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The signs were there. But only Baker Hughes could read them.

Objective: To achieve what the competition could not—accurately identify tar located directly below an oil reservoir so injector wells could be optimally placed to stimulate oil production.

Environment: Manifa Field, Saudi Arabia

Technology: A combination of INTEQ LWD services: **MagTrak™**, the industry's only 4 3/4-in. magnetic resonance tool; **TesTrak™**, real-time formation pressure service that achieved 95% seal efficiency; and **LithoTrak™** density and porosity logging.

Answers: Baker Hughes delivered answers the client needed for accurate formation evaluation and optimum wellbore placement. The tar location was confirmed, and Baker Hughes drilled the injection well more than 30,000 ft (9,144 m), precisely and efficiently.

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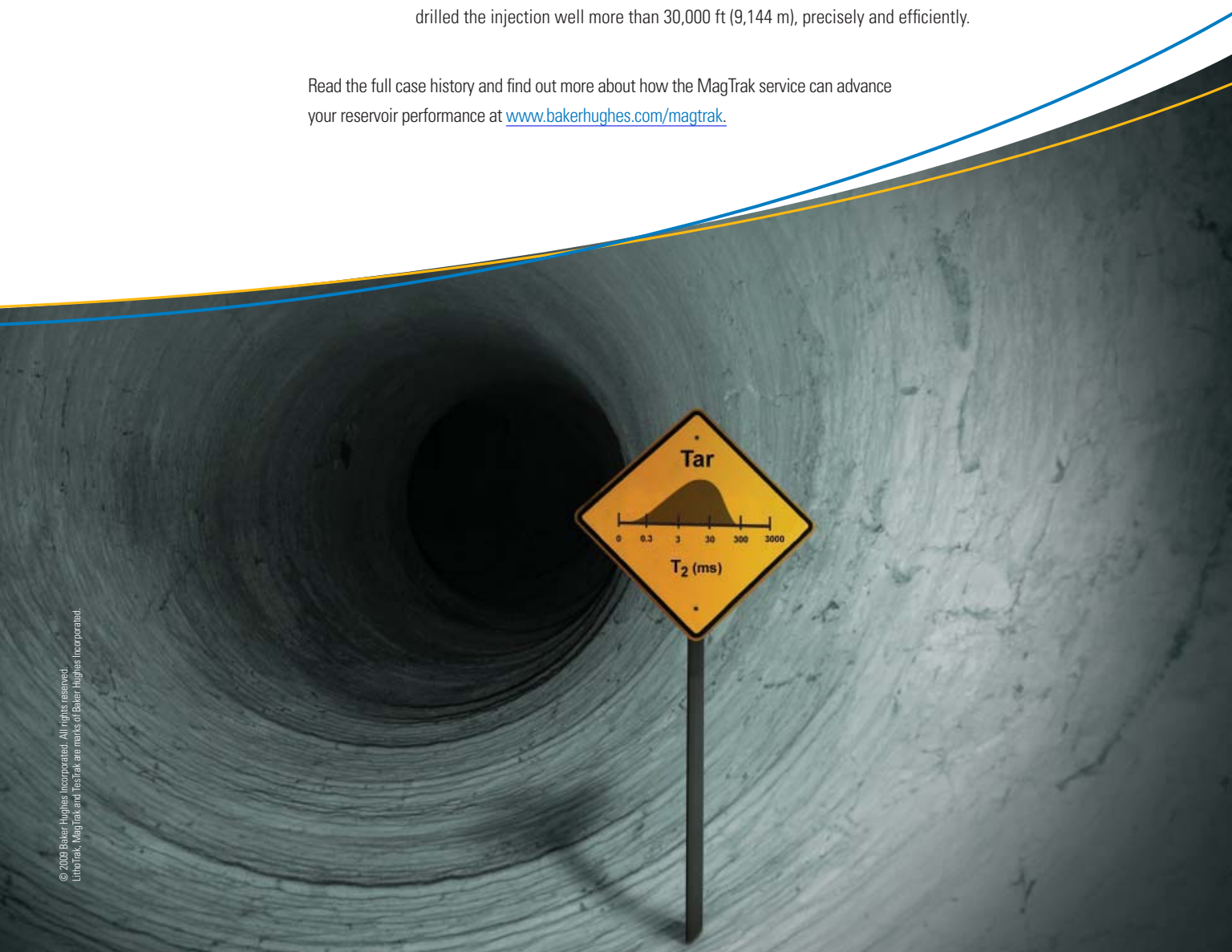
Read the full case history and find out more about how the MagTrak service can advance your reservoir performance at www.bakerhughes.com/magtrak.



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Our worldwide construction surveys are updated regularly

The PennEnergy editors and the OGJ Online Research Center are regularly conducting intensive survey efforts tracking new energy construction projects worldwide, keying the details into a spreadsheet and making them ready for your use!

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Semi-annual construction updates are provided in the following areas:

- Petrochemical
- Refining
- Pipeline
- Gas Processing
- LNG
- Sulfur

The Excel format enables efficient and rapid analysis of planned construction projects. The data collected includes Company, Location, Capacity, Expected Completion Date and Current Status, Contractor, Cost, Engineering and Process Design (when available). Some of these surveys are also available in historical version going back to 1996.

Production Projects Worldwide

Contains upstream projects in 47 countries, shows the development of individual fields, and the supporting infrastructure. The Survey in Excel spreadsheet identifies:

- country
- project name
- operator & company name
- project phase
- peak year
- development type details
- liquids and gas
- cost when available

Allows you to focus on what regions will have future growth, type of project, new discoveries, field redevelopment, stranded-gas projects, heavy-oil or deepwater projects and development of unconventional resources such as tight sands, shale gas, and coal bed methane gas.

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Planned Canadian Oil Sands development projects in four Excel worksheets. Includes: mining upgrading projects, in situ projects, reserves estimate of initial in-place bitumen, and historical table, commercial, experimental and exploration wells.

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Downhole cable heats high viscosity, high-paraffin oil
Cased pipe segments could be less safe than uncased

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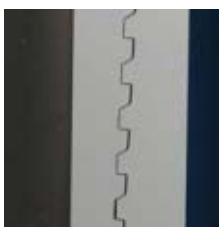

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OIL&GAS JOURNAL®

Apr. 20, 2009
Volume 107.15

PROCESS CONTROL TECHNOLOGY

REGULAR FEATURES

COVER

The residue fluid catalytic cracker at Petrovietnam's 148,000-b/d Dung Quat refinery employs cracking technology supplied by Shaw Energy & Chemicals Group and its alliance partner, Axens. The country's first refinery is currently undergoing commissioning. This issue's special report on Process Control Technology, beginning on p. 40, presents an overview of benefits for effective use of automatic process control in midstream oil and gas operations. Photo from Shaw and Petrovietnam.

In 2006, when engineers began restoration of an oil platform damaged by Hurricane Katrina, they were pleased to discover that TMEIC GE's Dura-Bilt5i™ Medium Voltage drives started up without incident, even though the equipment room in which they were located had been flooded and abandoned for a time following the devastating storm.

Even though these drives are rarely put to a test of this level, it's reward ing to know that Dura-Bilt dri built to this level of tough gas drilling and pipeli require a drive th in some of th environment

The conc a foundation time and lon relatively ne and promises both in energy consumption and in mechanical design by eliminatin conventional mill sections.

	EAF,%	To To
Top 10%	92.2	
Top 25%	91.5	
Average	85.8	
Bottom 25%	77	

New advan users to c environ drive impr ten to

or collect recent trend data for any of these events.

In the pioneering days of data gathering, numbers were simply evaluate a number of key in trends and quantify the overall power sup an illustration of reliabi due

nifica ations for operations nalysis techniques. tion turned to how ta and analysis to it performance. r similar omparison that of its have th

sign and operational the generation of power mping ability of substa-

m hurricanes to permafrost, Bilt's ruggedness, broad capac- nge, and top-tier warranty have de it a favorite for extreme tem- erature, high-starting torque load pplications. Recently, five Dura-Bilt5i MV drives have been chosen for projects in, Canada, two for a pumping station, and three for a tank project.

The Dura-Bilt is a medium voltage AC-fed drive series, recognized for its compact, air cooled design, with heat-pipe technology which requires smaller equipment rooms and extends transistor life. The drives' AC to DC converter uses a 24-pulse diode rectifier, that exceeds IEEE

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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OGJ Newsletter

Apr. 20, 2009

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General Interest — Quick Takes

IEA slashes worldwide oil demand forecast

The International Energy Agency in its April oil market report revised down by 1 million b/d its outlook for 2009 worldwide oil demand.

IEA cited a reassessment of global economic assumptions and much lower-than-expected first quarter demand data as the drivers of this revision. IEA went on to say it believes that economic and oil demand recovery will be deferred to 2010. With the expectation that global GDP will contract 1.4% this year, the agency now forecasts that worldwide oil demand will average 83.4 million b/d, which is 2.4 million b/d below 2008 demand.

In its previous monthly oil market reports, Paris-based IEA expected that global GDP would grow modestly in 2009 and that oil demand would recover in the second half of the year.

The bulk of the latest forecast cut for this year's oil demand is for the first quarter. IEA revised lower its estimate of first quarter 2009 demand by 700,000 b/d. Demand for middle distillates suffered despite spells of colder northern hemisphere weather, and industrial activity indicators remain universally weak, IEA said.

Forecast oil demand in countries of the Organization for Economic Cooperation and Development has been adjusted down for 2009 on the basis of much lower economic assumptions. IEA reports that OECD countries are set to face an unusually severe recession, with overall GDP contracting 3.9%.

Consequently, the agency now forecasts 2009 OECD oil demand at 45.2 million b/d, down 2.4 million b/d from last year and 760,000 b/d lower than previously estimated.

Meanwhile, IEA also cut its forecast for non-OECD oil demand, as economies in emerging countries are now expected to grow just 1.9% this year. Non-OECD oil demand will average 38.3 million b/d in 2009, almost 230,000 b/d lower than previously expected. Although small, this will be the first contraction in non-OECD demand since 1994, IEA said.

EPA cleared to issue climate endangerment finding

The White House has cleared the way for the US Environmental Protection Agency to issue an endangerment finding that greenhouse gases pose a danger to public health and welfare.

EPA officials said there is no timetable for when the endangerment finding might be issued. The US Supreme Court on Apr. 2, 2007, ordered EPA to determine whether carbon dioxide emissions from vehicles threaten public health and welfare (OGJ, Apr. 9, 2007, p. 33).

Under the administration of US President Barack H. Obama, the EPA moved forward on an endangerment announcement. Such an official announcement would enable the regulation of GHGs under the Clean Air Act.

EPA submitted its proposed finding in March to the White House Office of Management and Budget as part of the normal interagency review process.

"OMB has concluded their review, and we will determine what further action to take," EPA spokeswoman Adora Andy said in an Apr. 15 e-mail to OGJ.

The OMB clearance falls short of the White House's directing EPA to proceed with the regulatory process.

Meanwhile, a subcommittee of the House Energy and Commerce Committee expects next week to discuss proposed energy and climate legislation entitled the 2009 American Clean Energy and Security Act.

The Obama administration has suggested it would like to have Congress deal with climate change regulation through a cap-and-trade system.

Separately, the Center for Biological Diversity filed a petition with the federal government to protect US waters from ocean acidification, which results from oceans absorbing CO_2. The EPA on Apr. 15 said it will review whether those emissions should be regulated under the Clean Water Act.

OCS oil, gas support Louisiana jobs

About 154,000 high-paying manufacturing jobs in Louisiana depend on access to oil and natural gas on the US Outer Continental Shelf, federal officials were told at the second of four public hearings on Apr. 8.

Louisiana industries use oil and gas not only as energy but also as feedstocks for a wide variety of petrochemicals, testified Virginia Sawyer, vice-president of the Louisiana Association of Business and Industry, at the US Department of the Interior's hearing on a draft proposed 5-year OCS plan in New Orleans.

While Louisiana accounts for 13% of the total energy exported from oil and gas-producing states, industries use almost 77% of the gas consumed in the state, she said.

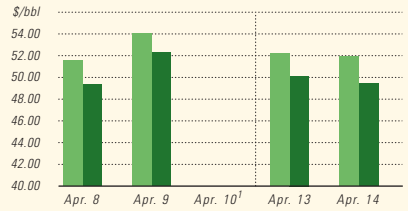
"Almost 58% of petroleum produced in Louisiana is consumed by the state's industrial sector, which employs 154,000 Louisianans, who have an average annual wage of $52,000. This average manufacturing wage is 40% higher than Louisiana's statewide average wage," said Sawyer, who also testified on behalf of the National Association of Manufacturers.

The potential for generating electricity from renewable and alternative sources does not mean federal policy should focus on it at the expense of oil and gas, she continued.

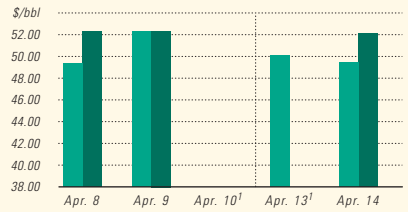
"While tens of thousands of jobs may be created by the development of alternative energy sources, hundreds of thousands of jobs in Louisiana and along the Gulf Coast will be negatively affected if OCS oil and gas production is not aggressively continued. Orderly development of energy should be as fuel-neutral as possible," Sawyer said. ✦

Industry Scoreboard

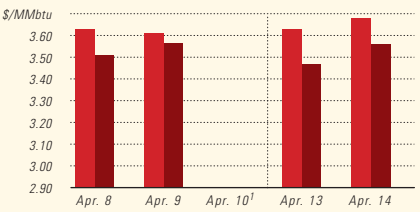
IPE BRENT / NYMEX LIGHT SWEET CRUDE



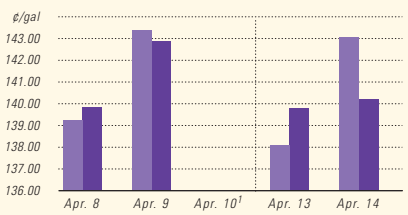
WTI CUSHING / BRENT SPOT



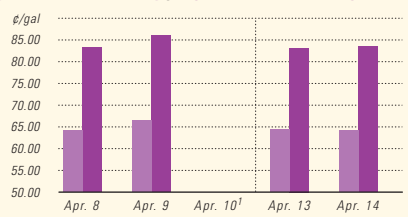
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



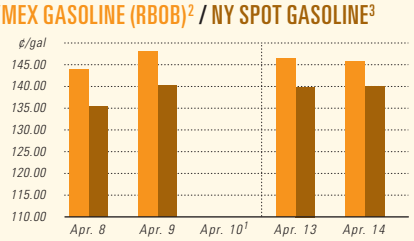
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

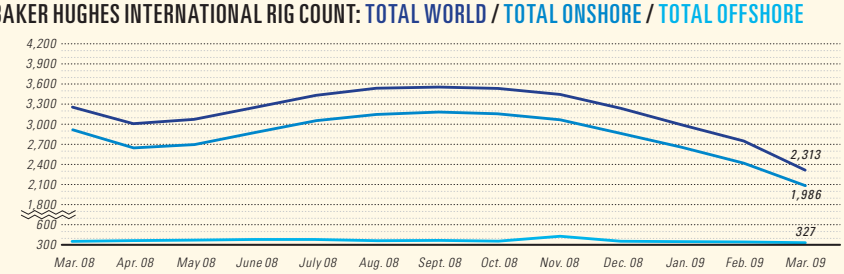
US INDUSTRY SCOREBOARD — 4/20

Latest week 4/3	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,051	9,073	–0.2	8,919	8,914	0.1
Distillate	3,842	4,138	–7.2	3,975	4,197	–5.3
Jet fuel	1,506	1,537	–2.0	1,392	1,540	–9.6
Residual	558	579	–3.6	579	601	–3.7
Other products	3,902	4,408	–11.5	4,280	4,624	–7.4
TOTAL DEMAND	18,859	19,735	–4.4	19,145	19,876	–3.7
Supply, 1,000 b/d						
Crude production	5,449	5,141	6.0	5,344	5,116	4.5
NGL production[2]	1,791	2,208	–18.9	1,904	2,179	–12.6
Crude imports	9,363	9,606	–2.5	9,411	9,736	–3.3
Product imports	3,087	2,961	4.3	3,166	3,148	0.6
Other supply[3]	1,642	1,401	17.2	1,574	1,444	9.0
TOTAL SUPPLY	21,332	21,317	0.1	21,399	21,623	–1.0
Refining, 1,000 b/d						
Crude runs to stills	14,226	14,408	–1.3	14,226	14,645	–2.9
Input to crude stills	14,575	14,693	–0.8	14,575	14,958	–2.6
% utilization	82.7	83.5	—	82.7	85.1	—

Latest week 4/3	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	361,072	359,427	1,645	316,016	45,056	14.3
Motor gasoline	217,449	216,793	656	221,268	–3,819	–1.7
Distillate	140,799	144,153	–3,354	106,027	34,772	32.8
Jet fuel–kerosine	39,061	39,540	–479	38,510	551	1.4
Residual	36,235	35,515	720	39,258	–3,023	–7.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	25.4	25.4	0.0	22.1	14.9	
Motor gasoline	24.0	24.0	0.0	24.0	0.0	
Distillate	36.6	38.2	–4.2	24.6	48.8	
Propane	33.5	31.4	6.7	19.5	71.8	
Futures prices[5] **4/10**			Change		Change	%
Light sweet crude ($/bbl)	50.46	50.32	0.14	103.49	–53.03	–51.2
Natural gas, $/MMbtu	3.63	3.76	–0.13	9.68	–6.05	–62.5

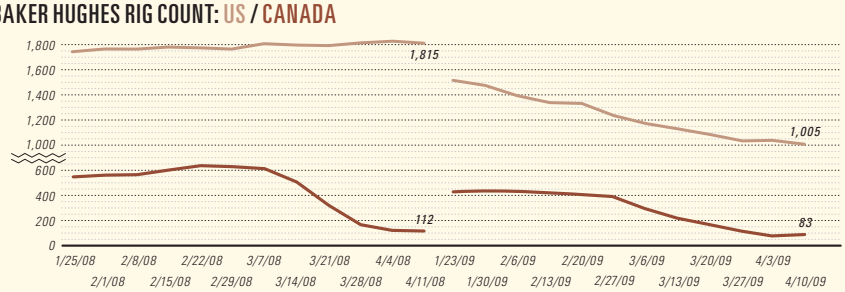
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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

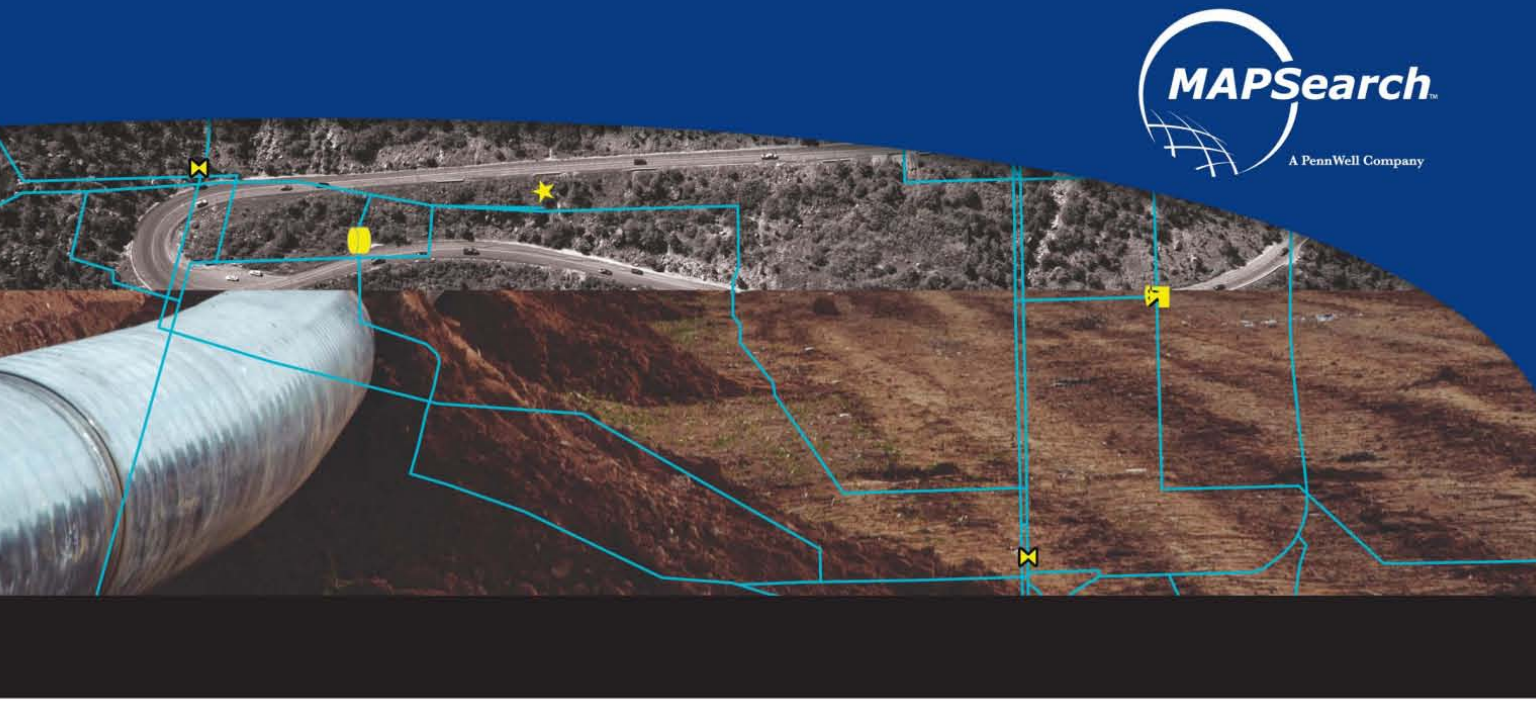


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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Exploration & Development — *Quick Takes*

Petrobras, Repsol YPF claim Piracuca find 'viable'

Brazil's Petroleo Brasilerio SA (Petrobras) and partner Repsol YPF SA said a light oil and natural gas find in Piracuca field off Brazil is commercially viable.

The partners said the find was made in reservoirs in the presalt layer on Block BM-S-7 in the Santos basin.

The companies presented a declaration of commercial viability to Brazil's energy regulatory agency, ANP, based on the "intense exploratory activity" the companies have carried out on the block, Petrobras said.

"With the new field, it will be possible to increase the potential for light oil and gas production in shallow waters," Petrobras said. Earlier, the Brazilian firm estimated that the field contained nearly 550 million boe.

Petrobras and Repsol YPF originally announced their discovery in January, saying that the find was made in214 m of water and a total depth of 3,970 m, above the region's subsalt layer.

"This discovery is of great importance because of the potential production of gas in shallow waters in the southern Santos basin," said Petrobras, operator of the block with a 63% stake. Repsol YPF holds the remaining 37%.

StatoilHydro acquires interest in DeSoto Canyon

BHP Billiton has granted a 40% interest to StatoilHydro in 50 frontier blocks in the DeSoto Canyon area of the Gulf of Mexico.

The DeSoto Canyon area lies east of Independence Hub in 1,000 m of water. StatoilHydro hopes to secure early access to new plays.

StatoilHydro conducted a similar early-access deal with Exxon-Mobil Corp. in 2005 in the Walker Ridge area of the gulf, according to Tony Dore, StatoilHydro vice-president of exploration for North America.

StatoilHydro and BHP Billiton bid successfully on 14 additional blocks within this same trend at the Central Gulf Lease Sale 208 held in New Orleans last month (OGJ Online, Mar. 18, 2009). Together, the two companies were the apparent high bidder on all blocks.

The partners are awaiting final approval from the US Minerals Management Service for the leases on those blocks.

Israel's Dalit discovery given 500 bcf

A group led by Noble Energy Inc., Houston, reported a flow of 33 MMcfd of natural gas from its Dalit deepwater discovery in the Mediterranean off Israel and said the well appears capable of achieving 200 MMcfd.

Noble estimated Dalit's gross mean resource at 500 bcf of gas from log and test results. The well is on the Michal license.

The 33-MMcfd flow, limited by test equipment capacity, came from 43 ft of the previously reported 110 ft of identified net pay.

Noble said the well improves confidence in its geological model for the region, and that it will begin shooting 3D seismic in the next few months to supplement that understanding of the basin and various leads on its acreage.

The rig will return to the Tamar discovery on the Matan license to drill an appraisal well. Tamar's estimated gross mean resource potential is 5 tcf (OGJ Online, Feb. 10, 2009).

Noble operates both licenses and holds 36% working interest. Other interest owners are Isramco Negev 2 with 28.75%, Delek Drilling 15.625%, Avner Oil Exploration 15.625%, and Dor Gas Exploration 4%. ✦

Drilling & Production — *Quick Takes*

Ziff: US unconventional gas share to leap

Ziff Energy Group forecasts unconventional gas production will supply 53% of US gas needs by 2020, up from 30% in 2000.

Ziff Energy's Shale Gas Outlook to 2020 says shale gas production in 2008 was more than 5 bcfd (8% of North American gas production), with 70% coming from the Barnett shale in the Fort Worth basin of Texas.

In the future, the report sees increased gas coming from the Barnett, Fayetteville, and Woodford shales as well as many other plays such as the Haynesville, Marcellus, Horn River, Utica, and Gothic.

The report expects in 2020 that North America will produce 87 bcfd compared with 70 bcfd in 2000.

Dana Gas starts output from Egyptian discoveries

Dana Gas, Sharjah, announced earlier this month it had started production from its recent Al Basant gas-condensate discovery on the West Manzala concession in Egypt's Nile Delta.

The company also began producing from its El Wastani East-2 sidetrack well, Dana Gas Egypt's first highly deviated, horizontal well in Egypt.

Dana drilled the Al Basant-1 well in October 2008 and tested it at 23.5 MMscfd and 1,027 b/d of condensate. The Al Basant-2 appraisal well was subsequently drilled, completed, and tested in December 2008. It yielded additional gas in a new zone that tested at 10.5 MMscfd gas and 150 b/d of condensate.

A third well in the field is to reach estimated target production of 45 MMscfd before yearend. Dana said that Al Basant field gas reserves are estimated to exceed 123 bcf.

The Al Basant discovery was developed on fast track, said the company, with two 17-km pipelines, one 6 in. OD and 12 in., to transport Al Basant production to the El Wastani integrated gas plant.

The plant has design capacity of 160 MMscfd and 7,500 b/d of condensate and LPG, but is currently operating at 153 MMscfd gas and 5,400 b/d.

Dana said the new gas production from Al Basant will "allow testing the plant beyond its full design capacity and identifying components that require modification, or upgrading." It will also maximize throughput, while targeting production levels of 170 MMscfd.

The company said the El Wastani East-2 sidetrack well was

drilled and completed in March in the East El Wastani development lease in the Nile Delta region. Gas production from EWE-2 started on Mar. 30, said the company, initially at 4.5 MMscfd gas, which will increase "after the well has been cleaned up." EWE-2 production is being processed in the company's El Wastani plant.

Ahmed Al-Arbeed, Dana Gas upstream executive director, said the company will continue its efforts to develop and produce the remaining three discoveries: Salma, Azhar, and Sondos (Haggag) in 2009-10.

