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International Petroleum News and Technology / www.ogjonline.com

Process Plant Maintenance and Turnaround

Uruguay attracts interest in its first licensing round
Bakken, Barnett, Manitoba fuel EOG's liquids binge
Biocides control shale frac fluid contamination
Parameters set for using assessment on networks

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OIL&GAS JOURNAL

May 18, 2009
Volume 107.19

Process Plant Maintenance and Turnaround

Image from ConocoPhillips

Regular Features

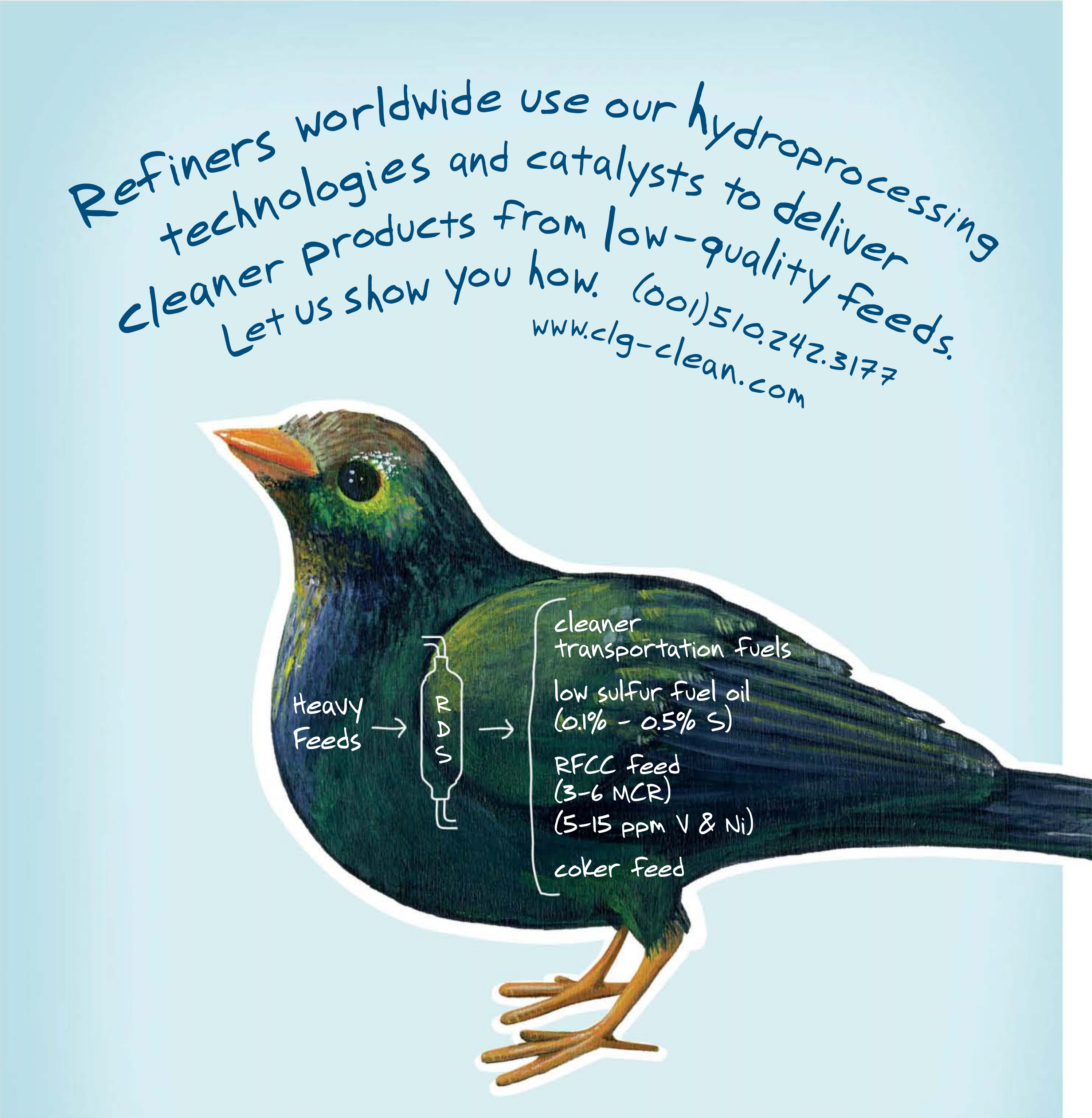
Cover

Maintenance issues were paramount in August 2008 as Hurricane Gustav approached the Louisiana coast, threatening Motiva Enterprises' 235,000-b/d Convent, La., refinery (cover), 30 miles southeast of Baton Rouge. The company shut down the refinery until after Gustav's landfall in Louisiana on Sept. 1 and managed to restart the plant without major difficulty, a spokesperson told OGJ. The importance of maintenance procedures is the focus of a series of three articles, Part 1 of which begins in this Oil & Gas Journal special report on Process Plant Maintenance and Turnaround that begins on p. 46. Photo from Motiva partner Shell Oil Co., Houston.

OIL&GAS JOURNAL online

The full text of Oil & Gas Journal is available through OGJ Online, Oil & Gas Journal's internet-based energy information service, at http://www.ogjonline.com. For information, send an e-mail message to webmaster@ogjonline.com.

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags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General Interest

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Processing

Transportation

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OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags


Where do You Want to be on the Performance Curve?
YOUR COMPANY
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Catalyst: P+MT4
NextGen Performance
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OGJ Newsletter

May 18, 2009

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General Interest — *Quick Takes*

Deutsche Bank: OPEC needs to cut output

With global oil and product inventories high and with demand deteriorating, the Organization of Petroleum Exporting Countries needs to further cut its crude output, according to Deutsche Bank analyst Adam Sieminski.

Despite this, Sieminski writes in a new report that OPEC is unlikely to lower its exports because prices have been rising. For the week ending May 1, US demand for motor gasoline climbed less than 5% from a year earlier, while for the preceding week demand was up 8%, and a month ago it was up over 10% from a year earlier, indicating the onset of a downward trend in the demand growth rate, Sieminski wrote.

Momentum in the demand rate for distillate fuels as reported by the US Energy Information Administration also decreased during the latest reporting week.

Although gasoline inventories, measured in terms of days of forward cover, look relatively normal, oil and gasoline inventories are very full, Sieminski said.

He added that crude prices recently have been driven higher by a combination of rising expectations for a faster economic recovery, increased funds flow into commodities, and higher utilization at US refineries, which were up 2.6% this week to 85.3%—the first rise since January. This rise in utilization shows refineries are gearing up for the US driving season, which begins on May 25.

Sieminski believes that gasoline cracks are holding on tertiary stocking and could come under pressure when that stocking runs its course.

"Eventually, in our view, refiners will have to scale back, and this will force crude oil back to $50/bbl," Sieminski said.

Deutsche Bank estimates that WTI will average $47/bbl for 2009, rising to average $55/bbl next year.

Meanwhile, the Deutsche Bank US natural gas forecast calls for an average of $4.50/MMbtu this year, rising to $6.50/MMbtu next year.

IOGCC: Alaskans press for gas development

The rest of the world will capitalize on the development of clean natural gas even if the US delays, speakers told the Interstate Oil & Gas Compact Commission on May 12 in Anchorage.

Both the Lower 48 and Alaska gas will be needed in 2018-20, said Mark Myers with the Alaska Department of Natural Resources.

Other countries such as China and Japan that have fewer supply options likely will snap up LNG, Myers said. LNG will go there because it will bring higher value than in North America.

Alaska has 85 tcf of unconventional gas resources on top of its vast conventional endowment, Myers said.

Infrastructure is in place except for the proposed 4.5 bcfd, 48-in. pipeline to northern Alberta, he noted.

Alaska Gov. Sarah Palin said Washington policymakers don't realize that delaying exploitation of Alaska's onshore gas and putting off exploration for offshore gas will result in greater greenhouse gas emissions in the interim until more renewable energy sources can be brought into play.

Two Dallas promoters named in SEC complaint

Two Dallas promoters raised $10 million from 300 investors nationwide through fraudulent offers and sales of oil and gas joint venture interests, the US Securities and Exchange Commission charged.

SEC filed a civil injunctive action in US District Court in Dallas alleging that Hartmut T. (Hardy) Rose and James Patrick Reedy acted through Geo Cos. of North America Inc., Geo Natural Resources Inc., and Geo Securities Inc. between August 2003 and August 2005.

SEC's complaint said the pair made numerous false and misleading representations and omissions in connection with the offers and sales of the interests, including Reedy's touting Geo's successful track record when, in reality, the firm had very few wells producing commercial quantities.

It also charged in several instances Rose and Reedy solicited funds from investors to complete wells without disclosing that Geo's geologists advised against completing them. Finally, the complaint alleged Rose and Reedy sought additional money from investors by falsely portraying prior wells as successful when they were actually dry holes.

It sought permanent injunctions, disgorgement of ill-gotten gains plus prejudgment interest, and civil penalties against the pair. Rose settled the charges by agreeing to pay $58,914 in disgorgement, $22,749.29 of prejudgment interest and a $50,000 penalty, the federal securities agency said. Litigation continues against Reedy, it indicated. ✦

Exploration & Development — *Quick Takes*

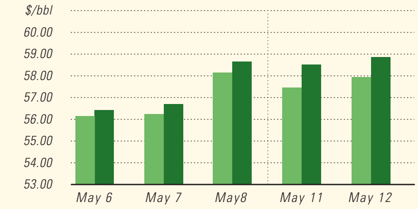
Total has oil find off Congo (Brazzaville)

Total E&P Congo gauged a third deepwater oil discovery in the northern part of the Moho-Bilondo license off Congo (Brazzaville) where it reported two successful exploration wells in 2007.

