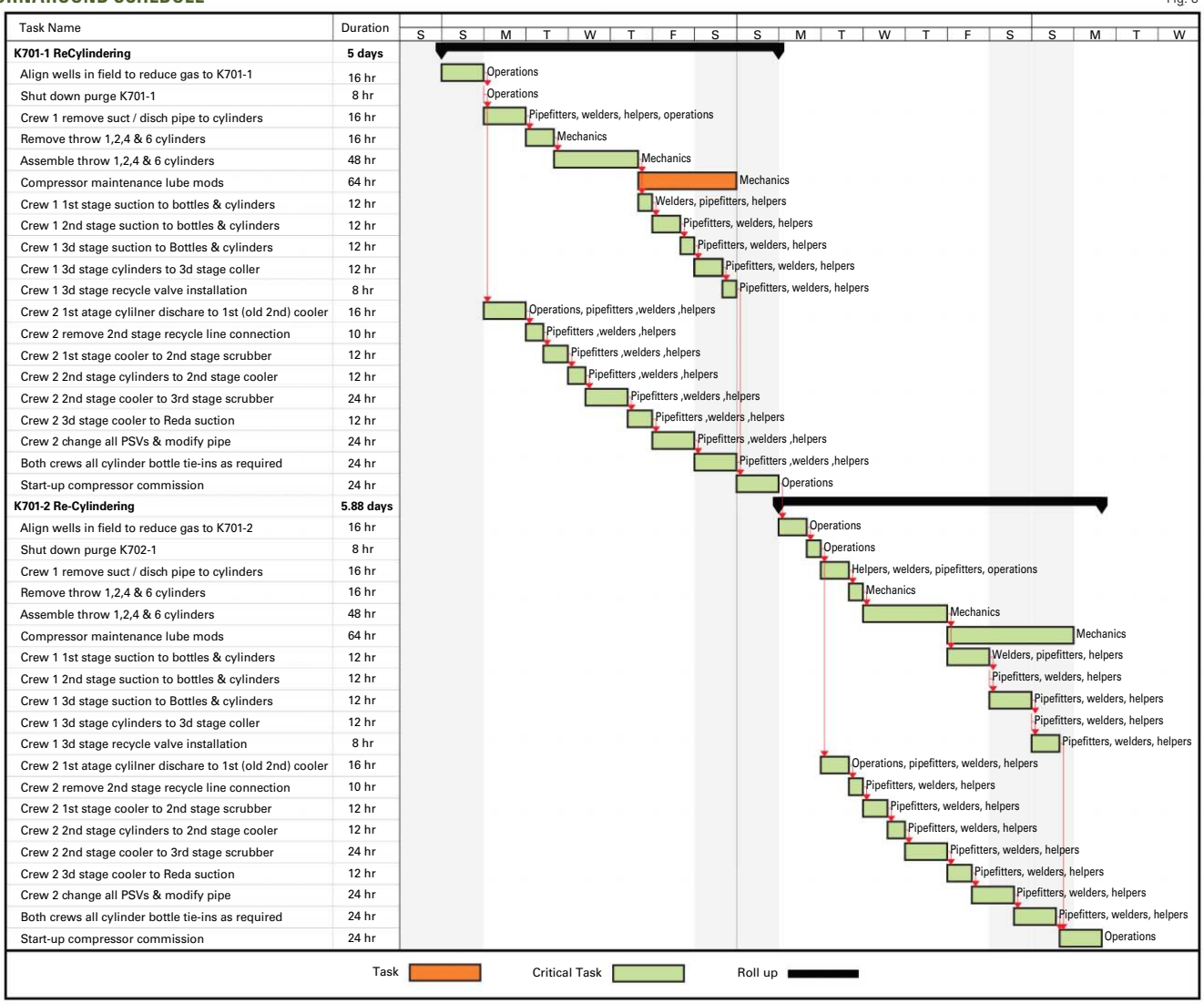
• Step 3 blows down the third-stage suction, third-stage scrubber, second-stage cooler with associated piping, and second-stage discharge line. The final pressure obtained in this step is 2,415 kPa (350 psia).

• Step 4 blows down the second-stage suction, second-stage scrubber, first-stage cooler with associated piping, and first-stage discharge line. The final pressure obtained in this step is 2,000 kPa (290 psia).

• Step 5 is optional and is for an emergency. Usually blowdown stops at Step 4. Step 5 involves blowing down the first-stage suction, first-stage scrubber, and the piping from ESD-1. The

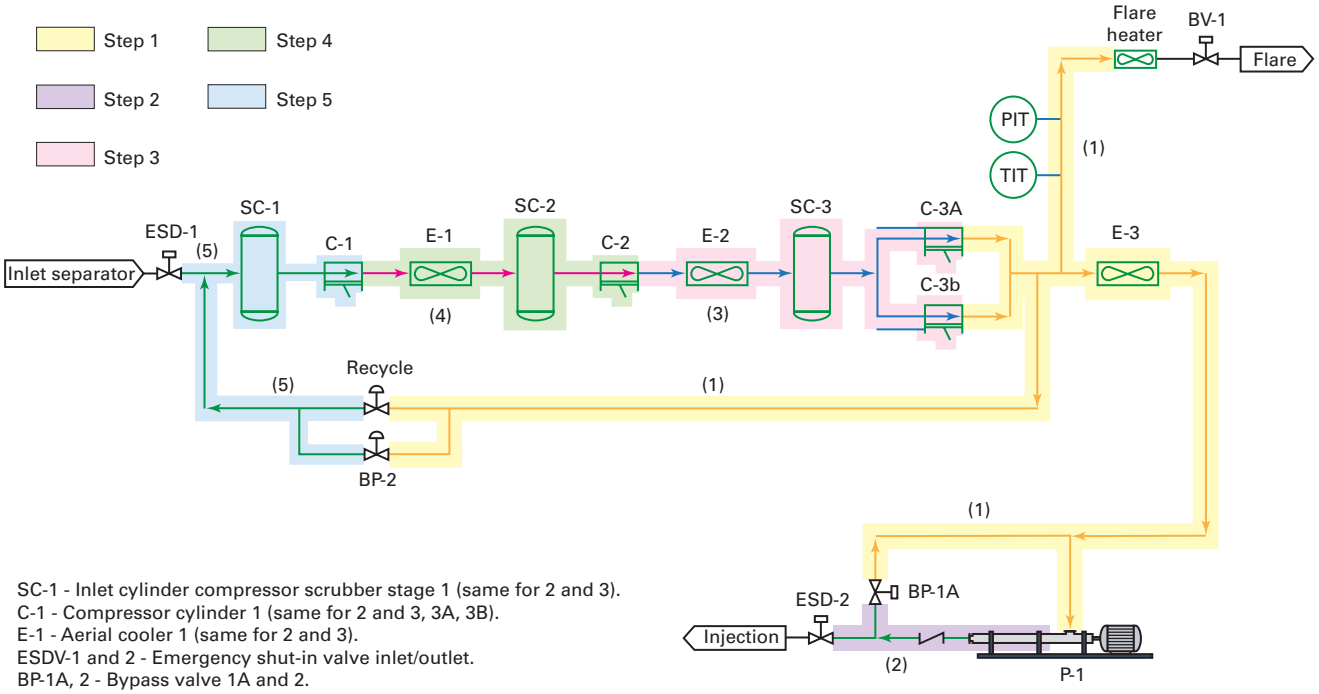
TURNAROUND SCHEDULE

Fig. 3



SIMPLIFIED COMPRESSOR-PUMP BLOWDOWN

Fig. 4



SC-1 - Inlet cylinder compressor scrubber stage 1 (same for 2 and 3).
C-1 - Compressor cylinder 1 (same for 2 and 3, 3A, 3B).
E-1 - Aerial cooler 1 (same for 2 and 3).
ESDV-1 and 2 - Emergency shut-in valve inlet/outlet.
BP-1A, 2 - Bypass valve 1A and 2.
BV-1 - Blowdown valve to flare. All blowdown is downstream of all cylinders as the cylinder valves act as check valves and they allow flow downstream only, so blowdown proceeds from ESDV-1 to 2.
TIT -Temperature-indicating transmitter
PIT - Pressure-indicating transmitter

final pressure obtained in this step is 500 kPa (75 psi), the final pressure in the partial blowdown sequence.

Tables 1 and 2 summarize the blowdown sequence pressures, temperatures, and times for depressuring each step up to Step 4.

To prevent hydrates from plugging the blowdown valve BV-1 and the flare lines, the scheme includes a flare heater before BV-1. Gas passes through the flare heater and a temperature indicator controller (TIC) monitors the temperature before the blowdown valve BV-1.

When the low set point temperature and pressure are not met, the valve throttles or closes until the gas heats up to the desired temperature. Using Tables 2 and 3, one can predict the hydrate point (temperature and pressure) and avoid blowing down at a critical temperature for the steps involved in Table 2.

The temperature set points of the TIC are pressure-dependent (measured by a pressure-indicating transmitter) and related to the hydrate temperature at that pressure. Table 3 shows the hydrate temperatures at different pressures.

Construction

EnCana managed the construction at the plant. The company divided the work among four local companies and two Calgary-based companies. All work proceeded quickly and costs were kept on budget. The accompanying box shows a summary of the work performed by each company

Construction and start-up went very well. Only one issue arose during construction. Operations requested to invert the compressor feeding the initially designated respective pump.

This involved a change in the main drawings; however, the skid drawings tags were not changed because construction on the skids started considerably earlier. Subsequently, this led to changing the equipment control and indication wiring between pumps.

The pumps started up and ran smoothly after 2 weeks.

As discussed in Part 1, the pump curves did not reflect the required horsepower per pump and required an upgrade to 600-hp motors.

Lessons learned

Several things were learned from this project.

Designing the injection scheme revealed that the gas behavior of mostly CO_2 (76% and above) recycle gas varies considerably for different temperatures. Above the critical point, the design requires specific gravities from reliable and consistent models. Although it is possible to pump the recycle gas in dense phase under certain circumstances, knowing the temperature at which it is pumped is critical because of the rapid changes in density.

The design requires pump curves that accurately predict pump horsepower draw (with the corresponding operating efficiency) and liquid flow-

rate for the fluid's specific gravity. If possible, it is advisable to run the pump at the actual conditions of operation and confirm the points on the curve for flow vs. horsepower draw and flow vs. pressure differential (ΔP).

Pumping dense-phase CO_2 at the right conditions is much more cost effective than compression. There are some constraints because the process requires a compressor initially to obtain the dense-phase pressure.

The scheme requires a careful study for selecting the optimal cost for the compression-pumping of the recycle gas. Retrofitting a reciprocating compressor requires that restaging is feasible and that the gas have the right specific gravity/dense phase (controlled by the temperature after compression entering the pump).

EnCana operations reports that the reciprocating compressor and pump combination is stable and operates smoothly when the ambient conditions are below 15° C. (60° F.) and easily achieves a flow of 1.134 million cu m/day (40 MMscfd). During the summer months, the pump capacity varies more, and the combination can usually be operated at 964,000 cu m/day (34 MMscfd).

The advantage of reciprocating vs. centrifugal compressors is that reciprocating compressors can compress water-saturated gas. Centrifugal compressors cannot tolerate any water saturation on the impellers.

Printed circuit heat exchangers are sensitive to impurities in the gas. They are prone to fouling easily. The Weyburn project team installed strainers before gas entry into the exchangers. Unfortunately, asphaltenes and other solids contaminate both the purchased CO_2 and the EnCana recycle gas. Operations found it problematic to maintain the strainers on line for very long. Because of the operating conditions of both streams (high pressure and high CO_2 content), the field considered the strainers almost inoperable. ✦

REFINERY GASES—1

Hydrogen, nitrogen assist compliance with new, tougher environmental regs

M. Heisel
B. Schreiner
W. Bayerl
Linde AG
Unterschleissheim, Germany

Refineries primarily process crude oil into motor and heating fuels, although other products can be made. These include gaseous fuels, feed gases for petrochemical processes, raw material for lubricant production, and asphalt.