In its announcement, the company claimed it is the Middle East's "first and largest regional private sector natural gas company."

RAK buys Heritage's interest in West Bukha

RAK Petroleum PCL has purchased a 10% interest in Block 8 in the Strait of Hormuz off Oman from a subsidiary of Heritage Oil Ltd. of the UK, bringing RAK's interest to 50%.

RAK operates Block 8, where it brought West Bukha field on production in February 2009 at 10,000 b/d of 42° gravity oil and 30 MMcfd of associated gas from two wells. The wells are on a six-slot, unmanned platform in 90 m of water 25 km off the Musandam Peninsula.

Discovered in 1976, West Bukha was believed to be a gas-condensate field and was abandoned as noncommercial.

Appraisal drilling by RAK Petroleum in 2006-08, including an extended horizontal section, demonstrated oil potential in the Mishriff-Maudud and Thamama reservoirs, said Bijan Mossavar-Rahmani, RAK Petroleum managing director and chairman of the executive committee.

A 12-in. multiphase flow line connects West Bukha to the nearby Bukha field production platform. Bukha field, also on Block 8, was developed in 1994 and can flow 10-15 MMcfd of nonassociated gas.

Output from both fields moves through a 16-in., 33-km multiphase flow line to shore for processing at the Khor Khwair plant in Ras Al Khaimah. Oil and condensate are slated for export, while gas is delivered to industrial and commercial users in Ras Al Khaimah.

LG International Corp., Seoul, holds the other 50% interest in Block 8.

RAK Petroleum, registered in Ras Al Khaiman's free trade zone, operates nine blocks in Oman and the UAE, of which six are in the exploration phase and two are undergoing appraisal for possible redevelopment. ✦

Processing — *Quick Takes*

Holly to buy, upgrade refinery in Tulsa

Holly Refining & Marketing has agreed to buy and plans to add diesel desulfurization capacity at Sunoco's 85,000-b/cd refinery in Tulsa.

The companies have signed a definitive agreement with a purchase price of $65 million. Closing of the deal is set for June 1.

Sunoco had announced last November that it was canceling plans to upgrade the refinery and that it would seek a buyer or operate the facility as a terminal. According to Oil & Gas Journal's 2008 Worldwide Refining Report, the refinery has 8,500 b/cd of delayed coking capacity, 17,500 b/cd of catalytic reforming capacity, and 24,000 b/cd of catalytic hydrotreating capacity for reformer feeds.

In addition to fuels, the refinery produces 8,500 b/cd of lubes and 350 tons/day of coke. It yields about 40% diesel and jet fuel.

Holly Corp. Chairman and Chief Executive Officer Matt Clifton said the buyer will install a diesel desulfurization unit by 2011 at an expected cost of $150 million.

Holly operates the 85,000-b/cd Navajo refinery in Artesia, NM, and a 26,400-b/cd refinery in Woods Cross, Utah.

Sunoco's other refinery locations and capacities are Philadelphia, 330,000 b/cd; Marcus Hook, Pa., 175,000 b/cd; Eagle Point, NJ, 150,000 b/cd; and Toledo, Ohio, 140,000 b/cd.

Qatar's Laffan refinery to open in July

The start-up of the 146,000 b/d Laffan condensate refinery in Ras Laffan City, Qatar, is scheduled for July.

Faisal Al Suwaidi, chief executive officer of Qatargas Operating Co. Ltd. (Qatargas), told OGJ that the refinery is 99% complete. "We still have a few things to do," he said. "Commissioning activities have already started. It is the largest single condensate refinery in the world." Products will be used internally and exported.

The project has cost $800 million, instead of the $668.7 million originally expected in 2005, and was expected to start by the third quarter of 2008. The delay occurred because of a shortage of skilled labor and materials following the construction boom of the industry over the last 3-4 years. The capacity of the condensate refinery will be doubled by 2014.

Qatargas and its partners, including ExxonMobil Corp. and Total SA, have built process units including utility systems, distillation units, naphtha and kerosine hydrotreaters, a hydrogen unit, and a saturated gas plant producing hydrotreated naphtha, hydrotreated kerosine, gas oil, and LPG for export.

A consortium of GS Engineering & Construction Corp. and Daewoo Engineering & Construction Co. hold the engineering, procurement, and construction contract. Technip SA handled front-end engineering and design.

Qatargas will operate the refinery and provide feedstock for it along with RasGas, a joint venture between Qatar Petroleum and ExxonMobil, and Al-Khaleej Gas.

The shareholders are Qatar Petroleum with 51%; ExxonMobil, Total, Cosmo, and Idemitsu, 10% each; and Mitsui and Marubeni, 4.5% each. ✦

Transportation — *Quick Takes*

Shell suffers fire on Trans-Niger oil pipeline

Nigerian firefighters have extinguished a blaze that shut in flow stations feeding into the Trans-Niger oil pipeline, said Royal Dutch Shell PLC.

Shell declined to give the volume of oil that was shut in or a timetable for restarting production. Nigerian reports have esti-

mated that 120,000-170,000 b/d was cut off.

The cause of the fire is still being investigated. The incident happened on Apr. 12 at the Bomu manifold in Ogoniland, in the Niger Delta.

Shell has called force majeure on the Bonny Light and Forcados facilities in Nigeria following attacks by militants.

US DOC quashes Broadwater LNG terminal plans

In an Apr. 13 decision with implications for natural gas supply to the US Northeast, the US Department of Commerce denied an appeal by sponsors of the planned Broadwater offshore LNG terminal in a dispute with New York state.

The decision stated Broadwater had failed to meet its burden of proof that the project "furthers the national interest" to the extent that it "outweighs the...adverse coastal effects."

Sponsors of the project, TransCanada Corp. and Shell Gas & Power, were appealing a decision by New York almost exactly 1 year ago that the project was "not consistent with six policies under New York's coastal zone management plan (OGJ, Apr. 28, 2008, p. 26)."

DOC's decision agreed with the state, going to state the "record does not establish that the project is necessary in the interest of national security."

The project had already received approval from the US Federal Energy Regulatory Commission (OGJ, Jan. 21, 2008, p. 44).

The Broadwater project sought to build and installed the world's first permanently moored floating LNG terminal, a 1,200-ft floating storage and regasification unit (FSRU). It was to have been moored near the middle of Long Island Sound about 9 miles from New York and 10 miles from Connecticut.

Vaporized LNG would flow through a 22-mile pipeline to shore, connecting there with the Iroquois pipeline and moving on to be distributed to consumers in Long Island, New York City, and Connecticut.

LNG storage capacity on the FSRU was to equal 8 bcf; maximum sendout was to have been 1 bcfd.

Explosion cuts Russian gas to Eastern Europe

Supplies of Russian natural gas to southeastern Europe are now under control, European Union gas experts said, after Russian gas supply fell by 40% last week when the Ananiev-Tiraspol-Ismail trunkline in Moldova's Transdniestr region was damaged in an Apr. 1 explosion.

According to reports, the blast created a crater measuring more than 110 sq m and damaged the 1,200 mm diameter pipeline, which was buried 2 m underground. The cause of the accident is unknown. To compensate for the curtailed supplies, gas was transmitted through parallel pipelines. "Volumes of gas supplies to Romania, Bulgaria, Macedonia, and Greece will remain the same through the Balkan corridor," Gazprom said.

Gazprom also increased gas deliveries through the Blue Stream pipeline to compensate for the reduction of supply to Turkey.

Bulgaria used gas from its Chiren underground gas storage to prevent disruption of service to its consumers, and the former Yugoslav Republic of Macedonia's reduced supply was compensated by its use of gas in the transport system.

"Romanian authorities indicated that their country was not affected by the accident," said the Gas Coordination Group.

Yemen LNG to start deliveries this summer

Yemen LNG will lift its first cargo in midyear, with operations starting by the summer, according to Yves-Louis Darricarrere, president of exploration and production at Total SA, a shareholder in the project.

The $4 billion Yemen LNG project is several months behind schedule due to technical problems and shortage of labor.

With a capacity of 6.7 million tonnes/year from two trains, it will provide cargoes to Asia Pacific and Atlantic Basin markets for its primary customers in North America and South Korea and potentially will add new customers in the future as the second train will start operations during the third quarter. Current capacity is sold out.

The company has chartered the 294.6 m Seri Balqis vessel for the lifespan of the project. It was built at the Mitsubishi shipyard in Nagasaki, Japan. Yemen LNG has completed hydrotesting both tanks, the company said.

Another three ships, Seri Balhaf, Maersk Arwa, and Maersk Marib, which have the latest maritime technology and can withstand the elements of the high seas, also are dedicated to this project.

Seri Balqis can carry 154,600 cu m of LNG and will transport the LNG to the North American market and its long term buyer Total Gas & Power. Other buyers are Suez and Kogas.

Feedstock gas for the liquefaction plant will come from Block 18 in the Marib area. It will be delivered via a new 320-km, 38-in. main pipeline to the liquefaction facilities in Balhaf (OGJ Online, Oct. 10, 2005). A spur line will extend to transport domestic gas to the Ma'bar area in central Yemen. Gas started flowing to the site on Nov. 19, 2008, for power generation initially, then for plant commissioning, and start-up. The site will also have two 140,000-cu m LNG storage tanks, and desalination, waste water, and steam generation plants.

This is the country's largest industrial investment, from which the government expects to earn $30-50 billion over the next 20-25 years. The liquefaction plant at Balhaf is on the Shabwah coast 200 km southwest of Mukalla and 400 km east of Aden.

Shareholders are Total with 39.62%, Hunt with 17.22%, Yemen Gas Co. 16.73%, SK Corp. 9.55%, Kogas 6%, Hyundai 5.88%, and the General Authority of Social Security and Pensions 5%

Enbridge tests Haynesville pipeline market

Enbridge Inc. will conduct a nonbinding open season from Apr. 13 to May 15 testing shipper interest in moving Haynesville shale natural gas from Carthage, Tex., to Washington parish in southeastern Louisiana.

The proposed LaCrosse Pipeline would extend 300 miles of 42-in. and 32-in. OD pipe from Enbridge's Carthage Hub to an interconnection with Sonat Pipeline, interconnecting with at least five interstate pipeline en route. LaCrosse could include as many as 12 pipeline interconnections, depending on shipper interest.

Enbridge expects to complete LaCrosse in late 2011 or early 2012 and is exploring the possibility of extending the line to Florida Gas Transmission's Station 10 near Wiggins, Miss. ✦

CONSTRUCTION PROJECT Data To Count On!

Our worldwide construction surveys are updated regularly

The PennEnergy editors and the OGJ Online Research Center are regularly conducting intensive survey efforts tracking new energy construction projects worldwide, keying the details into a spreadsheet and making them ready for your use!

Worldwide Construction Surveys

Semi-annual construction updates are provided in the following areas:

- Petrochemical
- Refining
- Pipeline
- Gas Processing
- LNG
- Sulfur

The Excel format enables efficient and rapid analysis of planned construction projects. The data collected includes Company, Location, Capacity, Expected Completion Date and Current Status, Contractor, Cost, Engineering and Process Design (when available). Some of these surveys are also available in historical version going back to 1996.

Production Projects Worldwide

Contains upstream projects in 47 countries, shows the development of individual fields, and the supporting infrastructure. The Survey in Excel spreadsheet identifies:

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- project name
- operator & company name
- project phase
- peak year
- development type details
- liquids and gas
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Four types of vessels are tracked – Jack-up Rigs, Semi-submersibles, Drillships, and Tender Assist Vessels. Include – Rig Name, Owner, Design, Shipyard, and Country, Delivery Date, Cost in $ millions.

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Planned Canadian Oil Sands development projects in four Excel worksheets. Includes: mining upgrading projects, in situ projects, reserves estimate of initial in-place bitumen, and historical table, commercial, experimental and exploration wells.

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Letters

Excluding science

Your Newsletter section contained an ironic statement by Rep. Edward Markey (D-Mass.): "Instead of allowing political interference in scientific…decisions… the Obama administration is letting the sun shine in on the dangerous realities of global warming (OGJ, Apr. 6, 2009, Newsletter)."

The truth of course is exactly the opposite. Science is now excluded from the decision process. First, note that Markey is a lawyer and presumably a little weak on the meaning of science. The earth may have warmed a bit over the last 100 years, but government action is only rational if such warming could be tied to human activity.

I have heard that there is strong disagreement about whether such causality exists. So where is the science? Sounds like another spotted owl hoax.

Doug Wood
Houston

Calendar

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

OIL&GAS JOURNAL online

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

2009

APRIL

Middle East Petroleum & Gas Conference, Dubai, 65 6338 0064, 65 6338 4090 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 19-21.

ERTC Coking & Gasification Conference, Budapest, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Hannover Messe Pipeline Technology Conference, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), website: www.hannovermesse.de. 20-24.

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

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

Pipeline Transport Conference & Exhibition, Moscow, +43 1 230 85 35 33, website: www.expopipeline.com. 21-23.

Base Oils and Lubricants in Russia & CIS Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-23.

Instrumentation Systems Automation Show & Conference, (ISA), Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 22-23.

CPS/SEG International Geophysical Conference & Exposition, Beijing, (918) 497-5500, (918) 497-5557 (fax), e-mail: semery@seg.org, website: www.seg.org. 24-27.

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

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

EAGE European Symposium on Improved Oil Recovery, Paris, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 27-29.

ENTELEC Conference & Expo, Houston, (972) 929-3169, (972) 915-6040 (fax), e-mail: blaine@entelec.org, website: www.entelec.org. Apr. 29-May 1.

MAY

EAGE International Petroleum Conference & Exhibition, Shiraz, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 4-6.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 4-7.

GPA Permian Basin Annual Meeting, Austin, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 5.

Interstate Oil and Gas Compact Commission Midyear Meeting (IOGCC), Anchorage, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 10-12.

ERTC Asset Maximisation Conference, Prague, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

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

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

North American Unconventional Oil & Gas Conference & Exposition, Denver, (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-13.

NPRA National Safety Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 12-14.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 12-14.

Pipeline Simulation Interest Group (PSIG) Meeting, Galveston, Tex., + 966 3 873 0139, + 966 3 873 7886 (fax), e-mail: info@psig.org, website: www.psig.org. 12-15.

Iraq Oil + Gas Summit, Houston, (202) 536-5000, (202) 280-1239 (fax), e-mail: lwilson@nfemail.com, website: www.New-Fields.com. 13-14.

Louisiana Oil and Gas Symposium, Baton Rouge, (225) 578-8657, (225) 578-9257 (fax), e-mail: hammer@lsu.edu, website: www.brgs.la.org. 19-20.

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

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

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

APPEA Conference & Exhibition, Darwin, +61 7 3802 2208, e-mail: jhood@appea.com.au. website: www.appea2009.com.au. May 31-Jun. 3.

SPE Latin American and Caribbean Petroleum Engineering Conference, Cartagena, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 31-Jun. 3.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-5.

Asia Oil & Gas Conference, Kuala Lumpur, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 7-9.

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

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 8-10.

International Oil Shale Symposium, Tallinn, Estonia, +372 71 52859, e-mail: Rikki.Hrenko@energia.ee, website: www.oilshalesymposium.com. 8-11.

SPE EUROPEC/EAGE Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

PIRA Understanding Global Oil Markets Seminar, Houston, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 9-10.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 9-11.

Petro.t.ex Africa Exhibition & Conference, Johannesburg, +27 21 713 3360, +27 21 713 3366 (fax), website: www.fairconsultants.com. 9-11.

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

ASME Turbo Expo, Orlando, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-17.

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

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 15.

IPAA Midyear Meeting, Dana Point, Calif., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 15-17.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16.

Atlantic Canada Petroleum Show, St. John's, Newfoundland & Labrador, 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 16-17.

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

PIRA Understanding Global Oil Markets Seminar, London, 44 1493 751 316, e-mail: miles@pira.com, website: www.pira.com. 17-18.

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

IAEE International Conference, San Francisco, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 21-24.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 21-24.

SPWLA Annual Symposium, The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 21-24.

International Offshore and Polar Engineering Conference (ISOPE), Osaka, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 21-26.

Asia LPG Seminar, Singapore, (713) 331-4000. (713) 236-8490 (fax), website: www.purvingertz.com. 22-25.

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

Oil opportunity in Oklahoma

Alan Petzet
Chief Editor-Exploration

The chance to recover billions of barrels of oil that remain in Oklahoma fields represents geological, engineering, and statistical challenges to oilmen willing to take risks.

Most emphasis in the state the past 20 years has been on natural gas, especially in shales, but the oil is still there, somewhere, writes Dan T. Boyd, a geologist with the Oklahoma Geological Survey.

The prize: Boyd estimates the state's thousands of oil fields will ultimately yield only 19% of the more than 84 billion bbl of original oil in place at present decline rates.

"Every 1% of the remaining oil in place represents a staggering 680 million bbl of incremental recovery," Boyd wrote. Indications are that a lot of the oil is in reservoirs from which recovery factors can be increased.

Boyd describes the potential in the February issue of the quarterly publication of the Society of Independent Professional Earth Scientists, based in Dallas.

A new effort called Energy Libraries Online could help by improving access to previously scattered, inaccessible, and incomplete well and production data (OGJ, Feb. 23, 2009, p. 34).

Oklahoma oil's decline

Oklahoma's oil production peaked in 1927.

The state has produced about 170,000 b/d in recent years, down from a later peak of 620,000 b/d in the 1960s when Tulsa newspapers still had oil departments and this editor broke into oil journalism. Tulsa was also Oil & Gas Journal headquarters for most of its existence until the 1990s.

Oklahoma got its last 100 million bbl oil field, Postle in the Panhandle, in 1958 and its last 10 million bbl field, Wheatland just west of Oklahoma City, in 1981, when this editor joined OGJ.

Most of the state's oil wells average 2 b/d, oil drilling is down to 1,000 wells/year, and without large discoveries "future reserve additions must come from improvements to the recovery in existing fields," Boyd wrote.

Oil drilling is sparse despite recent high oil prices. Economics of gas are better, and operators are concerned whether prices will be sufficient to recoup large initial investments and whether enough producible oil remains to justify large-scale improved recovery.

The oil is there

Cumulative production for the three main reservoir classes are blanket sandstones 2.592 billion bbl, carbonate shelf reservoirs 2.74 billion bbl, and fluvial-dominated deltaic sandstones 9.478 billion bbl.

Recovery factors are estimated at 44.1% for blanket sandstones, 10% for carbonate shelf reservoirs, and 21.2% for FDD sandstones.

Boyd points out, however, that 50% is possible in the best blanket sandstone reservoirs and that recovery was less than 30%—and often substantially less—in about half the reservoirs he studied.

"For the roughly half of the FDD channel-fill reservoirs in which EUR is less than 20%, a more detailed review is certainly warranted," he wrote. These reservoirs have the best possibilities.

"A great deal of the secondary recovery work done so far has been piecemeal," Boyd found. Except in the largest fields, many waterflood units have been subdivided and are operated in isolation or at cross purposes, and units operated since 1979 cover less than half of the state's currently producing oil leases.

Modern examples

Boyd cited instances in which operators have improved recoveries by innovative means.

In West Carney field in Lincoln County, a dewatering technique elevated a Hunton carbonate shelf reservoir with cumulative production of 38,000 bbl and 500 MMcf to one with reserves of 2.2 million bbl and 16 bcf.

Dewatering involved pumping and disposing of water at rates sufficient to "reduce the reservoir pressure until the associated gas in the unproduced oil expands." Boyd wrote, "This oil can then be pushed into the fracture system and ultimately the wellbore."

Another operator used dewatering to increase incremental recovery in Mount Vernon field in Lincoln County by 1.26 million bbl of oil, 18.5 bcf of gas, and 1.77 million bbl of condensate.

First steps

The effort to digitize early data, which is in need of funding, is starting on two important fronts.

Energy Libraries Online is scanning hand-drawn strip logs from 104,000 Oklahoma wells drilled with cable tools, of which 62,000 were oil wells. These logs are the only subsurface data for more than one fourth of the state's oil wells, one fifth of all wells, and nearly all wells drilled before 1935.

ELO is also digitizing hard-copy data that will extend the availability of monthly oil production data, now available only since 1970, back to 1935. ✦

Editorial

More ethanol distortion

In the competition of ideas that is so vital to democracy, studies by supposed experts, preferably disinterested, figure prominently. So does the selective use of facts from these studies by groups less disinterested.

As the US systematically suppresses market influence in energy choice, deception born of selectivity increasingly distorts policy discussions. This is because suppliers of energy unable to compete in markets must compete instead in the political arena for tax favors and mandates. Without rival in this practice is the politically triumphant but economically beleaguered ethanol industry.

Food and fuel

Ethanol took a public relations pummeling early last year when food prices zoomed. As it became clear that grain prices had jumped in partial response to corn use related to the production of fuel ethanol, the wisdom of burning food for fuel came under belated question. So the ethanol industry revved up its well-oiled propaganda machinery. Its message, clearly fashioned to exploit the oil industry's abysmal standing in popular opinion: Skyrocketing energy prices pushed up food prices more than did fuel made from corn.

The statement was true as far as it went. It also was irrelevant to questions about ethanol.

Energy prices jumped to extraordinary levels because of unusual market gyrations beyond anyone's control. How could they not push up food prices? But energy prices didn't jump because of an act of Congress. Furthermore, energy prices inevitably subside when market strains relax and have done so with a vengeance since the middle of last year. Demand for ethanol, however, will continue to rise, keeping upward pressure on grain and therefore food prices. The reason is an act of Congress. Unlike market gyrations, people have direct control over acts of Congress.

Ethanol's propagandists, who never make distinctions like these, have brought strategic selectivity to bear yet again in response to a new Congressional Budget Office report on ethanol's effects on food prices and greenhouse gas emissions. The Renewable Fuels Association began a press statement by quoting a sentence from the report's summary observing that during April 2007-April 2008, "certain other factors—for example, higher energy costs—had a greater effect on food prices than did the use of ethanol as a motor fuel." This finding, RFA argues, shows that "ethanol's role in food price increases is minimal."

How minimal? "The CBO report finds that ethanol contributed just '0.5 and 0.8 percentage points of the 5.1% increase in food prices' from April 2007 to April 2008," RFA says. That certainly sounds minimal.

But the quote lifted by RFA had more context than RFA chose to report. In the study period, CBO said, "the increasing demand for corn to produce ethanol contributed, in CBO's estimation, between 0.5 and 0.8 percentage points to the 5.1% increase in the price of food overall as measured by the component of the consumer price index for all urban consumers (CPI-U) that measures food prices." Anticipating confusion, CBO helpfully translated the economic jargon into terms meaningful to people who buy food—in the very next sentence, no less: "That is, the growing use of corn for ethanol accounted for about 10% to 15% of the increase in the CPI-U for food over the April-to-April period." RFA didn't see fit to report the translation.

More to come

So, yes, energy prices over which no one has control pushed up food prices in the study period—more so, in fact, than did ethanol mandates. But while energy prices have plummeted, ethanol mandates remain in effect. In fact, they—and their one-way influence on the price of food—will escalate—by act of Congress.

"As mandated use of biofuels rises over time," the CBO says, "increased production of ethanol and biodiesel will probably continue to push up prices for corn and soybeans." That sentence, with its implications for food prices, didn't find its way into the RFA statement, either.

Congress can constrain food prices by removing the ethanol mandate. It might actually consider doing so if enough Americans come to recognize what's happening to them and learn how to treat the ethanol industry's self-serving pronouncements. ✦

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Russia redesigns fiscal policy to boost oil E&P

Grigory Vygon
Ministry of Natural Resources and Environment of the Russian Federation
Moscow

Since 2004, private Russian oil and gas companies' exploration expenses, in nominal terms, increased 4.4 times, reaching 165 billion rubles in 2008 ($6.7 billion; Fig. 1). Despite this major inflation of costs—more than 30% in 2008—actual work accomplished remained almost flat. This is explained partly by the rapid decline in the price of crude oil and the expansion of the global financial crisis. However, the major reasons for decreasing exploration attractiveness are an unfavorable fiscal system and the absence of stimulus for the regions to finance exploration activities.

The Russian Federation's Ministry of Natural Resources and Environment (MNR&E) is paying close attention to these conditions and is developing and implementing economic instruments to stimulate activities in the industry.

Among the ministry's major responsibilities, it ensures rational subsoil use, allocates mineral rights, classifies new oil and gas reserves, conducts geological studies, and provides oversight for exploration efforts and oil and gas production.

Since 2005 the ministry has revised and approved a long-term program of geological study and mineral resource-base restoration to 2020. According to the program, during 2005-20, Russian exploration expenditures should reach about 4.5 trillion rubles (more than $180 billion), from which oil and gas would account for 88%.

The ministry believes that about 90% of total expenditures should be private, and it is keen to stimulate these companies' exploration activity. To stimulate exploration, MNR&E proposes several actions:

- It proposes introduction of tax credits or deductions for exploration expenses against the mineral extraction tax (MET).
- It proposes to allow regions to collect a share of auction revenues for areas explored at their own expense.

The first measure, a direct stimulus for private investments, is new for Russian tax legislation and may sufficiently increase exploration attractiveness. The other, in addition to generating higher spending, may improve exploration efficiency as knowledge of local geology may be better at the regional level.

Amendments to the Subsoil Law in 2008 define "strategic oil fields" as oil fields containing reserves of more than 70 million tonnes and strategic gas fields as having reserves above 50 billion cu m or that are located offshore.

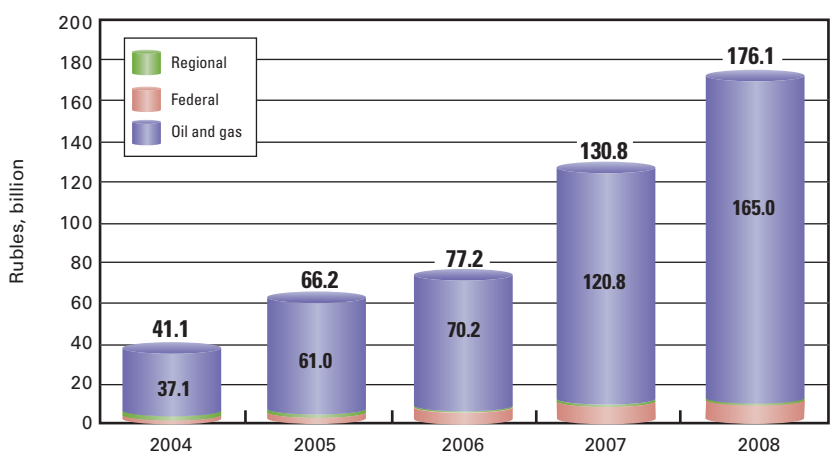
If foreign investors discover strategic reserves and the Russian government decides to withdraw the license, the investor will get full cost recovery (bonus and exploration expenditures) plus a reward.

Foreign investors may further participate in the development of strategic fields through joint ventures as minority stakeholders while operatorship is granted to state-controlled companies. From the ministry's prospective, clear rules and fair rewards should compen-

This article is the second of two parts addressing the challenges facing Russia's oil and gas industry. In Part 1, executives from Rosneft, Lukoil, and Gazprom Neft outlined the excessive taxes and duties that eat into operating expenses and obviate exploration efforts (OGJ, Mar. 9, 2009, p. 27). This article explains the actions the government is taking to address those problems and to encourage exploration and production.