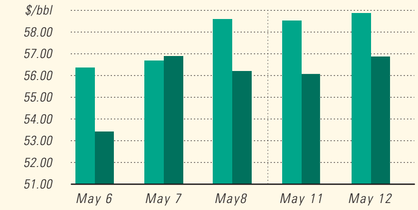
The Moho Nord Marine-4 well, 75 km offshore in 3,537 ft of water, flowed at the rate of 8,100 b/d on a $^{52}/_{64}$-in. choke. It proved

Industry Scoreboard

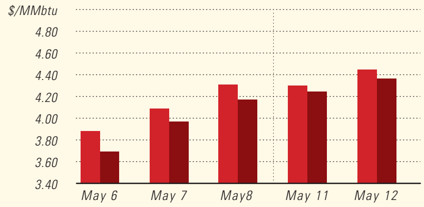
IPE BRENT / NYMEX LIGHT SWEET CRUDE



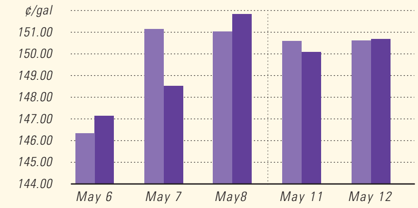
WTI CUSHING / BRENT SPOT



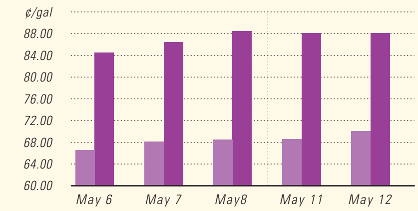
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



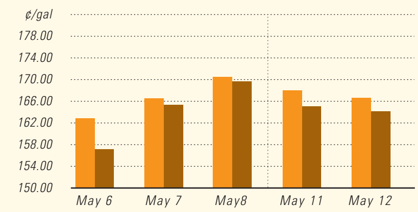
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

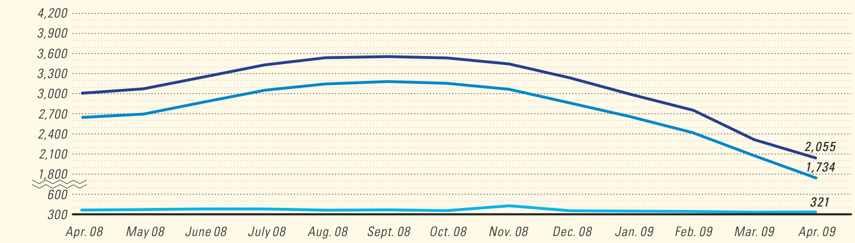
US INDUSTRY SCOREBOARD—5/18

Latest week 5/1	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	9,039	9,117	–0.9	8,897	8,961	–0.7
Distillate	3,527	4,108	–14.1	3,843	4,176	–8.0
Jet fuel	1,407	1,592	–11.6	1,401	1,552	–9.7
Residual	493	684	–27.9	563	620	–9.2
Other products	3,746	4,267	–12.2	4,039	4,542	–11.1
TOTAL DEMAND	18,212	19,768	–7.9	18,743	19,851	–5.6
Supply, 1,000 b/d						
Crude production	5,363	5,162	3.9	5,314	5,127	3.6
NGL production[2]	1,810	2,181	–17.0	1,810	2,180	–17.0
Crude imports	9,748	9,904	–1.6	9,532	9,775	–2.5
Product imports	2,739	3,330	–17.7	3,050	3,190	–4.4
Other supply[3]	1,717	1,348	27.4	1,657	1,420	16.7
TOTAL SUPPLY	21,377	21,925	–2.5	21,363	21,692	–1.5
Refining, 1,000 b/d						
Crude runs to stills	14,235	14,377	–1.0	14,235	14,645	–2.8
Input to crude stills	14,565	14,656	–0.6	14,565	14,958	–2.6
% utilization	82.6	83.3	—	82.6	85.1	—

Latest week 5/1	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	374,653	370,600	4,053	319,929	54,724	17.1
Motor gasoline	212,612	217,307	–4,695	211,089	1,523	0.7
Distillate	144,105	142,311	1,794	105,831	38,274	36.2
Jet fuel-kerosine	40,188	39,704	484	38,738	1,450	3.7
Residual	36,282	36,332	–50	39,522	–3,240	–8.2
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	26.2	26.0	0.8	22.0	19.1	
Motor gasoline	23.5	24.0	–2.1	22.8	3.1	
Distillate	39.1	38.1	2.6	24.9	57.0	
Propane	45.8	40.5	13.1	27.5	66.5	
Futures prices[5] **5/8**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	51.07	48.48	2.59	117.95	–66.88	–56.7
Natural gas, $/MMbtu	3.38	3.46	–0.08	10.78	–7.40	–68.6

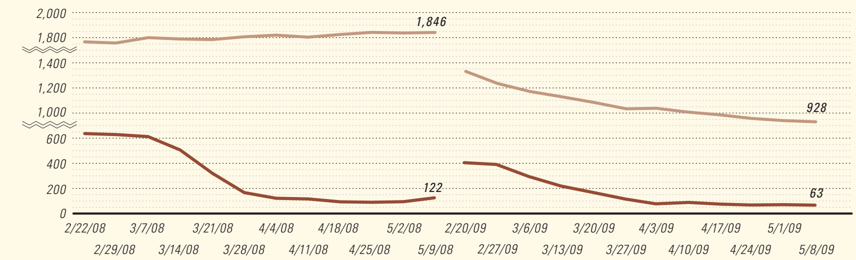
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



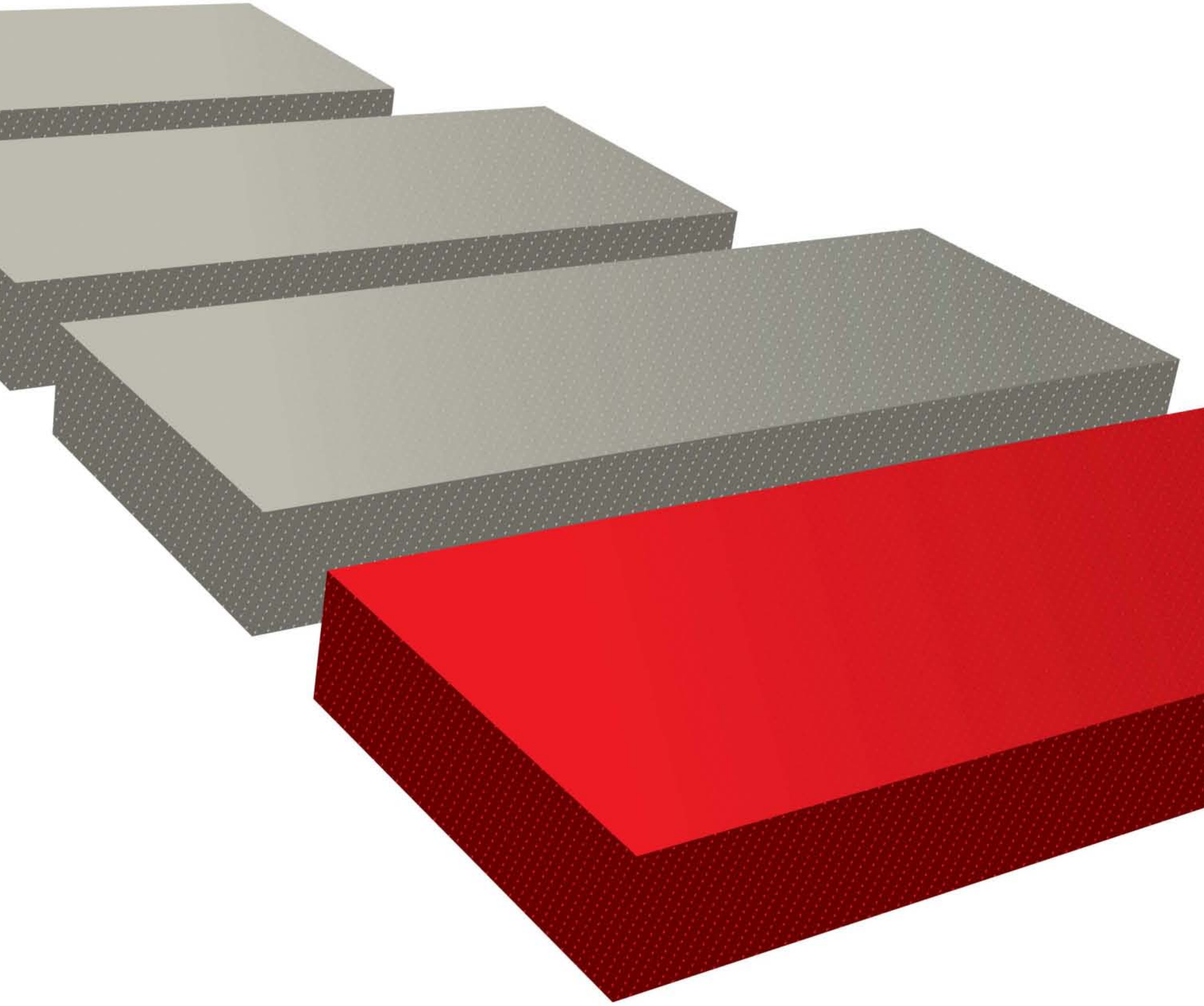
Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

OIL&GAS JOURNAL | Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page | qMags



a 163-m column of high quality oil in the Albian F formation. TD is 13,907 ft.

Total said the discovery "confirms the existence of significant Albian resources in the northern part of the Moho-Bilondo license, in addition to the already recognized Tertiary and Albian A and B resources."

Total said this and the Mono Nord Marine-1 and 2 finds in 2007 and the positive delineation well Moho Nord Marine-3 in 2008 "reinforce Total's confidence in the emergence of a development pole" in the northern part of the license. Preliminary development studies have begun.

The company started production in the Phase 1 development of Moho-Bilondo field in the southern part of the license in April 2008. It is drilling more wells and building production to an expected plateau of 90,000 b/d of oil equivalent from 14 wells in 2010.

License interests are Total E&P Congo 53.5%, Chevron Overseas Congo Ltd. 31.5%, and Soc. Nationale des Petroles du Congo 15%.

Total noted that it has drilled half of all exploration wells in Congo, begun production on 15 fields covering 9 of the 28 existing permits or concessions, and discovered 65% of initial listed reserves in the country.

It is operator with 53% interest at Nkossa field, where work undertaken since 2005 arrested a decline and stabilized production at 50,000 b/d.

In October 2008, Total began developing Libondo, a satellite of Yanga field, where it is operator with 65% interest.

The company continues to explore the Mer Tres Profonde Sud permit, on which it has made five discoveries. Total is operator with 40% interest.

Tullow discovers more oil in Uganda

Tullow Oil PLC said its Nsoga-1 exploration well, which was drilled in the Butiaba region on Block 2 in Uganda, has found "good quality Kasamene-type" oil-bearing reservoirs.

Tullow said the well was drilled 6 km horizontally from the top of the structure, to a total depth of 755 m and has been successfully cored, logged, and sampled.