The widespread use of fossil fuels has greatly affected the environment. Specifically the increase in automotive and air traffic has caused substantial pollution. One important result has been increasingly more stringent rules with respect to the environmental acceptability of automotive and heating fuels. In the European Union, for instance, new regulations for automotive fuels have been in force since 2000 that required substantial reductions in harmful components in gasoline and diesel. Table 1 summarizes the new guidelines.[1,2]

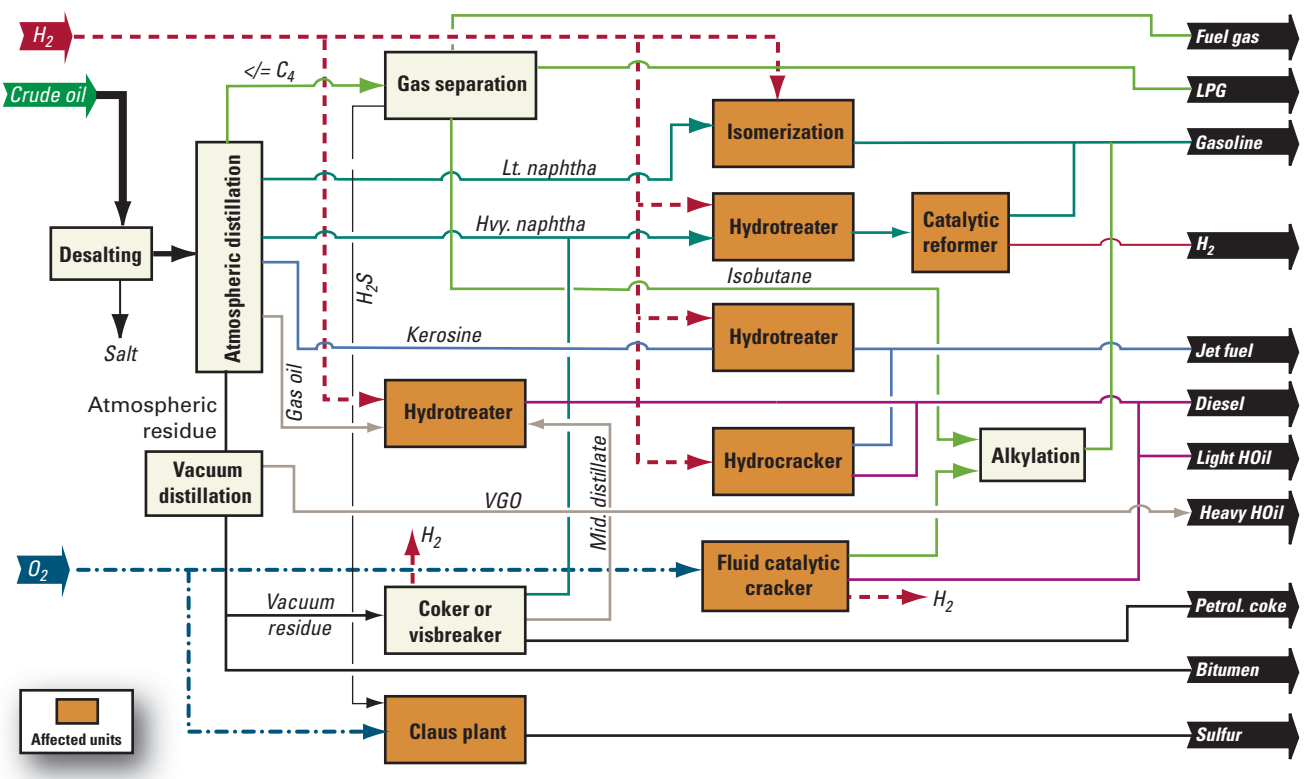
Use of industrial gases can play a major role in a refinery's compliance with these and other new requirements. For instance, desulfurization of products can be increased—as required by the regulations—by increased use of hydrogen. The reduced capacity of Claus plants due to increased desulfurization can be compensated for by use of oxygen.

The three-part series, which this article inaugurates, will discuss the effects of developments on refineries and their utilization of gases. At the same time, it will become clear that use of industrial gases offers possibilities for meeting the new requirements while avoiding major investments in new plants.

This first article will focus on uses of hydrogen and nitrogen. Part 2 (OGJ, Dec. 7, 2009) will discuss uses of

REFINERY EFFECTS OF CLEAN FUEL REGS

Fig. 1



oxygen. And the concluding article (OGJ, Dec. 14, 2009) will discuss uses of specialty gases and gas production plants.

Background

In a refinery, the new requirements have major effects on many plants. Fig. 1 shows their positions in a refinery.

Use of industrial gases in refineries has largely been limited to, for example, gassing reactors with nitrogen for inerting during catalyst changouts or use of analytical gases for the laboratories.

To the extent that hydrogen was used for hydrogenations, it was produced essentially from refinery gases, such as the exhaust from the reformer or the fluid catalytic cracker (FCC). Gases were products of the refineries and, in essence, were exported, not imported.

The new developments alter this situation thoroughly.

• More severe environmental protection laws require cleaner products and fewer emissions both in production and in use of the products. Among the emissions, not only must toxic gases be considered, such as NOx and SO_2, but increasingly the greenhouse gas CO_2 as well.

• Long-term market trends are shifting the range of products. Here are some examples:

—Heavy heating oil with high sulfur content is increasingly harder to sell.

—Increasing air traffic requires more kerosine.

—The rising proportion of diesel vehicles requires more diesel fuel, compared with gasoline. That means that more middle distillate must be produced in the refinery at the expense of the very light and very heavy products.[3]

• Globalization increases the pressure for operating refineries at optimum efficiency. That has already resulted in reduction of the number of refineries in Europe and the US and a slight decrease in capacity. One can see a trend to balance lack of capacity by importing refined products rather than by maintaining surplus capacity.[4]

Currently Europe exports gasoline mainly to the US and must import diesel, mainly from Russia. Mexico, which imported about 30% of its gasoline from the US, must now upgrade its refineries to produce the gasoline it cannot buy from the US anymore. There are many such chain reactions worldwide in order to adapt to new developments.

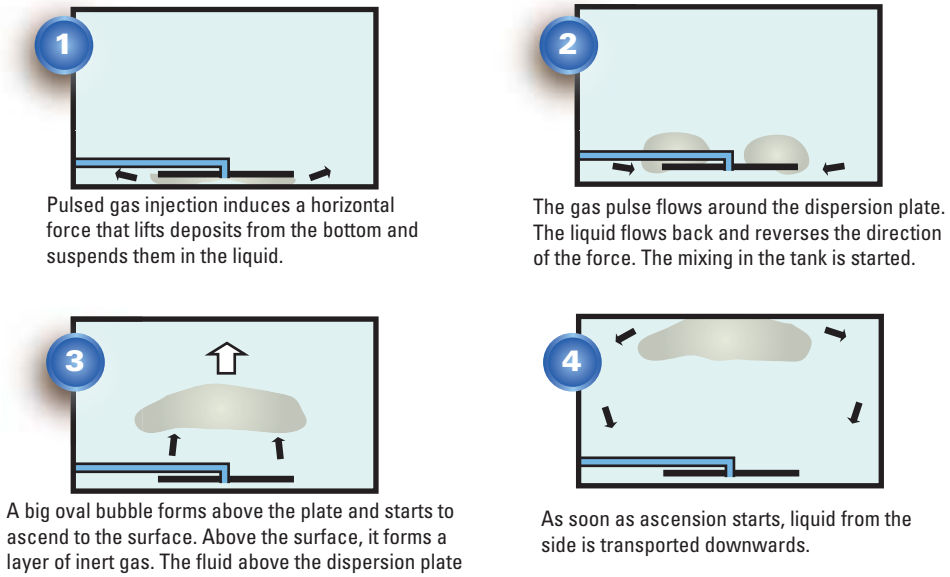
Hydrocracking, hydrotreating

There are many hydrocracking processes because of different feedstocks and objectives of the various refineries. For instance, atmospheric gas oil and vacuum gas oil are used in this process. The longer-chain hydrocarbons are broken down to lighter products and hydrogenated, as well as being partially desulfurized and freed of other heteroatoms.

The operating conditions are between 400° C. and 450° C. and between 70 and 210 bar (1,015 and 3.47 psi). Some hydrocracking processes have several stages in the reaction, with one stage for hydrotreating with an amorphous catalyst and one stage for hydrocracking with a zeolite catalyst. The chemical

PULSAIR PROCESS PRINCIPLE

Fig. 2



1 Pulsed gas injection induces a horizontal force that lifts deposits from the bottom and suspends them in the liquid.

2 The gas pulse flows around the dispersion plate. The liquid flows back and reverses the direction of the force. The mixing in the tank is started.

3 A big oval bubble forms above the plate and starts to ascend to the surface. Above the surface, it forms a layer of inert gas. The fluid above the dispersion plate is displaced and liquids and solids from beneath are transported upwards.

4 As soon as ascension starts, liquid from the side is transported downwards.

EFFECTIVE EU AUTOMOTIVE FUEL REQUIREMENTS

Table 1

Period	Up to 1996	2000	2005	2009
Gasoline				
Sulfur content, ppm	<500	<150	<50	<10
Benzene content, vol %	<5	<1	<1	<1
Aromatics content, vol %	–	<42	<35	<35
Density, kg/l., max.				<0.72-0.775
Diesel fuel				
Sulfur content, ppm	<500	<350	<50	
Cetane number, min	49	51	51	51
Polynuclear aromatics, wt %	–	<11	<11	<8
Density, kg/l., max.	<0.86	<0.845	<0.845	<0.839-0.825
Distillation T95, °C.	<370	<360	<360	<350-340

requirement for hydrogen in hydrocracking depends on the feedstock and is, for example, 2.75-2.90 wt % of the feed.

Hydrocracking is a major process for producing diesel fuel. Massive increases in demand for diesel fuel over the last few years and greater processing of heavy residues will result in expansion of hydrocracking capacities.

There are also various processes for hydrotreating, with the choice of process depending primarily on the feedstock and on the product grade desired. Sulfur, nitrogen, and metals in particular are removed from the various feedstocks, such as middle distillates and atmospheric or vacuum gas oils. That is intended to prevent catalyst poisoning to improve the product quality and of course to meet requirements of ultralow sulfur fuels. The chemical hydrogen requirement varies between 0.40 wt % and 1.35 wt % of the feed.

There are also special processes for hydrodesulfurization in which primarily organically bound sulfur is hydrogenated to hydrogen sulfide (H_2S). The hydrogen sulfide can be separated from the gas phase in a scrubber. Then it is available as feed for a Claus plant.

Table 2 shows that the hydrogen requirement for desulfurization increases more than proportionately with the degree of desulfurization.[5] One reason is that hydrogenation of organic nitrogen compounds to ammonia also occurs along with desulfurization. The more severe the desulfurization has to be in order to make clean fuels the more ammonia is formed as a by-product.

Demand for products with lower contents of sulfur, nitrogen, and metals is increasing in connection with more stringent environmental laws.

This tank farm is equipped with Pulsair system for inerting plus stirring. The four tanks in the lower left have a content of 14,700 cu m each, filled with biofuel (Fig. 3).

Isomerization

Isomerization is a reaction process being used increasingly to improve the properties of refinery products. Normal paraffins are converted to isoparaffins. Conversion of C_5 and C_6 paraffins from atmospheric distillation increases the research octane number (RON) and motor octane number (MON).

In hydroisomerization, for instance, the fraction rich in C_5-C_6 hydrocarbons is mixed with hydrogen and converted to the corresponding isomerizates in a reactor at about 150° C. to 200° C. with a zeolite, metal oxide, or chlorinated aluminum catalyst.

Isomerization can be linked with reduction of the benzene content. In the process, the double bonds of the benzene are saturated with hydrogen, producing cyclohexane so that an aromatic becomes a cycloparaffin. As the aromatic content will be even more strictly limited in the future, isomerization can provide reduction and rational use of aromatics. Isomerization, too, will increase in importance.

The ratio H_2/hydrocarbon is usually 0.1-4 mole/mole. Hydrogen is often recycled to ensure optimal utilization.

Equalizing hydrogen balance

As explained previously, the need for hydrogen is increasing today because of the stricter environmental legislation, greater utilization of residues, and higher consumption of diesel fuel compared with gasoline. Table 3 shows

HYDROGEN REQUIREMENT PER LEVEL OF SULFUR REMOVAL

Table 2

Sulfur removal, %	90	98	99
H_2 addition, wt % feed	0.51	0.74	0.94
H_2 requirement for a refinery with crude oil throughput of 9,000,000 tons/year, std. cu m/hr	≈60,000	≈87,000	≈110,000

HYDROGENATION PROCESSES IN REFINERIES

Table 3

Process	– H_2 use, wt % based on: – Process feed	Crude oil
Hydrotreating/hydrodesulfurization of:		
• Straight-run naphtha	0.05	0.01
• Cracked naphtha	1	0.05-0.1
• Kerosine	0.1	0.01-0.02
• Gas oil, low sulfur (<0.05%)	0.15	0.04
• Heavy vacuum gas oil (0.5-3.1% sulfur)	0.5	0.15
• Cracked gas oil	1	0.1
Hydrogenation of FCC recycle oils	3	0.3
Hydrocracking of vacuum gas oils	2-3	0.5-0.8
Deep conversion of atmospheric residue	2-3.5	1-2

Four 58-MW Rolls-Royce Trent GTGs Available for Immediate Delivery

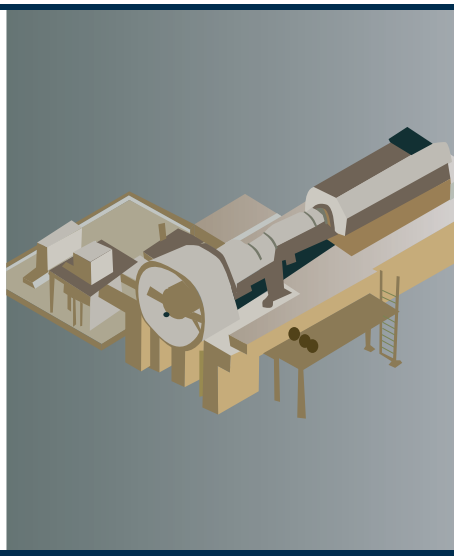
The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.