RUSSIAN OIL, GAS EXPLORATION EXPENSES

Fig. 1



sate foreign investors for restrictions in accessing strategic reserves.

Reclassification

New Russian oil and gas reserves classification should be implemented in 2012. The idea is to harmonize the existing system inherited from the Soviet era with internationally accepted standards. The major reason for modifying the current classification is to introduce economic principles into the methodology of recoverable reserves calculation.

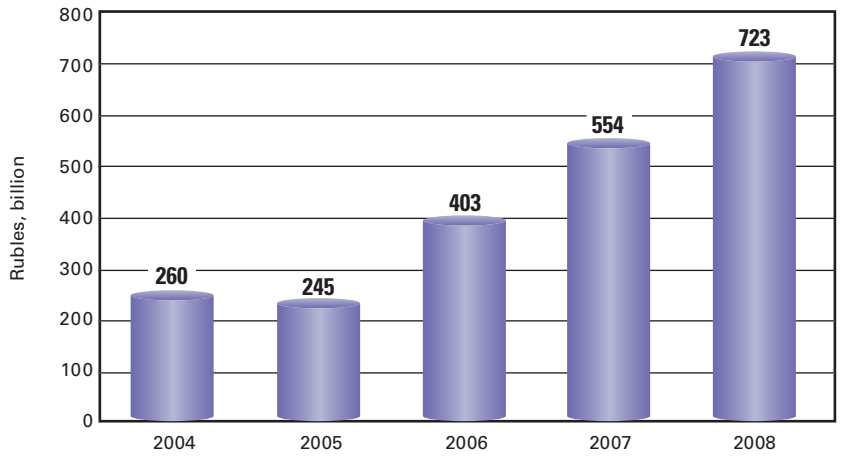
Since the beginning of the work on new classification, one of the most popular questions was whether Russia should modify its existing system or just switch to some widespread standard such as is used by the Securities and Exchange Commission (SEC) or the Society of Professional Engineers' Petroleum Resources Management System (SPE PRMS). While very tempting, the latter seems inappropriate for Russia, mainly because of the difference in its purpose. Classifications for financial markets (e.g., that used by SEC) is designed to improve the quality of financial reporting, help raise capital, and create fair market value. International classifications such as SPE PRMS are used by oil companies for investment planning, portfolio management, development plans, raising capital, and in mergers and acquisition activity.

Governmental classification should serve the following, somewhat different purposes:

- Accounting for the country's reserves balance.
- Managing an efficient resource base.
- Controlling and stimulating rational subsoil usage.
- Developing oil and gas industry infrastructure.
- Improving subsoil and tax legislation.
- Promoting market capitalization growth of domestic companies.

Although hundreds of different classifications exist simultaneously in the world, the general trend is a global unification. Thus SEC will adopt most of the SPE PRMS principles in 2010, and Norwegian classification has been closely aligned with SPE since 2001. For Russia, however, it will be more efficient to modify its existing classification to incorporate economics and a project-based approach but leave some degree of freedom in treating conditional resources and defining economic assumptions to better reflect national goals.

RUSSIAN OIL UPSTREAM INVESTMENTS Fig. 2



Production decline

Since 2004, upstream oil investments increased 2.8 times—to 723 billion rubles in 2008 from 260 billion rubles (Fig. 2). Such impressive dynamics resulted both from activity growth and from cost escalation. High base decline rates in mature provinces (about 20% in West Siberia) force companies to increase drilling to keep production flat, while strong demand for oil field services and pipes drives cost inflation. Nevertheless, Russian oil production decreased in 2008 for the first time after 8 years of continuous growth despite a 30% increase in upstream capital expense.

To stimulate upstream expenditures, it is necessary to improve the investment climate, in particular, the fiscal regime. Major changes occurred in 2002 when the mineral extraction tax (MET) was introduced and Russian oil taxation became essentially revenue-based. Export duties and MET account for about 95% of total tax payments by oil producers, with the tax burden exceeding 68% of gross revenue. The system has been very effective for rent collection and worked well for mature projects with low finding, development, and lifting costs. However, due to their nature and because neither MET nor export duties reflected rapid cost inflation and foreign exchange dynamics, they failed to stimulate upstream investments. It is no wonder that, since 2005, upstream free cash flow decreased despite oil price growth (Fig. 3).

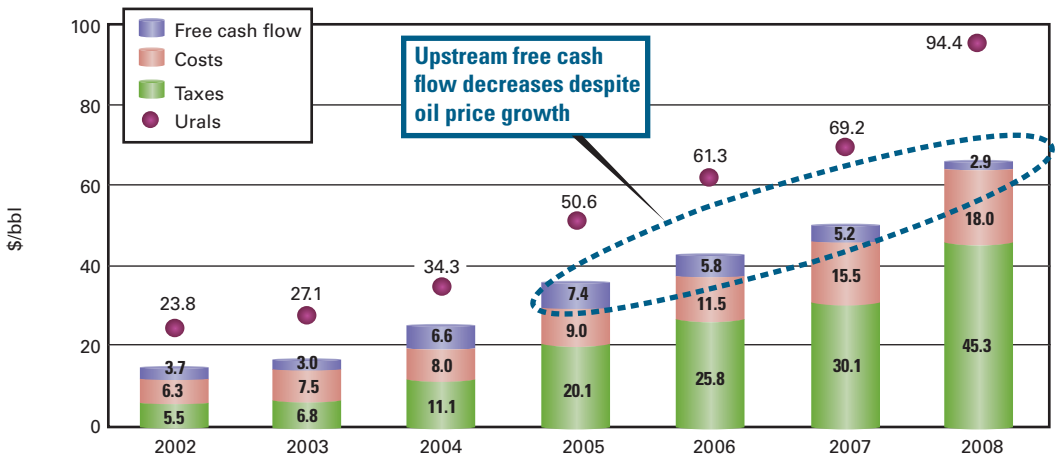
Encouraging investment

To improve the investment climate, the Russian government introduced several tax initiatives in 2008. From Jan. 1 of this year, the MET threshold price increased to $15/bbl from $9, equivalent to a tax decrease of $1.3/bbl; the corporate income tax rate was cut to 20% from 24%; the DD&A (depreciation, depletion, and amortization) allowance grew to 30% from 10%; and MET holidays were extended to more Russian regions.

Further work may be completed in indexing export duties and MET for cost inflation and foreign exchange dynamics. But the right strategic decision will be a gradual decrease of revenue-

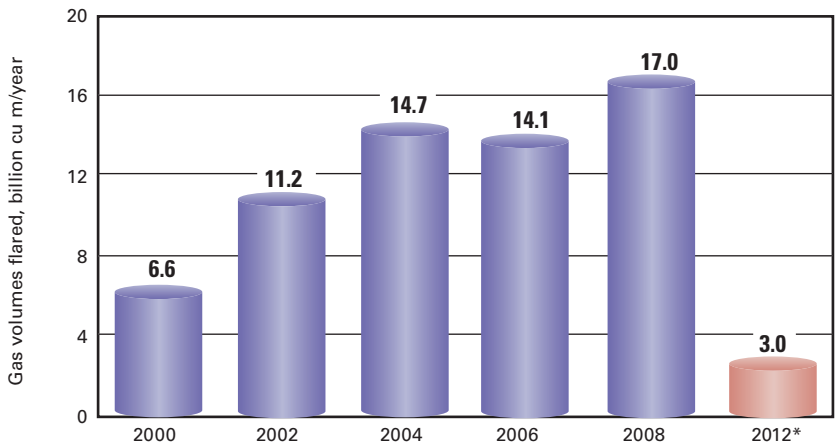
UPSTREAM FREE CASH FLOW DYNAMICS

Fig. 3



GAS FLARING DYNAMICS

Fig. 4



*Reduction goal.

based taxes in favor of profit-based ones. This is expected to be implemented for new prospective regions of oil production—Eastern Siberia and the continental shelf.

As for the new provinces, in addition to taxation other issues will matter. For example, the economics of projects in East Siberia will be strongly affected by tariffs on the East Siberia-Pacific Ocean (ESPO) pipeline, which have not yet been defined.

Another important issue is development of such basic infrastructure as transportation facilities. Several large oil producing centers such as Yurubcheno-Kuyumbinsky are located hundreds of kilometers from the main pipeline and must be linked to it via additional interconnectors. All of those factors may lead to delays in full-scale development of Eastern Siberia and to the decrease of Russia's total production. In the mid-term, ESPO will be partly utilized by up to 15 million tonnes/year of eastern oil from Talakanskoye and Verkhnechonskoye fields, while the rest should be provided by western oil from Vankor or Samotlor.

Financial solutions

Financial crises hit Russian oil producers heavily in fourth-quarter 2008 due to oil price declines and an export duty lag. The latter favored oil companies during periods of oil price increases but squeezed their income when the trend reversed. This was especially painful for small independents that have difficulties borrowing money and do not have refining capacity and thus can't enjoy a healthy domestic products market premium over export netback parity. This critical situation prompted the government to revise its rules for export duty calculation by decreasing the monitoring period from 2 months to 1 month and moving it closer to the accounting period. The new tax relief should help the industry to overcome such crises in 2009.

Another important support comes from the ruble devaluation from 23 rubles/US dollar in mid-2008 to 33 rubles/US dollar in April 2009. Because most of the operating and capital costs of Russian companies are ruble-nominated (except export duty and MET) while revenues are effectively in US dollars, this should improve upstream profitability considerably. In the current oil price and exchange rate environment, oil producers are expected to demonstrate good performance in 2009.

One of the highest priorities for MNR&E is stimulating rational subsoil use. With oil provinces maturing and oil recovery decreasing, there is a high proportion of idle and ownerless wells and evidence for selective reserves development.

One measure includes possible development of more small oil fields via MET differentiation. The exact parameters for a new tax formula will be defined after companies disclose their cost

structure and true project economics.

Another challenging task is stimulating enhanced oil recovery techniques through deduction of investments in improved oil recovery against MET. Such an instrument may be implemented only if companies prove the efficiency of their applied methods. MET redemption for production of idle wells may be used if separate metering exists for those wells.

Flaring solutions

Gas flaring is a well-known problem for Russia. According to official estimates, annual flaring exceeds 17 billion cu m/year, but this number is not very accurate due to poor associated gas production measurement. For example, fewer than 50% of flares are equipped with flowmeters.

To decrease emissions and use the components of gas that otherwise would be flared, the Russian government established a goal of achieving a 95% utilization level for associated gas by 2012 (Fig. 4). To stimulate investments in gas utilization programs, the government will impose penalties on emissions caused by flaring volumes exceeding the limit after 2012. Higher rates will be levied if direct measurement systems are absent.

However, this may not work for small oil fields due to the high cost of implementation and resulting poor economics. To solve that particular problem, it is suggested that several companies pool utilization programs on a regional basis.

All additional economic instruments proposed for fine-tuning the current tax system impose strict requirements on tax administration, metering, control, and financial transparency. The efficiency of their implementation will depend strongly on the trustworthiness between business and government. That's why MNR&E works closely with oil companies while creating a favorable environment for exploration, development, and production in a rational and mutually beneficial manner. ✦

The author

Grigory Vygon is director of the department of economy and finance at the Russian Federation's Ministry of Natural Resources and Environment. Before joining the ministry, he worked as a chief economist for TNK-BP. He also served as director of the corporate finance department for the Institute for Financial Studies and for other financial companies. Vygon graduated with honors in 1996 from Moscow Institute of Physics and Technology, Department of General and Applied Physics. In 2000 he defended his dissertation in central economics and mathematics at the Institute of the Russian Academy of Science with his thesis "Methods of oil companies evaluation under uncertainty." His scope of major activity is economics of natural resources and environmental management. Professional and scientific interests are companies' and investment projects evaluation, taxation, and pricing in commodity and financial markets, derivatives, and auctions.

OPEC summit reveals strategies for sustaining industry

Doris Leblond
OGJ Correspondent

The Organization of Petroleum Exporting Countries will try to keep prices at its current low level this year "to sustain the economy," said OPEC Sec. Gen. Abdalla Salem El-Badri at the 10th International Oil Summit in Paris in early April.

Organized by Institut Francais du Petrole and Consultant and Publisher Petrostrategies, the summit was held on the same day that G20 leaders were meeting in London to discuss the global economic situation, now deeply impacting the world's oil markets.

Calling the current $40-50/bbl price "a pragmatic price," El-Badri said, "OPEC member countries are already shouldering a good deal of the responsibility for turning the global economy around. At our March meeting, we maintained oil output at existing levels despite the current low price environment and the market's persisting oil stock overhang. OPEC's objective… is to bring about long-lasting market stability."

Bringing his point home, El-Badri added, "The fall in oil prices since last summer has offered some short-term relief to consumers. According to some institutions, today's oil price is providing a stimulus of [at least] $1 trillion to the struggling global economy. If we consider the last half of 2008 and 2009 together, the figure may reach $2 trillion, and OPEC's share accounts for some $800 billion of this. And at least some of this stimulus is already being felt by the whole world."

OPEC member countries are already shouldering a good deal of the responsibility for turning the global economy around. At our March meeting, we maintained oil output at existing levels despite the current low price environment and the market's persisting oil stock overhang.

—OPEC Sec. Gen. Abdalla Salem El-Badri

Nonetheless, El-Badri warned members not to lose sight of medium and long-term perspectives. "When we consider what the future holds for the oil industry, it is important to remember that the short, medium, and long-terms are all interlinked. Concerning ourselves only with the immediate situation will lead to a potential impasse in just a few years."

Summing up the price balancing

dilemma, El-Badri said, "High prices destroy demand; low prices prevent investment." He cautioned that the current oil price breaks the momentum of investment in the oil industry. This momentum, he said, "is as vital for continued research and development and encouraging new human capital, as it is for capacity expansion to meet future demand."

UAE Energy Minister Mohammed Bin Dhaen Alhamli voiced a further concern: "Production cuts, combined with the current low price, have massively reduced the export incomes vital to the economic advancement of developing countries," which he said includes OPEC members.

He also fears that low prices are harming the development of renewable energies, in which the UAE has "ambitious" plans. "The promotion of renewable energy goes hand-in-hand with our role as a leading producer of oil and gas," he stressed.

Learning from the past

The encouraging news from the summit was the broad consensus—among both national and international oil companies, major service and construction companies, and international energy organizations—that the mistakes made during past crises should not be repeated this time: short-term uncertainties must be managed while pursuing the development of long-term potential.

This reference to the past was made at the start of proceedings in the introductory statement of Nordine Ait-Laoussine, president of Geneva-based Nalcosa. He said that "when the idea of holding this summit was first discussed 10 years ago, world economic prospects were bleak in the aftermath of the Russian, Asian, and Brazilian financial crises.

"Oil prices were stagnating around $10/bbl in spite of a series of production cuts involving almost all exporting countries," noted Ait-Laoussine, adding, "The last 10 years were a period of unprecedented change during which we have witnessed a profound restructuring of the oil industry on a scale never seen before."

"Clearly," he insisted, "the current exceptional market conditions and their potential risk to the global economy and the oil industry underscore the importance of closer dialogue and cooperation at all levels, which is one of the fundamental objectives pursued from the beginning by the organizers of this summit."

Last year's profits are helping us maintain business in a low-priced environment.

—Total SA Chief Executive Officer Christophe de Margerie

Qatar's Deputy Prime Minister and Energy Minister Abdallah Al Attiyah put it more specifically: "Investment decisions which we make today will have an impact on how energy markets evolve over the next decades."

Maintaining investments

The two keynote speakers, Total's Chief Executive Officer Christophe de Margerie and Royal Dutch Shell's Chief Executive Jeroen van de Veer set an upbeat tone as they indicated they would maintain their investments in 2009.

"Last year's profits," said De Margerie, "are helping us maintain business in a low-priced environment." At the same time, he echoed the general feeling of summit participants that "the long-term view is easy; more difficult is the short-term view." He said, "The long-term view is good, the short-term not so good." While Total's strategy and its long-term vision have not changed, it is adjusting to short-term constraints by keeping a strict hold on costs.

Van de Veer expects short-term oil overcapacity until the economy picks up, "and then energy demand will come back," he said, predicting that "long-term energy demand will double between now and 2060 because of population growth." Classic oil and gas will not supply all the energy demand, he said, so coal and renewables will also be needed. But renewables will have to be geared to lower costs with no subsidies, he added.

Most of Shell's investments, however, will remain in oil and gas, Van de Veer said, adding that the group has abandoned none of its long-term projects and is preparing to bid for Arctic oil and gas resources when the time comes.

International oil companies, national oil companies, and service companies are complementary, he concluded: "NOCs own the land, IOCs design and build the house, service companies' role is [installing] the scaffolding and plumbing. Moral: you need one another," said Van de Veer.

While Repsol YPF SA Chief Operating Officer Mighel Martinez wondered how long it would take the economy to adjust supply to demand, he said the current situation allows his group to renegotiate some contracts and to continue with its investment commitments, despite a capex reduction to €29 billion from €33 billion.

Saudi Arabia building

Joining forces with the IOCs, Saudi Arabia also is "taking a longer-term view of oil market trends and is staying the course when it comes to its program and investments," said Ibrahim A. Al-Muhanna, advisor to Saudi Arabia's Ministry of Petroleum and Mineral Resources.

Saying oil demand will rise as soon as the economic crisis abates, perhaps later this year, he said if global production capacity is unable to meet demand at that time because of underinvestment, "Saudi Arabia is capable and willing" to meet any demand growth.

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the Khurais oil increment, the biggest increment in the history of the oil industry, Saudi Arabia will have a 12 million b/d sustainable production capacity" and will continue to play its role of "reliable supplier of oil in both good and bad times."

Declaring that 64 million b/d of gross oil capacity must be installed in 2007-30—five times Saudi Arabia's current capacity—to meet future demand growth and offset field declines, Executive Director of the International Energy Agency Nabuo Tanaka said more than $1 trillion/year in investments would be needed for the purpose. "The challenge is to do it, especially in the current economic climate," he said.

"Reserves can still be developed at $50/bbl," he said, adding that the economic crisis is "an opportunity to place a Clean Energy New Deal at the heart of the economic stimulus packages everywhere."

NOC-IOC cooperation

Taking a bird's eye view of current oil markets, Nader Sultan, former chief executive of Kuwait Petroleum Co., pointed to the "unusual" feature of the current oil crisis, which is occurring in combination with a financial and economic crisis. But "our industry is an industry of decades," he said, "and one can run a company on a $40-50[/bbl] price."

Sultan sees better cooperation building between NOCs and IOCs who, he said, will share risks and reduce costs, "as financing is back in a new dimension." He pointed out, however, that OPEC has postponed 35 projects while IOCs generally are maintaining investments. "NOCs cannot do this because they contribute to the national budgets and [they] don't have the money," he explained.

The summit heard comforting news from service firms Halliburton, Technip, Saipem, and CGG Veritas. They seemed to be learning from past mistakes when the service and construction industry had massive labor cuts and cut rig construction but then had to build it all up again.

Short-term oil overcapacity will prevail until the world economy picks up, and then energy demand will come back. Long-term energy demand will double between now and 2060 because of population growth.

—Royal Dutch Shell PLC Chief Executive Officer Jeroen van de Veer

For Tim Probert, executive vice-president for strategy and corporate development at Halliburton, the behavior of the current cycle differs from prior downturns as it is an economic, financial, and oil crisis. "We are still finding the bottom for demand destruction," he said. But he saw the longer term as "very positive."

Meanwhile, the company is reducing input costs, including inefficiencies in execution; managing effectively employed capital; focusing on quality execution; and adjusting its technology portfolio and general positioning, while aligning all four elements to its customer base. Probert acknowledged that there had been some staffing reductions, especially in the US.

Supply destruction generates risk on human capital as the price of oil and gas declines, agreed Thierry Pilenko, president and chief executive of Technip. He said capex will go down with prices. The workforce has grown strongly in the service industry, he said, but there is an aging pyramid. "Headcount reduction has started, and we are expecting it to decrease further as projects are postponed."

To mitigate the human resources impact, Pilenko said, Technip tries to "select the best, maintain R&D investment, rethink core processes and improve efficiency, and invest in competency development and employ lessons it has learned." He added, "In relations with oil and gas operators, we must stay engaged on the future projects (particularly the large and complex ones); drive standardization as well as simplification; and eliminate redundancies. We also need to keep recruiting university graduates to avoid future generation gaps and to maintain credibility."

To reduce costs, which have gone down by 5-6%, Pilenko said he starts with the group's own costs and looks for new types of suppliers. Inefficient subcontractors push up costs, he said.

Saipem Chief Executive Officer Pietro-Franco Tali said that, in the short-term, exploration and production investments suffer; in the medium-term, the economy recovers; oil prices rebound; and shareholders, irritated by production and reserve replacement declines, demand action. Oil companies then rush to make up for lost time except that new frontier projects will be tougher than before.

And he cautioned, "Contractors cannot organize themselves in survival mode." Saipem, he said, has made the choice of improving and nurturing competencies, working with clients, and investing in the future. It will continue to invest in new assets: Saipem is developing a new field vessel to work difficult future projects such as Shtokman and the Arctic region.

CGG Veritas has seen a substantial reduction in exploration and seismic budgets, but key projects are confirmed, although often spread out over time. However Pres. and Chief Operating Officer Thierry Le Roux insists that maintaining production levels tomorrow depends on exploration spending today.

The first half of 2009 has a backlog

cover, but the second half is uncertain, said Le Roux. He said lower costs for such things as fuel should help, especially in marine contracts. His strategy is to manage short-term uncertainties while developing long-term potential by bolstering technological advances and preserving human capital.

But, he cautioned, a strong balance sheet and a strong order book is mandatory to carry out such an ambitious strategy. ✦

CFTC: Cause of 2008's oil-price surge remains elusive

Nick Snow
Washington Editor

Nine months after crude oil prices reached record levels, experts agreed at the US Energy Information Administration's 2009 annual conference on Apr. 7 that speculators shouldn't be blamed. They also could not say definitively what pushed prices upward during the first half of 2008.

The US Commodity Futures Trading Commission's large trade reporting system gives it a powerful tool to determine what's moving markets, according to Jeffrey Harris, CFTC's chief economist. An effort is continuing to determine why crude prices surged and then plunged in 2008, he continued.

"The answers haven't been palatable to politicians or to us. We haven't been able to point at one particular type of trader and hold them responsible for running oil prices up to $140/bbl last summer. We have not been able to find the smoking gun," Harris said.

CFTC is the single government agency which identifies hedge funds in commodity markets, but it has found that index fund traders could not be found as easily, he said. "Index funds can come to the market through commodity pools or banks. Many come through swap dealers," he said.

Examinations of reported trades on regulated exchanges showed that the average index fund decreased its crude oil commodity position as prices rose, suggesting that adjustments were designed to maintain the positions as percentages of total commitments, Harris said. "We've since updated our reports with numbers for September and the end of 2008 and haven't found a widespread abandonment of the market," he said.

Incomplete data

But Robert F. McCullough Jr., managing partner at McCullough Research in Portland, Ore., said CFTC's investigation is not complete because it doesn't include unregulated over-the-counter trades. "We have no data. We don't survey spot oil transactions as we do for other commodities. This is Congress's fault," he said.

He agreed it was politically convenient to blame speculators when crude oil prices climbed amid growing inventories. But he said underlying fundamentals, including supply and demand, could not provide a reason for soaring prices either. "We were flat out of interesting events. Almost every answer the pundits gave us was wrong," he said.

McCullough said CFTC uses outmoded classifications that do not reflect the current makeup of commodities markets and concentrate on the largest traders using regulated exchanges. Harris said the commission actually has begun to receive fairly good data from over-the-counter markets, especially about index funds, to supplement its own findings.

Other panelists warned against trying to assign blame too quickly for soaring and plunging crude oil prices last year. "We have it in our heads that speculation is fraud. It's not," said Adam E. Sieminski, Deutsche Bank's chief energy economist.

Several factors could have set the stage for crude oil prices to soar in early 2008, he continued. Emerging market economies had an average annual growth in gross domestic product of 7% during 2000 to 2005. Crude oil prices did not rise enough to justify heavy exploration, reducing the Organization of Petroleum Exporting Countries' spare production capacity considerably. Refining capacity also didn't grow, and the value of the US dollar declined, he said.

Then there's stupidity

Finally, said Sieminski, "stupidity can drive decisions." He said, "That's the best explanation for somebody buying a crude oil contract at $147/bbl and expecting the price to go up. Governments can't regulate against this."

The conventional wisdom that heavy commodities trading causes volatile prices is driven more by intuition than facts or systematic analysis, according to Robert J. Weiner, an international business professor at George Washington University. "Over a time period where trading increased significantly, aggregate statistics did not show a corresponding increase in volatility," he said.

Weiner said traders adopting a herd mentality, where they made decisions by copying other market participants instead of examining fundamental influences, is a likelier force. "If lots of people try to get into or out of a position at the same time, volatility can result," he said.

Investigations have not found evidence of parallel trading among commercial market participants or financial speculators, although there were some apparent cases of what Weiner termed "flocking."

He said that scarcity of data and lack of market transparency serve traders and the public poorly. "We need to examine fundamentals to understand why oil markets change," he said. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Tax proposals still lurk

The oil and gas tax increases that were part of the Obama administration's fiscal 2010 budget request did not make it into either the US Senate or House's broad reconciliation proposals in early April. That doesn't mean that they won't be considered.

Industry observers told me the taxes and fees could show up in other legislation, possibly the energy bill being developed by the Senate Energy and Natural Resources Committee.

The proposals would exclude refiners from a tax credit other domestic manufacturers use to compete against overseas firms that receive subsidies from their governments.

"US refiners are closely connected to the world oil market," said Lou Pugliaresi, president of Energy Policy Research Foundation Inc. "Removing this tax credit would simply move more refining out of the country."

Independent producers have been among the most active groups against the proposals. "It will be Issue No. 1 for us when we come back there on Apr. 20," said Rock Zierman, president of the California Independent Petroleum Association.

Shares goal, but...

"We share the president's goal of wanting to wean the United States off foreign oil, but you can't do it by killing domestic production. That's what his tax proposals would do," Zierman continued.

The Independent Petroleum Association of Mountain States members tried to convey the message that more natural gas will be needed to achieve clean energy goals which congressional Democrats and the White House have set, according to Jon Bargas, public affairs director for IPAMS. "We were encouraged by most of our meetings. We tried to concentrate on members who would understand the adverse impacts these proposed tax increases would have, particularly on small, independent producers," he told me.

Freshman Democrats

IPAMS members, during their Washington callup, visited members of Congress from the Rocky Mountains and freshman Democrats from previously Republican districts, Bargas said. "A lot of them hadn't realized how harmful and extensive these tax increases would be to small independent producers or how much of our national gas comes from the Intermountain West," he said.

The upstream independents from the Rockies also explained that they're feeling the economic recession too, and that their industry is responsible for about 150,000 jobs in the region.

"With low commodity prices and shortage of capital—and our industry's high reinvestment rate—it made our message clear that increasing taxes could hurt our industry and make it more difficult for us to help achieve reduced greenhouse gas emissions and other environmental goals," Bargas said.