The total net Kasamene-type reservoir is 43 m thick, of which the top 3 m are oil-bearing at this location. "At the crest of the trap, which is 160 m vertically up-dip, the entire reservoir should be oil filled," the firm said.

Tullow said in a separate low net-to-gross section, immediately above this Kasamene-type reservoir, "12 m of thin-bedded oil-bearing sands were also encountered and are likely to have deeper oil water contacts based on seismic amplitudes and pressures."

"This latest result further extends the play and derisks several adjacent prospects located in Blocks 1 and 2, which are scheduled for drilling later in the year," Tullow said of Nsoga-1, which is the seventh successful test of the Victoria Nile Delta play fairway within the Lake Albert Rift basin.

The well is now being suspended as a future oil producer and on completion of operations the rig will move to test the Awaka prospect with drilling operations scheduled to commence this month.

Tullow has interests in three licenses in the Lake Albert Rift basin in Uganda. Tullow operates Block 2 with a 100% interest and has a 50% interest in Blocks 1 and 3A, which are operated by Heritage Oil 50%.

MMS, NPD sign cooperative exploration agreement

The US Minerals Management Service signed a memorandum of understanding with the Norwegian Petroleum Directorate, MMS announced on May 6.

The agreement's objectives are to establish and build relationships; promote cooperative resource management activities in exploration and production; promote the sharing of scientific and technical information, exploration, and production strategies as well as technical solutions; and conduct cooperative research studies, MMS and NPD officials said.

MMS acting director Walter D. Cruickshank and NPD director general Bente Nyland signed the MOU. They said the agreement will adhere to applicable US and Norwegian laws.

It complements an existing MOU between MMS and Norway's Petroleum Safety Authority, Cruickshank noted. ✦

Drilling & Production — *Quick Takes*

Reliance starts gas production from Dhirubhai finds

Reliance Industries Ltd. (RIL) started natural gas production from the Dhirubhai 1 and 3 discoveries on the KG-D6 block off India in early April.

This was a major discovery for India because it provided an increase in domestic energy supplies that raised questions whether the nation's energy import plans make sense. At peak production, the KG-D6 facility is expected to produce 550,000 boe/d. It was brought into production 6½ years from discovery.

The block is in the Krishna Godavari basin in the Bay of Bengal. The gas is received at the Gadimoga onshore facility and delivered to the East West pipeline. Wells, are connected by flow lines and production risers to a control and riser platform and are tied back to the terminal about 60 km from the gas fields—one of the longest tie backs in the world.

"At the seabed, equipment equivalent to over 110,000 tonnes of steel weight and over 2,400 line-km of flowlines and umbilicals have been installed to construct a deepwater production system. Subsea installations were carried out by remotely operated vehicles at sea bed depths ranging from 600-1,200 m, well beyond diver depths," said RIL.

This was a challenging project because of the harsh weather apart from a window of 4 months every year. Other difficulties included supply chain challenges and manpower shortages against tight schedules.

RIL will sell gas produced from its KG-D6 block off east India to several companies for power generation under a gas sales and purchase agreement (GSPA).

Buyers will take 11 million standard cu m/day of gas at 11 different power stations for 5 years, which will be delivered through the East-West pipeline owned by Reliance Gas Transportation Infrastructure Ltd. (RGTIL) and other pipelines.

RIL expects to sign GSPAs with other power companies shortly, which is anticipated to increase the contracted quantity of gas for the power sector to 18 million standard cu m/day.

The power companies also signed a gas transportation agreement (GTA) with RGTIL.

PMS Prasad, RIL president and chief executive officer of petroleum, said the expected supply of 18 million standard cu m/day of gas to the power sector would largely eliminate their gas supply deficit and would result in generation of 4,000 Mw of power, providing welcome relief in many parts of the country.

Telemark, Clipper Corridor development advances

Development of the ATP Oil & Gas Corp.-operated Telemark and Clipper Corridor discoveries in the deepwater Gulf of Mexico advanced with the awarding by Bluewater Industries Inc. of two lumpsum contracts to Technip.

Bluewater is managing the two development projects. ATP owns 100% of Telemark, and 55% of Clipper Corridor.

Telemark lies on Atwater Valley Block 63 in 4,450 ft of water and will be tied back to ATP's Titan Mini DOC deep-draft floating drilling and production platform scheduled for installation in midyear in Mirage and Morgus fields on Mississippi Canyon blocks 941 and 942, respectively.

The Telemark contract to Technip includes the design and manufacturing of one high-pressure, 2-mile long flexible riser, engineering for installation and welding of one 13-mile oil and gas production flowline, installation of the flowline and associated riser with an option to install an umbilical, fabrication and installation of subsea structures and a jumper, and precommissioning work.

Clipper Corridor lies on Green Canyon Block 299 in 3,460 ft of water and will be tied back to the Front Runner spar, operated by Murphy Oil Corp., on Green Canyon Block 338.

The Clipper Corridor contract covers design and manufacture of two 1½-mile high-pressure flexible risers; engineering for the installation and welding of one 15½-mile pipe-in-pipe oil production flowline and one 15½-mile gas line; installation of the flowlines, risers, and umbilical; fabrication and installation of four subsea structures and associated jumpers and flying leads; and precommissioning work.

Technip's operating center in Houston will execute these contracts, with riser fabrication in Le Trait, France, and flowline welding in Mobile, Ala.

Technip says offshore installation is scheduled for late 2009 to early 2010 for the Telemark project and for second quarter 2010 for the Clipper Corridor project, using the Deep Blue, Technip's deepwater pipelay vessel.

Technip will use also its Deep Pioneer deepwater construction vessel on the Telemark project.

Kurdistan plans Taq Taq oil exports

Addax Petroleum Corp., Calgary, has received notification from the Kurdistan Regional Government of plans to export crude oil from Taq Taq field in northern Iraq.

Addax and Genel Energy International Ltd., partners in Taq Taq Operating Co., submitted a field development plan in March envisioning peak production of as much as 180,000 b/d (OGJ Online, Mar. 18, 2009).

The government has requested that the companies prepare to carry oil by truck from the field to the Khurmala export station about June 1. At Khurmala, oil will enter Iraq's export pipeline transiting Turkey with a terminal at Ceyhan on the Mediterranean.

The joint venture currently is expanding Taq Taq production capacity to 70,000 b/d from its present level of as much as 40,000 b/d. Full field development will require construction of a pipeline.

The State Oil Marketing Organization will sell the oil. Taq Taq Operating works under a production-sharing contract.

Anadarko agrees to pay penalty for oil spills

Anadarko Petroleum Corp. and two of its units will pay $1.05 million in fines and upgrade their spill-prevention plans as part of a settlement for oil spills in Wyoming, according to US government agencies.

The US Department of Justice and the Environmental Protection Agency said Anadarko and units Howell Corp. and Howell Petroleum Corp. also will spend more than $8 million to implement plans to resolve violations of the Clean Water Act.

According to the consent decree, filed in US District Court in Cheyenne, Wyo., Anadarko and its Howell units will pay the fine and also will upgrade and implement appropriate spill-prevention plans and develop and implement facility response plans.

DOJ and EPA said the consent decree also requires the three companies to implement "a multiphased integrity and mitigation plan that incorporates inspection, monitoring, testing, data collection, and failure analysis activities."

According to a complaint filed at the same time as the consent decree, Anadarko and the two other firms allegedly discharged harmful quantities of oil from its facility in Wyoming on more than 35 occasions between Jan. 26, 2003, and Oct. 19, 2008.

The complaint alleges that more than 31,300 bbl of oily water and oil were released during the spills and resulted in an observable film, sheen or discoloration on the surface of the impacted water or shoreline.

The spills occurred on oil production fields in Park, Johnson, and Natrona counties and resulted in the pollutants being discharged into the tributaries or drainages of Silver Tip Creek and Salt Creek, which are tributaries to the Clarks Fork and Powder rivers, respectively. ✦

Processing — *Quick Takes*

Plant pulls helium from stranded Kansas gas

IACX Energy, Dallas, has started up what may be the world's smallest helium purification plant near Otis in Rush County in western Kansas.

Eight of the producers connected a gathering system formerly operated by a Oneok Inc. affiliate are selling low-btu gas to the plant, which has the capacity to extract 15-30 Mcfd of helium.

IACX polishes the helium to 95% purity, compresses it to 2,800 psi, stores it in tube trailers for transport, and sells it on fixed, take-or-pay contracts. The government-set helium price is $62.25/Mcf.

IACX also operates three nitrogen rejection units with 3 MMcfd of total inlet capacity on the site that brings the 800-btu raw gas up to pipeline quality. It vents the nitrogen. The first nitrogen unit came on in September 2008.

The company uses pressure swing adsorption, a molecular sieve process that works through activated carbon at low pressure and low volume. A chiller extracts natural gas liquids from the formerly stranded gas.

Gas produced from the Permian Chase Group and Cambro-Ordovician Arbuckle formations as deep as 3,000 ft in Reichel field and nearby fields 22 miles northwest of Great Bend contains 1.5% to 2% helium.

Many historical sales points for helium-rich gas are being closed or curtailed by gas purchasers, and helium production is on a sharp downward trend, IACX said. The company operates other nitrogen units in Kansas, Texas, Oklahoma, and Nebraska. ✦

Transportation — *Quick Takes*

QSN gas line starts flow in Australia

A natural gas link between Queensland, South Australia, and New South Wales has finally been completed with the opening this week of two new lines and compression facilities in Queensland.

Epic Energy built the 180-km, 400-mm high-pressure gas line, known as the Queensland-South Australia-New South Wales (QSN) line, which will transport gas from the Wallumbilla gas hub in eastern Queensland through the company's Southwest Queensland line to connect with the Moomba-Adelaide and Moomba-Sydney lines.

A second, 113-km, 400-mm line, commissioned by AGL Energy, will transport gas from a point about 8½ km east of Miles near the Condamine electric power station in central-eastern Queensland to the Wallumbilla hub.

Epic has increased the flow capacity of its Southwest Queensland line with construction of a midline compressor facility, while AGL designed and built a Wallumbilla compressor station to enable gas from AGL's Berwyndale coalseam methane field to enter the high pressure Southwest Queensland line.

Completion of all this work means there is an interconnected eastern Australian pipeline network that will provide a level of security of gas supply to customers in New South Wales and South Australia.

ExxonMobil signs Gorgon LNG deal

ExxonMobil Corp., one of three joint venture partners in the proposed development of the Gorgon-Jansz gas fields, agreed to sell some of its LNG production to Petronet LNG of India.