Unused GE D11 HP/IP Turbine Assembly Available for Immediate Sale

All parts professionally stored in Pensacola, Florida

Unused GE D11 HP/IP turbine assembly and other miscellaneous parts including LP casings and 304-MW generator stator now available for immediate sale.

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

Solar Centaur 40 T4701S Turbine Generator Package with approximately 60,000 accumulated hours at 50% load. Package was in service from 1999 until August 2007. Engine is BACT compliant with OEM 25 ppm Nox/50 ppm CO guarantee. Operates off SAB-type Ideal generator rated at 3500 kW, 4375 kVA and 13,800 volts at 60 Hz. Miscellaneous equipment includes inlet air filtration and simple exhaust systems, and auxiliary control console with start/stop/sync/control.

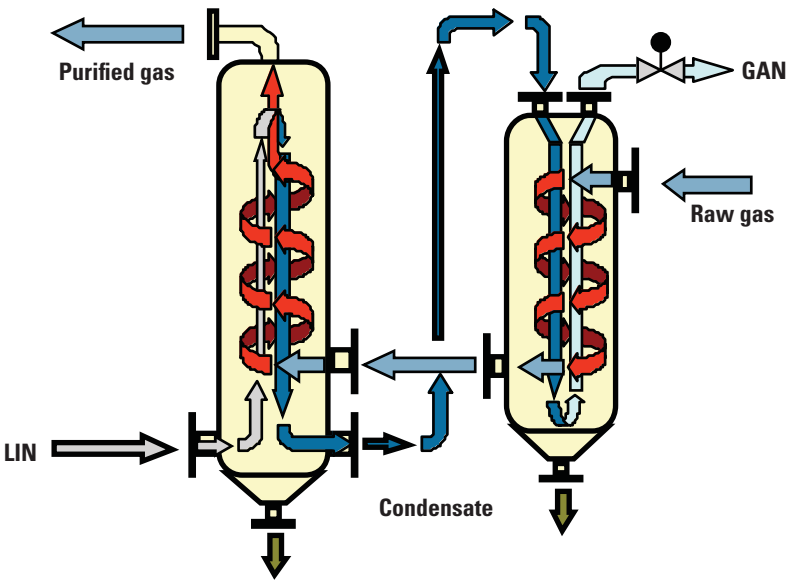
Williams

For Info or Pricing Contact

Randy Hall rhall@pennenergy.com P: 713-499-6330 | Bart Zaino bzaino@thomassenamcot.com P: 817-263-3273

CRYOCONDENSATION FOR EXHAUST GAS CLEANING

Fig. 4



a survey of the specific hydrogen consumption of the various hydrogenation processes, depending on the feedstock used.[6]

Catalytic reforming or platforming is the principal producer of hydrogen in a refinery. From 125 to 315 std. cu m/ton of feed can be produced in the process. Hydrogen production is much smaller in the fluid catalytic cracking process and in thermal processes such as visbreaking, in which hydrogen can amount to 2-16 std. cu m/ton of feedstock.

We can estimate, on a crude oil basis, that a crude oil with about 15 wt % naphtha will yield hydrogen in the reformer to the extent of about 0.4 to 0.6 wt % of the crude oil.

To make up the rest of the hydrogen requirement resulting from the developments described, it will be necessary to produce more and more hydrogen. The following processes are the main ones currently in use:

- Generation by steam reforming of methane.
- Gasification of residues from petroleum processing, obtaining hydrogen from the synthesis gas.
- Recovery from refinery gases, such as wastes from reformers, cokers, and FCC gas.

These processes for recovering and producing hydrogen will be discussed in Part 3 of this series.

Inerting, cryocondensation

Displacement of atmospheric oxygen and flammable gases with inert gases is proven to prevent oxidation, fire, and explosion. Inerting with nitrogen is one measure for primary explosion prevention.

There are four methods of inerting:

- Maintenance of overpressure.
- Permanent flushing.
- Controlled addition of inert gas.
- Pulsed injection of inert gas for stirring plus inerting the surface (Pulsair process).

Inerting is used particularly often in refineries for liquid storage tanks in which the liquids are covered with inert gases. Where it is favorable to stir the liquids, for example, to avoid settling of solids, the Pulsair process often is applied. This is especially true for tanks with biofuel. The process both protects the oil against degradation by oxidation and stirs the vessel. Fig. 2 shows the process principle; Fig. 3 shows a tank farm equipped with Pulsair.

If nitrogen inerting is planned and if the nitrogen is provided in liquid form, the cooling power of the nitrogen can be used for exhaust air cleanup, before serving for inerting. For that purpose, the major gas companies offer standardized units. Fig. 4 depicts the process.

While some units are tailored to the specific demands of the customer, others are standardized to a high degree. Tailored units are more flexible with respect, for example, to the pressure of the treated exhaust gas. Standardized units on the other hand can be kept in stock and may therefore be more quickly available on site.

In both types of units, the treated exhaust gas can be released to the environment as a purified gas. The dual use of the nitrogen in this variation of the process is particularly economical.

In processes with cryocondensation, a gas stream containing pollutants or valuable materials is chilled so strongly in heat exchangers that pollutants or valuable materials in the gas stream condense or freeze out because the temperature is below their dew points. The process uses liquid nitrogen as the chilling agent and is particularly easy to adapt to the present cooling demand, even if this demand fluctuates rapidly.

The required condensation temperature is controlled by the purity required in the exhaust gas. Temperatures below –150° C. are attained in certain cases.

Cryogenic condensation with liquid nitrogen (–196° C. at 1 bar) makes it possible to:

- Reach condensation temperatures far below those of conventional refrigeration machines.
- Adapt to the required condensation power, within wide limits, by variable addition of the chilling agent, nitrogen.
- Treat waste-gas streams heavily loaded with hydrocarbons.
- Achieve minimum residual loadings down into the ppm region.
- Combine this with other processes

such as adsorption without problems.

Industrial service

Industrial service includes an extensive range of services based on long experience and tested proprietary processes. Some of the services are carried out in cooperation with service companies. The processes aim at substantially shortening maintenance or shutdown and start-up.

An example is cooling of a hydrodesulfurization reactor. These reactors must be operated under increasingly severe conditions in order to achieve very low residual sulfur levels in the treated crude. Accordingly, the service life of the catalysts drops so that exchange must occur more frequently than the turnaround cycles of the refinery. Then any time saving by enforced cooling becomes economic.

Cooling such reactors from the operating temperature to less than 200° C. usually can be executed by internal means, especially stopping to heat the process gas. But reducing it to ambient temperature is then very time consuming. Here enforced cooling by cold gaseous nitrogen is advantageous (Fig. 6).

This custom-made cryocondensation unit has a gas capacity throughput about 100 std. m cu/hr and cooling power of about 100 kw (Fig. 5).

While cooling this reactor without enforced cooling typically required 4 days, it could be carried out in only 1½ days with cold nitrogen and required about 300,000 std. cu m of N_2. The longer operational time gained from the time saved in cooling easily paid for this service.

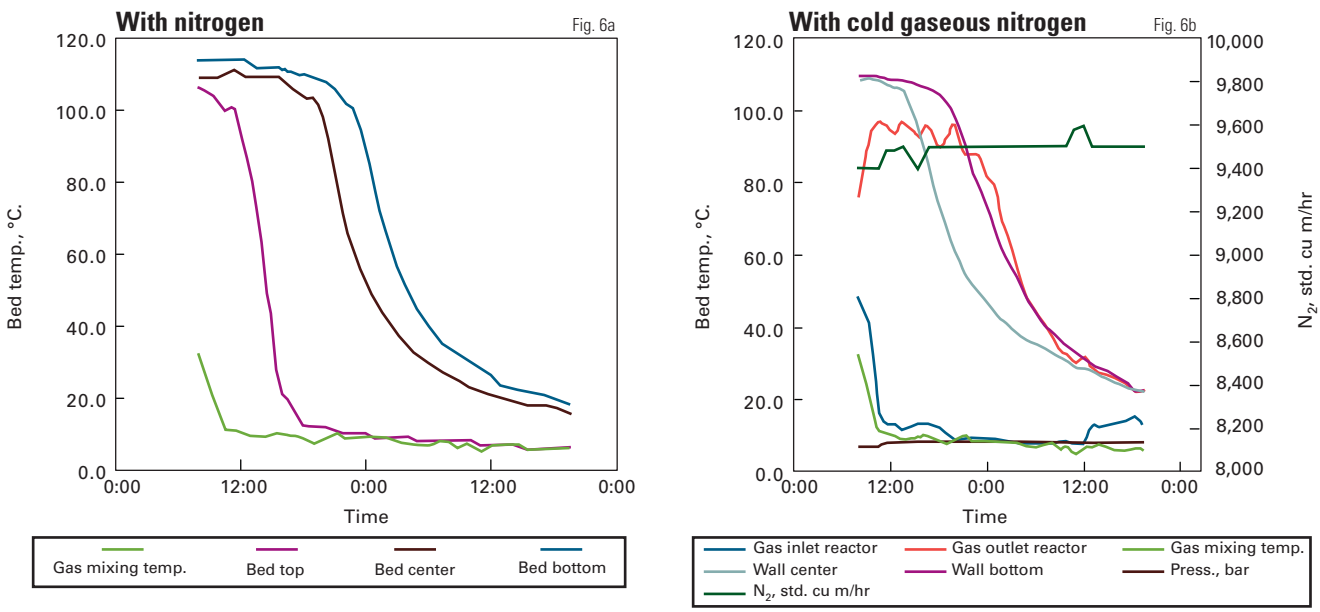
Similarly, Claus plants are increasingly cooled with cold nitrogen for repair or catalyst exchange between turnarounds. Roughly 1 tonne of nitrogen is required for each daily tonne of sulfur capacity, e.g., 50 tonnes of nitrogen for a 50-tonne/day Claus plant. This allows for cooling a Claus plant within only 3-4 days to ambient temperature; without enforced cooling, usually 8-10 days are required.

In many cases, it is even possible to avoid the time-consuming disassembly of parts of units. In that way, maintenance costs are saved and production can be restarted sooner.

The increasing requirements for environmental protection are also met by the service processes because the gases used, usually nitrogen and/or helium, are nonflammable, nontoxic, and noncorrosive. They place no stress at all on the environment. Fewer materials that do contaminate the environment are produced in treatment and cleanup work. Fire and explosion hazards are

HYDRODESULFURIZATION REACTOR: TEMPERATURE, GAS CONSUMPTION IN COOLING

Fig. 6



also reduced, making safer start-up and shutdown of plants possible.

Major gas companies usually are able to offer the following services, sometimes in cooperation with refinery service companies:

- Tube and pipeline cleaning with-without addition of abrasives.
- Leak tests with nitrogen-helium mixtures
- Nitrogen flushing, drying, and pressure testing of equipment, tubing systems, and pipelines.
- Reactor and reformer service.
- Pigging and pipeline cleaning, including camera inspection by intelligent PIGs.
- CryoClean process for cleaning surfaces of equipment with dry ice.

CO_2 for pipe cleaning

The CryoClean process is of particular interest for turnarounds. As it is finding rapidly growing interest in refineries, it will be discussed in more detail.

In any refinery process, there occurs buildup of unwanted deposits in pipes, valves, and on equipment surfaces in general. Because of the process technology, these contaminants must be removed at certain intervals. The materials used in the standard cleaning processes (blast-cleaning agents or solvents) are often questionable because of the costs of disposal of contaminated blasting agents, abrasive effects of many of them, undesired moisture content, contamination of products by residues of the blasting abrasives and environmental problems.

A pig trap and nitrogen injection point was installed for this pipeline restoration at Rongellen, Switzerland (Fig. 7)

Cleaning pipes in a heat exchanger in the chemical industry uses the CryoClean process (Fig. 8).

CryoClean is a surface treatment process similar to sandblasting. In this case, however, the blasting is done by granules of dry ice (solid CO_2) in rice-grain size. The dry ice pellets are metered from a supply hopper into a stream of compressed air or nitrogen, and accelerated to speeds of 180 to 330 m/sec in the blasting nozzle. The thermal and kinetic forces effect the cleaning.