"We face a struggle based on the economic cycle and the reality of energy prices today," said Zierman. "The number of active drilling rigs across the country has fallen by half the past few months. Throwing in more taxes now would be a serious mistake." ✦

DOI's OCS comment process limited, House Republicans charge

Nick Snow
Washington Editor

Ranking minority members of two US House committees expressed concern Apr. 7 that the US Department of Interior is limiting public comments as it considers a comprehensive 5-year US Outer Continental Shelf leasing plan.

"The system currently in place fails to meet a simple standard of inclusion to promote and facilitate an open exchange of public opinion," said Doc Hastings (R-Wash.) of the Natural Resources Committee and Darrell E. Issa (R-Calif.) of the Oversight and Investigations Committee, in a letter to US Interior Secretary Ken Salazar.

Persons wishing to submit comments must either mail or hand-deliver them to DOI headquarters in Washington, or "attempt to navigate the sprawling online database known as Regulations.gov, where users must first successfully input 'docket IDs,' 'legacy numbers,' and an 'RIN' before they have any chance of advancing to the main comment submission page,'" the two House members said.

They called the new policy "an unconstructive change" from the previous system. "The department's public comment process was especially user-friendly under the Bush administration, enabling Americans to easily submit their comments through a simple e-mail address. The department should immediately reinstate the user-friendly e-mail public comment system," they said.

A DOI spokesman said on Apr. 8 that the Bush administration made the decision to use the automated Regulations.gov system to receive and process comments on the draft proposed 5-year OCS program. US Minerals Management Service staff members recommended

replacing an earlier system, Public Connect, with Regulations.gov because the updated version has automated functions which sort, tally, and post public comments, he said in an e-mail.

Hastings and Issa said they were also troubled to learn that DOI's webcast of its Apr. 6 OCS public meeting in New Jersey ended at noon, nearly 8 hr before the meeting's actual conclusion. "Since many Americans took their personal time to participate in this public comment session until 8:00 in the evening, we cannot understand why the department would end the webcast at the time you departed and before the majority of the public finally had their chance to stand up, speak, and be heard," they told Salazar.

The DOI spokesman said greatly higher costs for a full-day webcast during the current economic downturn led to the decision to put only the first 3 hr online live.

Transcripts of the entire proceedings will be available later online at www.doi.gov/ocs and www.mms.gov, he said. ✦

DOE notes water as key issue in deep shale gas primer

Nick Snow
Washington Editor

Protecting and conserving water resources will be the key challenge in developing domestic deep shale gas, the US Department of Energy said as it released a primer for regulators, policymakers, and the general public on Apr. 14.

The primer was designed to be an objective source of credible information on the technology advances and challenges accompanying deep shale gas development, DOE's Fossil Energy Office said. Production of natural gas from hydrocarbon-rich deep shale formations is one of the fastest growing US energy activities, but much of it is occurring in areas with little or no oil and gas experience, it noted.

The DOE division said it developed the primer with urging from the Ground Water Protection Council, a national association of state groundwater and underground injection agencies. The council will hold its 2009 spring meeting Apr. 19-23 in Tucson in conjunction with the National Ground Water Association's groundwater summit.

DOE said it recognized the need for a report that addresses questions about the nature of shale gas development, potential environmental impacts, and the ability of current regulatory structures to deal with the resource's development.

Improved horizontal drilling and hydraulic fracturing technologies have played a key part in shale gas production's emergence as a major new domestic energy source, it continued. This has enabled producers to recover more gas economically and with less surface disturbance from deep shale formations, it said.

The primer's publication comes at an important time, according to the Independent Petroleum Association of America. It shows that the current state-federal hydraulic fracturing regulatory partnership is working despite suggestions from some members of Congress that the US Environmental Protection Agency should take over enforcement, said IPAA President Barry Russell on Apr. 14.

"For energy resources that were once considered too deep to find, too expensive to produce, in rock too hard to access, this report from [DOE] shows just how far America's independent natural gas producers have come in converting the potential of shale into the reality of clean-burning American energy," he maintained.

"More than that, though, the report underscores the lengths to which these businesses and state regulatory officials go every day to ensure that the energy development process is as safe, efficient, and transparent as possible," Russell said.

The primer is available online at www.fossil.energy.gov. ✦

China, Venezuela agree to speed up increased oil shipments

Eric Watkins
Oil Diplomacy Editor

Venezuelan President Hugo Chavez and his Chinese counterpart Hu Jintao, have agreed to bring forward the starting date of long-planned increased Venezuelan oil exports to the East Asian nation.

Apart from advancing the date of stepped up exports, however, Chavez's visit to China last week did not achieve any new break-throughs for his country, cash-strapped due to high social expenditures and the worldwide decline in oil prices over the past year.

"I proposed that, given the global situation, we study the possibility, and we agreed to move up the target [date] set in the strategic accord for 2013," Chavez said, adding that the extra shipments will begin in 2010.

During his visit, Chavez and Hu also held talks on the investment needed from China to reach the long-planned target of 1 million b/d, as well as the

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Japan wising up to Russia

The oil and gas industry has read much recently about the difficulties of dealing with Russia. But now, it seems, someone has finally gotten Moscow's number.

That view emerged last week with reports that the Russian government would be seeking financial and technological assistance from Japan to build a pipeline and LNG export terminal for its Sakhalin-1 project.

An official at Japan's ministry of foreign affairs confirmed that Russia is seeking help in constructing a pipeline from Sakhalin to Vladivostok, site of a future LNG export terminal.

Total costs for construction of the pipeline and export terminal are estimated at 500 billion yen, and Russian Prime Minister Vladimir Putin is expected to propose launching full-scale talks for assistance when he visits Japan in May.

Financing sought

One pipeline already connects Sakhalin Island to Khabarovsk on the Russian mainland, and the Japanese government—via the Japan Bank for International Cooperation—is considering financing the planned extension of the pipeline from Khabarovsk to Vladivostok.

Japan has in interest in acquiring gas from Sakhalin-1, where reserves are estimated at 485 billion cu m, and the sailing distance from Vladivostok across the Sea of Japan is, well, not worth talking about.

Sakhalin-1's gas reserves, at 485 billion cu m, are just slightly larger than the 480 billion cu m of the Sakhalin-2 project, which recently began exports. Reports say 60% of Sakhalin-2's output is likely to be shipped to Japan, supplying some 8% of the nation's needs.

Another 8% from Sakhlain-1 would be tempting.

At the moment, however, Russia plans to purchase all the gas produced from the Sakhalin 1 project, in which Japanese trading house Itochu Corp. and US oil major Exxon Mobil Corp. own stakes, and export it to Japan and elsewhere.

Japanese wary

That could be tempting to Japan, except for that tiny reference to "elsewhere." Where could that be? Well, as you might imagine, the most likely location is China—Japan's historic rival and current chief competitor for sources of energy.

The Japanese are well aware of that possibility. As one senior Japanese government official put it, Russia is more likely to seek bids for the construction of energy export infrastructure around Sakhalin Island from a variety of countries than to request help from any single country.

"Japan, South Korea, or China—whoever—would be fine for them, as long as they get a good deal," said Shin Hosaka, oil and natural gas division director of Japan's Agency for Natural Resources and Energy under the Ministry of Economy, Trade, and Industry.

Getting a good deal is the aim of business, and no one can fault the Russians for trying to do just that. What's new in the Japanese outlook, however, is that the Russians are being eyed a bit more warily than before, i.e., with "caveat emptor." ✦

launch of a joint venture for oil transport, and construction of a Venezuelan refinery in China.

"Those three top strategic objectives already justify the working visit to China, but we have other political and geo-political interests to discuss with President Hu Jintao," Chavez said after arriving in Beijing.

According to Chavez, the goal of shipping 1 million b/d to China is reachable because his country plans to divert much of the current 1.5 million b/d it sends to the US.

"We're diversifying our oil business," Chavez said. "Even though we're a small country, we're an oil giant and China doesn't have the reserves necessary to meet its needs," he said, adding that "God put the oil that China needs for the next 200 years in Venezuela."

During the visit, Venezuela's Energy and Mines Minister Rafael Ramirez, along with top executives of state-owned Petroleos de Venezuela SA, met with leaders of Chinese state-owned China National Petroleum Corp. and Sinopec to discuss current and future cooperation.

Venezuelan officials said the talks also took up the idea of a joint refinery project on Chinese territory capable of processing Venezuelan heavy crude into fuel and other products.

Following the Venezuelan leader's visit, CNPC Pres. Jiang Jiemin said the state firm would submit a plan to set up joint venture refinery with PDVSA in Guangdong province. Jiang said the refinery, which will process 20 million tonnes/year of oil, will be owned 51% by CNPC and 49% by PDVSA.

The talks between the two leaders largely reiterated discussions the two sides have been having for some time on the ways they can cooperate on a variety of oil developments.

In September 2008, Venezuela and China signed several accords, including one agreement for a joint study with Sinopec for construction of a refinery in Cabruta, northern Venezuela, to process heavy crude from the Orinoco heavy oil belt.

The signed documents also included a contract for the supply of crude and fuel oil between PDVSA and PetroChina as well as an agreement for the construction of four oil tankers for the Venezuelan-Chinese company CV Shipping.

In May 2008, Chinese state media reported that CNPC subsidiary PetroChina entered into a joint venture agreement with PDVSA to build a 400,000 b/d refinery in Guangdong province, configured to process Venezuelan heavy oil.

Under the agreement, witnessed by Chavez and Chinese Vice-Premier Hui Liangyu, the crude is to be sourced from the Junin 4 block in the Orinoco belt. At the time, officials said that the joint refinery, Venezuela's first such investment in China, would advance Chavez's goal of shipping 1 million b/d of oil to China by 2011, or 13% of current Chinese oil demand. Reports vary on just how much oil Venezuela actually ships to China. Last May, Ramirez said shipments amounted to 500,000 b/d of oil, while Chinese state media reported 380,000 b/d—300,000 b/d of products and 80,000 b/d of crude. ✦

US LNG market may get 2 bcfd surge

Sam Fletcher
Senior Writer

A 60-day surge of an additional 1.5-2 bcfd of LNG is likely to hit the US market this summer, on top of its baseload LNG supply of 0.7-1 bcfd, said analysts at Pritchard Capital Partners LLC, New Orleans.

"US facilities can probably handle 5 bcfd of LNG, but if imports got much greater than 3 bcfd, domestic producers would likely fight back to defend market share, although exactly what realistic options they would have remains to be seen," the analysts said.

"LNG traffic, all moving northbound through the Suez Canal, suggests that Asian markets are backing away from LNG purchases. A surge in LNG imports to the US in the late spring or early summer is highly likely," the analysts said. "The question is how big will the surge be." US natural gas prices as low as $3/Mcf "are a strong possibility this summer," they said.

"One wild card is that South Korea and Japan could take advantage of low prices before the winter buying season and start to fill up sooner, reducing the supply coming here," said Pritchard Capital Partners. "Three European facilities coming on line in 2009 will help absorb supply as the year progresses." They expect a return to baseload supply levels around September.

Demand from Japan, South Korea, and Spain—the "Big Three" importers of LNG—has fallen this year because the global economic recession, said Pritchard Capital analysts. LNG storage in Spain is above 80% of capacity, and Japan and South Korea are looking to divert some cargoes.

Pritchard Capital analysts earlier reported, "Japan (world's biggest user of LNG) is seeking to divert as many as six cargoes of the LNG from Indonesia over the course of this year as demand slows. Japan is very orderly on how they order LNG deliveries, so they're simply planning ahead. Net effect is supplies shift westward to India and China initially; new supplies soak up demand, then continue to shift further westward, ultimately to the US (OGJ Online, Mar. 16, 2009)."

LNG producers are unlikely to reduce output for two main reasons, said Pritchard Capital after hosting a Mar. 18 conference call with Zach Allen, president of Pan EurAsian Enterprises Inc., a management advisory firm specializing in energy. "First, throttling back on production is said to be technically very challenging. Second, and more important, after stripping out and selling the natural gas liquids, producers such as Qatar have an effective cost on the gas that can be measured in pennies, so transportation, which typically runs $2/Mcf or less, is the main cost," analysts said. "Therefore, LNG can be shipped here at prices below where we are today and still be profitable for the producers."

African producers Nigeria and Equatorial Guinea would have to settle for prices of for $2.50-3/Mcf for May delivery in Asian markets, "making UK and US markets look better and better," said Pritchard Capital analysts. "For the same reason, shipments from Trinidad will likely look toward the US."

They said, "LNG will go to the UK as much as it can as storage there was drawn down by the Russia-Ukraine [gas] dispute earlier this year, but once that is absorbed the US becomes the destination of choice."

During the conference call, the analysts said, "The point came up that if the market really believed that we were going to get the kind of LNG surge being bandied about, should not the forward curve [in the gas futures market] be in a backwardation rather than contango position? The main conclusion to that was we are in unchartered territory and to some extent will have to wait and see what happens as spring then summer approaches." ✦

RPSEA advances six small-producer projects

The nonprofit Research Partnership to Secure Energy for America (RPSEA) has selected six proposals for negotiation of advanced-technology assistance to small producers.

The technologies focus on production from mature oil and gas fields.

Each proposal under RPSEA's Small Producer Program must provide at least a 20% cost share, with as much as 50% for field demonstration projects.

RPSEA, a group of US energy research universities, companies, and independent research organizations,

promotes the development of technologies applicable to US hydrocarbon resources. Under contract with the Department of Energy, it manages research and development funding authorized by the Energy Policy Act of 2005.

Here are titles and participants of the new projects selected for negotiation under the Small Producer Program:

- Development Strategies for Maximizing East Texas Oil Field Production, led by Bureau of Economic Geology, University of Texas at Austin, with participation by Danmark Energy LP and John Linder Operating Co. LLC.
- Field Demonstration of Alkaline Surfactant Polymer Floods in Mature Oil Reservoirs, Brookshire Dome, Texas, led by Layline Petroleum 1 LLC with participation by TIORCO LLC and University of Texas at Austin.
- Electrical Power Generation from Produced Water: Field Demonstration of Ways to Reduce Operating Costs of Small Producers, led by Gulf Coast Green Energy with participation by Denbury Resources, ElectraTherm Inc., Dry Coolers Inc., Southern Methodist University, and Texas A&M University (GPRI).
- Mini-Waterflood: A New Cost Effective Approach to Extend the Economic Life of Small, Mature Oil Reservoirs, led by New Mexico Institute of Mining and Technology with participation by Armstrong Energy Corp.
- Commercial Exploitation and the Origin of Residual Oil Zones: Developing a Case History in the Permian Basin of New Mexico and West Texas, led by University of Texas of the Permian Basin with participation by Chevron Corp., Yates Petroleum, and Legado Resources.
- Evaluation and Modeling of Stratigraphic Control on the Distribution of Hydrothermal Dolomite Reservoir Away from Major Fault Planes, led by Western Michigan University with participation by Polaris Energy Co. ✦

Pemex upbeat about Mexico's oil production goals

Eric Watkins
Oil Diplomacy Editor

Mexico's Petroleos Mexicanos, faced with reports of steep production declines, has announced plans to raise its replacement rate to 100% by 2012 for proved reserves of oil and natural gas.

"The rate of integrated return of proven reserves is 71.8%…smaller than the objective of 100% by the end of the current administration," said Carlos Morales Gil, Pemex director of exploration and production, in a conference call with analysts.

Morales Gil's statement, however, coincided with publication of a new report by the US Energy Information Administration that sees Mexican oil production slipping by 10% in 2009 largely due to falling output from Cantarell oil field.

"EIA forecasts that Mexico will produce 2.9 million b/d of oil in 2009 and 2.7 million b/d in 2010," it said, explaining that "the decline is driven mainly by falling production at the supergiant Cantarell field, which has only been partially offset by higher production from other areas."

In its remarks, EIA acknowledged that Cantarell field is one of the largest oil fields in the world, but that production there has declined "dramatically in the past several years."

As production at the field declines, so too does its relative importance to Mexico's oil sector: Cantarell contributed 36% of Mexico's total crude oil production in 2008, vs. 62% in 2004.

In 2008, it said, Cantarell produced 1 million b/d of crude oil, down more than 30% from the 2007 level of 1.47 million b/d and down nearly 50% from the field's peak production level of 2.12 million b/d in 2004. Cantarell's production stood even lower this January at just 772,000 b/d.

Despite the evident downturn, however, Mexican officials remain optimistic that Cantarell will average 756,000 b/d in 2009 due to increased investment in drilling and well maintenance.

Mexican officials also believe they can slow, and even reverse, the country's declining production over time due to increased production from other regions, especially Chicontepec.

On Mar. 18, Mexican President Felipe Calderon said that his country's proved oil reserves, which fell 2.7% in 2008 to 14.3 billion boe, were declining at a slower pace now than in 2007.

"We are halting the fall in reserves," he said, explaining that Mexico found 1.5 billion bbl of oil and natural gas in 2008, 41% more than in 2007. The discoveries, he said, replaced 72% of the amount of oil and gas Mexico produced last year—essentially the same figure cited by Morales Gil.

"There are a lot of reservoirs we need to explore and develop," said Calderon on his visit to the Chicontepec region, an occasion which celebrated the 71st anniversary of the nationalization of Mexico's oil industry.

Calderon's visit to the oil-producing region and his statement concerning its future development reflect optimism at Pemex over Chicontepec's potential.

Last month, Morales Gil cited independent reports in claiming 139 billion boe at Chicontepec. At the time, Morales Gil said about 18 billion bbl could be recovered over the next 30 years using current technology, while the rest could be "squeezed" out by new technology yet to be discovered.

Morales Gil said Pemex is working on a "model contract" to govern Chicontepec development.

Meanwhile, Morales Gil said the current production schedule for Chicontepec calls for the conventional drilling of more than 17,000 wells in 29 fields with the eventual goal of producing around 100 b/d oil from each one of them. ✦

Russia's Samotlor to produce 90 more years, says TNK-BP

Alan Petzet
Chief Editor-Exploration

Western Siberia's supergiant Samotlor field should continue to produce until the year 2099, said the TNK-BP Russian amalgam, which plans to invest $1 billion/year through 2011 to sustain it.

Samotlor, discovered in 1965, on marshlands and taiga in the Khanty-Mansi Autonomous area just north of Nizhnevartovsk in the Tyumen region, has produced 19.2 billion bbl of oil since development began in 1969, TNK-BP said.

The latest study found remaining recoverable volumes of more than 7 billion bbl of oil and 3.53 tcf of gas. Samotlor is one of the world's five largest oil fields, TNK-BP said.

Apr. 3, the 40th anniversary of Samotlor's commercial development, found the field producing 582,750 b/d. TNK-BP said its efforts should maintain production at or slightly above this level at least until 2012 even though decline rates are accelerating in the field's most mature parts.

Production peaked in 1980 at nearly 3.2 million b/d, almost half of Russia's output, and had fallen to 400,000 b/d by 1999. Samotlor has 13,400 oil wells and 4,500 injection wells.

Under a development plan approved in 2005 by Rosnedra, Russia's agency for subsoil use, the existing well stock and certain specific exploration and technological activities will account for just over 70% of production in the next 90 years. The rest will come from access to new reserves in field extensions and application of advanced technologies.

Samotlorneftegaz and TNK-Nizhnevartovsk, incorporated into TNK-BP, took over operation of the field in 2003. TNK-BP's license runs until 2038.

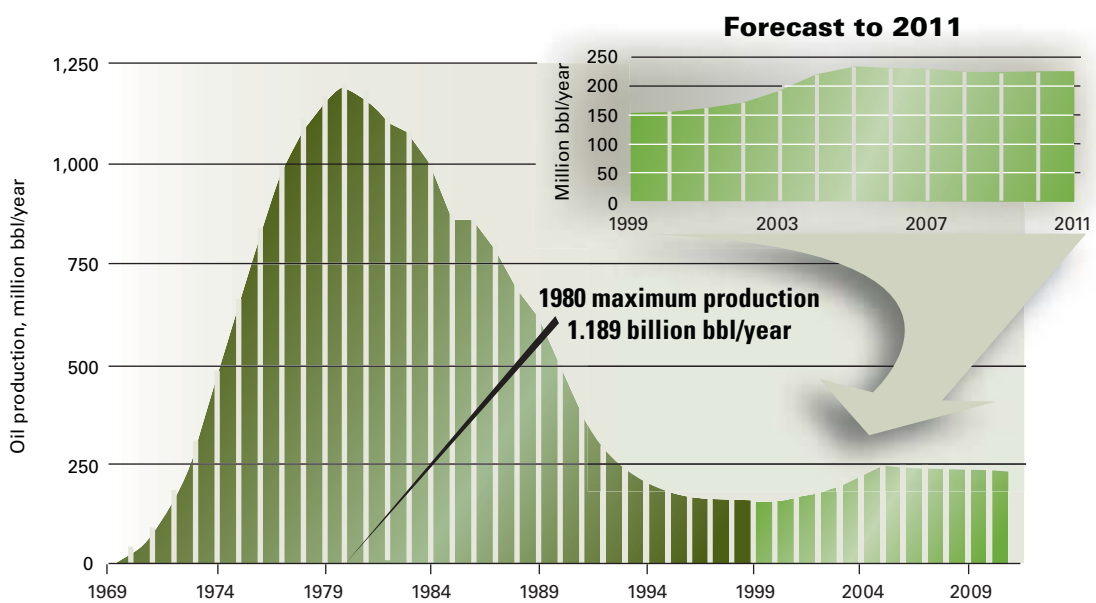
Since 2003, it has reactivated more than 1,250 idle wells, pumped hydrofracs at workovers, run electric submersible pumps, and drilled sidetracks.

It is near completion of 4,000 sq km of 3D seismic from which it has identified numerous satellite structures, five of which are under development with extended reach drilling. One satellite, Ust-Vakh, has yielded more than 46.5 million bbl of oil in 5 years with 100 million bbl left to recover.

Samotlor's ultimate recovery was estimated at 15 billion bbl of oil in a 1986 compilation by the American Association of Petroleum Geologists. It listed the producing formation as a Cretaceous sandstone at 7,300 ft.

The US Energy Information Administration in 1997 gave Samotlor's EUR as 24.7 billion bbl of oil, 11.9 tcf of associated gas, and 3.2 tcf of nonassociated gas. ✦

OIL PRODUCTION AT SUPERGIANT SAMOTLOR FIELD



Source: TNK-BP

Petrobras, Repsol YPF make large oil discovery in Brazil's Santos basin

Brazil's state-run Petroleo Brasileiro SA and partner Repsol YPF SA filed a declaration of commercial viability with the country's Agencia Nacional do Petroleo (ANP) for a light oil and gas discovery made on Block BM-S-7 in the Santos basin.

Piracuca field lies in 200 m of water off Sao Paulo state, 200 km southeast of Santos. The partners, Petrobras 63% and Repsol YPF 37%, estimate recoverable volumes at 88.5 million cu m or "about 550 million boe."

The declaration of commercial viability is the outcome of "intense exploratory activity" carried out on this block, the partners said, adding, "With the new field, it will be possible to increase the potential for light oil and gas production in shallow waters."

The announcement coincided with reports that Petrobras notified ANP on Apr. 6 that it found traces of oil in a test well drilled on the CM-401 Block offshore in the Campos basin. Petrobras holds a 100% stake in the block.

Petrobras reported that data from early March showed that the Peregrine 1 drillship was drilling at the site in 977 m of water and targeting a depth of 3,333 m.

Meanwhile, ANP said ExxonMobil Brazilian subsidiary Esso Santos is drilling a second well on Brazil's Santos basin Block BM-S-22 to a depth of 5,404 m in 24 m of water.

ExxonMobil Chairman and Chief Executive Officer Rex Tillerson said the second well is designed in part to give ExxonMobil a "better understanding" of BM-S-22, but he declined to confirm what the firm expects to discover.

While the block is close to major finds in Santos's presalt layer, Tillerson played down projections of discoveries at BM-S-22, saying, "We have one well," and "it's just too early" to predict what will be found on it.

ExxonMobil is operator of the block with a 40% stake. Hess Corp. also holds a 40% interest, while Petrobras owns the remaining 20%. ✦

Firm plans work on four blocks in Ecuador

Ecuador's state-owned Petroamazonas, a subsidiary of national oil company Petroecuador that operates oil assets previously owned by Occidental Petroleum Corp., expects to develop oil fields on four oil blocks this year.

Reiterating plans announced in February, Petroamazonas General Manager Wilson Pastor said his firm would aim at drilling 14 wells in Panacocha field, with initial production set at 5,000 b/d from the second quarter of 2010, eventually rising to 25,000 b/d.

Pastor said 13 wells would be drilled in Panayacu-Quinde field, with output potential of 10,000 b/d. Four wells will be drilled in Paka Sur field, with initial output of 3,000 b/d possibly online by yearend 2009.

Petroamazonas also hopes to develop Block 31, where it wants to drill 14 wells, but financing remains a problem. Pastor said the firm wants to start work on Block 31 this year.

Pastor was reiterating plans that had been announced in February following a meeting between Petroamazonas and Ecuadoran President Rafael Correa.

At the time, Correa's office issued a statement saying Petroamazonas would spend up to $820 million to start four projects: Panacocha ($216 million), Panayacu-Quinde ($150 million), Paka Sur ($40 million), and Block 31 ($414 million).

Correa's office said that Block 31 will see the drilling of 14 wells with output scheduled to start in January 2011. Peak production will reach 33,400 b/d.

Budget cut

Prior to Correa's statement, Ecuador's El Universal newspaper reported that Petroecuador's budget for 2009 had been ratified at $3.002 billion, a drop of 38% from 2008. It said that Petroamazonas's share would be $967.8 million and that its developmental priorities would include Panacocha and Block 31.

In January, Petroamazonas announced plans to produce an average of 100,600 b/d in 2009, compared with 95,000 b/d in 2008.

Petroamazonas said the production would come from Block 15: 60,400 b/d from Eden-Yuturi field and 40,200 b/d from Indillana.

To output targets under budgetary constraints, Pastor told Ecuador's El Comercio newspaper in February, Petroamazonas would seek alliances to secure investments.

He said the company needed to invest $509 million in order to meet its output target for 2009, although the government budgeted only $359 million.

Pastor said the outstanding $150 million would be financed through association contracts which would be put out to tender.

For Block 31, formerly operated by Petroleo Brasileiro SA, Pastor said Petroamazonas would consider a joint venture partnership to help with the planned $300 million of needed investment for development.

Petroecuador holds 80% of Petroamazonas, while Petroecuador subsidiary Petroproduccion holds 20%. ✦

China

Roc Oil (Bohai) Co., Sydney, plans to start a 12-well drilling program in April in the C and D oil fields at its Zhao Dong Block in southwestern Bohai Bay

off China, which is producing 21,500 b/d of oil.

The company started producing on Mar. 20 from the C-51 well in the extended reach area (ERA) of the C and D fields, and that well is making 1,000 b/d. C-52 came on in Mar. 29 and is exceeding 2,000 b/d. D-43 is under completion.

One more well will be drilled and two workovers performed before the 2009 drilling operations are finalized at ERA and C4 oil fields.