ExxonMobil will supply 1.5 million tonnes/year of LNG to the Indian company for 20 years. This represents 10% of the three-train project's total planned capacity of 15 million tonnes/year of LNG.

ExxonMobil has a 25% share in the project and its production. ExxonMobil and Petronet will work to conclude a sale and purchase deal in June.

Petronet intends to ship its LNG from the proposed Barrrow Island plant to a new receiving terminal in the port city of Kochi, which will have a total capacity of 2.5 million tonnes/year of LNG. The terminal is scheduled to begin operations in 2011.

This is the latest move to develop the Gorgon-Jansz project, the most recent being the conditional environmental approval by the Western Australian EPA last week for a third LNG train to be added to the development plans on Barrow Island.

TransCanada wins Mexico gas pipeline contract

TransCanada will build, own, and operate the 310-km Guadalajara Pipeline, extending from an LNG regasification plant being built near Manzanillo on Mexico's Pacific Coast to Guadalajara. The 30-in. OD pipeline will have capacity to ship 500 MMcfd of natural gas, with a targeted in-service date of 2011.

Mexico's state-owned electric power utility Comision Federal de Electricidad (CFE) has a 25-year contract for all gas shipped through the line, which will be used to serve power generation load in both Manzanillo and Guadalajara as well as connecting to an existing Petroleos Mexicanos (Pemex) line near Guadalajara. Peruvian LNG will supply most of the gas for the pipeline.

The pipeline's 2011 in-service target coincides with the planned 2011 startup of the Manzanillo LNG terminal. Mexico already has two LNG regasification plants in operation—at Altamira on the Gulf of Mexico and Ensenada on the Pacific Coast—part of Ministry of Energy plans to increase LNG imports to 1.99 bcfd by 2017 from January 2009 levels of 503 MMcfd (OGJ Online, Jan. 7, 2009).

TransCanada owns and operates the 130-km Tamazunchale Pipeline in central Mexico and in the 1990s built the 700-km Mayakan Pipeline and the 214-km El Bajio pipelines. It has since sold these pipelines.

The Guadalajara Pipeline will cost an estimated $320 million.

Skanled partners place gas line plans on hold

The Skanled partners have suspended the pipeline project that was to deliver Norwegian gas to Sweden and Denmark because of the global economic uncertainty and increased commercial risk.

The pipeline was scheduled to start operations in 2012 and Gassco AS, the leader of the consortium, said it was unclear on what future gas demand would be.

"Despite strong efforts by many stakeholders to succeed with the project, it is Gassco's view that the current economic environment and also subsequent uncertainties related to timing of new field developments on the Norwegian Continental Shelf, have weakened the basis for the project," said Thor Otto Lohne, Gassco executive vice-president.

"The project might be relaunched if the commercial conditions become more favorable in the future," Lohne said.

It has been difficult for the partners to secure gas volumes to underpin the project as the shippers have not been able to reach the gas sales agreements. They planned to submit installation and operation plans to the authorities in April.

Skanled, which will cost an estimated 10 billion kroner, was interdependent on receiving terminals in Norway, Sweden, and Denmark. The pipeline's capacity was 24 million standard cu m/day (OGJ Online, Jan. 17, 2009). ✦

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Letters

CO_2 challenge urged

A strong legal challenge needs to be made to the EPA finding that CO_2 is harmful. The grounds would be that they have exceeded their authority and that they have misapplied science. A vigorous presentation needs to made in a fair court of the true science and a cross examination done on the junk science.

The recent facts are that the sun has changed from global warming to global cooling and that for about 10 years world temperatures are down as the sun spot cycle produces less radiation heat. Historical data shows that increases in atmospheric CO_2 come AFTER the earth warms slightly and therefore cannot be considered a cause. Data shows that modest earth temperature-change cycles are normal and not related to man. The models predicting catastrophe are too simplistic and biased to be believable or relied on.

There are plenty of facts for a strong legal challenge, and a successful one would be of great benefit to the country and to many industries.

Larry Haverly
Denville, NJ

Calendar

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

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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.

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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.

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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.

Shaping the pipeline future

Christopher E. Smith
Pipeline Editor

The current US energy policy debate includes at least two areas of great interest to pipeliners: biofuels and carbon capture and sequestration (CCS). President Barack Obama this month designated more loan guarantees and economic stimulus money for biofuels research. He also said an interagency group would explore ways to get more ethanol-fueled cars produced and more ethanol fueling stations built.

However, these announcements were accompanied by a preliminary assessment that corn ethanol wouldn't meet the 20% greenhouse gas (GHG) reduction from gasoline mandated 2 years ago by Congress.

Obama's administration is funding science in the first instance that can help create alternative methods of producing ethanol or the alternatives to ethanol that the preliminary environmental assessment suggests might be necessary.

These actions might appear to be activist; the government leading the US and global energy markets in a direction they might not otherwise go. Rhetoric such as this makes for good political talking points, but one doesn't need to look too far down the energy food chain to find evidence to the contrary.

Shell and sustainability

In its 2008 Sustainability Report, Royal Dutch Shell PLC says it will spend the next few years stepping up its efforts in sustainably sourced transport biofuels with good carbon dioxide performance, elevating its work in this area above wind and solar to be the primary focus of its renewable energy activities. Shell Chief Executive Jeroen van der Veer points out the need for government support in encouraging technological development of renewable energy, while noting that even governments can't subsidize renewable on the scale needed to change the world's energy mix.

The Shell report goes on to link an increased emphasis on renewable energy with efforts to control GHG emissions, calling for these efforts to be accelerated despite the recession.

Shell's call for government action is even more strident in the context of GHG reduction and CCS. Its preferred sustainability scenario sees governments "aggressively promoting" fuel efficiency, lower CO_2 fuels, and CCS. Further, Shell sees the emergence of an internationally recognized price for emitting GHGs as necessary to reaching sustainable energy goals. In this scenario, 50% of the world's power is produced from renewable energy by 2050.

In the shorter term, Shell sees investment in CCS and renewables as helping generate employment.

Changes into action

Parties in a position to affect this sort of change aren't just talking about the changes, they are actually making them. In 2008 Shell launched CO_2SINK in Ketzin, Germany—Europe's first project to inject CO_2 underground onshore. It will store up to 60,000 tonnes of CO_2 in a saltwater aquifer over the next 2 years. Shell designed the pilot project to find the most cost-effective ways to store CO_2 in aquifers and help governments design effective safety regulations.

National Grid, meanwhile, is planning a pipeline network to move CO_2 generated in the UK to storage beneath the North Sea. The company cites its expertise in running natural gas pipeline networks regarding its abilities to build and operate the £2 billion project to support future power plants fitted with CCS technology.

In North America, Enhance Energy received a grant from the Canadian government in March 2008 to help develop a $300 million (Can.) CO_2 pipeline the company says will initially move 5,000 tonnes/day into storage via a 240-km, 24-in. OD high-vapor pressure pipeline. Enhance says this first line of the Alberta Carbon Trunk Line will connect industrial complexes northeast of Edmonton to crude fields east of Clive, Alta. Depending on timing of regulatory approvals, construction will start early-2010 with initial service by 2012. Design throughput of the pipeline is 40,000 tonnes/day.

A wide range of research also continues on addressing problems regarding transport of biofuels through pipelines. At the NACE Corrosion 2009 conference (Atlanta, Mar. 22-26) companies and organizations presented papers on stress corrosion cracking characteristics of ethanol on steel.

The sheer volume of projects and research undertaken by established industry participants such as Shell, National Grid, ConocoPhillips, Colonial Pipeline Co., and Petroleo Brasilerio SA suggests their recognition of not just the need but the potential economic benefits of addressing CCS and biofuels.

Maybe their smaller brethren would do well to take notice. And maybe current policy initiatives reflect reality to the same degree they're trying to shape it. In any event, pipelines will be heavily involved in both endeavors. ✦


BLUE MARLIN

Editorial

Lessons from biofuels

As markets balk, the US government recommits itself to the care and feeding of renewable fuels. Lavish subsidies and volumetric mandates haven't been enough. The administration of Barack Obama could save itself trouble and the US money by learning that subsidies and mandates never will be enough.

Setting the leading renewable fuels back onto their feet won't be easy. Fuel ethanol and biodiesel are now flat on their backs. Producers of both politically pampered fuels are struggling if not already bankrupt. Part of the reason is that recession has made business tough for everyone. But that's far from the only problem.

Dependent energy

Energy sources dependent on governmental favoritism live or die by bureaucratic assessments of future business conditions and politically motivated dispensation of third-party funds. That means they die. Governments do no better than anyone else at predicting energy markets and worse than everyone else at reacting to market surprises. Political fuel choice is at best erroneous, at worst corrupt, and too frequently both.

Few in Washington, DC, will admit it, but the American biofuels program is a rapidly degenerating fiasco. Ill-considered energy laws require the use of biofuels in amounts that the market soon may not be able to absorb and that producers later may not be able to supply.

The immediate problem is escalation of biofuel mandates in a market for transportation fuels that has stagnated. Within a few years, the US gasoline market won't need all the ethanol required by law at the 10% blending level. Consumer resistance and distribution-system limits probably will keep 85% ethanol blends in gasoline—E85—from making up the difference. Seeing trouble ahead, ethanol promoters want Congress to raise the cap on ethanol concentrations in fuel burned in conventional engines. Automakers and manufacturers of small engines fear the extra alcohol would damage their products.

Beyond the immediate problem of the market's ability to absorb ethanol at required rates lie concerns about longer-term supply. The law requires escalating sales of fuel ethanol made from cellulose. There is no commercial production of such material at present, although reports of technical progress appear frequently. Even if cellulosic ethanol crosses the commercial threshold soon, the ability of the industry to expand production fast enough to satisfy future mandates remains in doubt.

Meanwhile, the heavily subsidized industries that produce conventional ethanol and biodiesel are retrenching. Both expanded too rapidly in response to government boosterism and now reel from excess capacity and feedstock costs uncompensated by fuel prices in a tepid market. Their government sponsors didn't foresee such a squeeze. The future thus looks cloudy for the economics of conventional ethanol and the technology of its cellulosic successor. Biodiesel, which is far less important to energy supply than ethanol, teeters on the economic brink.

On May 5, therefore, the same day the Environmental Protection Agency proposed regulations implementing an RFS expanded by the Energy Independence and Security Act of 2007, Obama crooned to the rescue. He directed the agriculture secretary to "aggressively accelerate the investment in and production of biofuels" with financial help, interagency collaboration, and market enhancements. In other words, he ordered his administration to compound an enormous and very expensive mistake.