The local cooling of the deposit when contacted by dry ice sheers off the deposit from the material below and forms cracks in the deposit's surface. Dry ice particles hitting the surface at high speed partially liquefy similar to ice under the skates of an ice skater. This liquid CO_2 diffuses into the cracks formed in the deposits and is vaporized there. It expands eventually and thus helps to remove the deposit and push it into the blasting gas stream, which takes it out of the equipment cleaned.

As the process leaves no residue of blasting agent, it is often possible to clean components in place. Therefore, the time for dismantling and reassembly is reduced and often even the heating phase of items can be omitted. The nonabrasive action of the process also increases the lifetimes of the components. Because the process is easily controlled, even complex units can be cleaned easily.

There have been very good results for the following substances, among others: oils, fats, waxy substances, salt deposits, anticorrosion paints, adhesives, and resins. ✦

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The authors

Michael Heisel (Michael.Heisel@linde-gas.com) is a project manager with Linde Gas and Engineering based in Germany. He is responsible for gas applications in refineries, especially novel applications for process intensification. Previously he worked in Linde's engineering and contracting division. Heisel holds a PhD from the Technical University of Munich.

Bernhard Schreiner (bernhard.schreiner@linde-gas.com) has been with the central application department of Linde Gas since 1999, active in gas uses in the chemical process industry. He started work at Linde AG, first in the research and development department of the engineering group specializing on gas processing plants. Schreiner obtained a PhD in chemistry at the Ludwig-Maximilian-University in Munich in 1991.

Wilhelm Bayerl (wilhelm.bayerl@linde-gas.com) manages the specialty gas application department at Linde AG, which he joined in 1992. He started as lab manager, changed to specialty gas production, cylinder logistics, and finally became head of the department. Previously, he worked for BMW as a research and development engineer for engine development. Bayerl studied physical chemistry at Fachhochschule Munich, receiving his diploma in 1983.

Pipelines

Coal seam oxidation leads to CP failure, pipeline corrosion

Wei Chu
ConocoPhillips Co.
Bartlesville, Okla.

Muhdi Sujatmiko
ConocoPhillips Indonesia Inc. Ltd.
Jakarta

SPECIAL Report
Pipeline Report

Coal seam oxidation under wet, high-temperature conditions caused accelerated external corrosion of a buried carbon steel natural gas flowline despite application of impressed-current cathodic protection and a liquid epoxy polymer coating.

Coal seam oxidation can create a highly acidic and corrosive environment for pipelines buried nearby. High-temperature surfaces can concentrate acidic water to an even lower pH, creating an even more corrosive environment around the pipe. Installed cathodic protection may be unable to protect pipe in an sufficiently aggressive acidic and high-temperature environment. External coating also may not resist such an environment and the accompanying increased risk of cathodic disbonding.

Background

An external coating failure and corrosion found as part of a scheduled corrosion survey forced the December 2007 closure of a 16-in. OD, 52-km natural gas flowline in southern Sumatra. The pipeline had been operating for about 11 months. A direct-current voltage gradient survey detected the coating failure and excavation found external corrosion under the coating. The corrosion site lay about 250 m away from the gas well. Multiple coating damages and pitting corrosion had caused pipe wall loss.

The pipeline consisted of API 5L X52-grade carbon steel. Operational temperature and pressure measured 90-110° C. (150° C. maximum) and 1,000-1,300 psi (6.9~9.0 MPa). The corroded pipe section lay 1.5-2 m deep in a downhill coal seam. Liquid epoxy polymer coated the pipeline's external surface. An impressed-current cathodic protection system lay at the gas-plant end of the flowline.

Site investigation and laboratory analysis showed the surrounding soil to be highly acidic. Close-interval poten-

Based on presentation to NACE Corrosion 2009 Conference, Atlanta, Mar. 22-26, 2009.

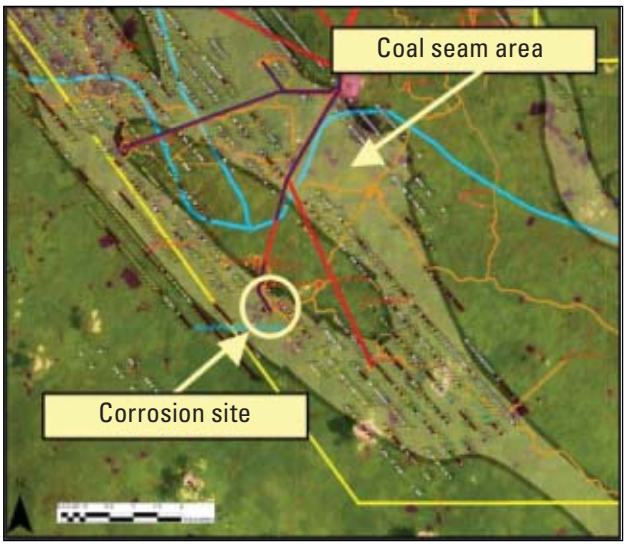
EXCAVATION-SITE WATER MAKEUP Table 1

Item	Result	Unit	Remarks
pH	2.57	—	—
Sulfide, S^{2-}	—	ppm	—
Sulfate, SO_4^{2-}	730	ppm	—
Chloride, Cl^-	25.35	ppm	—
Carbonic acid, H_2CO_3	—	ppm	—
Nitrate, NO_3^-	21.9	ppm	Calculated

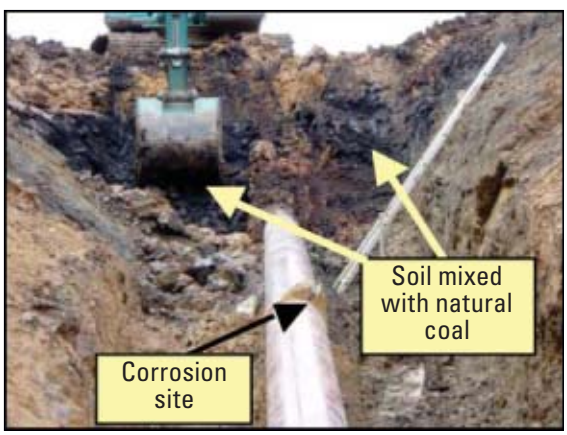
tial survey data demonstrated cathodic-protection potential was meeting accepted standards.

The oxidation of sulfur in coal can generate a highly corrosive sulfuric acid in the soil in tropical environments. The high temperature around the pipe surface may have concentrated the acid. Literature contains limited knowledge regarding coating with CP in low-pH, high temperature conditions.

A DCVG survey showed other flowlines buried in the same area were also susceptible to external corrosion. This article highlights a research project initiated to investigate this corrosion issue and evaluate the coating stability within the CP's operational parameters.



Corrosion of a 52-km, 16 in. OD natural gas flowline occurred in a coal seam area near the line's origin (Fig. 1).



Excavation at the corrosion site showed the soil combined with coal (Fig. 2).

Field investigation

The corroded section of the pipeline lay in coal seam-rich soil. Other parts of the flowline lie in the wet soil. A nearby coal seam has spontaneously combusted several times since the start of operations.

Fig. 1 shows the geographic location of the flowline.

DCVG survey and site excavation revealed coating failure and external corrosion on the pipe. Fig. 2 shows the excavation site and the soil condition.

The gas flowline was backfilled with clay soil 50-80 cm thick. Coal dominated local soil composition. Analysis showed the coal was subbituminous with total sulfur content of 0.22-1.59% and volatile matter content measuring 28-38.5%. Soils with these ranges of sulfur and volatile matter have a tendency to combust spontaneously.

A suspected coating burn was found between the 4 and 8 o'clock positions at the failure site. The coating had a dark color on its exterior and a red color on its interior (steel pipe side). Coating failure spots had either blistered or peeled off. The pipe steel surface under the failed coating spots experienced severe corrosion and metal loss.

Fig. 3 illustrates the orientation of coating failure spots on the pipe surface and where corrosion occurred. Fig. 4 shows a typical coating failure and the external corrosion's appearance.

During excavation a water sample from the ditch was collected and analyzed. Fig. 5 shows the sample collection site, and Table 1 lists the analysis results.

Fig. 6 shows results of a periodic CP survey on the flowline. The protective potential was –935 mv ($Cu/CuSO_4$). The commonly accepted criterion for cathodic protective potential is a polarized potential more negative than –850 mv.[1,2]

Preliminary experiments sought to determine pH and temperature effects on CP performance and the hydrogen evolution that could contribute to the coating disbonding. A Gamry potentiostat collected dynamic polarization curves in various concentrations of sulfuric acid solution at different temperatures for the experiments.

Table 2 lists chemical composition of the X-52 pipeline steel. A Foundry-Master spark emission spectrometer obtained the results. About 40 ppm NaCl and 900 ppm Na_2SO_4 added to the solutions simulated the excavation site water. Table 3 lists the test solutions.

Fig. 7 shows the room-temperature polarization curves at various pH points. Fig. 8 shows the polarization curves in 0.01M H_2SO_4 solution at various temperatures.

Soil acidification

The subbituminous type coal at the failure site has a total sulfur content of 0.22-1.59%. Likely forms of sulfur include monosulfide (S^{2-}), pyritic sulfur (S_2^{2-}), and sulfate sulfur (SO_4^{2-}). Pyrite (FeS_2) is a major sulfur mineral in the coal, present in both the coal seam and sandstone strata adjacent

Equations

$$2FeS_2 + 7O_2 + 2H_2O \rightarrow 2Fe^{2+} + 4SO_4^{2-} + 4H^+ \quad (1)$$

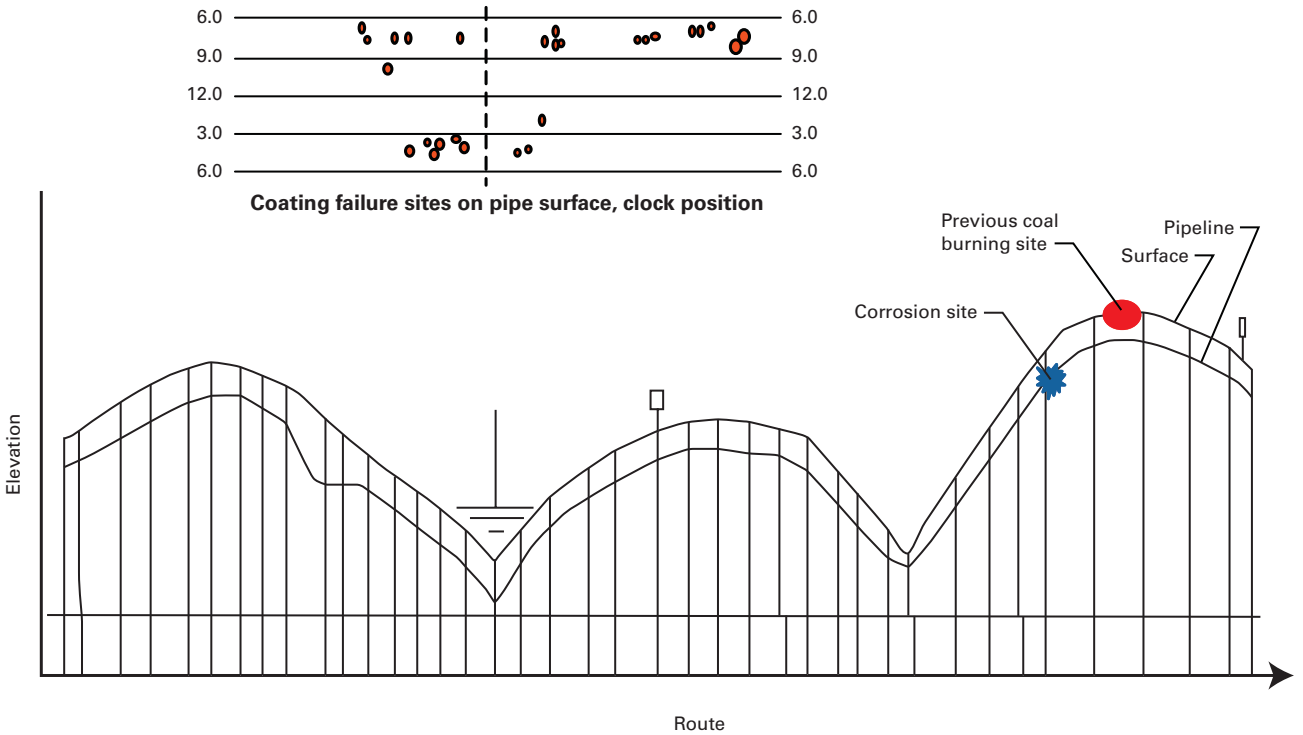
$$4Fe^{2+} + O_2 + 4H^+ \rightarrow 4Fe^{3+} + 2H_2O \quad (2)$$

$$4Fe^{3+} + 12H_2O \rightarrow 4Fe(OH)_3\downarrow + 12H^+ \quad (3)$$

$$FeS_2 + 14Fe^{3+} + 8H_2O \rightarrow 15Fe^{2+} + 2SO_4^{2-} + 16H^+ \quad (4)$$

CORROSION SITE, COATING FAILURE LOCATIONS

Fig. 3



The acidic soil environment created by the coal seam, moisture, and elevated temperatures caused the coating disbondment and external pitting corrosion shown here, despite cathodic protection (Fig. 4).