The upcoming program, with fewer wells than in 2008, is designed to maintain production at the 2008 average of 18,050 b/d. Roc Oil is commissioning a second drilling platform, installed in 2008, and plans to install and commission a second processing platform in the second half of 2009.

Interests are Roc Oil and New XCL-China LLC 24.5% each and PetroChina Co. Ltd. 51%.

Part of the 1H pilot area in the Shouyang block in Shanxi Province, China, has reached critical desorption pressure, and the pilot area is producing more than 200 Mcfd of coalbed methane, said Far East Energy Corp., Houston.

The company said it believes this volume is enough to start talks with China United Coalbed Methane Co. about jointly marketing the gas. Sales would likely occur through a compressed natural gas facility with a capacity of 1-3 MMcfd.

Three wells appear to meet the definitions for Chinese reserves qualification as long as they maintain sufficient production levels until an official certification can be obtained. Far East Energy will spud three deviated wells in the pilot area within a few weeks.

Indonesia

Eni SpA plans to appraise a discovery named Jangkrik on the Muara Bakau block in the Kutei basin off Indonesia.

While giving few details, the company said it will assess the commercial viability of a fast-track development for Jangkrik. The well is in 400 m of water in the Makassar Strait off East Kalimantan.

Elsewhere in the basin, Eni participates in gas developments in the Rapak and Ganal blocks and holds stakes in the Aster and Tulip discoveries, both in an advanced appraisal phase, in the Tarakan basin to the north.

Oman

RAK Petroleum PCL of the emirate of Ras Al Khaimah plans to drill the Zad-2 well on Block 47 in Oman later in 2009 after having acquired subsidiaries of Indago Petroleum Ltd., London, that hold rights in Oman.

RAK Petroleum raised its interest to 100% in blocks 31 and 47 with acquisition of Indago Ventures 31 Ltd. and Indago Ventures 47 Ltd.

If successful, RAK Petroleum said, the Zad prospect will become an important gas-condensate field 10 km from an existing pipeline. The exploration well will test the fractured Cambrian Amin sandstone reservoir, an analog to Kauther field.

Uganda

Tower Resources PLC said its Neptune Petroleum (Uganda) Ltd. unit let a contract to ASCOM SA Group to provide a rig to drill in Uganda.

The rig will drill Iti-1, Neptune's first commitment well in license EA5 covering 6,040 sq km in the unexplored Rhino Camp basin south of the border with Sudan in the northern Albert graben.

The well is expected to spud in mid-May 2009. Projected TD is 800 m.

Uzbekistan

Tethys Petroleum Ltd., Guernsey, Channel Islands, UK, is working to hike oil production in North Urtabulak field in Uzbekistan after completing the acquisition of Rosehill Energy Ltd., which holds a production enhancement contract for the field.

Work is under way on further production enhancement with workovers, optimizing beam pumps, and other means. A gas lift system is to be installed. Further development drilling and attention to nearby fields is under consideration.

North Urtabulak field is in the Afghan-Tajik basin.

Gulf of Mexico

Cobalt International Energy LP, private Houston firm, and France's Total E&P USA Inc. will combine their Gulf of Mexico exploratory lease holdings, which Cobalt will operate generally with 60% interest.

The position totals 214 blocks now, and the companies agreed to joint participation in any future opportunities. A multiwell program is to start in mid-2009 using a rig supplied by Total. The combination is subject to US Minerals Management Service approval and other closing conditions.

Louisiana

St. Mary Land & Exploration Co., Denver, turned its first operated Jurassic Haynesville shale well to sales at an initial rate of 4 MMcfd of gas and 525 b/d of load water.

The flow came at the Johnson Trust 1-2 well with 3,150 psi flowing casing pressure on an $^{18}/_{64}$-in. choke after a 10-stage frac in a 3,400 ft lateral at 15,100 ft measured total depth. The well is in Spider field, DeSoto Parish. A second operated well drilling northern San Augustine County, Tex., will core Haynesville and evaluate the deeper Cotton Valley lime.

The company said the outcome is lower than nearby wells but within the range of reported Haynesville results. It holds 50,000 net acres with Haynesville potential, including 40,000 acres in East Texas and 10,000 in Louisiana, including 4,200 acres in Spider field.

Downhole cable heats high viscosity, high-paraffin oil

Several fields in Russia have installed a downhole cable that heats high viscosity and high-paraffin crude, according to Nefteservis-NN LLC.

Nefteservis-NN developed and sells the cable and associated equipment. Development of the well heating unit, called Fontan, started 5 years ago.

Benefits

Nefteservis-NN says the cable heats fluid flowing in the tubing to a temperature exceeding the wax dropout point. Some benefits of the system include:

- Ensures walls inside the wellbore, x-mas tree, and adjacent flowlines remain clean at all times.
- Prevents hydrate, asphaltine, and paraffin buildup.
- Increases well production rate, especially for high-viscosity crude oil.
- Improves electric submersible pump (ESP) performance and service life, because of a lower fluid viscosity.
- Reduces well downtime by increasing time between well repairs.
- Eliminates the use of other paraffin removal methods.
- Liquefies hydrate accumulations in gas wells.
- Heats water wells located in permafrost regions.
- Heats pipelines.

The company says operators can adjust the unit for the best temperature and power-saving operations, as well as for intermittent use.

Installations

Companies in Russia that have installed the cable include RN-Stavropolneftegas LLC (Rosneft), NGDU Buguruslanneft (TNK-BP), Lukoil JSC, TPP Lukoil-Usinskneftegas, TPP Lukoil-Ukhtaneftegas, TPP Lukoil-Severneftegas, NGDU Nurlatneft (Tatneft JSC), Naryanmarneftegas LLC, NGDU Talakanneft (Surgutneftegas JSC), Kyrgyzneftegas JSC (Kirgisia), and Kazmunaineftegas JSC (Kazakhstan).

Operators have placed the heating cable inside or outside of tubing and inside hollow sucker rods. In these

The heating system includes the cable in the well and associated control equipment (Fig. 1; photo from Nefteservis-NN).

Additional equipment in the photo at left includes a wellhead system for running the cable in the well (Fig. 2; photo from Nefteservis-NN). Operators in the photo above can place the cable inside or outside of the tubing, as shown here (Fig. 3; photo from Nefteservis-NN).

wells, the cable is within the interval of wax crystallization.

Nefteservis-NN says production in wells equipped with the cable increased from 10-30% and uptime of wells with ESPs has increased to 700 or more days from 365 days.

It estimates that for wells producing 150-220 bo/d with continuous operation of the cable at 50 kw, the unit will pay out in about 60 days.

The standard set of equipment for the unit includes heating cable, control desk with spare parts, wellhead packer, connection terminal, wellhead wired temperature gauge, flash memory (MMS-card), and software. Fig. 1 shows one installation on a well in Russia.

Additional equipment includes wellhead running in hole and pulling out of hole device, step-up transformer (if cable length is greater than 1,150 m), and drawworks.

Fig. 2 shows workers installing the cable.

The automatic controls allow for:

- Switching on and off the cable heating.
- Controlling cable voltage and load current.
- Controlling temperature change.
- Decreasing heat when pump unit is off.
- Protecting the cable from short circuits.
- Switching on after power interruption or when temperature drops below the wax crystallization point.
- Monitoring operation parameters.
- Recording operations.
- Data transmission for remote monitoring and control from a distant control room or personal computer. The sites in Russia use wire-linked modems or cellular communication with GSM-modems.

The cable except for the load-bearing wireline has armored polymeric skin. For lengths greater than 2,000 m, the cable has a central load-bearing wireline (Figs. 3 and 4).

To obtain greater cable reliability, Nefteservis-NN connects the heating conductors to various poles of a feed supply by dividing them into groups through isolating wire bundles.

Nefteservis-NN says that since 2004 no well equipment with the cable has ceased production or needed repair because of wax accumulation.

Pilot tests

Nefteservis-NN ran pilot tests on the cable technology in wells in Kharyaga field, in the Timan Pechora province of Russia.

In Well 1126, it installed the cable at 1,479 m in May 2004. In the previous year, 2003, the company said the well had experienced eight stuck scrapers prior to running in hole with a gamma-ray tool, two workovers for removing hydrate-wax deposits, and seven jobs/month for reaming out tubing to about 1,400 m. The reaming jobs tagged wax at 200-400 m and 700-900 m.

The operator also treated the well continuously with a dewaxing unit 14-16 times/day to a 1,000-m depth. In 2003, the well had 52 hot-oil treatments, which involved 19 flowline flushing jobs and 33 jobs on the ESP. The average flushing volume was 9 cu m/job for the flowline and 30 cu m/job for the ESP and required 1.5 hr/job for the flowline and 4.5 hr/job for the well.

In 2003, the well's hot-oil treatments consumed 1,100 cu m of oil.

Nefteservis-NN says before running in hole with the gamma ray, the well produced at 42 cu m/day with a 1% water cut. With the cable installed, the average surface temperature was 43° C. with a cable temperature of 69° C., and the well increased production to 50-55 cu m/day.

The 1,525-m long cable was in service 677 days during the 730 days in which the well was in operation, according to Nefteservis-NN.

In Well JVg 4089, Nefteservis-NN ran the cable to 1,605 m in September 2004.

Initial production from the well started in June 2003. Before running in hole with a gamma ray, the well during 6 months in 2003 experienced 11 stuck scrapers, 2 workover operations for removing hydrate-wax deposit, and a daily reaming of the tubing string to 1,400 m, according to Nefteservis-NN. Wax deposits were at 700-1,350 m.

The operator also treated the well with a dewaxing unit 14-16 times/day to a 1,000 m depth, and in 2003 the well had 29 hot-oil treatments on the flowline and ESP.

Nefteservis-NN says before running the gamma ray, the well produced 45 cu m/day of oil with a 1% water cut and increased to 55 cu m/day after cable installation.

The cable was in service for 902 days during which the well operated for 1,013 days, according to Nefteservis-NN.

The cable either has a flat or round shape (Fig. 4; photo from Nefteservis-NN).

Other installations

Nefteservis-NN says that it has installed the heat-tracing cable systems in 32 wells in Kharyaga field, 10 wells in Vozey field, and 6 wells in Kyrtaelskoye field.

On wells with sucker-rod pumps experiencing wax accumulation, it says average overhaul life has increased to 355 days from 82 days and hot-oil washings have decreased to 0.1 from 8.2 operations/year. Also average production rate increase for the 85 wells was 9.8 cu m/day, while water cut decreased in most wells with a high water cut, according to Nefteservis-NN.

It notes that in Lukoil-Usinsk Khariaginskoe oil field, the wells producing with the service life of wells ESP have increased to more than 900 days.

At Buguruslan-Oil's Rodnikovskoe oil field, the field has experienced no production stops because of wax accumualtion since installation of the cable in December 2005, the company says.

One recent installation of the cable is in Well 1109 of Granichnoye oil field. The well produced intermittently a sucker-rod pump because the crude had a viscosity greater than 20,000 cp, according to Nefteservis-NN.

After the operator installed the cable heating unit in the casing annulus in October 2008, Nefteservis-NN notes that the pump worked continuously with a higher surface temperature of 15° C. and reduced crude viscosity to 5,258 cp. Current production is 2 cu m/day with a cable temperature of 86° C., Nefteservis-NN says. ✦

Petrobras's 5-year plan targets large production expansion

Petroleo Brasilerio SA (Petrobras) in its 2010-13 strategic plan, released in January, included the development of presalt discoveries as well as continued development of discovered heavy oil and gas accumulations.

The figure below shows the timetable for its operated fields that sees its oil production increasing to 2.68 million b/d in 2013 from 2.05 million b/d in 2009. Combined gas and oil production increases to 3.32 million boe/d in 2013 from 2.51 million boe/d in 2009.

Its assessment is that by 2020, its share of presalt production will reach 1.8 million bo/d. Announced producible oil estimates in subsalt discoveries include 5-8 billion bbl in Tupi, 3-4 billion bbl in Iara, and 1.5-2 billion bbl in Jubarte, for a total of 9.5-14 billion bbl. When added to its booked reserves, these estimated will nearly double Petrobras's proved reserves.

Jubarte is in the Espirito Santo portion of the Campos basin and was the first presalt find to begin production. The field produces a 30° oil to the P-34 floating production, storage, and offloading (FPSO) vessel. Petrobras estimates that with the subsalt finds in the Jubarte and Parque das Baleias area, total volumes discovered including the heavy oil above the salt is about 3.5 billion boe.

Other activity in the Jubarte presalt area includes:

- Starting pilot production from Cachalote field to the Seillean FPSO in December 2008.
- Moving the Capixaba FPSO from Golfinho field to Cachalote-Beleia Franca in the first-half 2010.
- Starting pilot production of Baleia Azul to the Pipa II FPSO in second-half 2010.
- Installing a permanent production unit in Baleia Azul in fourth-quarter 2012.

In the Baleia Franca, Petrobras said it has found about a 400-m oil column similar to the column found in Iara, a discovery in the Santos basin that is 600 km from Baleia Franca.

It now estimates that its presalt area has a similar size to the entire US Gulf of Mexico area.

The figure below does not include projects operated by other companies, such as Chevron's Frade and Shell's Parque das Conchas and Parque da Baleia. Frade and Parque das Conchas are expected to start production in 2009.

Petrobras has five large gas projects starting in 2009. Camarupim includes an FPSO for producing 6 million cu m/day, Canapu is a pipe-in-pipe system that produces 2 million cu m/day, Lagosta produces 1.5 million cu m/day, Manati expansion produces 2 million cu m/day, and the Urucu system brings about 6 million cu m/day of gas from the middle of Amazonas to Manaus.

During 2009-13, Petrobras expects to start production from 10 large oil projects and 3 large gas projects.

The Tupi pilot will produce to a 100,000-b/d FPSO, with production starting in December 2010. Cachalote, Baleia Franca, and Baleia Ana will produce to an FPSO moved from Golfinho to accelerate presalt production. Jubarte presalt development includes installation of the P-57 FPSO in 2011. Also in 2011, Petrobras plans to install the P-56 FPSO in Marlim Sul.

In 2013, it expects to install five offshore facilities, with three producing 180,000 b/d each. Guara or Iara will have a 100,000-b/d FPSO for producing the presalt in the Santos Basin.

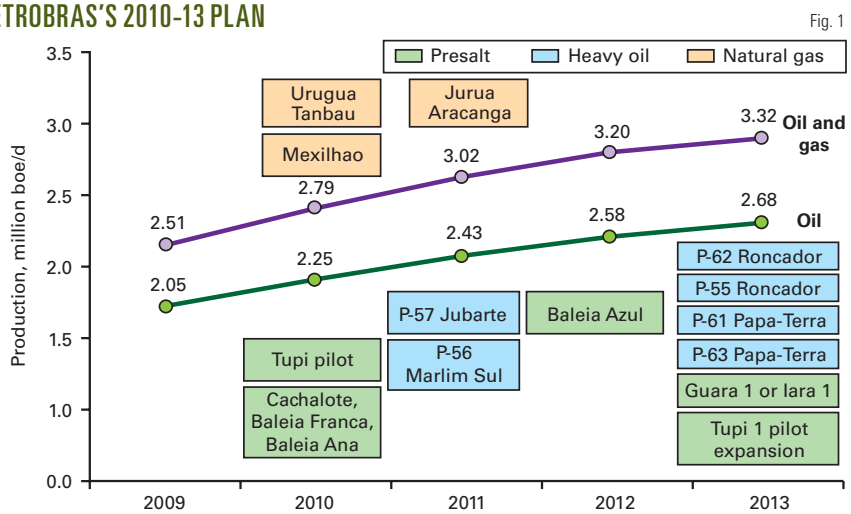
Mexilhao is an offshore gas field with a fixed platform expected to produce 15 million cu m/day, starting in 2010.

In 2009, Petrobras expects to add seven rigs to the two drilling in the presalt in 2008. It will increase the rig count to six more in 2010 and one more in 2011, for 16 drilling rigs for the presalt below 2,000 m of water.

The company estimates the production from the presalt will reach 219,000 b/d of oil and 7 million cu m/day of gas in 2013, increasing to 582,000 b/d of oil in 2015 and 1.8 million b/d in 2020. The discovered presalt oil has 28-31° gravity. ✦

PETROBRAS'S 2010-13 PLAN

Fig. 1



Practical advanced control helps midstream operations

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Although digital control systems—distributed control systems, programmable logic controller, and other automation equipment—are present in practically every process safety management (PSM) facility and in many non-PSM facilities in the midstream oil and gas industry, the use of the automatic control capability in those systems continues to be lower than it could be.

Many issues contribute to the large number of control loops that can be found in manual mode at most facilities, and most control strategies employed in today's midstream processes simply mimic designs developed for panel-board instruments decades ago. But gaining practical, sustained benefits from this process-control equipment is readily achievable: Typically, little capital investment is required other than initial engineering and commissioning labor.

With a reasonable investment in such basic support as maintenance and training to sustain performance, the effective use of automatic process control can deliver substantial operating benefits over the long term.

Control systems seem to be regarded in many operations as more a necessary evil than a benefit, and the choice of control equipment, the execution of the programming tasks, and the theoretical knowledge of many of the designers of complex controls reflect this attitude.

Even though control systems can have a major impact on operations for good or ill, much more time and energy are spent on the maintenance of rotating machinery and other process equipment run by the control system than on the most essential components of the control system—the engineering and design of the software included in the system that converts it from a collection of parts into a purpose-built system tailored to control a specific facility.

Yet control systems can play just as beneficial a role in successful processing operations as a well-maintained 6,000-hp compressor or a modern cryogenic demethanizer.

Where employed

Automatic control systems are employed in most areas of midstream, including:

- Field compression.
- Gas conditioning (sweetening and dehydration).
- NGL extraction.
- NGL fractionation.
- Heating systems.

Each of these operating areas holds opportunities for achieving benefits from either advance process control (APC) or from enhanced proportional-integral-derivative (PID) controller strategies typically referred to as advanced regulatory control (ARC).

Field compression

Field compressor stations and remote skids used for gathering systems are typically operated as unmanned facilities and frequently can be found operating with limited automatic controls. For many operators, the approach is to check compressor status via a supervisory control and data acquisition system and send someone out when a unit trips. Smaller operations without SCADA may simply perform periodic site visits and restart units found to be tripped.

Several areas of control present the operator with compressor automation opportunities:

- Automatic compressor station upset management for "bumps" caused by liquid slugs and equipment trips. Temporarily reducing inlet volume rates to limit liquid surge rates to the capacity of liquids handling equipment during pigging, new well commissioning, etc. can reduce the number of trips and restarts.

Well-tuned station capacity control strategies with effective overrides can prevent trips due to upstream or downstream unit shutdowns and restarts.

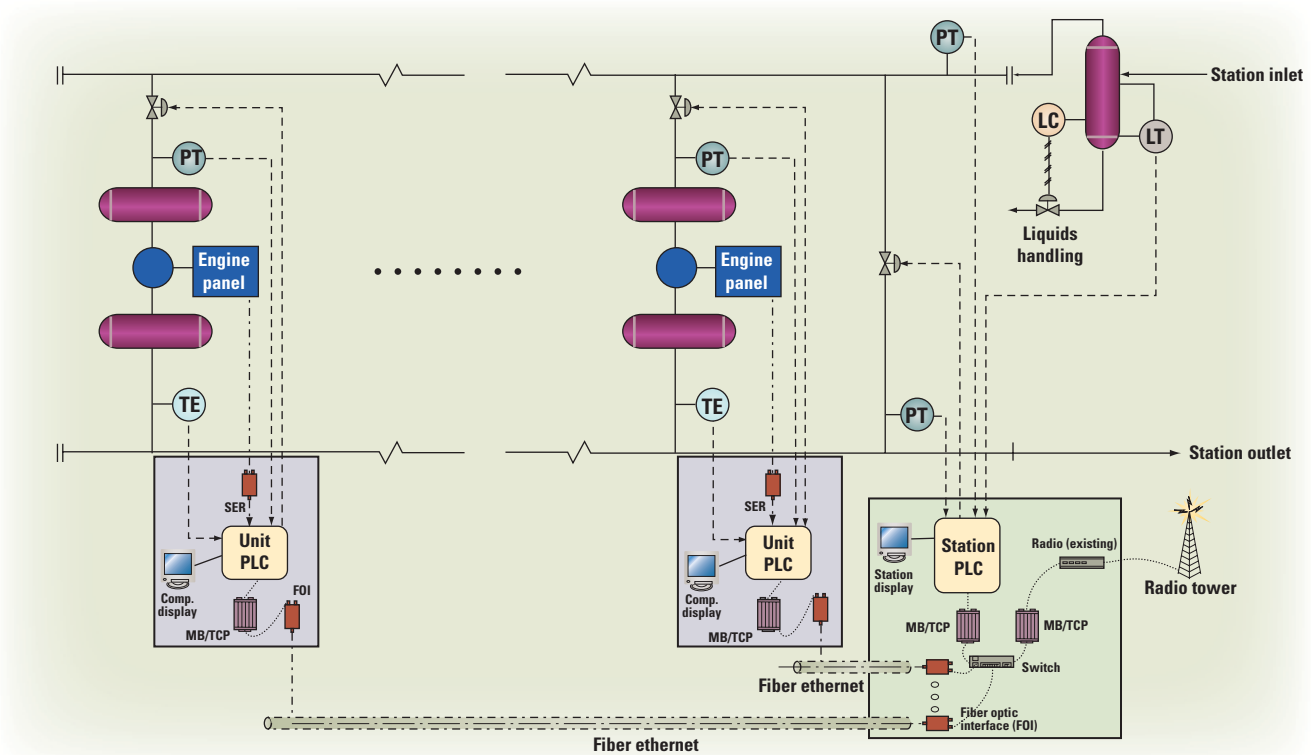
- Compressor station capacity control employing strategies that minimize compression ratios per stage, reduce recycle volumes, and manage excess capacity with speed controls and automation of volume pockets and unloaders can improve operations and reduce specific fuel consumption per unit volume compressed.
- Historical data analysis of processed volumes and fuel consumption can be used to bias station rate controls to operate each parallel unit closer to its most efficient operating range to reduce fuel consumption per volume processed.

For single compressor units, an operator can reap dividends by upgrading the unit controller to a PLC or, if already equipped, upgrading the PLC logic to

Enterprise Products owns and operates the Thompsonville gas plant south of Hebbronville, Tex. The recently expanded to 330-MMscfd turboexpander NGL recovery plant was built in 1993 by Optimized Process Designs Inc., Katy, Tex. It employs advanced control strategies for gas processing rate management as well as automatic composition control of the demethanized product. Photo from Enterprise Products.

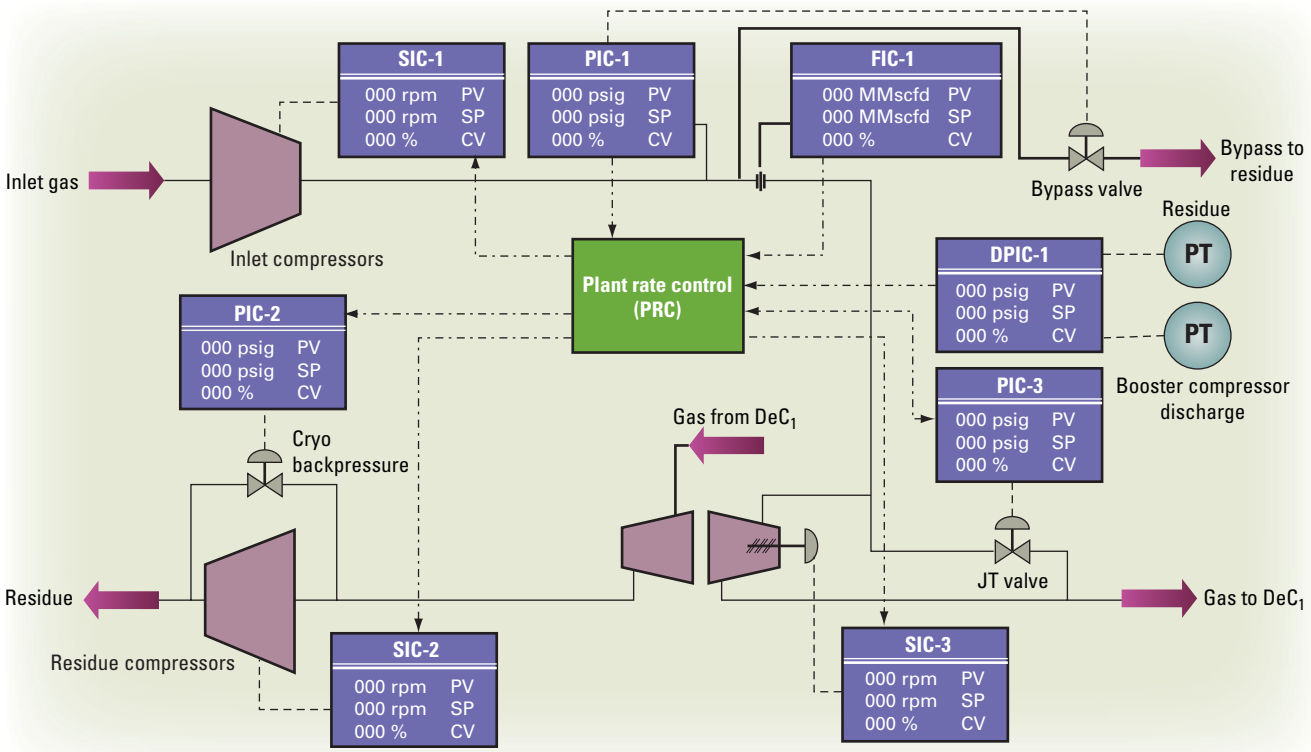
FIELD COMPRESSOR CONTROLS

Fig. 1



TURBOEXPANDER PLANT RATE CONTROL

Fig. 2



perform automatic capacity control and trip prevention. For multiple unit stations, adding a station controller (either a PLC or a small DCS) to manage common inlet systems and to provide station capacity control for parallel units can be effectively accomplished (Fig. 1).

Gas treating

One of the most common midstream processing operations is gas treating and conditioning. Amine treaters remove CO_2 and H_2S either in unmanned field systems or units operated at manned facilities. These are typically paired with triethylene glycol (TEG) dehydration units and may be operated in conjunction with refrigerated or Joule Thomson dewpoint control units to remove the heaviest NGLs.

These units typically employ a local PLC that performs all process control and shutdown functions.

Effective automatic control of gas treating can reduce operating costs and improve on-spec performance. Consistent regeneration of amine units by robust control of amine reboilers can help ensure on-spec product. Many conventional units use a still-bottoms temperature controller on the reboiler for simplicity, but this strategy typically yields poor results and frequently results in degraded amine with subsequent foaming, corrosion, and other problems.

Using a constant stripping ratio strategy will yield more consistent results and will avoid overheating amine if proper temperature overrides are included. In dewpoint plants, process chillers typically are operated at less than optimum levels of refrigerant. A strategy that automatically senses whether the tubes are covered is very simple to add and low in cost. Coupled with upset management, which protects against carryover due to sudden loss of load, this kind of simple enhancement can significantly improve capacity, reduce energy, or both.