Economic health won't come to biofuels by presidential decree. It can come only through survival of the rigors of commercial competition. Aggressive political support has put biofuels on a downhill path toward economic ruin, missed targets, and—at some point—political revulsion.

Political pressures

Obama and Congress should be discussing at least the relaxation of mandates and subsidies and a quick end to tariffs on imported ethanol. It's too much to ask, but they also should take a critical look at price supports for corn.

That they're not doing any of this testifies to the political pressures that have shoved these growing burdens onto the economic shoulders of American taxpayers and fuel consumers. Politics will keep politicians from genuinely fixing biofuels. But lessons from this latest misadventure with market intrusion should lead them to resolve not to make the same mistakes with other energy forms. ✦

Uruguay attracts interest in its first licensing round

Maria V. Vargas
Consultant
Houston

Uruguay, with no current oil and gas production, has completed the qualification step of its first offshore bid round, offering 11 continental shelf blocks that drew interest from six operators.

The Administracion Nacional de Combustibles, Alcohol y Portland (ANCAP) opened the 2009 Uruguay Round last year and adjusted terms in March to reflect the slump in global oil and gas prices.

On May 6 the government said ANCAP is evaluating information submitted from BHP Billiton, Galp Energia SGPS SA of Portugal, Petroleos de Venezuela SA (PDVSA), Petrobras of Brazil, and Pluspetrol and YPF SA of Argentina. Qualifying companies will be able to submit bids.

This article presents a general background of Uruguay's hydrocarbon industry and its position within the Latin American context. It then discusses the main fiscal terms of the contracts on offer.

Seeking alternatives

Uruguay has not been a major target for international energy companies looking for prospects abroad. This small South American country, neighboring Argentina and Brazil, has no current oil or gas production. It has been meeting its energy needs with imports, particularly natural gas from Argentina, to which Uruguay is connected by two natural gas pipelines, the Gasoducto del Litoral and the Gasoducto Cruz del Sur.[1] Since Argentina started cutting its exports, Uruguay has been exploring alternative sources to cover its energy needs.

These alternatives include a proposed LNG regasification facility at Montevideo. Earlier this year, the Uruguayan Ministry of Industry, Energy, and Mines (MIEM) announced a tender for construction of the Montevideo LNG Plant, which would use a floating LNG tanker with an initial capacity of 3-4 million cu m/day.[2]

The Uruguayan government seems keen to pursue this project to fruition and continues studying its feasibility and structure.

Safe haven

In comparison with some of its neighbors, Uruguay represents a safe haven for international investments.

International oil companies (IOCs) venturing into Latin America are justifiably concerned about contract stability and creeping expropriation, having witnessed, or fallen victims to, resurgent resource nationalism.

A wave of nationalistic moves started in 2006 when the administration of Venezuelan President Hugo Chavez required the conversion of operating service agreements, executed by IOCs with previous governments under the Apertura (opening), into mixed companies majority-owned and controlled by the Corporacion Venezolana del Petroleo (CVP), an affiliate of PDVSA. The companies now must sell all hydrocarbon production exclusively to PDVSA.

Bolivia came next with President Evo Morales's issuance of a nationalization decree on May 1, 2006, and subsequent execution of operations contracts between IOCs and the state oil company, Yacimientos Petroliferos Fiscales Bolivianos (YPFB), in which YPFB retains ownership of produced hydrocarbons and full control over their commercialization.

In October 2007, Ecuador's President Rafael Correa imposed a windfall profits tax whereby the government keeps 99% of oil profits, changing the previous law that called for 50-50 sharing with foreign oil companies of profits from rising oil prices. This tax is still in place despite the decline in oil and gas prices.

Argentina has not resisted this nationalistic fervor. Populist governments have capped natural gas prices, keeping wellhead prices far below international market levels. The restriction has discouraged upstream investment and created shortage.

Resource nationalism has not taken

ground in Colombia, Peru, Brazil, or Chile, which continue to offer attractive terms and contract stability to foreign oil investors.

Chile, in fact, shows how a country with no history of hydrocarbon production and heavily reliant on imports (98% of the crude oil it needs, 96% of the coal, and 75% of the natural gas) has been able to attract foreign investment to exploratory opportunities.[3] The country's last bid round, held in June 2008 for the Magallanes basin, resulted in the award of eight blocks. Three of the blocks involve participation of state-owned Empresa Nacional del Petroleo (ENAP) in 50-50 joint ventures with the selected contractors—Pan American Energy, Greymouth, and Apache. Blocks with no ENAP participation went to IPR Mans, Apache, and Greymouth Petroleum (two).

Uruguay thus is trying to join the safe-haven list of Latin American countries with its offshore bid round offering attractive commercial and fiscal terms to IOCs.

From the standpoint of political stability, Uruguay ranks in the top 75-90 percentile range, according to World Bank Governance Indicators.[4] It ranks first in Latin America for lowest corruption, first for judicial independence, and second in South America for protection of property rights.[5 6]

Uruguay also has a solid track record of respecting foreign investment, with not a single case filed against it before the International Center for the Settlement of Investment Disputes. It is a party to numerous bilateral investment treaties (BITs), affording protection to foreign investment in the form of national treatment, most favored nation treatment, and restrictions on expropriation or nationalization requiring prompt, adequate, and effective compensation. It has signed 29 BITs with countries including the US, Canada, the UK, France, and Spain.[7]

Uruguay's basins

Bidding procedures

ANCAP will accept bids from qualifying companies for the award of production-sharing contracts for 11 blocks comprising a total surface area of 74,000 sq km in the Punta del Este, Pelotas, and Oriental del Plata basins.

The areas have been the subject of geological, geophysical, and geochemical study through surveys commissioned by ANCAP. According to ANCAP's technicians, many leads and plays have been identified in shallow to ultradeep water, some of them analogous to productive systems elsewhere in the Atlantic.[8] Seismic records include bright spots—amplitude patterns that may indicate the presence of natural gas.[9]

Prospective bidders had to prequalify by Apr. 30, producing evidence of compliance with legal, financial, and technical criteria. Prequalified companies may then bid for any number of areas provided an independent bid is submitted for each. The term for submission of bids by prequalified companies is scheduled for June 14-July 1. The blocks will be awarded according to the following factors:

- Minimum work program.
- Economic terms, including: (a) the maximum percentage of production requested for cost recovery, (b) the profit-sharing percentages per type of hydrocarbon and levels of accumulated production, and (c) the increase of ANCAP's sharing percentage for hydrocarbons price increments.
- Maximum participation allowed for ANCAP in any exploitation lot of 20-40%.

Main fiscal terms

The Uruguayan PSC provides for an exploration period of 4 years, during which the contractor must carry out the minimum work program. The contractor has the option to extend the exploration period by 2 years.

The exploitation period is 25 years, subject to a maximum PSC term of 30 years. The contractor may request a 10-year extension.

As in many PSCs, the contractor's remuneration under the Uruguayan agreement includes cost-recovery and profit-sharing elements.

The cost recovery portion reimburses exploration, development, and production costs incurred by the contractor.

The basic profit-sharing split, with the stipulated range of 20-40% for ANCAP, depends on the contractor's bid. ANCAP's share is subject to an increase linked to increases in the prices of oil and gas over base levels, the percentages being matters of bidding.

Contractors may export their shares of production, subject to a preferential right of ANCAP to purchase all or part of the hydrocarbons as necessary to satisfy domestic needs. ANCAP may request that the contractor sell its share of hydrocarbons.

The government charges no royalties and exempts PSC contractors from taxes and levies other than the tax on the income from business activities (TIBA).

Further, acknowledging the decline of international crude prices and consequent cuts by IOCs to exploration budgets, ANCAP eased the terms in March, eliminating the requirement for the drilling of at least one well during the exploratory period for certain blocks and leveling the exploration guarantee at 10% of the minimum exploration program.[10]

Other terms

The PSC attempts to assure the contractor of fiscal stability through a cost-reimbursement mechanism. Under this provision, any new taxes and levies taking effect after signing of the PSC and any changes to the TIBA that increase the contractor's burden can be treated as recoverable costs.

If a PSC yields a discovery warranting development, ANCAP has the right to participate in the exploitation phase. If it decides to participate, its notice to the contractor must include the percentage it will acquire, ranging between 20% and the maximum percentage indicated by the contractor in its bid.

ANCAP's participation is subject to its payment to the contractor of an amount equal to its interest in the direct drilling and completion costs of the exploration wells in production. For appraisal wells, ANCAP must pay the contractor its participating-interest share of all direct expenses plus 15% to cover indirect expenses. However, no costs are reimbursed for appraisal wells less than 25% productive.

Effect of slump

Given the country's history of political and legal stability, Uruguay may be an attractive destination for foreign investment in energy ventures.

ANCAP has been actively promoting the 2009 Uruguay Round, including road shows in Houston and London.

A major challenge for the 2009 Uruguay Round stems from global economic problems and budget cuts by companies responding to a slump in oil and gas prices. However, in times of crisis, companies that take advantage of good investment opportunities can position themselves to fare better than their competitors in the long term. ✦

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Venezuela's Chavez nationalizes oil services firms

Eric Watkins
Oil Diplomacy Editor

Venezuelan President Hugo Chavez, attempting to bolster his socialist spending programs, has nationalized nearly 40 domestic and international oil services companies operating in his country, with another 20 still under threat.

"This is a revolutionary offensive," Chavez said on national television, adding, "These spaces are now for the people, we have freed them from capitalism, they are for the creation of a new country."

The property seized includes at least 13 oil rigs, 39 terminals, 300 boats, and other installations, including two major gas operations. The seizures come just 2 months after Chavez sent troops to take over key oil ports in the country (OGJ Online, Mar. 17, 2009).

'Poor signals' to investors

Apart from adversely affecting current operations, however, Chavez's recent seizure of the oil service companies also is likely to have an adverse effect on future investment, not least, the country's planned Carabobo licensing round.

"This sends very poor signals to prospective investors in the Carabobo block," said Patrick Esteruelas, an analyst with the Eurasia Group in New York.

"Service companies were seen as relatively safe given their critical role, and now [state-run oil firm Petroleos de Venezuela SA (PDVSA)] is sending shots across the bow to the entire services sector," Esteruelas told OGJ.