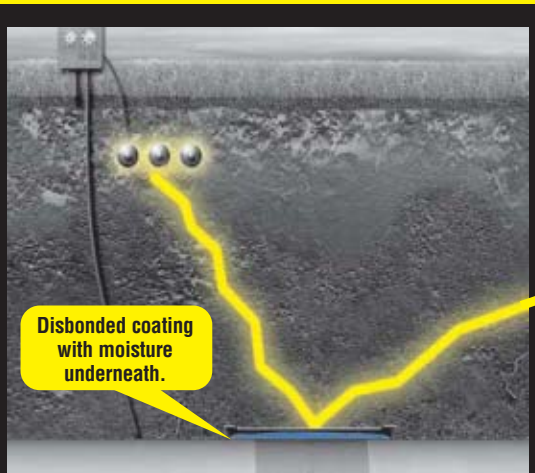
to the coal beds at the corrosion site.

Once sulfide minerals are exposed to air and water, the oxidation process can produce sulfuric acid and ferrous sulfate. Further reaction can produce ferric sulfate, ferric hydroxide, and more sulfuric acid. Equations 1-4 (accompanying box) show the generally accepted sequence of pyrite oxidation reactions.[3-5]

Similarly, when the coal seam burns spontaneously, oxidized sulfur escaping as gas can combine with water in the soil to produce an acidic environment. Field analysis on the excavation ditch water showed oxidation of the sulfur in the coal generated low pH (2.54) water with SO_4^{2-} being the dominant anion.

CATHODIC SHIELDING BY DISBONDED COATINGS

Why you need Polyguard RD-6



Graphic Illustration of Shielding

Extracted from NACE document "Coating Failure Definitions in Relation to CP"

Definition of "Shielding With No Holiday"

"A substantial diversion of cathodic current away from its intended target (i.e.steel substrate) due to a disbonded coating with a high dielectric characteristic and no holidays on the disbonded coating. Steel substrate is deprived of protective current and corrosion can continue undetected and unchecked, including MIC activity, until failure occurs. Traditional diagnostic techniques such as CIS and DCVG cannot identify the existence of such anomalies."

DISBONDMENT
Even the best coatings can disbond in areas over time. Disbondment risk is greatest with girth weld coatings which are application sensitive and subject to soil stress.

HIGH DIELECTRIC
Corrosion coatings with solid film backing have this high dielectric characteristic.

INSIDIOUS #1
We at Polyguard believe that the problem of shielding disbonded coatings is one of the most serious in the pipeline industry. Our belief is reinforced as large operators who discover the shielding problem convert to our RD-6 coating system.

INSIDIOUS #2
Shielding hides corrosion not only from CP, but also from common diagnostic techniques. Shielding is truly an insidious phenomenon.

Two corrosion coatings are proven to be non-shielding, that is to allow passage of protective CP current into disbonded areas. One of these is FBE. The other is the Polyguard RD-6 coating system. After 21 years, and thousands of installations, there has been no significant metal loss found under the Polyguard RD-6 coating system.

Polyguard

Phone: (1) 214.515.5000 www.polyguardproducts.com

ISO 9001 BUREAU VERITAS Certification
N° 180576

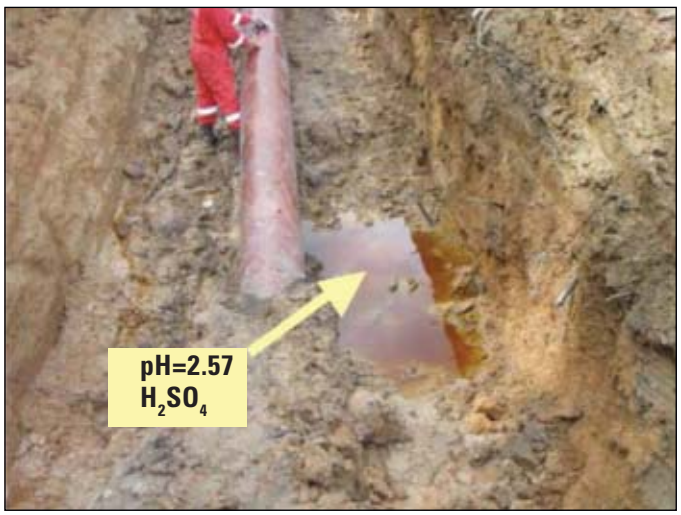
Polyguard has been ISO 9000 certified since 1996.
Current certifications are:
- American Natl. Standards Institute
- Dutch Council for Certification
- Deutscher Akkreditierungs Rat

Visit www.polyguardproducts.com/flash.htm to review the dozens of technical papers published on the subject of shielding since the mid 1980's, and to see an animated graphical explanation of CP shielding.

The water's color may show dissolved ferric compounds to be present, but further chemical analysis would be necessary to confirm. A neutralization reaction with soil may also cause the water to contain cations dissolved from the soil.

Acidic water surrounding the hot pipe surface (90-110° C.) could be concentrated, resulting in an even lower pH. Research on acidic mine waters in California has showed negative pH and high sulfate concentration underground. Investigators believed the extreme acid water was formed primarily by pyrite oxidation and could be concentrated by evaporation with a high atmospheric temperature.[6]

The oxidation of the surrounding coal seam generated a highly acidic and corrosive environment for the buried pipe. The high temperature of the pipe surface could concentrate the acidic water to an even lower pH value. The coating on the external pipe surface also may not resist such an acidic environment at high temperature.



Water collected near the corrosion site had pH = 2.57 (Fig. 5).

Cathodic protection

Pipelines are often coated with nonmetallic coatings, supplemented by cathodic protection to mitigate corrosion at defects and holidays in the coating. Hydroxyl ions and hydrogen will form at the surface of the cathodically protected object. These products may cause disbonding of nonmetallic coatings by mechanisms including chemical dissolution and electrochemical reduction processes at the metal-coating interface. The buildup of hydrogen pressure at this interface may also contribute to disbonding. Heat flow to the metal-coating interface can accelerate this cathodic disbanding process on components containing hot fluids.[1]

Coating disbondment results in more bare steel surface exposure to the environment, increasing the cathodic protection current necessary to maintain protection. The required protective current eventually may exceed the capabilities of the CP system. The steel surfaces shielded by disbonded coating debris also may not get enough current to be protected. If an acidic liquid intrudes between coating and steel surface, corrosion would be severe especially at elevated temperature.

The cathodic reaction on the steel surface with CP applied leads to reduction of the hydrogen ion in acidic environments.[7] According to the Nernst equation, the hydrogen redox potential will be shifted more positive with lower pH.[7] The hydrogen reduction line moves to the right at lower pH, and in sequence, the corrosion potential of steel shifts more positive, requiring more protective current to achieve the same cathodic protection level in lower pH environments.

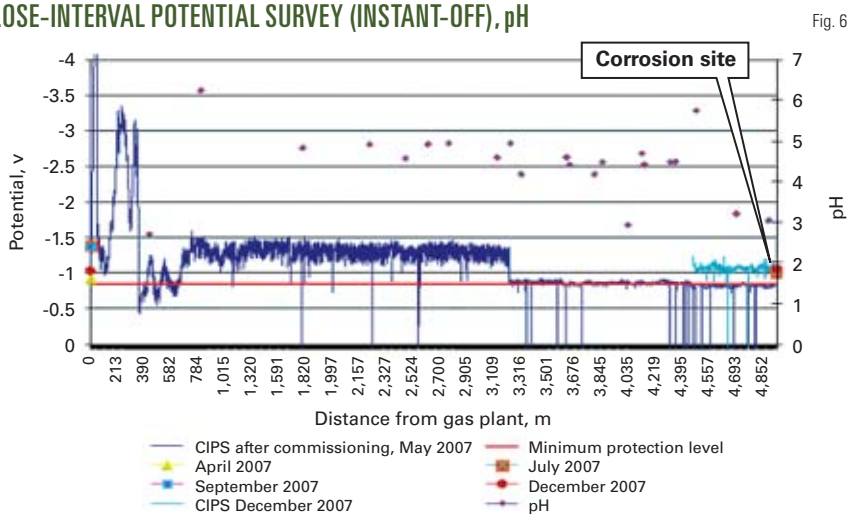
The preliminary experiment results shown in Fig. 7 demonstrate the corrosion potential shifting more positive at a lower pH and requiring a higher protection current to maintain the CP system at the same protective potential. Higher cathodic current, however, could also generate more hydrogen, potentially exacerbate coating disbondment.

Although an industry standard men-

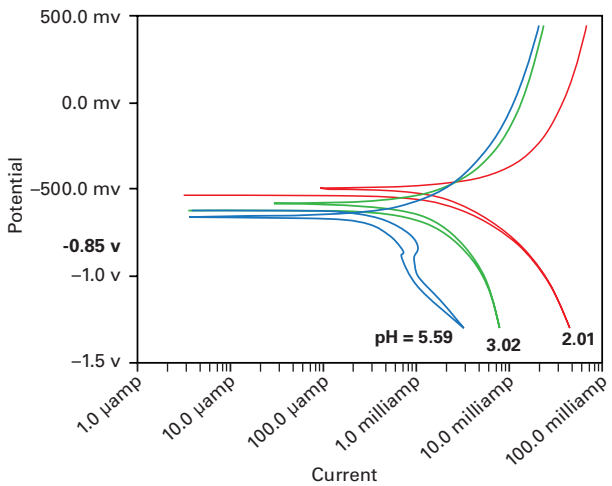
X-52 PIPE STEEL CHEMICAL COMPOSITION Table 2

Element	Fe	C	Mn	P	S	V	Nb	Ti
Content, %	98.1	0.0837	1.31	0.0165	0.004	0.002	<0.002	0.0082

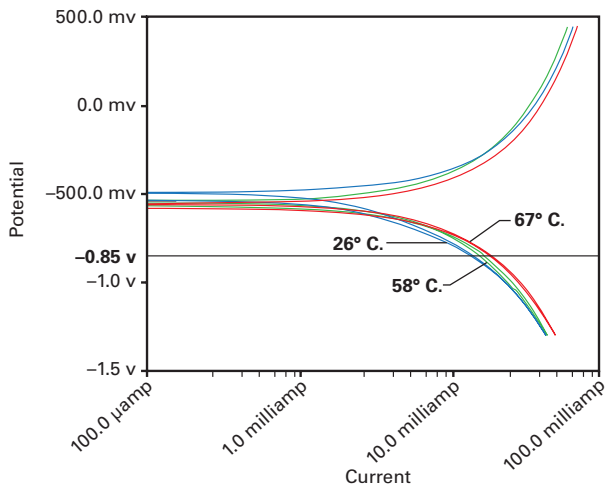
CLOSE-INTERVAL POTENTIAL SURVEY (INSTANT-OFF), pH Fig. 6



CARBON-STEEL POLARIZATION CURVES, H_2SO_4, 26° C. Fig. 7



CARBON-STEEL POLARIZATION CURVES, 0.01M H_2SO_4 Fig. 8



tions higher current is required for CP in an acidic environment,[8] in strong acidic environments such as this, the amount of the current required and the higher risk of coating disbonding by hydrogen evolution would render CP impractical.[7] CP survey data showed protection potential at the corrosion site at 950 mv, showing cathodic protection potential in compliance with industry standards. The coating and the CP, however, still failed to protect the pipe from corrosion.

Fig. 7 also shows the anodic part of the polarization curve shifting in a higher current direction at pH = 2.01, meaning a higher corrosion rate for the steel. A surface condition change of steel at this pH may cause the shift.

Industry standards also suggest pipelines operating at more than 30° C. increase their current density values.[2] Although experimental results in Fig. 8 show a higher protection current as being required at elevated temperature, in this case, temperature is not as sensitive as pH to the CP operation.

TEST SOLUTION PROPERTIES, 26° C. Table 3

H_2SO_4 solution pH, measured	Conductivity, milliSiemens/cm	Na_2SO_4, ppm	NaCl, ppm
5.59	1.518	887	42
3.02	2.01	896	42
2.01	7.72	895	45

Future

Testing to resolve the coating degradation and corrosion issue would involve the following research:

- Identification of effective coating and CP operation parameters to protect the pipe in low pH and high-temperature environments.
- Monitoring coating failure and external corrosion.
- Improving quality of survey data.
- Laboratory experiments to evaluate acidification and acid concentration and test the stability of the coating and cathodic disbonding at various pHs and temperatures.
- Investigating the effect of low pH and high temperature on corrosion behavior and corrosion rate of the steel in a quiescent acidic solution.