NGL recovery

In situations where economic quantities of NGLs are to be recovered, enhanced automatic process control strategies present many opportunities for beneficial upgrades. The processes generally employed for NGL recovery include the following:

- *Refrigerated NGL recovery plants.* Where LPG recovery (C_3+) is the objective and either there is little ethane or there is no market for ethane, NGL recovery may be achieved by refrigeration of inlet gas with glycol injection or glycol dehydration to prevent freezing.

As in refrigerated dewpoint control processes, effective control of refrigeration can improve plant performance and reduce horsepower when:

—An enhanced refrigeration load control strategy manages operation to maximize recovery and observe plant constraints, while providing a rapid response to plant upsets and minimizing the potential for liquid carryover.

—Using a simple and inexpensive

control strategy to ensure the chiller tubes are always operated at efficient refrigerant levels. Refrigeration horsepower and heat exchanger surface area are used to process the maximum achievable capacity of gas with the most effective temperature control of processed gas.

• *Lean oil plants.* There are still many refrigerated absorption (lean oil) facilities operating in which additional ethane recovery is insufficient to justify the capital cost of replacement with a turboexpander plant or the gas composition is not well suited for turboexpander processing. Opportunities exist to implement enhanced control strategies at many such plants, including:

—Lean oil/inlet ratio controls to compensate for inlet composition and tower loading. The ratio strategy includes constraints to ensure adequate contactor liquid loading, deethanizer operation performance, and NGL fractionation.

—Refrigeration load management and refrigerant level optimization for chiller efficiency and stable operation.

—Predictive control of de-ethanizer feed composition for enhanced response to load changes and upsets.

—Composition control for the lean oil still for consistent absorber performance and NGL quality control.

—Enhanced steam boiler (where used) firing rate control to stabilize steam-driven equipment operation during upsets and large load start-ups and shutdowns.

• *Cryogenic turboexpander plants.* Turboexpander plants for deep cut NGL recovery typically operate with a basic control strategy. A pressure controller regulates the expander vanes, while a temperature controller maintains bottoms composition. The majority of these plants do not employ any sort of composition control on the demethanizer, and the processing rate is typically determined either by an operator readjusting the speed of recompressors or, in more automated instances, by a simple pressure controller regulating the speed or recycle valve on the recompressors.

Yet with a small investment, most turboexpander plants can reliably incorporate both demethanizer composition control and enhanced processing rate control in the basic process control system.

Field-proven strategies have been successfully implemented and operated over long periods on cryogenic turboexpander plants, including:

—Turboexpander plant processing rate control. Processing rates are determined by the supply of available inlet gas or by setting of a desired rate for a straddle plant, subject to equipment limits such as demethanizers maximum allowable operating pressure (MAOP) or recompressor differential pressure or rod loading.

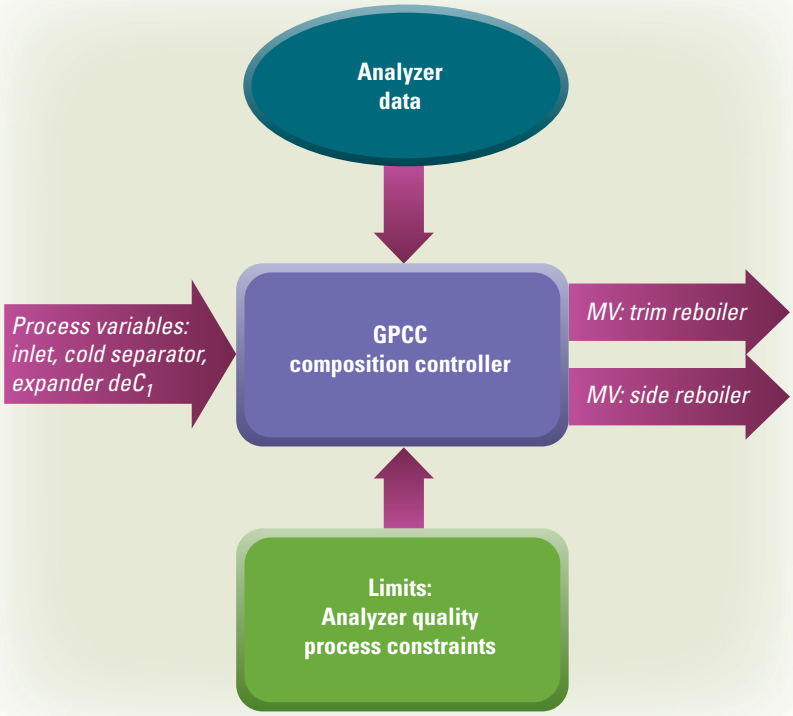
Coordinated manipulation of expander vanes and recompressor capacity continuously readjusts conditions in the direction of the highest recovery possible for a given rate and feed composition. This design has been used in single and parallel train sites. This strategy has been operated reliably for up to 15 years at several sites (Fig. 2).

—Demethanizer bottoms composition control (Fig. 3). This strategy continuously corrects tower boil-up based upon changes in bottoms temperature, tower pressure, expander discharge temperature, and other relevant conditions. Paired with rate control to eliminate the need for operator adjustments whenever the demethanizer pressure changes (Fig. 4), it can employ a typical existing multistream analyzer to reduce capital costs.

Analysis data are tested before use each time a sample is received, and this has proven effective in maintaining the strategy in long-term service. Operators are unlikely to return untrustworthy strategies to automatic after repeated failures. This composition control strategy has been in use as long as the rate-management strategy.

—NGL product surge tank level

COMPOSITION CONTROL DIAGRAM Fig. 3



smoothing. This is a simple strategy to allow surge tank levels to "float" within a limited range rather than being held at a fixed set point by a level controller (which eliminates the surge effect) that can be added to any PLC or DCS. This smoothes the flow from the surge tank to fractionation, product treating, or the pipeline, making those units run smoother.

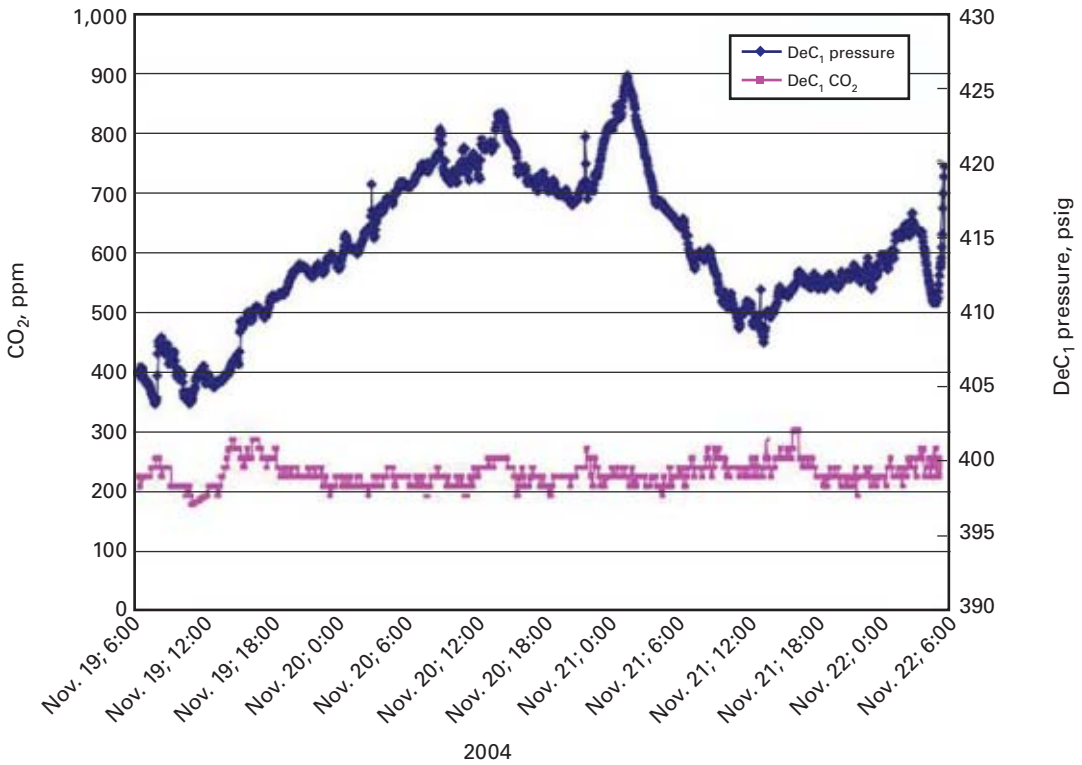
—Expander and recompressor trip management. Rotating machinery trips are typical events in turboexpander plants. Pressure controllers may not be tuned fast enough to catch the resulting pressure excursion, and lifted relief valves or complete shutdown on low recompressor suction pressure may result.

The DCS or PLC can be configured to monitor the status of key rotating equipment and take corrective action much faster than the fastest operator and faster than a traditional PID loop.

—Expander, booster compressor surge and overspeed controls. When expander overspeed shutdowns are an issue, a speed control override has been configured to limit the action of the pressure or flow controller that normally controls the expander vanes. This permits an expander to be operated reliably very close to its maximum speed, allowing full use of its capacity without large safety margins to protect against overspeed.

Similarly, the expander PLC or plant DCS or PLC can readily be programmed to provide surge control on the booster compressor, and this has been successfully implemented at several locations.

EFFECTS OF DEC$_1$ PRESSURE VARIATIONS Fig. 4



NGL fractionation controls

NGL fractionation can benefit greatly from advanced control strategies.

Overpurification is a common practice to provide "cushion" and sometimes just because the equipment is capable of it. Because many fractionators rely solely on temperature controls rather than direct analyzer or model-based controls, changes in feed composition or other disturbances may cause towers to go off spec or result in upsets such as flooding if the operator is otherwise occupied and doesn't react in time.

Overpurification uses more energy than necessary, may reduce capacity, and most importantly, reduces the yield of higher valued products.

Improved controls reduce variation in product composition due to all causes, permitting operations to move target set points closer to specifications. This generally increases the yield of higher valued products while reducing the energy necessary to separate each barrel of feed (Figs. 5 and 6).

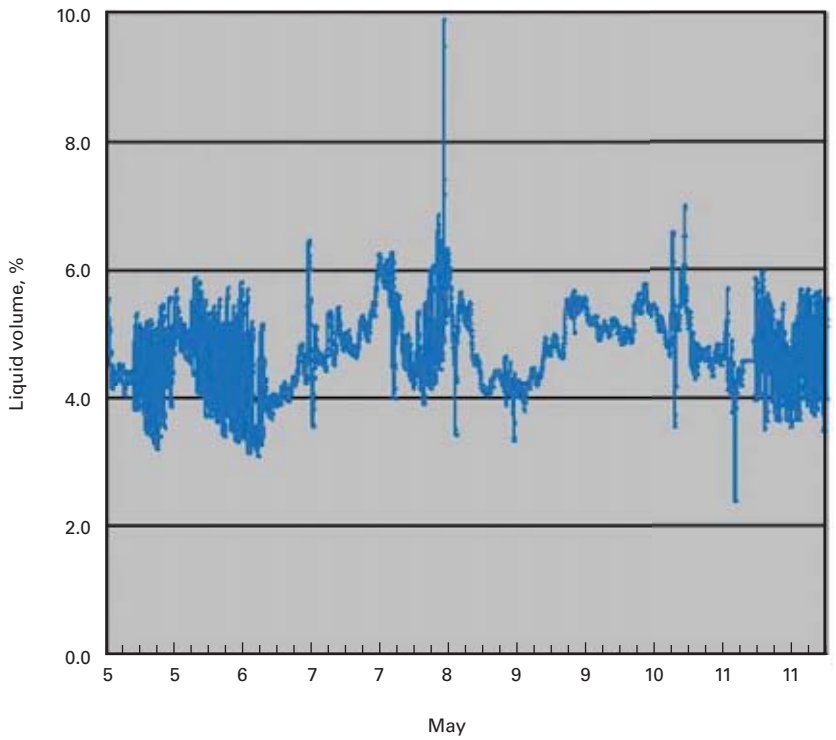
Without use of third-party advanced control software packages, modern distributed control systems can be configured with enhanced NGL fractionation strategies to improve distillation column performance over traditional temperature control with designs that include:

- Model-based composition control.
- Energy balance models to maintain column separation performance.
- Internal material balance control for stable column operation.
- Material balance reflux management for more stable column operation.
- Constraint control-based optimizers to maximize feed rates or reduce energy consumption (Fig. 7).

One common issue, during use of on stream analyzers for closed loop control, is that they are less reliable than most other instrumentation. Because

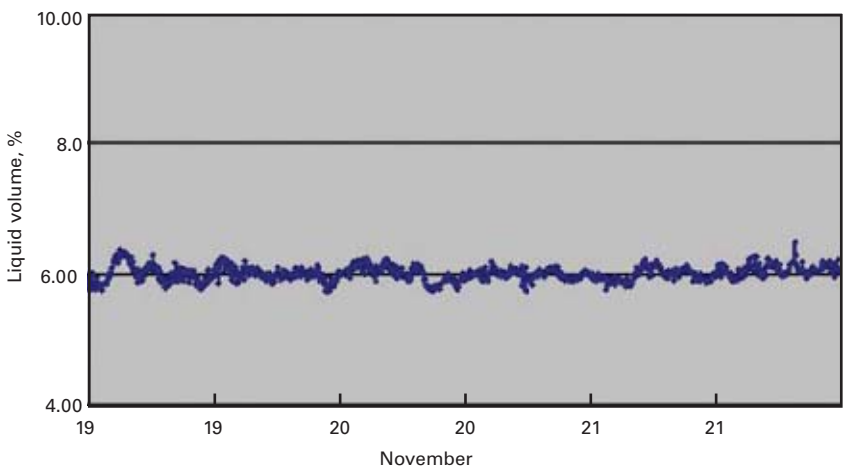
PRE-APC DEC$_3$ OVERHEAD C$_2$

Fig. 5



POST-APC DEC$_3$ OVERHEAD C$_2$

Fig. 6



the components are mostly lighter boiling paraffins of varying molecular weight, regressive models developed from historical data work well in making short term (hours to days) predictions of composition based upon column operating conditions.

When automatically corrected with validated on stream analyzer data, composition models are reliable and accurate for advanced control strategies. Performance of automatic tests on the reasonability of new analysis data typically catch analyzer failures before they cause control problems.

And because analyzer samples are used periodically to correct the model rather than in closed-loop control, analyzer failures can usually be corrected without causing composition control problems. Several sites have operated reliably for years with this type of DCS-based control.

Heating system controls

Most gas and NGL treating, recovery, and fractionation plants use some form of heating system, such as steam from boilers and waste-heat boilers or heat-medium circulation from direct-fired heaters and waste-heat recovery units. Because there are usually multiple heat sources in parallel and multiple heat users also in parallel, however, heating systems frequently cause process cycling and upsets.

A disturbance in one tower can cause the heating system to cycle in reaction, thus upsetting all the other heat supply and heat-consuming equipment. Frequently a few flow and temperature controllers are the only automatic controls, with the operator setting a significant amount of excess recycle heat medium flow or waste steam to the deaerator to handle surges in self defense. Without an overall strategy to balance the supply of heating fluid with the demand, each change in supply or demand causes an upset in the other side of the equation.

Although "advanced" control is not typically required here, the arrangement of control loops can make major differences determining whether the heating system is a tool for maintaining stable control or is another contributor to upsets and quality variation in Amine stills, demethanizers, and fractionators. And if properly designed, the control strategy can prevent heat-medium breakdown (a common problem) due to overheating.

It can also be designed to ensure that waste-heat sources are kept at maximum capacity while fired heaters are used only for swing loads to reduce energy consumption. All that is normally

PETROLEUM EVENTS CALENDAR 2009

Subsea Tieback Forum & Exhibition
March 3 – 5, 2009
San Antonio, Texas USA
Website: www.subseatiebackforum.com

Offshore Asia Conference & Exhibition
March 31 – April 2, 2009
Bangkok, Thailand
Website: www.offshoreasiaevent.com

Oil Sands and Heavy Oil Technologies Conference & Exhibition
July 14 – 16, 2009
Calgary, Alberta, Canada
Website: www.oilsandstechnologies.com

Oil & Gas Maintenance Technology North America Conference & Exhibition
September 1 – 3, 2009
New Orleans, Louisiana USA
Website: www.ogmtna.com

Unconventional Gas International Conference & Exhibition
September 29 – October 1, 2009
Ft. Worth, Texas USA
Website: www.unconventionalgas.net

Deepwater Operations Conference & Exhibition
November 10 – 12, 2009
Galveston, Texas USA
Website: www.deepwateroperations.com

Offshore Middle East Conference & Exhibition
October 27 – 29, 2009
Manama, Kingdom of Bahrain
Website: www.offshoremiddleeast.com

Deep Offshore Technology
International Conference and Exhibition
November 3 - 5, 2009
Monte Carlo, Monaco
Website: www.deepoffshoretechnology.com

Emerging Unconventional Resources Conference & Exhibition
December 8 – 10, 2009
Shreveport, Louisiana USA
Website: www.EmergingResourcesConference.com

Oil & Gas Maintenance Technology Conference & Exhibition
Co-located Pipeline Rehabilitation and Maintenance
January 19 – 21, 2010
Cairo, Egypt
Website: www.oilandgasmaintenance.com

Pipeline Rehabilitation & Maintenance
Co-located with Oil & Gas Maintenance Technology
January 19 – 21, 2010
Cairo, Egypt
Website: www.pipeline-rehab.com

Deep Offshore Technology
International Conference and Exhibition
February 2 – 4, 2010
Houston, Texas, USA
Website: www.dotinternational.net

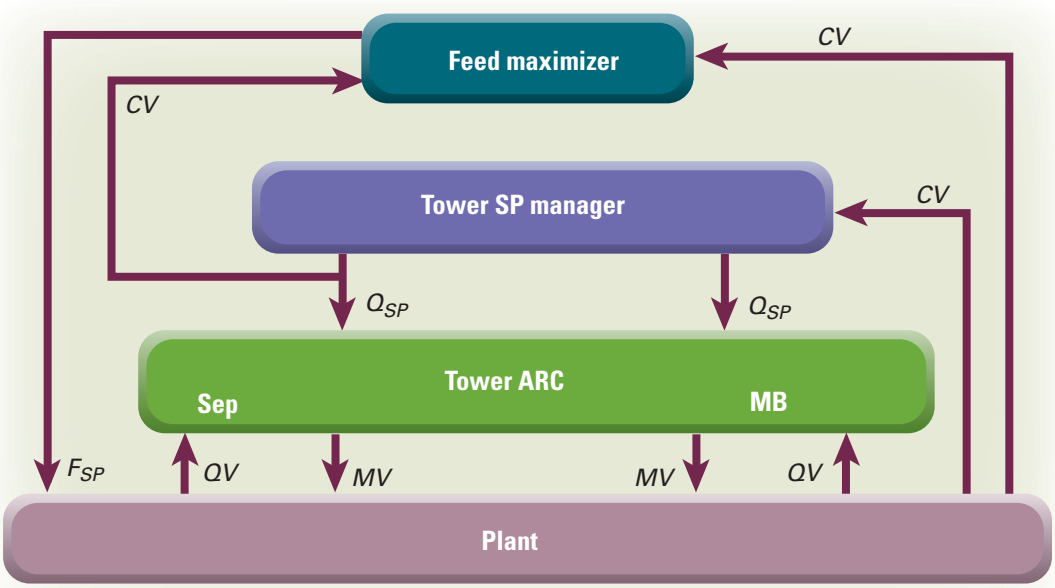
Offshore West Africa Conference & Exhibition
March 23 – 25, 2010
Luanda, Angola
Website: www.offshorewestafrica.com

Rocky Mountain Unconventional Resources Conference & Exhibition
April 6 – 8, 2010
Denver, Colorado USA
Website: www.RMURconference.com

WORLD ENERGY CONGRESS
September 12 – 16, 2010
Montréal, Quebec, Canada
Website: www.wecmontreal2010exhibit.com

FRACTIONATOR CONTROL

Fig. 7



required is a few carefully arranged PID loops with effective tuning to maintain a balance between heating fluid supply and demand.

Executing a successful project

Like all successful projects, an advanced control project requires certain steps in its execution to achieve the desired results and to ensure that it delivers long-term benefits. To be successful, an APC project needs:

- Clear objectives (scope).
- Adequate resources in terms of instrumentation and DCS or PLC equipment as well as skilled personnel for implementation.
- Committed management support.
- Proper pre-commissioning preparation.
- Effective commissioning.
- Thorough operator training.
- Monitoring tools ("dashboards") to verify effective use.
- Periodic maintenance and operator refresher training.

APC projects are typically initiated based either upon a process study that has determined that the achievable benefits justify the investment and are sustainable or upon the need to manage a known performance issue such as product specifications in which the cause of off-specification product has been determined to be control-related.

The first step is to survey available information, control system capacity, operator familiarity with advanced controls and with the process, and condition of instrumentation and control devices such as valves. Of particular significance is the condition of any on stream analyzers and the maintenance support that is available to deal with any issues that may be identified with the quality of on stream analysis.

Although APC and ARC controls can be engineered to be reliable during analyzer failures, on stream analyzers must provide accurate data when they are functioning correctly. Lack of skilled analyzer support staff will severely impair the ability to execute a successful APC project.

Another important step in building a successful APC project is in the testing, repairing, and tuning of the basic control loops that already exist in the plant or that will be added to support the APC or ARC strategy. Many of the

Example 'dashboard' indicators

1. For all APC/ARC strategies:
   - % time in automatic for previous 30 days (or other interval).
   - Number of times placed in manual for previous 30 days (or other interval).
   - Number of analyzer or other instrument failure alarms previous 30 days (or other interval).
2. For compressor control performance:
   - Average compression ratio each stage.
   - Specific fuel consumption, btu/hp-hr.
   - Fuel consumption, btu/MMscf of throughput.
3. For plant control performance:
   - Number off-spec events for previous 30 days (or other interval).
   - Average C_1/C_2 ratio.
   - Average recovery of C_3+.
   - Average btu/bbl of NGL.
   - Average volume processed.

benefits of an advanced control project accrue from this first step, and it is an important one, whether the project is to implement a DCS-based APC/ARC upgrade or to install advanced multivariable control software for a complex process.

Too much focus on the advanced aspects of the project can result in missed opportunities to gain improved control benefits by ensuring that all instruments and valves are working properly and all major loops are controlling as well as possible at the lowest level.

Commissioning is another major step. It is important to stress test the APC/ARC strategy under real-world conditions. All constraints and alarms should be verified, and any special event logic or override loops should be triggered or forced into action to verify stability.

Operator familiarization and training may be the single most important aspect of an APC/ARC project. If any of the operators lack confidence or familiarity with the use of and expected behavior of the controls, additional training and "go-by" documentation needs to be provided. If the APC/ARC controls at times make process changes that are counter intuitive or go against prevailing beliefs about how the process should be operated, their performance needs to be demonstrated to each operator until the confidence to trust the controls is developed.

It is also true that operators are often aware of equipment constraints or process events that are infrequent enough that the APC/ARC engineer may be unaware of them. Having all the operators undergo first-hand controller operation in training (as opposed to classroom training) can provide additional design feedback that can be used to make the strategy more reliable. Make no bones about it: Reliability is a primary requirement of a successful APC/ARC strategy.

To ensure that the strategies are used by operations and to provide management and maintenance with adequate feedback about the successful operation of the controls, each project should include automatic reporting and the configuration of a display "dashboard" that provides readily understood performance measurements, or key performance indicators (KPIs). An accompanying box presents an example of "dashboard" indicators.

Finally, to provide sustained performance and true justification for investment, the successful APC/ARC project must include adequate documentation to permit the operating staff to perform routine troubleshooting and maintenance. It is also important to incorporate periodic site visits of a few days or remote PC access by APC/ARC support engineers to verify tuning, address issues that have arisen, and perform refresher training for previous and replacement operators. The periodic site visits should be scheduled at least annually, if not more often. This continued investment will be a small cost compared with the annual returns the APC/ARC strategies typically achieve. ✦

The author

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EXTERNAL CORROSION—Conclusion

Cased pipe segments could be less safe than uncased segments

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A comparison of scheduled or immediate responses/mile vs. number of repairs from an Interstate Natural Gas Association of America (INGAA) study and the US Pipeline and Hazardous Materials Safety Administration (PHMSA) database suggests cased pipe segments could be less safe than uncased segments, although this result is not conclusive.

New analysis of US Office of Pipeline Safety (OPS) 1988 report data and analysis of new data provided for this study, however, show that shorted casings are more susceptible to corrosion than nonshorted casings. This result contradicts the OPS conclusion in 1988: "A shorted casing does not enhance or reduce corrosion activity on carrier pipe." The OPS study neglected the fact that the nonshorted casings were much more numerous than shorted casings.

Depression of cathodic protection (CP) current resulting in elevated corrosion of the carrier pipe upstream and downstream of the casing ends can occur when a metallic short or electrolytic coupling exists between the casing and the carrier pipe. Nonconductive filler in the casing-carrier pipe annulus may not fully eliminate external corrosion of the carrier pipe in the casing unless a high quality filler is properly applied and does not deteriorate.

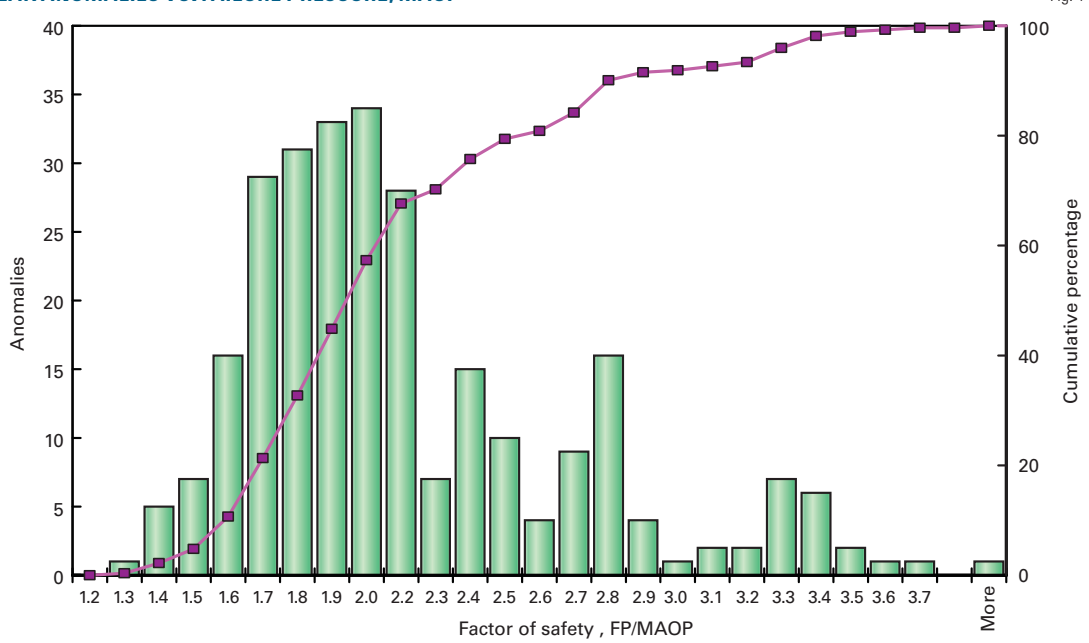
A review of reportable pipeline incidents in casings between Aug. 7, 1984, and Nov. 8, 2006, in the OPS-record database shows among 11 incidents identified, 5 were known to be caused by corrosion, 3 by excavation, and 3 by unknown causes. Of the 5 corrosion incidents, 3 resulted from atmospheric corrosion.