The takeovers occurred on May 8, a day after their authorization by the Chavez-controlled National Assembly, which said the government will pay book value for the assets or provide bonds in lieu of cash as compensation.

The contractors all operate in the Maracaibo Lake area of Zulia state, a major center of oil production as well as political opposition to the Venezuelan president.

Chavez's power struggle

Chavez, newly emboldened by victory in a Feb. 15 referendum that allows him to run for office indefinitely, has since embarked on an aggressive campaign against his political opponents, aiming to consolidate power in his own hands.

Manuel Rosales, the mayor of Maracaibo and the opposition's candidate in the 2006 presidential election, suffered harassment at the hands of the Venezuelan secret police and was recently granted political asylum in Peru, while the National Assembly recently reduced the powers of Antonio Ledezma, the opposition mayor of Caracas.

Apart from wresting power from his opponents, however, Chavez's takeovers also reflect his desire to assume complete control of Venezuela's oil and gas industry, which finances the central government as well as social spending programs that keep Chavez in power.

Faced with the need to maintain spending on those programs, the Chavez government in August 2008 began suspending payments of fees to domestic and foreign oil service contractors, with estimates of the debt ranging $8-14 billion.

According to Venezuela's El Universal newspaper, which cited a yearend report sent to the National Assembly, PDVSA owed local and foreign contractors nearly $14 billion by yearend 2008.

At the time, contractors began to respond to the problem in a variety of ways: some wrote off the debt, others suspended work, and others began negotiating with PDVSA, which sought

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Oil diplomacy at work in Asia

The Sultanate of Brunei has long had a certain cache among members of the international oil and gas industry. After all, who would not like to work on a South Pacific island with a lot of oil and gas?

A year ago, things were not looking very bright. Industry analysts were estimating that Brunei's reserves would run dry in about 12 years, while problems were mounting with Malaysia over maritime boundaries.

Brunei's Minister of Energy Pehin Dato Haji Yahya tried to put a positive spin on the situation. "You'll never know—technology can change a lot of things," he said, suggesting that new technology could discover and reach new deposits.

As for the troubles with Malaysia, they came to a head 5-6 years ago when both countries awarded similar acreages to two different consortia. Tensions rose when a Total SA exploration vessel, working under a Bruneian contract, was chased off by a Malaysian gunboat.

Consider the stakes

At stake is a potentially oil and gas-rich area, which both countries covet, especially in an era of tightening belts. Yet, when discussing the matter a year or so ago, Yahya admitted that little progress had been made.

"We think this needs a chance for diplomacy," he said, adding—perhaps optimistically—that Brunei's crude output had meanwhile stabilized at about 200,000 b/d and may stay there in coming years.

Was it all just wishful thinking? Yahya's hope for diplomatic solution might have received the horse-laugh from cynics, but in fact it was borne out in March when the two nations reached an agreement over their long-disputed maritime boundary.

It came about when, among other things, the two sides established a "commercial arrangement area" under which oil and gas revenues in the formerly disputed area will be shared between the two nations.

There's no telling what got the two countries to reach an agreement after so many years of failing. But it may have something to do with a statement by David Blevins, chief operating officer of Nations Petroleum Sdn. Bhd.

Polo Club perk

At a dinner in October 2008 at Brunei's Jerudong Park Polo Club, Blevins said the "first shot" of the Block L 3D seismic program was a significant event, and it marked the beginning of a fruitful and successful venture between the Block L partners and Petroleum Brunei.

Even a cursory glance at the map reveals that the area covered by Block L is near the region long under dispute by Brunei and Malaysia. Did someone recognize that the disagreement could hinder exploration? Or did someone recognize that an agreement could ease exploration?

Either way, it was a victory for diplomacy and for the oil and gas companies who could soon be investigating the region's potential. Meanwhile, don't be surprised if you see an announcement that output figures are beginning to rise in the Sultanate of Brunei. ✦

discounts of as much as 40%, saying that falling oil prices had slashed the value of contracts along with revenues.

Companies seized

Among the companies seized by Chavez is the Simco consortium, 49.5% owned by the Houston-based Wood Group, which had a 16-year contract with PDVSA for operations and maintenance of water-injection facilities on Lake Maracaibo.

"Simco consortium disappears today," said Chavez, adding, "Now, it belongs to PDVSA." Wood Group confirmed the seizure, saying that that PDVSA took over its operations earlier this year after the consortium submitted a notice of default due to nonpayment and other contractual disputes.

Tulsa-based Williams Cos. Inc., which last month wrote off $241 million in unpaid debt, also confirmed the Venezuelan government seizure of its El Furrial and PIGAP II gas compression projects in eastern Venezuela.

Apart from companies, however, Chavez's takeover has adversely affected Venezuela's labor unions, with one labor leader estimating that 22,000 oil contractors stand to lose their jobs as a result of his action.

"This law does not benefit us," Bernardino Chirinos, leader of the Union of Oil Workers in the western state of Zulia, told El Nacional newspaper.

"There are 35,000 workers on the east coast (of Zulia state) and only 8,000 will be absorbed" into PDVSA, Chirinos said. "There are 22,000 workers without guarantees," he said.

The takeovers could also have an adverse effect on current drilling operations as drillers step up their efforts for back payment, or lacking it, stop work.

Ensco International, which halted drilling off Venezuela in January to protest $36 million in unpaid bills, said it would terminate its contract for the rig Ensco 69 by the end of the month unless PDVSA pays the back fees.

Meanwhile, PDVSA said there were no problems in the region on May 12, and that operations in the Maracaibo region were "normal" after the government takeover.

"Operations are completely normal, and we have implemented provisions to respond to anything that comes up," said Oil Minister and PDVSA Pres. Rafael Ramirez, who added that PDVSA is paying contract workers. ✦

Baghdad approves Kurdish exports; contracts thought 'illegal'

Eric Watkins
Oil Diplomacy Editor

The Iraqi government, despite recently approving the export of oil from Kurdistan, still considers contracts signed between the Kurdistan Regional Government and international oil companies illegal.

"All we are saying is that these contracts are illegal and illegitimate," said Oil Minister Hussein Al-Shahristani. "The [Kurdistan] region does not have the right, nor does any province or anyone else, to sign contracts on behalf of Iraq without authorization," Shahristani told state television.

"Any contracts must be submitted to the ministry," he said following reports that his ministry had approved exports of oil to begin from the Kurdish region.

On May 9, the KRG announced exports of oil from fields in the Kurdish region would start officially June 1 with 60,000 b/d from DNO International ASA's Tawke field. DNO confirmed it received formal notice to commence exports on that date.

The KRG said the Kurdish oil would be marketed by Iraq's State Oil Marketing Organization, and the revenues would be deposited into the Iraqi state treasury "for the benefit of all Iraqi people."

In March, DNO was poised to begin exports of oil, having connected the Tawke oil field to Iraq's northern pipeline system.

Hardly had DNO announced its export plan than Addax Petroleum Corp. also said it received notification from the KRG of plans to export crude oil from the Taq Taq field in the Kurdish area of northern Iraq (OGJ Online, May 11, 2009).

Addax also will commence its exports June 1, but unlike DNO does not have a pipeline in place. It will have to truck its oil from the field to the Khurmala export station, where it will join the Kirkuk-Ceyhan line.

The decision of the Iraqi government was several months in the making and is due to the country's need for additional revenues amid the current economic downturn, according to industry sources.

Regardless of the reasons for its decision, however, Baghdad is likely to come under increasing pressure to step up exports as more discoveries come online in the Kurdish region.

Earlier this month, Heritage Oil Corp. reported the discovery of a giant oil field in Iraqi Kurdistan with 2.3-4.2 billion bbl of oil in place, of which 50-70% appears recoverable.

The company said it could start trucking production from Miran West-1 by yearend, with individual flow rates likely to be 10,000-15,000 b/d (OGJ Online, May 6, 2009). ✦

OTC: Shtokman Phase 1 development tenders due out

Guntis Moritis
Production Editor

Shtokman Development AG plans to send out soon tenders for developing the giant Shtokman gas field in the Barents Sea, off Russia's north coast, said Philippe Rondy, Total SA's Shtokman planning manager. Speaking at a topical luncheon at the Offshore Technology Conference in Houston on May 6, Rondy said once the bids are returned by yearend, the company will have a better idea on project costs.

Rondy said the front-end engineering and design on the project that commenced in December 2007 will finish in November, with the company making an investment decision on Phase 1 at the beginning of 2010.

The field, which was discovered in 1988, has an estimated 135 tcf of recoverable gas and lies in 1,100 ft of water near the edge of the winter sea ice. To date, one exploration well and six appraisal wells have delineated the field.

The conceptional stage of Phase 1 has been completed, Rondy said. Phase 1 will involve the production of 2.4 bcfd of gas from three subsea templates with 20 producing wells. The gas will flow to a shipshaped disconnectable floating production unit before being transported in dual two-phase 36-in. pipelines to a planned 7.5 million tonne/year LNG plant at Teriberka in the Murmansk Region with another portion entering the North Stream pipeline from Teribeka to Vyborg and then to Germany.

Gazprom has announced that gas deliveries will commence in 2013 with LNG exports beginning in 2014.

Rondy said the large 1,200 ft long, 150 ft wide FPU will have topsides that weigh more than 40,000 tonnes.

He noted that subsurface and subsea development work is not expected to be problematic, but much of the project's difficulty relates to the short weather window for installation work and for the ongoing operations in arctic conditions that include sea ice (possibly every 3 years), 100-ft ice ridges, unpredictable ice drift, ice bergs, polar-low cyclone conditions, and –40° F. temperatures, Rondy said.

Partners in Shtokman Development are OAO Gazprom 51%, Total SA 25%, and StatoilHydro 25%. Twenty-five years after commissioning of the project, Gazprom will become 100% owner of the project, Rondy said. ✦

OTC: Nigeria changes gas-flaring deadline

Uchenna Izundu
International Editor

Nigeria is considering its new zero gas flaring target as 2011, which is 3 years later than its previous deadline of Dec. 31, 2008.

Speaking May 5 at the Offshore Technology Conference in Houston, Hon. Igo Aguma, chairman of the House of Representatives Committee on Gas, said the date had been requested by Nigerian National Petroleum Corp. (NNPC).

Aguma told reporters, "We are all aware that there is currently a gas utilization program ongoing to support the power industry. We also know the capacity of the industry to receive the gas that is being flared. So, projects need to go on before we can have a zero flare-out date."