Acknowledgments

The authors thank William Thomason, Juri Kolts, Mike Joosten, Dale McIntyre, and Ronnie Summerlin for sharing their knowledge, draft review, and experimental assistance. We also thank ConocoPhillips Indonesia and the Production Assurance Technology group in ConocoPhillips Co. for their support. ✦

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The authors

Wei Chu (wei.chu@conocophillips.com) is a senior scientist at ConocoPhillips Co., Bartlesville, Okla. He has also served as senior scientist at Montana State University's Western Transport Institute and at Florida Atlantic University. He holds a doctoral degree (2000) from Xiamen University. He is a member of NACE and ECS.

Muhdi Sujatmiko (muhdi.sujatmiko@conocophillips.com) is a senior corrosion engineer at ConocoPhillips Indonesia Inc. Ltd., Jakarta. He has also served as corrosion and pipeline integrity engineer at BP Indonesia Inc. Ltd. He holds a BE in chemical engineering (1997) from Institut Teknologi Bandung, Indonesia. He is a member of NACE.

New launching technology increases pigging efficiency

Neil Errington
Pipeline Engineering & Supply Co. Ltd.
Catterick, UK

A new technology allows multiple pig launching with existing pipeline equipment.

Aging pipeline networks and the installation of new lines over greater distances and in more hostile environments have heightened demand for pigging technology. Pipeline pigging is essential for removing debris and collecting sample fluids, ensuring flow is maintained and corrosion minimized. Pigging, however, is time consuming and can disrupt production and operational efficiency.

The UK oil Industry's Technology Facilitator issued a call for technology proposals to increase production capacity and efficiency. Participants identified reliable flow-assurance techniques as critical. This article details field testing of a technology developed by Pipeline Engineering & Supply Co. Ltd. in response to the ITF's call for proposals.

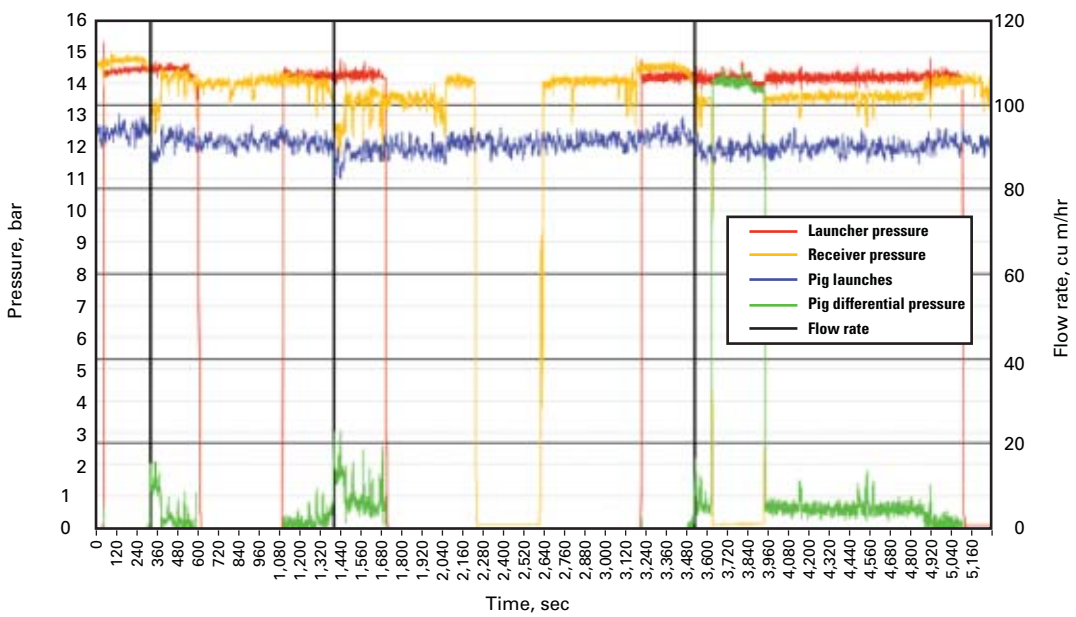
AMPL

The Automatic Multiple Pig Launching System is a new multipigging tool designed by PE. It uses existing pipeline equipment, retrofitted with a cassette loaded with independently launchable pigs. AMPL requires neither modification to existing pipeline launchers nor an external power supply.

Existing automatic pig launchers generally operate a complex arrangement of kicker lines and valves or release flaps for multiple launching. The latter mechanism cannot be retrofitted to existing traps and often requires an external power supply. The

MONTROSE AMPL TEST DATA

Fig. 1



complexity of the design can also add substantially to the cost of a launcher.

Opening a trap closure also has health, safety, and environmental implications. These issues become even more complex when pigging from an unmanned platform or during a remote subsea operation. Mechanisms built into the pigs rather than the launcher control pig launching by AMPL, negating the need for human intervention and reducing the intensity and risk of regular pigging activities.

ITF worked with PE to secure industry support from four of its member companies for an AMPL Joint Industry Project to be carried out in two phases. Following successful completion of Phase 1, PE secured further support for two sets of field trials to assess the overall system performance and functionality and gain further understanding of the bypass systems on individual AMPL tools.

JIP participants used a 10-in. AMPL system for the first set of field trials, recently completed at the Petrofac facility in Montrose, Scotland. These trials successfully launched and received the AMPL pigs at flow velocities of 0.5 m/sec and 1 m/sec (14,000 and 28,000 b/d, respectively). The pigs launched successfully and confirmed tests previously undertaken at PE's North Yorkshire base to test and validate AMPL's setup before mobilization to the Montrose base.

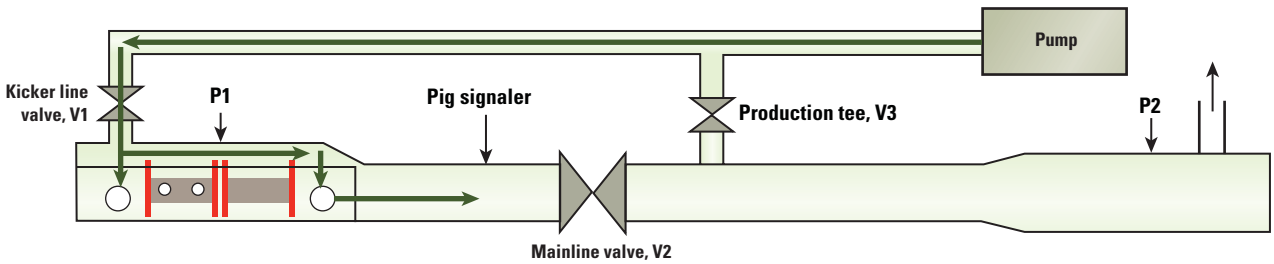
Montrose test

The AMPL system cassette was loaded with three suitably configured pigs. Earlier flow tests had shown this configuration to be successful at launching individual pigs with the fluid flow rate set to 0.5 m/sec. Fig. 1 shows data produced from this multiple launch test.

This first test demonstrated the AMPL system launching while the pipeline was operating at 14,129 b/d. Both flow rate and pressure ~15 barg were established in the pipeline before testing. Loading a lead AMPL pig and two

MULTIPLE-LAUNCH TEST SCHEMATIC

Fig. 2



AMPL PHYSICAL REQUIREMENTS

Table 1

Feature	Capability
Line sizes	6-36 in. OD
Multidiameter capability	Single line sizes only
Minimum bend radius	3D
Tees	Can pass typical in-line tees
Wyes	Wye piece passage not required as standard
Valves	Can pass ball, gate valves
Line pipe types	Steel, flexible pipe

AMPL OPERATIONAL REQUIREMENTS

Table 2

Feature	Description
Pig types	Mandrel cup, disc types only
Jetting head	Jetting head option to be available
Maximum operating pressure	300 barg
Minimum operating pressure	15 barg
Maximum operating temperature	90° C.
Minimum operating temperature	0° C.
Minimum pig speed	0.25 m/sec
Maximum pig speed	3 m/sec
Line fluids	Oil, water, gas, and multiphase
Contaminants	Suitable for sour service
Line debris	Capable of pigging typical debris
Pig tracking	Space for pingers and isotopes
Data logging	Space for data loggers
Longevity	Maximum 3 months armed in trap
Partial-pressure arming	Can arm on partial trap depressurization

standard AMPL pigs into the launch cassette preceded loading the cassette into the pig launcher.

Opening Valve V1 (Fig. 2) flooded the launcher and brought it to operating pressure. Opening Valve V2 allowed product flow through the launcher, cassette, and pigs. Closing Valve V3 diverted flow through the launcher. At about 300 sec the lead pig launched and was confirmed by the pig signaler, product was allowed to continue flowing through the trap for an additional 300 sec to test for unplanned pig launch. None occurred. Reversing this process depressurized the trap.

The trap remained depressurized for about 400 sec but at no point was it drained or opened. At around 1,000 sec repressurization occurred and the valves operated in the same manner as for the lead AMPL pig. At about 1,400 sec launch of the second AMPL pig happened, again confirmed by the pig signaler. The trap remained flooded after once again being depressurized.

During the launch of the second AMPL pig, detectors signaled receipt of the lead pig. Isolating and draining the receiver to retrieve the pig confirmed only the lead pig had launched. The receiver was flooded and repressurized ready for receipt of the second AMPL pig.

At around 3,200 sec, technicians pressurized the launcher again, operating the valves by the same process as the first two pigs. Launch detection of the final AMPL pig occurred at about 3,500 sec, confirming individual launch of each the AMPL pigs. During the launch of this final pig, the receipt of the second AMPL pig was detected. Immediately retrieving the pig confirmed its individual launch.

The pipeline continued operating until around 5,000 sec when the final AMPL pig was detected and retrieved in the receiver. The pipeline was shut down and data retrieved.

The next stage of field trials will take place in Oman, where AMPL will be tested in an 8-in. OD oil pipeline about 9 km long and currently under a fortnightly pigging schedule. ✦

The author

Neil Errington (neil.errington@pipelineengineering.com) is an account manager at Pipeline Engineering based in Catterick, North Yorkshire, UK. He has also held various international engineering positions for BG and has previously lived and worked in Turkey, Indonesia, and Brazil and represented the UK oil and gas industry on secondment to the British Embassy in Jakarta. He is a member of the Institute of Gas Engineers.

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Worldwide Gas Processing Survey — Gas processing plants worldwide with details.
E1209 Current E1219C Historical, 1985 to current

International Ethylene Survey — Information on country, company, location, capacity, etc.
E1309 Current E1309C Historical, 1994 to current

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LNGINFO

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

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

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

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

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

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

Production Projects Worldwide — List of planned production mega-projects.
PRODPROJ

See website for prices

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Imports of crude and products

	Districts 1-4		District 5		Total US		
	11-6 2009	10-30 2009	11-6 2009	10-30 2009	11-6 2009	10-30 2009	*11-7 2008
	1,000 b/d						
Total motor gasoline	669	1,074	63	3	732	1,077	589
Mo. gas. blending comp.	485	884	60	0	545	884	447
Distillate	177	197	0	0	177	197	36
Residual	215	349	33	0	248	349	228
Jet fuel-kerosine	23	34	12	52	35	86	36
Propane-propylene	125	110	12	12	137	122	182
Other	642	(193)	(2)	79	640	(114)	1,065
Total products	**2,336**	**2,455**	**178**	**146**	**2,514**	**2,601**	**2,583**
Total crude	**7,865**	**7,252**	**791**	**874**	**8,656**	**8,126**	**9,503**
Total imports	**10,201**	**9,707**	**969**	**1,020**	**11,170**	**10,727**	**12,086**

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

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OIL&GAS JOURNAL online research center

OGJ crack spread

	*11-13-09	*11-14-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	82.89	65.51	17.38	26.5
Brent crude	76.46	53.32	23.14	43.4
Crack spread	6.43	12.19	–5.76	–47.2
FUTURES MARKET PRICES				
One month				
Product value	83.47	64.42	19.05	29.6
Light sweet crude	78.21	58.64	19.57	33.4
Crack spread	5.26	5.78	–0.53	–9.1
Six month				
Product value	90.58	72.32	18.26	25.3
Light sweet crude	81.46	63.05	18.41	29.2
Crack spread	9.12	9.26	–0.14	–1.5

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

Purvin & Gertz LNG netbacks—Nov. 13, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.12	4.58	5.87	4.47	5.17	5.79
Everett	3.81	1.72	3.44	1.80	2.26	4.10
Isle of Grain	4.24	2.14	3.60	2.08	2.68	3.63
Lake Charles	1.92	0.31	1.70	0.44	0.58	2.54
Sodegaura	5.25	7.55	5.50	7.24	6.49	4.56
Zeebrugge	6.16	3.92	5.48	3.82	4.53	5.54