Although peak anomalies tend to be located near the ends of the casing (see Part 1, OGJ, Apr. 6, 2009, p. 56), the severity of the individual anomalies determined by the factor of safety does

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

PEAK ANOMALIES VS. FAILURE PRESSURE, MAOP

Fig. 1



not depend on location.

Part 1 of this article reviewed the background of this issue and described the data gathering and analysis methods used in reassessing casings' role in corrosion.

Anomaly distribution

The factor of safety (FP/MAOP) reflects the severity of damage to cased pipe integrity by corrosion anomalies independent of an individual pipe's nominal WT, OD, and steel properties characterized by the specified minimum yield strength (SMYS) because both failure pressure (FP) and maximum allowable operating pressure (MAOP) are proportional to the term SMYS (2 × WT/OD), based on the original or modified ASME B31G. FP/MAOP thus can give an unbiased estimate of the threat of corrosion anomalies for different pipe sections (with different WT or OD) from different operators.

Fig. 1 shows a plot of the number and cumulative percentage of anomalies vs. FP/MAOP. Only five peak anomalies of the total 272 have FP/MAOP less than 1.39 (requiring a scheduled response action following Modified B31G). These do not, however, include the deepest anomaly (84% WT) whose FP/MAOP is rather large, 1.64, due to its small length (0.79 in.).

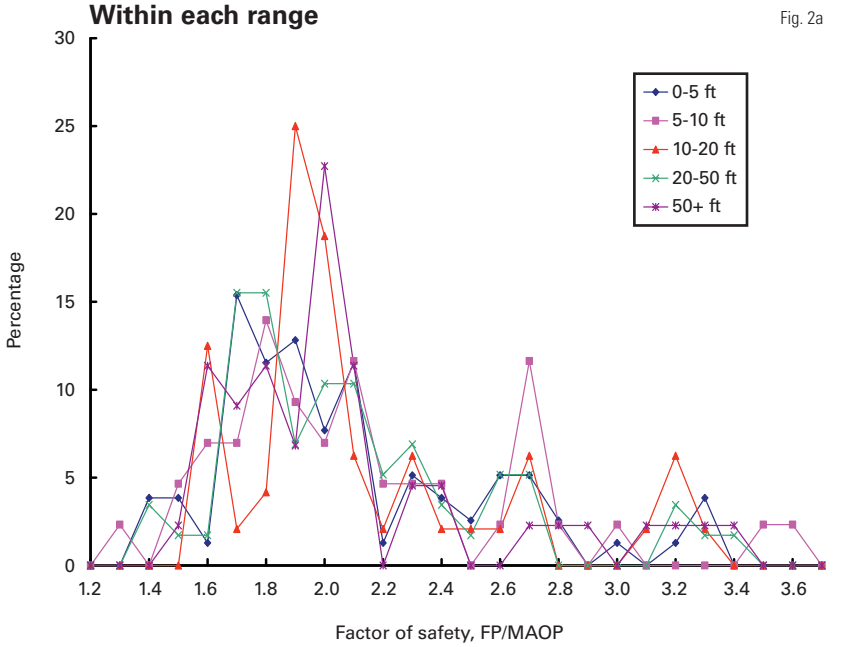
Following modified ASME B31G criteria, the pipe segment containing this deepest anomaly (>80% WT) requires replacement to prevent a leak. The lowest FP/MAOP for all peak anomalies is 1.28.

Excluding this deepest anomaly, 98.2% of the remaining peak anomalies require no response action according to modified B31G for carrier pipes with a design factor of 0.72. For crossings of roads or railroads with casings, ASME B31.8 recommends a design factor of 0.72 (1/1.39) for both Division 1 and Division 2 of Class 1, except for private roads of Division 1 where the recommended design factor is 0.8.

Of all cased pipe segments studied for this article, 2,733 in total, 99.82% do not require response action

Anomaly distribution vs. FP/MAOP Fig. 2

Within each range Fig. 2a



Cumulative Fig. 2b

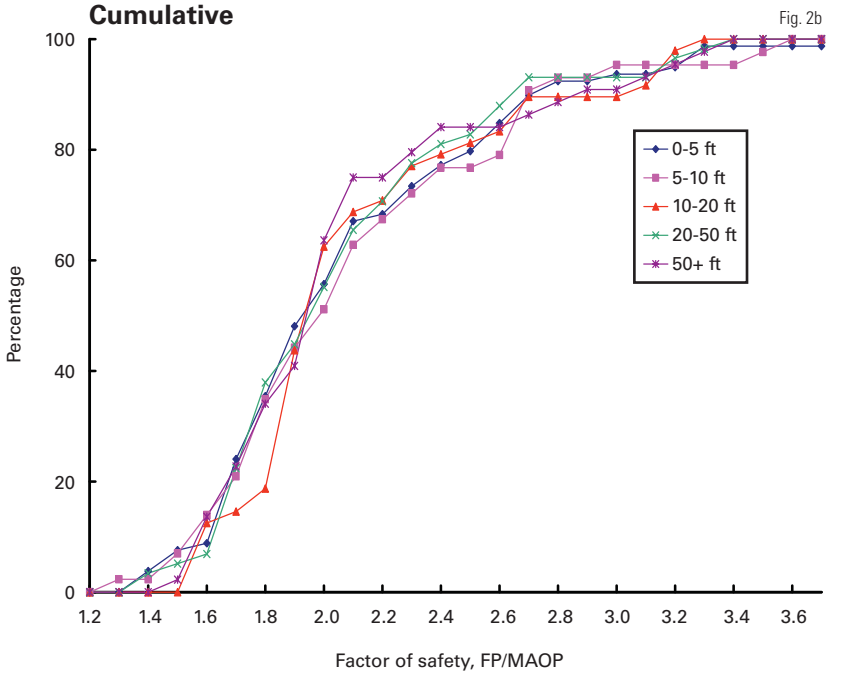


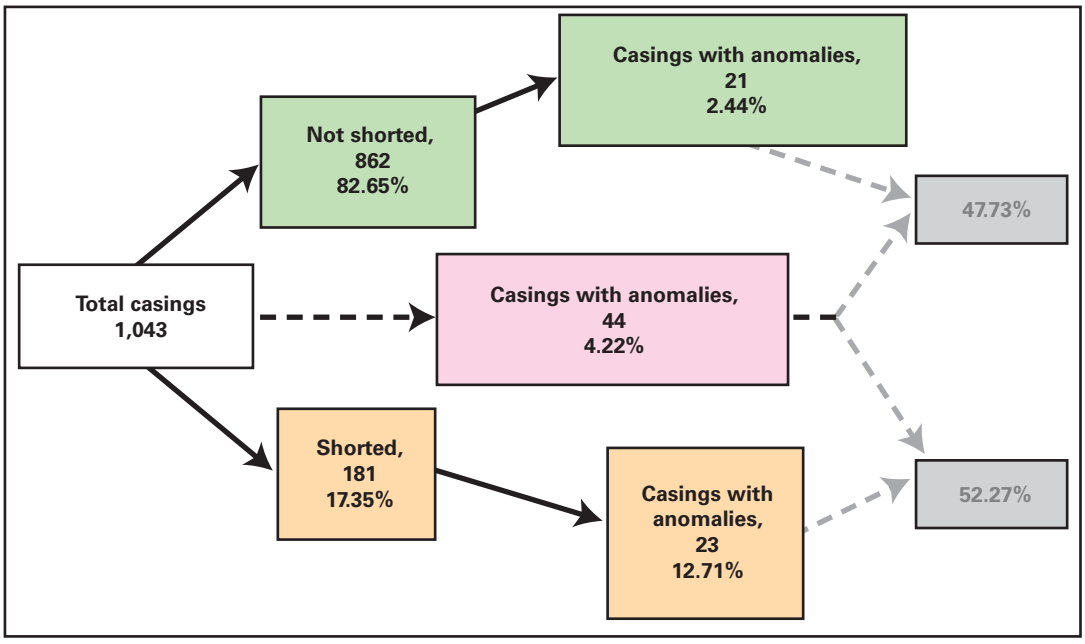
Fig. 1 also shows 46% of all anomalies as having FP/MAOP falling between 1.7 and 2.1, inclusive. The average is 2.1 and the median is 2.0. This high average ratio reinforces the idea that cased crossings are in excellent condition overall.

FP/MAOP can help determine if the severity of an individual anomaly is preferentially located near the ends of cased pipe segments, similar to the preferential location of anomalies along cased pipe segments discussed in Part 1.

Fig. 2 shows the distribution of anomalies vs. FP/MAOP, calculated with the number of anomalies in every

OPS 1988 STUDY, NEW ANALYSIS

Fig. 3



ILI CASING DATA; COMPANIES C, E

Table 1

Company name	C	E	Total
Total casings	149	36	185
Casings with ≥20% WT anomalies	32	5	37
Total nonshorted casings, N1	121	36	157
Casings with ≥20% WT anomalies, Nc1	16	5	21
Nc1/N1 x 100%	13.2%	13.9%	13.4%
Total shorted casings, N2	28	0	28
Casings with ≥20% WT anomalies, Nc2	16	0	16
Nc2/N2 x 100%	57.1%	n/a	57.1%
Total casings with ≥20% WT anomalies for C, E (Nct = Nc1+Nc2)			37
Nc1/Nct x 100%			56.8%
Nc2/Nct x 100%			43.2%

0.1 interval of FP/MAOP divided by the subtotal number of the anomalies within an interest range of shortest distance from the ends of cased pipe segments (0-5 ft, 5-10 ft, 10-20 ft, 20-50 ft, and more than 50 ft). The number of anomalies within these five ranges is similar.

Fig. 2a shows the percent distribution of anomalies vs. FP/MAOP for each range, with a point to replace column bars such as shown in Fig. 1. Fig. 2b represents the cumulative distribution of anomalies vs. FP/MAOP; the integration of Fig. 2a normalized to 100%.

The patterns for the five different distance ranges are similar in each figure. Since the difference in the distribution for the five different distance ranges reflects levels of the corrosion damage severity along cased pipe segments, the similarity of the five distributions (representing different distances along the cased pipe segments) indicates the damage severity of individual anomalies does not depend on locations.

A simple example is given here to explain the nonpreferential location of damage severity of peak anomalies represented by FP/MAOP. For multiple casings on one pipeline with the same carrier, OD, WT, and operating conditions, this nonpreferential distribution of FP/MAOP means peak anomalies have similar sizes (depth and length) regardless of being near the ends of casings or between the ends.

Report review

The 1988 OPS report[2] under the US Department of Transportation stated, based on a casing study, that "a shorted casing does not enhance or reduce corrosion activity on carrier pipe." This statement seems to contradict the normal understanding that a metallic short can increase the chances of carrier pipe corrosion because of its possible elimination of CP benefits.

Fig. 3 summarizes the ILI data for cased pipe segments in this OPS report following reexamination and new analysis in the current study. Among the total 1,043 casings, the nonshorted casings (a subtotal of 862 casings or 83% of total casings) are four times more numerous than the shorted casings (a subtotal of 181 casings or 17% of total casings).

Although the number of cased pipe segments with corrosion anomalies (anomaly depth was not specified in the report) for nonshorted casings (21) is slightly less than for shorted casings (23), the percentage of nonshorted cased pipe segments with anomalies among its subtotal (2.4%, or 21 of 862) is much smaller than the percentage of shorted casings (12.7%, 23 of 181), suggesting shorted casings are more susceptible to corrosion than nonshorted casings.

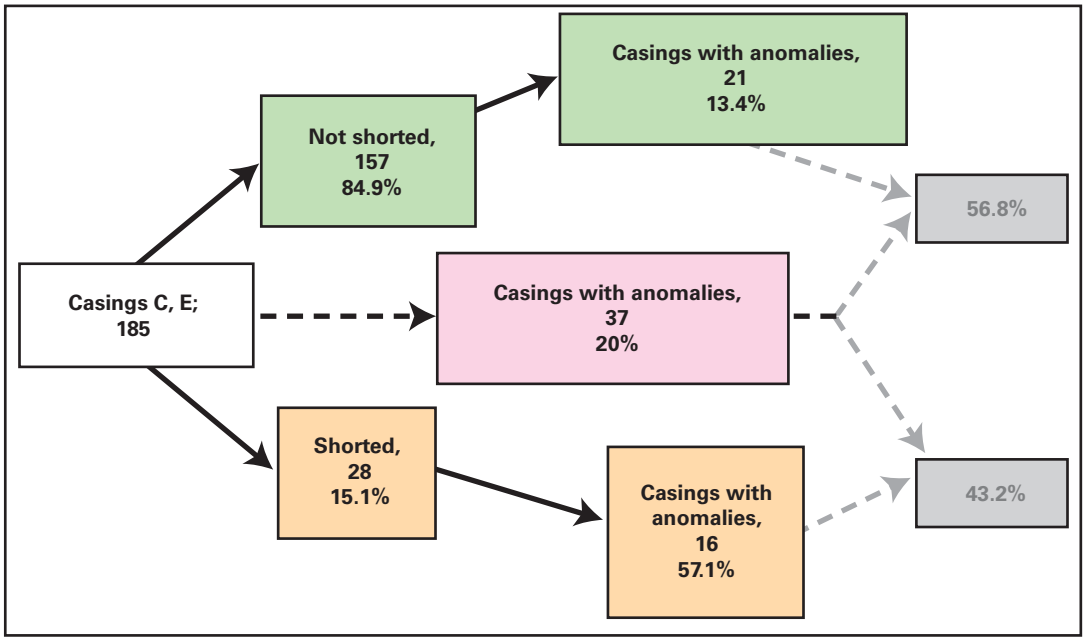
The 1988 OPS report[2] compared

only the percentage of the 21 nonshorted vs. the 23 shorted cased pipe segments with anomalies (44 total casings). Anomalies were found on 47.7 % of the nonshorted cased pipe segments and 53.3 % of shorted cased pipe segments. This comparison, however, neglected the fact that nonshorted cased pipe segments included were four times more prevalent in the data set than the shorted cased pipe segments, which should be taken into account when comparing the susceptibility of the shorted or nonshorted casings to external corrosion.

The higher susceptibility of shorted cased pipe segments to corrosion suggests metallic shorts increase the chance of external pipe corrosion and thus shorted casings should be given higher priority when conducting integrity assessment.

ILI CASING DATA ANALYSIS, CURRENT STUDY

Fig. 4



DOT-REPORTABLE PIPELINE INCIDENTS IN CASINGS

Table 2

Incident date	Company name	Class location	Offshore, onshore	Incident type
Apr. 27, 1985	Texas Eastern Pipeline Co.	1	Onshore	Rupture
Aug. 16, 1988	Amoco Gas Co.	3	Onshore	Leak
Mar. 18, 1992	Natural Gas Pipeline Co. of America	1	Onshore	Leak
Sep. 13, 2006	Columbia Gulf Transmission	1	Onshore	Leak
Oct. 16, 2006	Southern Star Central Gas Pipeline	n/a	Onshore	Leak
July 9, 1985	Westar Transmission Co.	1	Onshore	Other
Feb. 8, 2002	Enogex Inc.	1	Onshore	Rupture
Jan. 7, 2003	Southern California Gas Co.	3	Onshore	Leak
Apr. 23, 2003	El Paso Field Services	1	Onshore	Other, road casing vent leak
Aug. 22, 2003	Pacific Gas & Electric Co.	1	Onshore	Leak caused by longitudinal tear
June 18, 2005	Columbia Gulf Transmission	n/a	Offshore	Leak

Incident state	Pipe type	Pipe coat	Installed	OD	WT, in.	Cause
Kentucky	Transmission	Coated	1952	30	0.375	Corrosion
Texas	Transmission	Coated	1961	12	0.22	Corrosion
Nebraska	Transmission	Coated	1942	26	0.25	Corrosion
Louisiana	Interstate	Coated	1954	30	0.5	External corrosion
Kansas	Interstate	Coated	1971	20	0.26	External corrosion
Texas	Transmission	n/a	1963	20	0.25	Test damage
Oklahoma	Intrastate	n/a	1970	20	0.25	Third-party excavation damage
California	Intrastate	n/a	1947	12	0.22	Miscellaneous
Texas	Intrastate	n/a	1971	12	0.22	Miscellaneous
California	Intrastate	n/a	1931	8	0.25	Third-party excavation damage
Louisiana	Interstate	n/a	n/a	18	0.41	Unknown

Visual exam results	Core cause
General corrosion	Atmospheric corrosion inside casing
External localized pitting corrosion	Galvanic corrosion
External localized pitting corrosion	Other, atmospheric corrosion
General corrosion	Atmospheric corrosion inside casing
General corrosion	Disbonded coating in area shielded by casing

Results

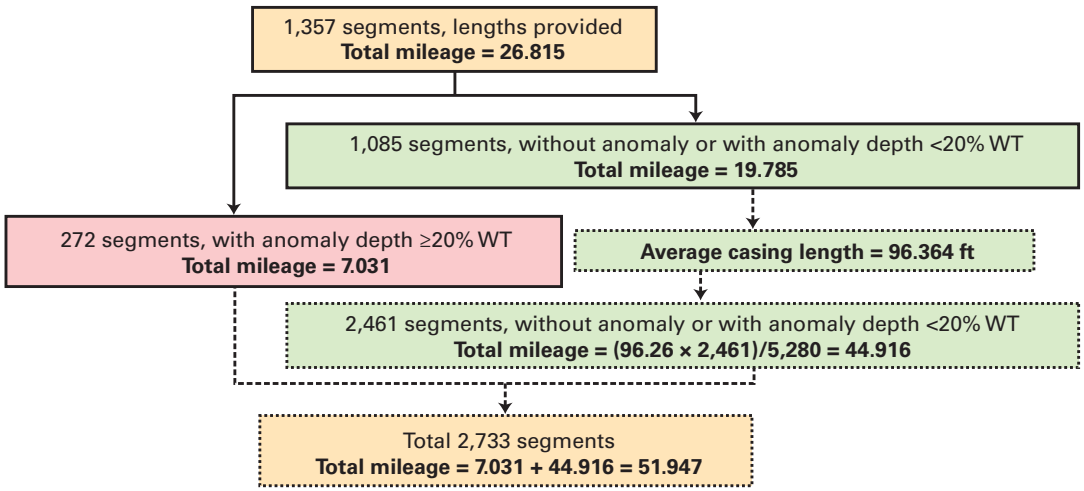
Only four companies provided data for this study with shorted and nonshorted casings labeled. But data from only two of these four companies included corrosion peak anomalies of any depth, information sufficient to determine the effect of metallic short on external corrosion.

Table 1 summarizes data from these two companies, for which both total casings, including those without anomalies on the carrier pipe, and casings with a peak anomaly depth of 20% WT or greater on the carrier pipe are included for both shorted and nonshorted casings.

Fig. 4 graphically presents the numerical values of Table 1, offering a comparison with Fig. 3. Consistent with Fig. 3, Fig. 4 shows nonshorted casings (a subtotal of 157) are four times more prevalent than shorted cas-

MILEAGE DETERMINATION

Fig. 5



ings (28), even though the number of casings with a peak anomaly depth of 20% or greater is similar regardless of the casings being shorted or nonshorted. This result reinforces the supposition that metallic shorts can increase the corrosion susceptibility of carrier pipe in casings.

As discussed in Part 1, the carrier pipe in casing can be protected by CP when it is partially or fully submerged in electrolyte in the annulus and when the casing and carrier pipe are isolated. When the casing wall is bare, this large bare surface with a more positive potential than the carrier pipe can serve as a conductor drawing CP current otherwise flowing to the carrier pipe outside the casing. This can result in CP current depression or reduced CP protection on the carrier pipe upstream and downstream near the casing ends. This CP current depression would increase when there is presence of short, which further minimizes resistance of CP current flow to the carrier pipe inside the casing, allowing more current to be from soils upstream and downstream of the casing ends.

Data were not available in this study to provide a quantitative understanding of the performance of a nonconductive electrolyte filler, but several points concerning this matter bear discussion. Some believe placing a nonconductive material in the annulus eliminates all corrosion problems, based on the theory that the nonconductive material can block the electrolyte pathway required for corrosion to occur. In reality, the wellness and durability of the filling can depend on the type and quality of nonconductive material used and how it is placed.

Poor field application or low quality filler could lead to conditions in which the annular spaces are not full, cracks develop in the filling, or gaps are left between the filling and casing-pipe wall. Degradation of the material over time and CP shielding of an electrolyte path, if it develops within cracks, can induce corrosion which might be avoided if the filling were absent.

Field incidents

A review of reportable natural gas pipeline incidents involving casings in the OPS database includes two incidents useful in gaining an understanding of real corrosion incidents involving casings.[2]

- *Colonial Pipeline Co. (1980, hazardous liquid pipeline).* An incident occurred on Mar. 6, 1980, on a Colonial Pipeline 32-in. OD liquid pipeline inside a cased highway road crossing in Virginia. The failure resulted in an estimated loss of 8,000 bbl of aviation kerosine. No human deaths or injuries occurred, but 5,000 fish and small animals lost their lives because of the failure. Cleanup of the polluted farm land, streams, river banks, and reservoirs took several months.

The casing had been electrically shorted to the carrier pipe for 10-12 years. Metallurgical examination of the failure led to the following conclusion: The "failure occurred at an area near the bottom of the pipe that had been thinned by corrosion. Apparently, the corrosion resulted from ground water leakage past the pipe-to-casing seal and into the annular space between the pipe and casing, where shielding effect of the casing would mitigate against obtaining adequate CP in this area…."

The report also stated: "The fact that the casing was shorted to the pipe may have prevented a small amount of CP current from entering the annular space, but the effect on the overall rate of attack probably was small."

This OPS report regarded the metallic short as a minor factor in the incident, while the shielding effect was treated as the major cause. It is, however, likely the shielding effect resulted mainly from the short, and the short therefore is likely a key factor in the incident. Experimental tests showed sufficient CP can be achieved on the carrier pipe if the casing-pipe annulus is filled with electrolyte and the casing and pipe isolated.[3-5] Direct metallic short could remove the CP benefit and allow free corrosion to occur.

- *Texas Eastern Gas Pipeline Co. (1985, natural gas pipeline).* The National Transportation Safety Board (NTSB) report of Feb. 18, 1987, detailed an incident on Apr. 27, 1985, when a 30-in. OD natural gas pipeline owned by Texas

Eastern ruptured under Kentucky State Highway 90.

The escaping gas ignited and burned an area about 700 ft long and 500 ft wide. Five persons in one house were killed and three others burned as they ran from their mobile home. There was extensive damage to buildings, construction equipment, and other property.

The NTSB report stated the probable cause of the accident was "unsuspected and undetected atmospheric corrosion." Atmospheric corrosion occurs on a pipeline when moisture from the air, along with contaminates, comes into contact with the exposed metal.[6]

This casing was located about 2 miles downstream of a compressor station with line temperatures of 140-160° F. High heat had badly damaged the coating. The presence of vents and the line temperatures consistently higher than local temperature caused cyclic water condensation on the carrier pipe, providing electrolyte necessary for the atmospheric corrosion.

Reviewing the DOT reportable incident database for the period between Aug. 7, 1984, and Nov. 8, 2006, provided an understanding of the number of incidents involving cased crossings and the number caused by external corrosion.

A search of the DOT reportable-incident database related to casings turned up a total of 11 incidents involving cased crossings. Table 2 summarizes these incidents.

Among the 11 known incidents, corrosion caused 5 (highlighted in red on the table). Excavation damage accounted for 3. Reports noted the causes of the other 3 incidents as either unknown or miscellaneous. These results point to corrosion and excavation as the primary causes of failures in cased crossings.

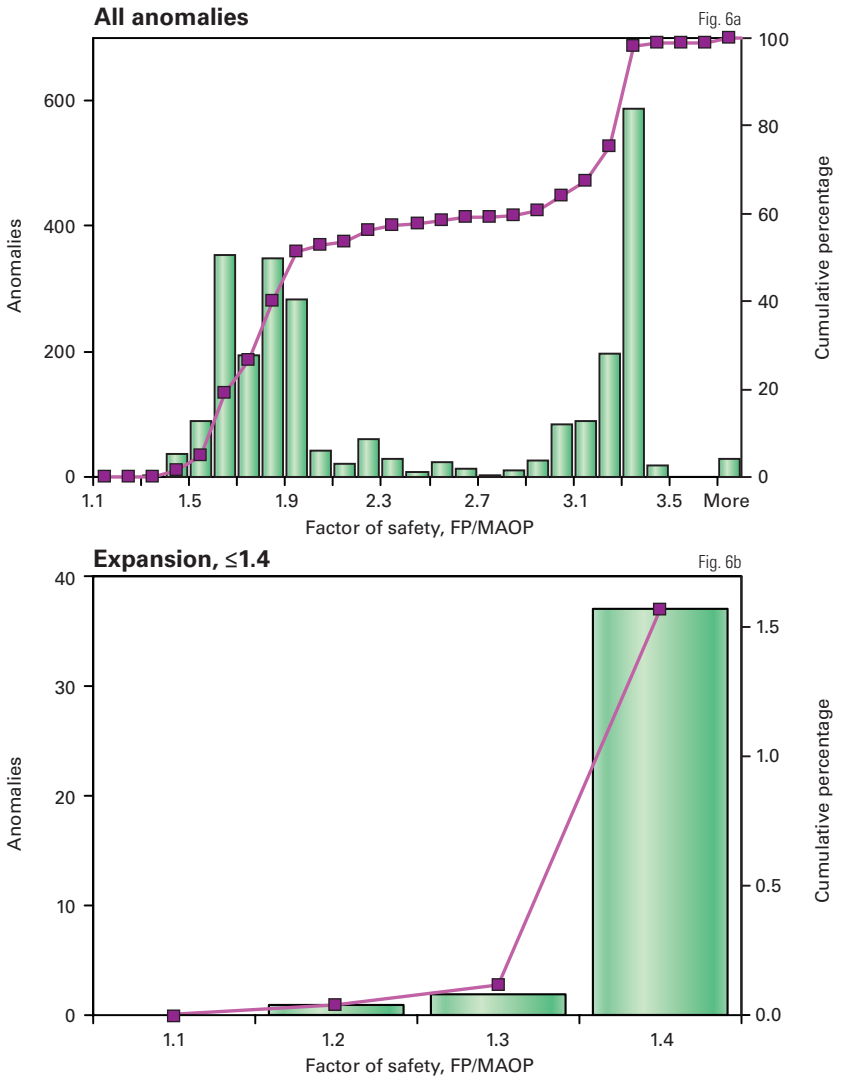
Of the 5 corrosion incidents, 3 resulted from atmospheric corrosion (Texas Eastern Pipeline Co., 1985; Natural Gas Pipeline Co. of America, 1992; and Columbia Gulf Transmission, 2006).