But achieving this target requires investment by the industry and NNPC has struggled to meet its share of funding for joint venture projects in Nigeria that would build the pipelines and gas gathering systems to stop the flaring. Shell Petroleum Development Co. has previously said that it cannot meet the flaring deadline as the government has not met its financial obligations.

Aguma said it would take at least 2 years to establish the facilities needed to transport associated gas from the oil fields to demand centers.

However, operators are skeptical that even the 2011 date could be met, suggesting instead that 2013 would be feasible. One said before any progress could be made it was necessary to stop disruption of constructing gas projects in the Niger Delta and that the government provided adequate funds to finance its equity in these projects.

Billy Agha, acting director of the Department for Petroleum Resources (DPR), threatened to penalize oil firms who failed to stop flaring after December's deadline, but this has not stopped the problem. The DPR has not published a list of the fields that it has shut down and environmentalists have complained that the government prefers profit—this would be reduced if it shut the oil wells to collect the gas.

Since 1984 when Nigeria first declared it would end gas flaring, it has repeatedly changed the target date citing problems in the Niger Delta and a lack of cooperation by operators. Gas flaring is wasteful and damaging to the environment with the country losing $2.5 billion/year. Nigeria lacks the pipelines and gathering systems to harness the gas for the domestic market, which is one of the reasons why the government is determined to develop a major market under its Gas Master Plan.

According to estimates by the World Bank, Nigeria is one of the worst culprits in the world in flaring. It flares 40% of the gas it produces and reinjects 12% to enhance oil recovery (OGJ Online, Nov. 3, 2008). In 2007, Nigeria did make some improvement in lowering its flaring, according to the report by the US National Oceanic and Atmospheric Administration. ✦

OTC: Palau lays foundation for first licensing round

Uchenna Izundu
International Editor

The tiny island nation of Palau is laying the foundations to offer its first licensing round with the assistance of the World Bank.

Bill Cline, chief executive of Gaffney, Cline & Associates, told delegates at a panel May 6 at the Offshore Technology Conference in Houston that the government was preparing the legislation and institutions necessary for a licensing round.

Cline told OGJ that World Bank had given a grant to Palau and it was "very early days," adding, "This is a pristine, tropical environment and the World Bank wants it protected and to open any licensing round with transparency."

By September, Palau expects to have written a hydrocarbon code and model agreement, petroleum operations regulations, environmental regulations, and hydrocarbon tax regulations.

There is already exploration interest in Palau, which has a population of 21,000 and lies 800 km east of the Philippines. Palau Pacific Exploration (PPX) is shooting an aeromagnetic survey on its concession in the north of the island and expects to finish next month, a senior company official told OGJ.

Justin Pettett, PPX finance and operations manager, said the company plans to drill two test wells in 2010. "We have

1 million acres of concession there and maybe Palau could have legislation in place by the end of the year."

PPX has a 75% farmin working interest in the block and will use the Synergy drillship to drill a wildcat in 100 ft of water to a target depth of 5,000 ft.

According to an independent report by H.J. Gruy & Associates, the Palau prospect could hold giant oil world-class reserve potential.

"Potential reservoirs, determined from seismic sequence stratigraphy, are thick Miocene age carbonate reef system with associated onlapping stratigraphic sequences with a thick overlying stratigraphic section," PPX said. ✦

Obama keeps new oil, gas taxes in final 2010 budget

Nick Snow
Washington Editor

US President Barack H. Obama released his final fiscal 2010 federal budget on May 7. It included $31.5 billion of new oil and gas taxes over 9 years that were part of the original request he submitted to Congress in February.

Collections would begin in fiscal 2011. The White House projects that through 2019, total revenues would reach $13.3 billion from denying oil and gas companies the tax deduction available to other US manufacturers, $8.3 billion from repealing the percentage depletion allowance, and $5.3 billion from placing an excise tax on new Gulf of Mexico production.

Another $3.3 billion would come from repealing expensing of intangible drilling costs, $1.2 billion from increasing independent producers' geophysical and geological amortization period to 7 from 5 years, $62 million from repealing the tertiary injectants deduction, and $49 million from repealing the passive loss exception for interests in oil and gas properties.

It also repeals the enhanced oil recovery credit and marginal oil and gas well tax credit. The Office of Management and Budget did not list revenues from either of these actions, probably because of price thresholds.

The budget also reinstates superfund taxes, which OMB projects would raise $6.7 billion during 2011-19. It establishes fees on nonproducing federal leases (the so-called "use it or lose it" concept) and reinstates permit fees that the 2005 Energy Policy Act prohibited at the US Department of the Interior. OMB projects $574 million of revenue during 2011-19 from the first action and $171 million from the second.

A lobbyist said only the tax on new Gulf of Mexico production remains in play. "Everything else looks final," he told OGJ.

'Punishes gas production'

The new taxes and other provisions in the budget will make it more difficult to develop domestic energy, according to Independent Petroleum Association of America Pres. Barry Russell. "This budget does not recognize that in order to decrease our reliance on foreign oil, we need to increase our own American supplies of natural gas and oil. It also punishes American gas production, which could play a lead role in climate change discussions as our abundant, affordable, clean-burning energy source," Russell said.

"From repealing existing tax provisions that encourage American production to new excise taxes on offshore production to new user fees that will go to pay for an already complex and costly permit process, this budget takes our natural resources and puts them further out of reach," Russell said.

Natural Gas Supply Association Pres. R. Skip Horvath said Obama's budget was bad news for American consumers and worse news for American jobs. "People don't appreciate how big the gas industry is in this country. Four million Americans depend on domestic gas for their livelihoods, both those who work directly in the industry as well as those in second jobs, such as steel and concrete, and retailing," he said.

He said that it was too soon to say definitively how many jobs would be lost, "but just a 10% decrease in direct natural gas jobs could wipe out the beneficial effects of a doubling of wind and solar jobs.

'Basic misunderstanding'

Horvath said, "Tax policies directly impact the decisions that are made regarding drilling, especially for smaller companies. More importantly, over 80% of the gas in the US is actually produced in this country. We are troubled that this administration has such a basic misunderstanding of how domestic gas markets will be impacted."

Marc Smith, executive director of the Independent Petroleum Association of Mountain States in Denver, found the White House's assertion in its budget that the oil and gas industry has tax loopholes absurd.

"The president's budget repeals the expensing of intangible drilling costs (IDCs), which are costs similar to those that all other manufacturing and production industries can expense. Without IDCs, the domestic gas industry would further contract and capital which otherwise would be reinvested in American energy would be reduced by 30-50%," he said on May 7.

"These tax increases will render many natural gas projects in the Rocky Mountain region uneconomic at today's prices, and will have the perverse effect of destroying thousands of green jobs that already exist in the natural gas industry," Smith warned.

"Tax policies directly impact the decisions that are made regarding drilling, especially for smaller companies," Horvath said. "More importantly, over 80% of the gas in the US is actually produced in this country. We are troubled that this administration has such a basic misunderstanding of how domestic gas markets will be impacted," he said. ✦

EPA proposes renewable fuels regulations for 2010

Nick Snow
Washington Editor

The US Environmental Protection Agency issued proposed new renewable fuels regulations for 2010 and beyond on May 5 as part of a broader Obama administration initiative.

US President Barack Obama also issued a directive forming a biofuels interagency working group to be chaired by Sec. of Agriculture Tom Vilsack, Energy Sec. Steven Chu, and Environmental Protection Agency Administrator Lisa P. Jackson. The president also announced that another $786.5 million from the recently enacted federal recovery and reinvestment act will be available for biofuels research and development and for biofuel refineries.

The new renewable fuels regulations were outlined in a proposed rulemaking notice on the Renewable Fuel Standard. They outline EPA's strategy

fuels as mandated by the 2007 Energy Independence and Security Act. EPA would establish four renewable fuels categories (cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuel).

The proposal would require 36 billion gal of renewable fuels be produced annually, 16 billion gal of which would have to be cellulosic biofuels and 1 billion gal of which would have to be biomass-based diesel. At the most, 15 billion gal of the renewable fuel mandate could be met by corn-based ethanol and other conventional biofuels.

Comparable reductions

For the first time, some renewable fuels would have to achieve greenhouse gas reductions comparable to the gasoline and diesel fuel they displace. Refiners would have to meet the requirements to receive credit toward meeting the new standards, according to EPA. It said thresholds for new categories would be 20% less GHG emissions for renewable fuels produced from new facilities, 50% less for biomass and advanced biofuels, and 60% less for cellulosic biofuels.

The proposed regulations also would address the GHG lifecycle issue for the first time. If adopted, EPA would solicit peer review analysis of methods to measure various fuels and feedstock combinations' GHG impacts, including indirect emissions from land use changes, before implementation.

Lifecycle emissions include emissions from growing, harvesting, and transporting the biomass and from producing and transporting the fuel, according to the US Department of Energy's Energy Efficiency and Renewable Energy (EERE) office.

"With land use changes included, EPA proposed to allow only the five most sustainable process pathways for producing ethanol from corn starch to qualify as renewable fuels, while ethanol produced from sugar in a biomass-fueled facility can qualify as an advanced biofuel. Likewise, biodiesel from virgin plant oils qualifies as a renewable fuel, while biodiesel can qualify as an advanced biofuel," EERE said in a May 6 newsletter posted on its web site.

EPA will accept public comments on the proposed regulations, which it expects to put into effect on Jan. 1, 2010, for 60 days following their publication in the Federal Register. Several groups and individuals responded immediately.

'Questions unresolved'

National Petrochemical & Refiners Association Pres. Charles T. Drevna noted that while the trade group plans to comment more specifically, "the questions of commercial viability, product liability, and the lack of adequate scientific review with regard to mandated increase quantities of ethanol remain unresolved."

Drevna said, "We hope more light will be shed on these problems during the comment period, and trust that EPA will seriously and transparently consider the concerns raised by fuel, public health, environmental, and engine manufacturing interests as it proceeds toward finalizing guidelines for RFS implementation."

Renewable Fuels Association Pres. Bob Dineen said the fuel ethanol trade association welcomes debate on indirect GHG impacts. "The science of market-mandated, secondary impacts is very young and needs more reliance on verifiable data and less reliance on unproven assumptions. Done correctly, such an analysis will demonstrate a significant carbon benefit is achieved through the use of ethanol from all sources," he said.