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	11,383	56,624	38,729	12,272	74,769	14,235	4,971
PADD 2	80,190	49,023	24,394	8,134	29,601	1,161	28,017
PADD 3	174,424	69,273	41,014	14,512	47,804	16,661	33,100
PADD 4	16,112	5,916	1,924	588	3,099	232	[1]2,421
PADD 5	55,567	30,001	25,969	9,146	12,452	3,734	—
Nov. 6, 2009	**337,676**	**210,837**	**132,030**	**44,652**	**167,725**	**36,023**	**68,509**
Oct. 30, 2009	**335,914**	**208,277**	**130,265**	**45,183**	**167,376**	**35,054**	**69,632**
Nov. 7, 2008[2]	**311,949**	**198,095**	**101,088**	**36,835**	**128,351**	**38,976**	**60,276**

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

Refinery report—Nov. 6, 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	1,228	1,238	2,351	66	423	119	60
PADD 2	2,868	2,856	2,227	160	911	74	214
PADD 3	7,010	6,823	2,561	681	2,054	348	688
PADD 4	536	537	319	29	201	10	[1]167
PADD 5	2,483	2,371	1,461	385	465	130	—
Nov. 6, 2009	**14,125**	**13,825**	**8,919**	**1,321**	**4,054**	**681**	**1,129**
Oct. 30, 2009	**14,241**	**13,970**	**9,040**	**1,351**	**3,957**	**625**	**1,066**
Nov. 7, 2008[2]	**14,897**	**14,463**	**9,024**	**1,314**	**4,371**	**610**	**1,065**
	17,672 Operable capacity		**79.9% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 11-11-09	Pump price* 11-11-09	Pump price 11-12-08
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	227.9	259.3	228.3
Baltimore	220.3	262.2	237.8
Boston	221.3	263.2	228.2
Buffalo	211.1	274.3	217.7
Miami	226.3	279.2	230.6
Newark	221.3	254.2	222.6
New York	209.9	273.1	237.6
Norfolk	214.6	252.3	217.7
Philadelphia	219.5	270.2	235.5
Pittsburgh	218.5	269.2	237.4
Wash., DC	230.4	272.3	238.4
PAD I avg	220.1	266.3	230.2
Chicago	241.7	296.8	235.3
Cleveland	237.7	284.1	220.2
Des Moines	219.8	260.2	215.3
Detroit	235.6	287.2	230.3
Indianapolis	231.7	281.8	225.3
Kansas City	211.5	247.2	199.1
Louisville	230.0	270.9	225.3
Memphis	212.3	252.1	209.3
Milwaukee	225.7	277.0	224.1
Minn.-St. Paul	225.6	271.2	218.4
Oklahoma City	198.9	234.3	188.9
Omaha	210.8	256.5	198.3
St. Louis	211.0	246.7	209.6
Tulsa	195.7	231.1	187.5
Wichita	205.7	249.1	200.0
PAD II avg	219.6	263.1	212.5
Albuquerque	215.2	252.4	219.8
Birmingham	219.1	258.4	208.9
Dallas-Fort Worth	211.1	249.5	204.4
Houston	213.4	251.8	194.0
Little Rock	206.3	246.5	209.5
New Orleans	220.6	259.0	224.6
San Antonio	216.6	255.0	219.3
PAD III avg	214.6	253.2	211.5
Cheyenne	220.3	252.7	221.3
Denver	218.9	259.3	249.9
Salt Lake City	211.4	254.3	240.2
PAD IV avg	216.9	255.4	237.1
Los Angeles	232.1	297.9	265.9
Phoenix	220.5	257.9	255.6
Portland	237.5	280.9	270.2
San Diego	233.1	298.9	275.6
San Francisco	239.2	305.0	280.6
Seattle	239.0	294.9	265.6
PAD V avg	233.6	289.3	268.9
Week's avg.	**220.7**	**265.5**	**226.8**
Oct. avg.	**208.4**	**253.6**	**317.6**
Sept. avg.	**211.0**	**256.6**	**367.2**
2009 to date	**183.3**	**228.8**	—
2008 to date	**300.9**	**345.0**	—

*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

	11-6-09 ¢/gal		11-6-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	192.15	New York Harbor	195.44
Gulf Coast	187.65	Gulf Coast	192.94
Los Angeles	195.28	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	197.30	ARA	194.89
Singapore	196.90	Singapore	203.69
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	190.15	New York Harbor	171.50
Gulf Coast	188.40	Gulf Coast	172.93
Los Angeles	190.15	Los Angeles	185.63
		ARA	173.23
		Singapore	179.18

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

BAKER HUGHES RIG COUNT

	11-13-09	11-14-08
Alabama	4	4
Alaska	8	10
Arkansas	40	59
California	25	46
Land	24	46
Offshore	1	0
Colorado	40	124
Florida	0	1
Illinois	1	1
Indiana	3	2
Kansas	21	10
Kentucky	11	12
Louisiana	166	178
N. Land	108	85
S. Inland waters	13	21
S. Land	13	21
Offshore	32	51
Maryland	0	0
Michigan	0	1
Mississippi	6	14
Montana	5	7
Nebraska	1	0
New Mexico	48	80
New York	3	5
North Dakota	54	90
Ohio	8	12
Oklahoma	77	189
Pennsylvania	62	27
South Dakota	0	0
Texas	432	899
Offshore	3	8
Inland waters	0	0
Dist. 1	22	27
Dist. 2	18	33
Dist. 3	28	64
Dist. 4	25	94
Dist. 5	65	169
Dist. 6	49	125
Dist. 7B	15	26
Dist. 7C	36	68
Dist. 8	79	124
Dist. 8A	22	28
Dist. 9	28	45
Dist. 10	42	88
Utah	19	48
West Virginia	20	29
Wyoming	39	74
Others—HI-1; NV-2; OR-1; TN-1; VA-3	8	19
Total US	**1,101**	**1,941**
Total Canada	**263**	**418**
Grand total	**1,364**	**2,359**
US Oil rigs	361	429
US Gas rigs	728	1,498
Total US offshore	37	64
Total US cum. avg. YTD	**1,079**	**1,886**

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	11-13-09 Percent footage*	Rig count	11-14-08 Percent footage*
0-2,500	80	3.7	87	3.4
2,501-5,000	63	71.4	139	53.2
5,001-7,500	124	27.4	262	11.8
7,501-10,000	223	7.1	459	2.8
10,001-12,500	221	13.1	424	1.4
12,501-15,000	152	2.6	391	—
15,001-17,500	148	—	167	—
17,501-20,000	66	—	72	—
20,001-over	34	—	35	—
Total	**1,111**	**11.7**	**2,036**	**6.2**
INLAND	18		32	
LAND	1,053		1,947	
OFFSHORE	40		57	

*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]11-13-09	[2]11-14-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	22
Alaska	710	722
California	652	651
Colorado	66	67
Florida	6	6
Illinois	27	25
Kansas	110	110
Louisiana	1,414	941
Michigan	18	16
Mississippi	64	63
Montana	86	86
New Mexico	167	167
North Dakota	209	210
Oklahoma	181	180
Texas	1,402	1,298
Utah	65	65
Wyoming	150	146
All others	67	73
Total	**5,415**	**4,848**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	11-13-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	76.25
California-Midway Sunset 13°	67.45
Lost Hills 30°	76.05
Wyoming Sweet	68.10
East Texas Sweet	72.25
West Texas Sour 34°	67.75
West Texas Intermediate	72.75
Oklahoma Sweet	72.75
Texas Upper Gulf Coast	65.75
Michigan Sour	64.75
Kansas Common	71.75
North Dakota Sweet	62.25

*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]	11-6-09
United Kingdom-Brent 38°	76.53
Russia-Urals 32°	76.03
Saudi Light 34°	75.65
Dubai Fateh 32°	77.14
Algeria Saharan 44°	77.51
Nigeria-Bonny Light 37°	78.71
Indonesia-Minas 34°	80.18
Venezuela-Tia Juana Light 31°	76.77
Mexico-Isthmus 33°	76.66
OPEC basket	77.16
Total OPEC[2]	76.56
Total non-OPEC[2]	76.05
Total world[2]	76.34
US imports[3]	75.31

[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]

	11-6-09	10-30-09	11-6-08	Change, %
		bcf		
Producing region	1,199	1,189	960	**24.9**
Consuming region east	2,093	2,085	2,037	**2.7**
Consuming region west	521	514	467	**11.6**
Total US	**3,813**	**3,788**	**3,464**	**10.1**
	Aug. 09	**Aug. 08**	**Change, %**	
Total US[2]	**3,352**	**2,867**	**16.9**	

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

Statistics

World oil balance

	2009 2nd qtr.	2009 1st qtr.	2008 4th qtr.	2008 3rd qtr.	2008 2nd qtr.	2008 1st qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	18.75	19.07	19.53	19.20	20.05	20.31
Canada	2.06	2.20	2.26	2.28	2.19	2.31
Mexico	2.01	2.05	2.07	2.14	2.19	2.12
Japan	4.03	4.72	4.71	4.34	4.63	5.45
South Korea	2.17	2.34	2.14	2.10	2.11	2.35
France	1.81	2.02	2.04	1.95	1.95	2.01
Italy	1.52	1.55	1.62	1.64	1.64	1.66
United Kingdom	1.67	1.73	1.73	1.65	1.73	1.73
Germany	2.39	2.57	2.65	2.71	2.43	2.49
Other OECD Europe	6.83	7.05	7.40	7.60	7.33	7.45
Australia & New Zealand	1.10	1.08	1.12	1.10	1.11	1.10
Total OECD	**44.34**	**46.38**	**47.27**	**46.71**	**47.36**	**48.98**
NON-OECD						
China	8.44	7.62	7.54	7.78	8.07	7.94
FSU	4.19	4.10	4.48	4.47	4.22	4.23
Non-OECD Europe	0.77	0.77	0.80	0.80	0.80	0.79
Other Asia	9.53	9.30	8.83	9.06	9.74	9.64
Other non-OECD	16.32	15.33	15.68	16.53	16.12	15.29
Total non-OECD	**39.25**	**37.12**	**37.33**	**38.64**	**38.95**	**37.89**
TOTAL DEMAND	**83.59**	**83.50**	**84.60**	**85.35**	**86.31**	**86.87**
SUPPLY						
OECD						
US	8.97	8.78	8.46	8.18	8.75	8.67
Canada	3.20	3.38	3.40	3.40	3.22	3.38
Mexico	2.99	3.06	3.12	3.15	3.19	3.29
North Sea	4.00	4.40	4.37	4.06	4.31	4.44
Other OECD	1.53	1.54	1.59	1.59	1.57	1.52
Total OECD	**20.69**	**21.16**	**20.94**	**20.38**	**21.04**	**21.30**
NON–OECD						
FSU	12.87	12.60	12.46	12.42	12.60	12.59
China	3.98	3.92	3.99	3.97	4.00	3.94
Other non-OECD	12.42	12.40	12.35	12.29	12.12	12.20
Total non-OECD, non-OPEC	**29.27**	**28.92**	**28.80**	**28.68**	**28.72**	**28.73**
OPEC*	**33.68**	**33.41**	**35.16**	**36.18**	**35.84**	**35.72**
TOTAL SUPPLY	**83.64**	**83.49**	**84.90**	**85.24**	**85.60**	**85.75**
Stock change	**0.05**	**–0.01**	**0.30**	**–0.11**	**–0.71**	**–1.12**

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

US petroleum imports from source country

	July 2009	June 2009	Average YTD 2009	Average YTD 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	329	458	462	526	–64	–12.2
Angola	320	447	513	527	–14	–2.7
Kuwait	261	179	187	209	–22	–10.5
Nigeria	879	830	708	1,052	–344	–32.7
Saudi Arabia	1,153	959	1,095	1,554	–459	–29.5
Venezuela	959	1,237	1,147	1,193	–46	–3.9
Other OPEC	722	704	819	1,020	–201	–19.7
Total OPEC	**4,623**	**4,814**	**4,931**	**6,081**	**–1,150**	**–18.9**
Canada	2,639	2,529	2,450	2,506	–56	–2.2
Mexico	1,316	1,183	1,280	1,306	–26	–2.0
Norway	119	173	134	115	19	16.5
United Kingdom	188	268	252	218	34	15.6
Virgin Islands	273	268	301	330	–29	–8.8
Other non-OPEC	2,894	2,667	2,849	2,528	321	12.7
Total non-OPEC	**7,429**	**7,088**	**7,266**	**7,003**	**263**	**3.8**
TOTAL IMPORTS	**12,052**	**11,902**	**12,197**	**13,084**	**–887**	**–6.8**