A more recent incident took place on a Columbia Gulf Transmission Co. gas line Dec. 14, 2007, near Delhi, La.[7] A natural gas release, explosion, and fire killed one person and injured another in the same vehicle as they traveled on the highway where the pipe crosses in a casing.

Investigators do not know the exact cause of the failure, but a preliminary visual examination suggested external corrosion to be the cause. Investigators suspect corrosion inside the casing caused the explosion, but are not certain whether the failure actually initiated inside or outside the casing.

ANOMALY DISTRIBUTION: COMPANIES A, C, D, E, AND F

Fig. 6



Relative safety

The casing length distribution determines total mileage of the 2,733 casings surveyed for this study (Fig. 5). Actual casing data determined the values in the blocks with solid edges; values in blocks with broken edges were calculated.

Of the 2,733 casings, known lengths existed for 1,357 with a total mileage of 26.815. This mileage consists of 7.031 miles of 272 casings containing a peak anomaly ≥20% WT and 19.785 miles of the remaining 1,085 casings that either do not have an anomaly or have a peak anomaly depth <20% WT.

The average length of the latter casings is 96.36 ft.

This average can be used to derive the mileage of the 2,461 (2,733 minus 272) casings that either do not have an anomaly or have a peak anomaly depth <20% WT. The mileage of these 2,461 casings equals 44.916. Adding this to mileage of the 272 casings with peak anomaly depth ≥ 20% WT yields a total mileage for 2,733 casings of 51.947.

Of the estimated 51.947 miles of casings surveyed, 5 peak anomalies have FP/MAOP <1.39. These anomalies do not include the anomaly with depth of 84% WT. Using 5 as the number for scheduled responses yields a response rate of 0.0963 scheduled response/mile.

Since no anomaly has an FP/MAOP <1.1, no immediate response is required. The anomaly of 84% WT in depth requires replacement of the pipe section, a rate of 0.019 replacement/mile. Including this deepest anomaly in the scheduled response yields a scheduled response and replacement response/mile of 0.115.

The exclusion of one casing with nonpeak anomalies in a casing limits this safety analysis. Including nonpeak anomalies in this analysis requires excluding Companies B and G because they did not provide nonpeak anomaly data.

The casings of A, C, D, E, and F total 1,185. Of these 108 had a peak anomaly ≥20% WT. Of the 108 casings, 5 peak anomalies were recorded with FP/MAOP <1.39, requiring scheduled response per ASME B31G. For the 1,185 casings, anomalies <20% WT in depth totaled 2,553 (minimum depth recorded 5% WT), averaging roughly 2.15 anomalies per casing. Of the 2,553 anomalies, 38 were recorded with FP/MAOP <1.39 and none with FP/MAOP <1.1.

Fig. 6 shows (a) distribution of all anomalies vs. factor of safety of the above five companies irrespective of anomaly depth and (b) magnification of (a) near the lower end of safety factor (1.4 or less). The data suggest nonpeak anomalies can have a low factor of safety due to possible larger anomaly length. It is therefore highly likely Companies B and G have anomalies with FP/MAOP <1.39, even though such data were not available in this analysis.

RESPONSES PER MILE Table 3

	2004	2005	2006
Immediate	0.026	0.090	0.045
Scheduled	0.150	0.150	0.099

Source: PHMSA

With the total length of 1,185 casings determined to be 22.58 miles (average casing length of 100.6 ft), the total of 38 anomalies with FP/MAOP <1.39 corresponds to 1.68 scheduled response/mile casing length, more than 10 times the 0.13 scheduled repair/mile of the INGAA study and 0.099-0.15 scheduled repair/mile in the PHMSA data for transmission pipelines (Table 3).[8]

Since it is unknown how many of the 38 anomalies would turn into defects scheduled for repair, the above comparison may not confirm cased crossings are less safe than noncased pipes but does raise the likelihood this could be true. The immediate repair/mile determined by the INGAA study equals 0.054 and in the PHMSA data between 2004 and 2006 (Table 3) equals 0.26-0.90. The immediate response for the cased segments studied is zero.[8]

Leaks per mile are another measure of pipeline safety, but these data are not available for this study. ✦

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Imports of crude and products

	Districts 1–4		District 5		Total US		
	4-3 2009	3-27 2009	4-3 2009	3-27 2009	4-3 2009	3-27 2009	*4-4 2008
	1,000 b/d						
Total motor gasoline	1,207	989	4	147	1,211	1,136	944
Mo. gas. blending comp.	884	788	0	12	884	800	590
Distillate	263	449	0	0	263	449	322
Residual	272	261	97	115	369	376	316
Jet fuel–kerosine	58	38	92	18	150	56	111
Propane–propylene	249	137	36	23	285	160	145
Other	(116)	126	117	108	1	234	762
Total products	**2,817**	**2,788**	**346**	**423**	**3,163**	**3,211**	**3,190**
Total crude	**8,634**	**8,186**	**920**	**1,198**	**9,554**	**9,384**	**10,283**
Total imports	**11,451**	**10,974**	**1,266**	**1,621**	**12,717**	**12,595**	**13,473**

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

Purvin & Gertz LNG netbacks—Apr. 10, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	9.69	6.23	7.40	6.14	6.75	7.33
Everett	2.99	1.24	2.69	1.35	1.68	3.22
Isle of Grain	3.24	1.50	2.74	1.42	1.93	2.75
Lake Charles	1.51	0.04	1.33	0.16	0.26	2.00
Sodegaura	4.01	5.92	4.27	5.67	5.07	3.49
Zeebrugge	5.33	3.11	4.74	2.98	3.84	4.78

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	13,178	58,107	38,879	9,157	53,310	13,164	2,730
PADD 2	85,607	51,919	23,093	7,321	33,718	1,411	13,456
PADD 3	187,446	71,158	40,917	12,870	40,657	16,024	21,238
PADD 4	14,972	6,410	2,487	576	3,321	248	[1]833
PADD 5	58,224	29,199	24,181	9,616	13,147	4,668	—
Apr. 3, 2009	**359,427**	**216,793**	**129,557**	**39,540**	**144,153**	**35,515**	**38,257**
Mar. 27, 2009	**356,583**	**214,568**	**125,867**	**39,344**	**143,932**	**34,714**	**37,738**
Apr. 4, 2008[2]	**319,164**	**224,710**	**113,610**	**38,067**	**109,720**	**39,736**	**24,897**

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

Refinery report—Apr. 3, 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	1,157	1,189	2,029	117	266	114	36
PADD 2	2,903	2,895	2,096	163	847	47	203
PADD 3	7,316	7,194	2,837	724	2,109	230	625
PADD 4	508	502	288	17	168	10	[1]161
PADD 5	2,518	2,378	1,483	390	492	185	—
Apr. 3, 2009	**14,402**	**14,158**	**8,733**	**1,411**	**3,882**	**586**	**1,025**
Mar. 27, 2009	**14,451**	**14,135**	**8,723**	**1,393**	**3,713**	**621**	**1,034**
Apr. 4, 2008[2]	**14,361**	**14,207**	**8,608**	**1,505**	**3,856**	**705**	**1,070**
	17,621 Operable capacity		**81.7% utilization rate**				

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

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

OGJ crack spread

	*4–10–09	*4–11–08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	57.99	121.89	–63.89	–52.4
Brent crude	51.57	108.26	–56.69	–52.4
Crack spread	6.42	13.63	–7.20	–52.9
FUTURES MARKET PRICES				
One month				
Product value	60.57	123.25	–62.68	–50.9
Light sweet crude	50.46	109.74	–59.29	–54.0
Crack spread	10.11	13.51	–3.40	–25.1
Six month				
Product value	62.21	118.17	–55.95	–47.4
Light sweet crude	58.82	106.57	–47.75	–44.8
Crack spread	3.40	11.59	–8.20	–70.7

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

OGJ GASOLINE PRICES

	Price ex tax 4-8-09	Pump price* 4-8-09	Pump price 4-9-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	152.9	199.4	330.5
Baltimore	154.6	196.5	320.5
Boston	152.6	194.5	315.5
Buffalo	140.0	200.9	336.6
Miami	145.9	197.5	343.5
Newark	201.3	233.9	308.6
New York	124.5	185.4	316.6
Norfolk	150.7	189.1	318.4
Philadelphia	152.4	203.1	325.3
Pittsburgh	159.2	209.9	324.2
Wash., DC	173.6	212.0	326.4
PAD I avg	155.3	202.0	324.2
Chicago	156.2	220.6	359.8
Cleveland	157.7	204.1	327.4
Des Moines	159.7	200.1	326.0
Detroit	146.7	206.1	324.9
Indianapolis	140.0	199.4	329.9
Kansas City	158.2	194.2	321.2
Louisville	159.2	200.1	335.7
Memphis	158.2	198.0	327.8
Milwaukee	152.7	204.0	324.7
Minn.-St. Paul	158.8	202.8	320.1
Oklahoma City	153.7	189.1	318.4
Omaha	152.3	197.6	329.9
St. Louis	154.3	190.3	314.9
Tulsa	153.6	189.0	312.2
Wichita	151.7	195.1	314.8
PAD II avg	154.2	199.4	325.9
Albuquerque	160.4	196.8	319.8
Birmingham	155.5	194.8	329.8
Dallas-Fort Worth	153.5	191.9	323.8
Houston	153.0	191.4	322.8
Little Rock	154.9	195.1	327.7
New Orleans	152.8	191.2	325.5
San Antonio	151.7	190.1	317.7
PAD III avg	154.6	193.1	323.9
Cheyenne	158.3	190.7	314.8
Denver	156.1	196.5	334.5
Salt Lake City	148.7	191.6	326.9
PAD IV avg	154.3	192.9	325.4
Los Angeles	144.5	211.6	352.7
Phoenix	162.8	200.2	310.6
Portland	178.2	221.6	347.7
San Diego	161.9	229.0	364.7
San Francisco	166.9	234.0	380.5
Seattle	165.7	221.6	355.7
PAD V avg	163.3	219.7	352.0
Week's avg.	**155.9**	**201.5**	**328.8**
Mar. avg.	**147.6**	**193.2**	**319.7**
Feb. avg.	**144.0**	**189.6**	**303.1**
2009 to date	**143.1**	**188.7**	—
2008 to date	**267.7**	**311.3**	—

*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

	4-3-09 ¢/gal		4-3-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	138.07	New York Harbor	142.60
Gulf Coast	137.57	Gulf Coast	139.98
Los Angeles	153.40	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	134.56	ARA	143.69
Singapore	141.52	Singapore	141.19
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	135.57	New York Harbor	105.43
Gulf Coast	142.75	Gulf Coast	102.69
Los Angeles	163.75	Los Angeles	111.19
		ARA	101.24
		Singapore	104.78

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

BAKER HUGHES RIG COUNT

	4-10-09	4-11-08
Alabama	3	6
Alaska	9	9
Arkansas	48	43
California	19	36
Land	18	35
Offshore	1	1
Colorado	50	123
Florida	0	0
Illinois	1	0
Indiana	0	2
Kansas	18	12
Kentucky	8	12
Louisiana	136	140
N. Land	75	47
S. Inland waters	5	18
S. Land	15	22
Offshore	41	53
Maryland	0	0
Michigan	0	0
Mississippi	9	11
Montana	0	12
Nebraska	0	0
New Mexico	34	76
New York	1	7
North Dakota	44	55
Ohio	7	12
Oklahoma	102	210
Pennsylvania	30	24
South Dakota	0	3
Texas	394	879
Offshore	4	7
Inland waters	1	1
Dist. 1	12	24
Dist. 2	13	37
Dist. 3	35	53
Dist. 4	39	91
Dist. 5	100	183
Dist. 6	70	122
Dist. 7B	11	31
Dist. 7C	15	71
Dist. 8	40	126
Dist. 8A	10	22
Dist. 9	14	35
Dist. 10	30	76
Utah	18	38
West Virginia	24	23
Wyoming	37	72
Others—NV-5; TN-3; VA-3; WA-2	13	10
Total US	**1,005**	**1,815**
Total Canada	**83**	**112**
Grand total	**1,088**	**1,927**
US Oil rigs	204	355
US Gas rigs	790	1,451
Total US offshore	48	62
Total US cum. avg. YTD	**1,301**	**1,777**

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	4-10-09 Percent footage*	Rig count	4-11-08 Percent footage*
0-2,500	43	6.9	71	5.6
2,501-5,000	53	64.1	120	53.3
5,001-7,500	132	25.0	209	16.7
7,501-10,000	222	3.1	429	2.7
10,001-12,500	188	1.5	484	3.9
12,501-15,000	191	--	296	--
15,001-17,500	114	--	119	--
17,501-20,000	58	--	71	--
20,001-over	37	--	37	--
Total	**1,038**	**7.7**	**1,836**	**7.2**
INLAND	9		30	
LAND	984		1,749	
OFFSHORE	45		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]4-10-09	[2]4-11-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	730	714
California	658	652
Colorado	64	65
Florida	6	6
Illinois	28	27
Kansas	108	106
Louisiana	1,467	1,287
Michigan	15	16
Mississippi	62	59
Montana	91	86
New Mexico	168	161
North Dakota	204	148
Oklahoma	178	170
Texas	1,373	1,338
Utah	60	56
Wyoming	151	149
All others	68	71
Total	**5,452**	**5,132**

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

US CRUDE PRICES

	4-10-09 $/bbl*
Alaska-North Slope 27°	35.34
South Louisiana Sweet	52.75
California-Kern River 13°	44.95
Lost Hills 30°	52.95
Wyoming Sweet	39.24
East Texas Sweet	48.25
West Texas Sour 34°	42.75
West Texas Intermediate	48.75
Oklahoma Sweet	48.75
Texas Upper Gulf Coast	41.75
Michigan Sour	48.75
Kansas Common	47.75
North Dakota Sweet	42.25

*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]	4-3-09
United Kingdom-Brent 38°	48.58
Russia-Urals 32°	46.56
Saudi Light 34°	47.47
Dubai Fateh 32°	48.24
Algeria Saharan 44°	48.85
Nigeria-Bonny Light 37°	50.16
Indonesia-Minas 34°	51.41
Venezuela-Tia Juana Light 31°	49.30
Mexico-Isthmus 33°	49.19
OPEC basket	48.80
Total OPEC[2]	48.37
Total non-OPEC[2]	47.73
Total world[2]	48.09
US imports[3]	47.51

[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]

	4-3-09	3-27-09	4-3-08	Change, %
	bcf			
Producing region	744	731	498	**49.4**
Consuming region east	647	641	565	**14.5**
Consuming region west	283	282	173	**63.6**
Total US	**1,674**	**1,654**	**1,236**	**35.4**
	Jan. 09	**Jan. 08**	**Change, %**	
Total US[2]	**2,141**	**2,055**	**4.2**	

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

International rig count

Region	Mar. 2009 Land	Mar. 2009 Off.	Mar. 2009 Total	Mar. 08 Total
WESTERN HEMISPHERE				
Argentina	54	1	55	—
Bolivia	4	—	4	—
Brazil	30	30	60	26
Canada	195	1	196	408
Chile	2	—	2	—
Colombia	30	—	30	—
Ecuador	11	—	11	—
Mexico	96	30	126	30
Peru	4	2	6	1
Trinidad	—	—	—	6
United States	1,060	46	1,105	1,797
Venezuela	52	11	63	15
Other	1	—	1	—
Subtotal	**1,539**	**120**	**1,659**	**2,283**
ASIA-PACIFIC				
Australia	11	10	21	9
Brunei	1	4	5	2
China-offshore	0	23	23	16
India	50	23	73	25
Indonesia	53	15	68	24
Japan	3	0	3	—
Malaysia	—	13	13	10
Myanmar	3	1	4	1
New Zealand	1	—	1	3
Papua New Guinea	2	—	2	—
Philippines	3	—	3	—
Taiwan	—	—	—	—
Thailand	4	9	13	7
Vietnam	—	7	7	7
Other	—	—	—	2
Subtotal	**131**	**105**	**236**	**106**
AFRICA				
Algeria	25	—	25	—
Angola	—	5	5	4
Congo	1	1	2	1
Gabon	—	1	1	2
Kenya	—	—	—	—
Libya	13	1	14	1
Nigeria	5	3	8	7
South Africa	—	—	—	—
Tunisia	2	1	3	2
Other	2	1	3	1
Subtotal	**48**	**13**	**61**	**18**
MIDDLE EAST				
Abu Dhabi	8	4	12	2
Dubai	—	1	1	—
Egypt	45	5	50	7
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	1	—	1	—
Kuwait	13	—	13	—
Oman	53	—	53	—
Pakistan	20	—	20	—
Qatar	1	8	9	9
Saudi Arabia	57	12	69	13
Sudan	—	—	—	—
Syria	20	—	20	—
Yemen	12	—	12	—
Other	2	—	2	—
Subtotal	**232**	**30**	**262**	**31**
EUROPE				
Croatia	—	1	1	—
Denmark	—	3	3	2
France	—	1	1	—
Germany	10	2	12	1
Hungary	2	1	3	—
Italy	3	1	4	—
Netherlands	—	2	2	3
Norway	—	24	24	22
Poland	3	—	3	—
Romania	9	1	10	3
Turkey	2	3	5	—
UK	2	20	22	21
Other	5	—	5	—
Subtotal	**36**	**59**	**95**	**52**
Total	**1,986**	**327**	**2,313**	**2,490**

Definitions, see OGJ Sept. 18, 2006, p. 42.
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	215	2.46
Caribbean	Houston	Resid.	380	93	1.20
Caribbean	Houston	Resid.	500	105	1.35
N. Europe	New York	Dist.	200	158	2.91
N. Europe	Houston	Crude	400	109	2.94
W. Africa	Houston	Crude	910	80	2.46
Persian Gulf	Houston	Crude	1,900	32	1.83
W. Africa	N. Europe	Crude	910	71	1.60
Persian Gulf	N. Europe	Crude	1,900	32	1.32
Persian Gulf	Japan	Crude	1,750	46	1.53

*Mar. 2009 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

Waterborne Energy Inc. US LNG imports

Country	Jan. 2009	Dec. 2008	Jan. 2008	Change from a year ago, %
	MMcf			
Algeria	—	—	—	—
Egypt	6,060	5,820	2,960	104.7
Equatorial Guinea	—	—	—	—
Nigeria	—	—	—	—
Norway	2,980	2,980	—	—
Qatar	—	—	—	—
Trinidad and Tobago	25,400	22,590	22,570	12.5
Total	**34,440**	**31,390**	**25,530**	**34.9**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
Data not available at press time.

Propane prices

	Feb. 2009	Mar. 2009	Feb. 2008	Mar. 2008
	¢/gal			
Mont Belvieu	65.88	65.34	142.52	147.47
Conway	70.46	65.59	148.92	146.63
Northwest Europe	100.73	67.16	159.06	165.01

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid–west	US West Coast	North–west Europe	South–east Asia
	$/bbl					
Mar. 2009						
Product revenues	56.46	52.79	54.69	58.02	52.94	50.55
Feedstock costs	–50.80	–50.39	–48.90	–47.48	–46.90	–48.72
Gross margin	5.66	2.40	5.79	10.54	6.04	1.83
Fixed costs	–2.12	–2.46	–2.39	–2.79	–2.39	–1.86
Variable costs	–1.40	–1.06	–1.28	–2.20	–1.89	–0.70
Cash operating margin	**2.14**	**–1.12**	**2.12**	**5.55**	**1.76**	**–0.73**
Feb. 2009	4.15	1.86	5.18	19.99	4.81	2.83
YTD avg.	4.32	1.29	5.27	15.04	4.36	1.96
2008 avg.	9.09	3.04	11.53	13.42	6.35	3.07
2007 avg.	12.60	6.65	18.66	20.89	5.75	2.25
2006 avg.	12.54	6.38	14.97	23.69	5.88	0.90

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

Feb. 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	196.52	167.14	199.48	188.47
Taxes	49.72	38.40	52.19	46.40
Wholesale price	136.31	132.08	158.85	142.10
Spot price	127.91	120.33	157.84	122.47
Retail margin	10.52	–3.34	–11.56	–0.03
Wholesale margin	8.40	11.75	1.01	19.63
Gross marketing margin	**18.92**	**8.41**	**–10.55**	**19.60**
Jan. 2009	22.23	10.44	1.08	25.22
YTD avg.	20.58	9.42	–4.74	22.41
2008 avg.	33.11	32.15	27.22	41.81
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	20.34	18.03	27.90

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Margins include ethanol blending in all markets.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Mar. 2009			
Product revenues	38.52	56.45	66.81
Feedstock costs	–14.05	–37.28	–67.57
Gross margin	24.47	19.17	–0.76
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–3.06	–3.54	–4.63
Cash operating margin	**16.03**	**9.27**	**–12.58**
Feb. 2009	14.90	11.04	–6.77
YTD avg.	14.81	8.87	–8.36
2008 avg.	20.99	22.72	–6.11
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.54	22.45	1.36

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

Muse, Stancil & Co. US gas processing margins

Mar. 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	3.79	2.45
Liquids	0.68	1.77
Gas purchase cost	4.22	3.30
Operating costs	0.07	0.15
Cash operating margin	**0.18**	**0.77**
Feb. 2009	0.12	0.70
YTD avg.	0.12	0.70
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	69%	54%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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Studies challenge job creation via overhaul of energy

A centerpiece of the Obama administration's proposal to overhaul US energy markets—the promise of an employment surge from "green jobs"—has come under attack.

Two recent studies strengthen doubt that wasteful spending is a way to bolster employment. A study published by University Rey Juan Carlos of Madrid examines the experience of Spain, which has followed the European Union pattern of subsidizing renewable energy in quest of green jobs. The Obama administration's aggressive energy initiatives emulate that model. Results aren't encouraging, say authors Gabriel Calzada Alvarez, Raquel Merino Jara, Juan Ramon Rallo Julian, and Jose Ignacio Garcia Bielsa.

They don't hesitate to relate Spain's experience to the US initiative. "The study's results demonstrate how such 'green jobs' policy clearly hinders Spain's way out of the current economic crisis, even while US politicians insist that rushing into such a scheme will ease their own emergence from the turmoil," the authors say.

From an analysis of data for Spain generated by the Monitoring and Modeling Initiative on Targets for Renewable Energy, partly funded by the European Commission, the study draws this conclusion:

"For every renewable-energy job that the state manages to finance...the US should expect a loss of at least 2.2 jobs on average, or about 9 jobs for every 4 created, to which we have to add those jobs that nonsubsidized investments with the same resources would have created."

A University of Illinois paper, meanwhile, examines literature projecting massive creation of high-quality green jobs via government subsidization of renewable energy and concludes that it's "built on mythologies about economics, forecasting, and technology." Authors are Andrew P. Morriss of the University of Illinois College of Law, William T. Bogart of York College of Pennsylvania, Andrew Dorchak of Case Western Reserve University Law Library, and Roger E. Meiners of the University of Texas at Arlington.

The Spanish study can be found on the web site of the Juan de Mariana Institute, of which the lead author is director, at www.juandemariana.org/pdf/090327-employment-public-aid-renewable.pdf. An abstract of the University of Illinois paper appears at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1358423.

(Online Apr. 9, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Oil prices climbed in March, April

After trading at lower levels for 4 months, benchmark oil prices climbed above $50/bbl in late March and early April, exceeding $52/bbl in light trading Apr. 9 ahead of commodity markets closing for the Good Friday holiday in New York and London.

For 4 weeks through Apr. 9, the May crude contract finished each week on the New York Mercantile Exchange at virtually the same price as the previous week, said Olivier Jakob at Petromatrix, Zug, Switzerland.

Oil prices, however, fell below $50/bbl in early trading Apr. 13 amid negative economical indicators after the Paris-based International Energy Agency again reduced its 2009 estimate of world demand for oil. Based on its reassessment of world gross domestic product and lower-than-expected first quarter demand data, IEA lowered its outlook by 1 million b/d to 83.4 million b/d—the lowest level in 5 years and 2.4 million b/d below the 2008 level.

"The pace of contraction is close to early 1980s levels, with a growing consensus that economic and oil demand recovery will be deferred to 2010," said IEA officials. It was the eighth consecutive month IEA reduced its original forecast of 2009 demand.

Oil supplies decline

IEA reported global oil supplies fell 400,000 b/d to 83.4 million b/d in March. Oil produced by the Organization of Petroleum Exporting Countries declined by 235,0000 b/d from February to 27.8 million b/d in March. Among OPEC members other than Iraq, production was up 720,000 b/d above their 24.9 million b/d target quota.

"Supplies stand at 5-year lows amid exceptionally weak demand, with [OPEC] ministers meeting again May 28. Effective spare capacity is around 5.5 million b/d. The call on OPEC crude and stock change is 28.2 million b/d for 2009, 2.6 million b/d below 2008 levels," said IEA. Non-OPEC supplies fell 170,000 b/d, with a 220,000 b/d dip among members of the Organization for Economic Cooperation and Development partly offset by higher non-OECD output. IEA reduced its 2009 estimate of non-OPEC supplies by 320,000 b/d, largely due to lower biofuels production and weaker first quarter crude production in Asia. "Non-OPEC output now falls from 50.6 million b/d in 2008 to 50.3 million b/d in 2009," IEA said.

In Houston, analysts at Raymond James & Associates Inc. noted, "The agency also said that February 2009 oil inventories in developed nations grew to the highest levels recorded since 1993. The IEA revision occurred despite Chinese data showing increasing crude oil imports and industrial output growth. Preliminary trade data revealed that China imported 16.3 million [tonnes] of crude oil in March, up 33% from 11.7 million [tonnes] in February, as industrial output growth grew to 8.3% in March after a record low of 3.8% in the first 2 months of 2009."

OECD industry stocks increased 7.5 million bbl in February to 2.74 billion bbl, 7.2% above year-ago levels. Lower North American products only partially offset a rise in Pacific crude stocks. An upward revision to January inventories, plus increasing February stocks and weaker forward demand, pushed stock cover to 61.6 days by the end of February, 7.9 days above a year ago.

IEA expects lower global crude runs to persist through into the third quarter. "Demand revisions, weak middle distillate cracks and reports of bulging product inventories in several markets, suggest a further painful period of weak margins as refiners adjust operating rates to the 2.8% decline in demand now expected for this year," officials said.

Coal-to-gas switching

Meanwhile, Raymond James analysts reported, "Over the past 6 months, natural gas and coal prices have plummeted, dropping 50% and 60%, respectively." Under current conditions, they said, the market price that most likely would encourage customers to switch from coal to gas is "near $3.25/Mcf." They added, "This is just a theoretical guess given that the actual price band using the full range of gas and coal plant efficiencies could be as low as $2/Mcf and as high as $4/Mcf."

The analysts said, "Despite the persistent talk of coal-to-gas switching, it is difficult to find evidence to support such claims on a massive scale." They anticipate an average 500 MMcfd of coal-to-gas switching in the period of Nov. 1-Oct. 31. "At most, we wouldn't expect more than 1.5 bcfd of coal-to-gas fuel switching to actually occur, and that would only last for a few months in the spring. The bottom line is that coal-to-gas fuel switching would not appear to be the savior of the summer gas market, nor the death knell for the coal markets," said Raymond James officials.

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

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