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

OECD total net oil imports

	July 2009	June 2009	May 2009	July 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,407	–1,547	–1,186	–1,047	–360	34.4
US	9,704	9,939	9,581	11,073	–1,369	–12.4
Mexico	–1,001	–989	–1,039	–1,007	6	–0.6
France	1,710	1,687	1,798	1,904	–194	–10.2
Germany	2,071	2,105	2,146	2,441	–370	–15.2
Italy	1,451	1,297	1,532	1,498	–47	–3.1
Netherlands	621	1,103	937	1,057	–436	–41.2
Spain	1,417	1,487	1,330	1,524	–107	–7.0
Other importers	3,795	3,722	3,593	4,017	–222	–5.5
Norway	–2,156	–1,779	–1,912	–1,387	–769	55.4
United Kingdom	278	58	–85	20	258	1290.0
Total OECD Europe	**9,187**	**9,680**	**9,339**	**11,074**	**–1,887**	**–17.0**
Japan	3,886	4,157	3,973	4,793	–907	–18.9
South Korea	2,276	2,070	1,964	2,167	109	5.0
Other OECD	972	919	832	947	25	2.6
Total OECD	**23,617**	**24,229**	**23,464**	**28,000**	**–4,383**	**–15.7**

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

OECD* total gross imports from OPEC

	July 2009	June 2009	May 2009	July 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	351	447	339	425	–74	–17.4
US	4,623	4,814	4,471	6,121	–1,498	–24.5
Mexico	18	21	10	45	–27	–60.0
France	831	808	855	927	–96	–10.4
Germany	390	365	450	560	–170	–30.4
Italy	982	969	927	1,157	–175	–15.1
Netherlands	516	533	516	516	0	0.0
Spain	577	756	758	594	–17	–2.9
Other importers	1,262	1,189	1,002	1,286	–24	–1.9
United Kingdom	257	348	315	289	–32	–11.1
Total OECD Europe	**4,815**	**4,968**	**4,823**	**5,329**	**–514**	**–9.6**
Japan	3,597	3,309	3,503	4,336	–739	–17.0
South Korea	2,468	2,384	1,950	2,570	–102	–4.0
Other OECD	550	547	522	581	–31	–5.3
Total OECD	**16,422**	**16,490**	**15,618**	**19,407**	–2,985	–15.4

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

Oil stocks in OECD countries*

	July 2009	June 2009	May 2009	July 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	174	173	176	179	–5	–2.8
Germany	277	280	281	274	3	1.1
Italy	127	129	133	135	–8	–5.9
United Kingdom	97	92	92	95	2	2.1
Other OECD Europe	714	729	720	709	5	0.7
Total OECD Europe	**1,389**	**1,403**	**1,402**	**1,392**	**–3**	**–0.2**
Canada	201	197	199	200	1	0.5
US	1,842	1,839	1,829	1,698	144	8.5
Japan	607	611	609	627	–20	–3.2
South Korea	157	149	149	153	4	2.6
Other OECD	108	110	112	105	3	2.9
Total OECD	**4,304**	**4,309**	**4,300**	**4,175**	**129**	**3.1**

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

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Credibility claim shows low quality of climate debate

The Editor's Perspective

by Bob Tippee, Editor

Everything wrong about debate over climate change congealed in a single sentence at a Senate Finance Committee hearing Nov. 10.

The words came from Sen. John Kerry (D-Mass.) in response to warnings about costs of the cap-and-trade legislation he has sponsored with Sen. Barbara Boxer (D-Calif.).

"Your studies aren't credible because you haven't considered the impacts of inaction," Kerry said (OGJ Online, Nov. 11, 2009). In other words, the senator isn't listening. He and his allies promote an apocalyptic view of planetary warming in response to which they hope to seize control of energy markets.

With the help of a dazzled popular media, they have succeeded in polarizing discourse into two camps: believers and nonbelievers. As Kerry's flippant dismissal of serious warnings by serious adults makes clear, nonbelievers aren't welcome in the debate.

Before he'll take seriously the possibility that cap-and-trade legislation might idle 8 million b/d of US refining capacity and raise the price of oil products by $1/gal, he wants those highlighting the threat also to present the "impacts of inaction."

Yet all the senator needs to do is look around. If his dangerous bill doesn't pass, things won't change much.

Yes, carbon dioxide will further accumulate in the atmosphere. Depending on climate mechanics no one yet knows how to predict accurately, the accumulation might enhance global warming that was going to happen anyway but seems lately to have stalled. Or it might not. Global average temperature responds to many influences beyond human emissions of CO_2, some of them much stronger. People can't affect it much.

In fact, Kerry should confess to the temperature impacts of action on his bill: nothing. A cap-and-trade scheme won't influence temperature. It will just raise energy costs and make the US more popular than it is now among the ruling elite of Europe.

Still, moderating CO_2 emissions—like the companion tactic of moderating energy use—makes sense. It can be done, however, without nationalizing energy consumption and destabilizing the economy. Toward such sensible aims the first step should be to shed comic-book panic about climate catastrophe.

But don't expect Kerry to listen.

(Online Nov. 13, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude trades in tight price range

After trading over a fairly tight range for more than 4 months on the New York Mercantile Exchange, the front-month crude contract finally broke through to the upside only to trade within an even tighter range of $79-80/bbl through 19 days in late October and early November.

There was no explosive breakout—"just a subtle adjustment of the range, and market dynamics have returned to being a fairly relaxed chess game," said Paul Horsnell, managing director and head of commodities research at Barclays Capital in London. "The immediate floor to prices has been moving up, beyond $70/bbl and perhaps as high as $75/bbl, and the downside below that has become more protected by a continuing flow of reasonably supportive macroeconomic and global oil data," he said.

Energy prices fell Nov. 12 with benchmark US light, sweet crudes down $2.34 to $76.94/bbl on NYMEX as traders focused on a US Energy Information Administration report of a larger than expected increase in crude inventories during the previous week. Prices continued to decline Nov. 13 as low as $75.57/bbl before closing at $76.35/bbl.

Crude prices rebounded in early trading Nov. 16 on news China's economy—second only to the US—beat expectations and grew at an annual rate of 4.8% in the third quarter, said analysts in the Houston office of Raymond James & Associates Inc. China's power consumption was reported up 16% from 2008. A declining dollar and growing speculation that the Organization of Petroleum Exporting Countries will leave production unchanged at its December meeting helped boost the price of crude Nov. 16.

EIA reported commercial US benchmark crude inventories increased 1.8 million bbl to 337.7 million bbl in the week ended Nov. 6, the latest period at press time. That surpassed Wall Street's consensus of a 1 million bbl gain but was well below the American Petroleum Institute's more-bearish report of a 3.2 million bbl build. Gasoline stocks for the same week were up 2.5 million bbl to 210.8 million, while analysts expected a 400,000 bbl draw. Distillate fuel inventories increased 300,000 bbl to 167.7 million bbl, also above average and in the opposite direction of analysts' anticipation of a 700,000 bbl decrease.

Refinery runs

Imports of crude into the US in that period were up 530,000 b/d to 8.7 million b/d. In the 4 weeks through Nov. 6, crude imports averaged 8.6 million b/d, down 1.5 million b/d from the comparable period in 2008. Nonetheless, the input of crude into US refineries dropped 145,000 b/d to 13.8 million b/d during the week with units operating at 79.9% of capacity as refiners continued to reduce utilization rates due to weak refining margins. Jacques H. Rousseau, an analyst at Soleil-Back Bay Research, said it was the first time in years refinery utilization dropped below 80% "absent hurricane-related shutdowns." He said, "With refining margins near their lowest level of 2009, we expect this lower supply trend to continue for the remainder of the quarter. The fourth quarter should be the worst quarter of the year for refiner earnings, in our view."

Rousseau added, "EIA regional data showed a continued trend of rising West Coast gasoline inventories, which have increased 9% over the past 4 weeks. Surprisingly, despite very weak refining margins, utilization rates increased in the Rocky Mountains (from 81% to 86%) and West Coast (from 85% to 87%) regions last week, which could raise inventory levels further in those markets in the coming weeks."

Horsnell said Nov. 12, "Plenty of support seems to have built up beneath prices to reduce the sustainability of any sharper moves to the downside. There has also been a degree of increased control over the upside to prices, further compressing the recent trading range. In our view, since the break out above $75/bbl occurred, the nature of the selling pressure at the top of the range...appears less motivated by macro shorts and technicals, and now seems to contain a greater component of reference towards the policy of, and signals from, major oil producers. Those signals are rarely as frequent or quite as subtle as the market often imagines, but the general message has emerged that an immediate charge towards $90/bbl is likely to be overtly damped. In the absence of clearer indications, the market is currently trading as if somewhere around $80/bbl is the safest ceiling, and as if too fast a progression beyond that might attract a more overt damping strategy from producers."

(Online Nov. 16, 2009; author's e-mail: samf@ogjonline.com)

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Phone: +1 713 963 6283
Fax: +1 713 963 6212
Email: kristins@pennwell.com

Bob Lewis
(Power Companies)
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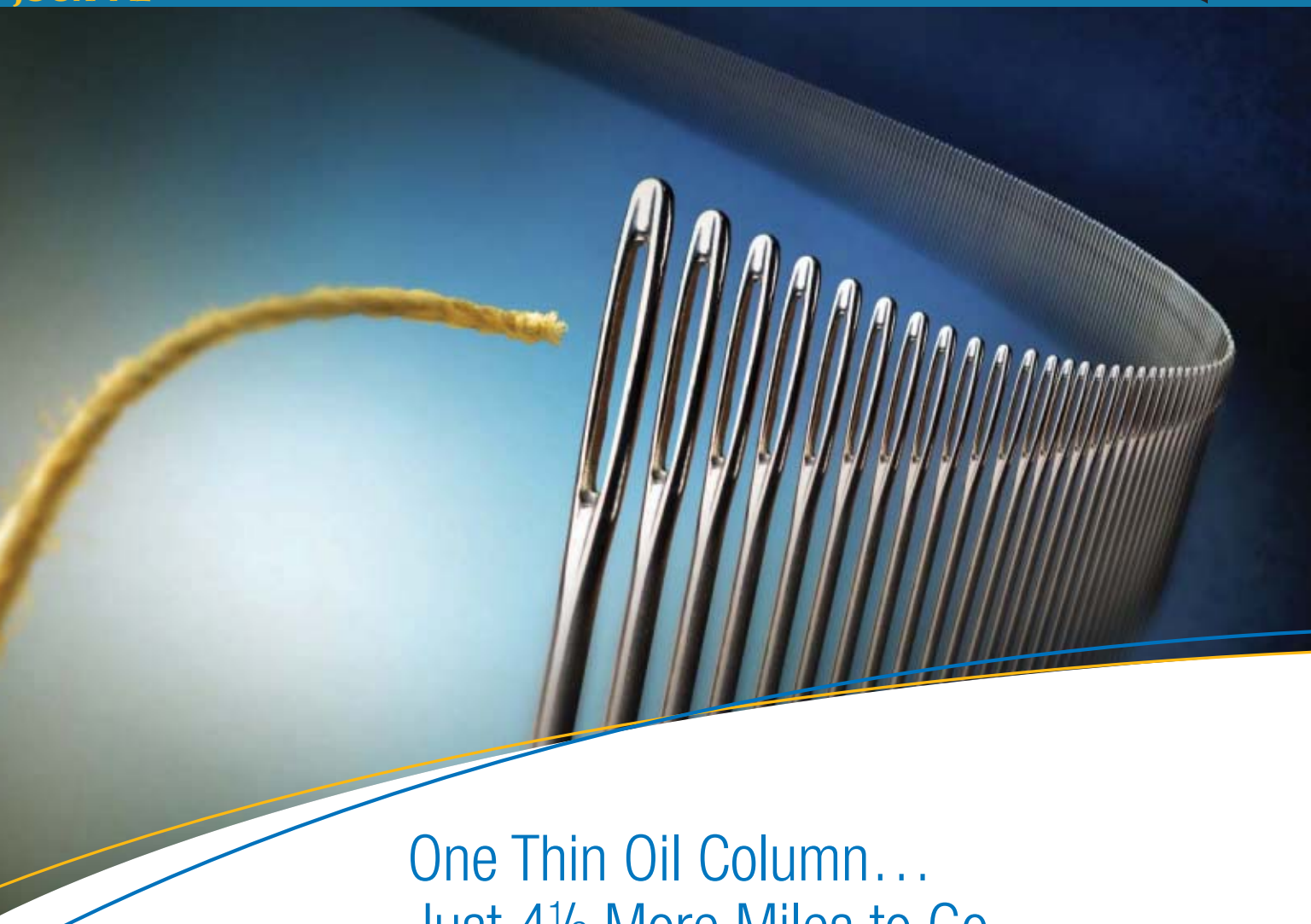

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