Steffen Mueller, principal research economist at the University of Illinois at Chicago's Energy Resources Center, said he was encouraged by EPA's announcement that its treatment of indirect land use would be subject to scientific review. "Based on the limited body of science that exists, our land use studies, and our most recent work on satellite imaging used to assess land use impact, it is clear that additional time is required before indirect land use rules can be applied with any certainty," he said. ✦

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

Seasoned hand on Alaska gas line

Deputy US Transportation Secretary Thomas J. Barrett will join the office coordinating federal agencies' responses to expedite construction of a natural gas pipeline from Alaska to the Lower 48 as its deputy coordinator on May 26.

His appointment will bring an administrator to the office with experience not only in Alaska, where he was US Coast Guard Commander from 1999 to 2002, but also as a federal pipeline regulator.

Barrett, who is a retired US Coast Guard vice admiral, was sworn in as the first administrator of the US Pipeline and Hazardous Materials Safety Administration on May 31, 2006. He became deputy Transportation secretary on Aug. 8, 2007, after being named acting deputy secretary on Mar. 3 of that year.

"I've had the pleasure of working with Tom for nearly 20 years, both in Alaska and the Lower 48. [He] brings leadership, experience, and incredible energy to this new challenge which is so crucial to the long-term energy security of the United States and to the state of Alaska," said Drue Pearce, federal coordinator for Alaska natural gas projects, as she announced Barrett's selection on May 6.

Three decades of discussion

Construction of a gas line from Alaska's North Slope to the Lower 48 and in Alaska has been discussed for 30 years, Barrett noted.

"This pipeline is not just an Alaska project but is a vital national infrastructure project. Tens of thousands of good jobs will be created through the life of the project and clean energy will be delivered to Americans," he said. Barrett will return to Alaska, where he lived for 14 years, to direct the ANGP federal coordination and manage its field office in Anchorage.

Salt Lake City-based Northwest Energy Corp. originally proposed the idea of building such a pipeline in 1977, but dropped the plan soon after it became a Williams Cos. Inc. subsidiary.

Basic challenge

High gas prices in the late 1990s led to its revival. Depressed prices now, and the potential to produce gas from more shale formations in the Lower 48, have some observers questioning whether so massive a project would ever be economic. The challenge for federal and Alaska state government officials will be to keep it moving.

Alaska Gov. Sarah Palin welcomed Barrett's appointment. "His career has put him in positions to protect Alaska's people fisheries and environment. We are fortunate to have him watching over the development and construction of the Alaska natural gas pipeline," she said on May 6.

"I look forward to working with Federal Coordinator Pearce, Adm. Barrett, and their entire staff. Having this quality of individual involved in moving the Alaska gas pipeline project forward is a benefit to Alaska and the entire nation," said Mark Myers, the state's Alaska Gas Inducement Act coordinator. ✦

Aramco to stick with investment program, production levels

Nick Snow
Washington Editor

Saudi Arabia's state oil company is feeling the impact of lower prices, but does not plan to change its spending plans or production levels, its chief executive officer said on May 6.

"We were expecting to produce around 10 million b/d at this time and now are producing about 8 million b/d. We're not seeing any imminent increase in production because we're not seeing any imminent increase in demand, but we continue to invest along the petroleum value chain because we expect high demand to return," said Khalid A. al-Falih.

"We're somewhat concerned because other oil producing countries aren't continuing to invest at the same time because prices are low. At the same time, however, lower prices encourage economic recovery," he said during an appearance at the Center for Strategic and International Studies.

Al-Falih noted that Aramco will put in place another 12 million b/d of oil production capacity in a few more weeks when it completes its Khurais oil field program. Its goal is to raise proven reserves within Saudi Arabia to 900 billion bbl from 700 billion bbl and its average recovery rate from 50% to 70%. The additional production will be both light and heavy crudes, including one onshore-offshore field, which it expects to produce 900,000 b/d when it comes on stream, he said.

'World looks to us'

"When there is underinvestment in other producing countries, the world looks to us. There are plenty of resources outside of the Kingdom and we believe they should be produced. We're technically capable of producing much more, but the government will need to decide if we need to go much above 12 million b/d. We think the optimum would be to stretch our resources out for as long as we can," Al-Falih said.

Aramco's investments include developing an "intelligent" field to maximize recovery; futuristic devices such as "res-bots," tiny robots inserted into reservoirs to continuously report conditions; carbon capture and storage; and prerefining crude desulfurization, he continued. "All of these efforts will reduce environmental impacts while building on our experience with proven technologies and practices in a worldwide market," he said.

With current low prices discouraging investments already, Al-Falih warned that governments talking too much about incentives for research and developing alternatives would only increase uncertainty in capital markets. He said a more pragmatic approach would be to improve proven fuel sources, complemented by growing research and development on alternatives.

"I think it would be very risky to bet the farm on unproven new energy technologies. Continuing to use conventional energy resources does not mean continuing to do business as we have, however. Environmental issues must be addressed, starting with carbon," he said.

Unrealistic targets

Al-Falih said he expects refining to change as biofuels are developed. "We don't believe some biofuel targets are realistic, but some gasoline crack spreads have been affected. We believe new refining configurations will emphasize distillates. We also expect bunker fuels and heavier products to be phased out gradually. Over time, the industry will adjust," he said.

Al-Falih said he believes it would be more appropriate for US policy-makers to talk less about energy independence and more about energy security. "We believe the US can increase its energy security by increasing its energy interdependence. That may seem like a contradiction, but the US already has diverse sources. I also believe it's appropriate for the US to start developing alternative technologies now, but it needs to be prudent because conventional fuels still will be needed to meet growing demand," he said.

"Within the foreseeable future, we're not adjusting our investments based on any discussions in Washington. Other producing countries might, such as Canada with its oil sands. The US will also need to consider producing more of its domestic resources, although some of them are in parts of the country where oil is viewed as evil. That issue should be addressed because all of us here know that oil is not evil," Al-Falih said.

He suggested that additional government regulation of financial markets may be necessary after crude oil prices spiked in 2008. "We're in the minority on what happened, at least publicly. We felt the market was well-supplied. At the same time, we were on the phone literally begging our customers to take more barrels to reduce pressure on prices. We continue to believe that speculators drove the increase a perception that supplies were tight. We found this odd since we had so much spare inventories and production capacity," he said. ✦

FACTS: 2009-10 LNG demand flat; supplies to glut markets

The 2009 LNG outlook is grim, according to a recently published review of global LNG by FACTS Global Energy, Singapore.

FGE authors Nelly Mikhaiel and Siamak Adibi say that supply gluts, an economic malaise depressing energy demand, and plunging petroleum prices characterize global markets.

In Asia, current LNG demand is sluggish, while a year ago its markets needed a steady supply of Atlantic Basin LNG. This year, Asian cargoes are likely to be seeking markets west of Suez.

Those markets, however, evince "indifferent energy demand" as well as a fresh new slug of LNG supply coming online by yearend to exacerbate already saturated global markets.

Demand

Weak economic growth in Asia will depress LNG demand in the region to 112 million tonnes in 2009, nearly 5% off demand in 2008, says the FGE report.

Japan, perennially the world's largest LNG importer, will lead the way. Japanese utility companies, says the analysis, have all but eliminated all spot purchases for 2009. The country's imports, therefore, will be around 62 million tonnes, down 10%, from 2008. Imports for 2010 will recover to around 64 million tonnes.

For Korea, which traditionally comes in second in global LNG imports, overall gas consumption will decrease by about 6%. As a result, 2009 Korean LNG imports will fall by an estimated 7%, compared with 2008, to 25.6 million tonnes.

Spot 2009 Korean imports will be "virtually nil," say the report's authors, until possibly autumn when the traditional storage filling season begins in advance of winter.

In China, despite the effects of financial recession, long-term contracts will nonetheless bring more LNG into the country. The 2.6-million tonnes/year (tpy) Fujian LNG terminal will by mid-year begin receiving shipments from Indonesia's much-delayed Tangguh project. A pipeline explosion at the Shanghai terminal, China's third, has pushed commissioning back to at least yearend 2009. Malaysia LNG (Tiga) is

Canaport LNG terminal, shown here in April when it was more than 95% complete, expects a commissioning cargo from Trinidad and Tobago in June or July. The 1 bcfd terminal will be Canada's first LNG regasification terminal and will send out gas to Canada and the US. Subsidiaries of Irving Oil Ltd. (25%) and Repsol YPF SA (75%) comprise Canaport LNG LP. Repsol will provide all the LNG and will hold the capacity of the terminal. First commercial cargo will arrive in the third quarter. Photo from Canaport LNG.

to supply the terminal under long-term contracts.

The study also notes that India could attract cargoes unwanted by Japan, Korea, and Taiwan. Its import levels, say the authors, are closely linked to natural gas prices: The lower the prices, the more India can import. The country's shorter distance from Pacific Rim and Mideast LNG exporters would be an attraction and make LNG competitive with naphtha and some domestic gas.

What is clear, say the FGE authors, is that "India has the potential to reduce the amount of LNG that some analysts expect to be delivered to the Atlantic Basin" from mid-2009 on.

European LNG demand this year will increase only marginally from 2008. Gas and power players will need to replenish low storage levels, a "hang-over from the Russia-Ukraine pipeline dispute this past winter."

That demand will be augmented by start-up of new UK LNG terminal capacity as well as additional supply. Previously troubled production in Algeria and Nigeria are likely to recover, says the report, supplemented by new supply from Qatar that targets Europe and the US.

North America

Forecasts of US LNG imports for 2009 are for about 7.4 million tonnes, rising to 9.4 million tonnes in 2010. But those projections are subject to considerable uncertainty, say the authors, about how much LNG tanker traffic can be expected into US ports during the next 18 months.

US industrial gas demand, expected to fall by 6% in 2009, will more than offset small projected increases in other sectors. And US gas storage injections are running ahead with ample gas still in storage. Many observers, the report states, are anticipating a major gas glut in 2009.

But the US is the "home of choice" for LNG volumes unwanted by Asia and even Europe. Although Henry Hub's current price levels yield less than attractive netbacks for exporters, the market "remains deep enough to absorb LNG cargoes unwanted elsewhere—assuming, or course, that LNG exporters are willing to accept the returns."

In addition to about 68 million tonnes of existing LNG import capacity, North America will commission this year at least three new terminals with a combined import capacity of more than 33 million tpy—Cameron, La. (Sempra), Golden Pass, Tex. (Port Arthur, Tex.), and Canaport (St. John, NB; photograph). More capacity will follow in 2010.

The authors note that counterseasonal South American gas demand may take some load off saturated North American LNG markets. Official Brazilian gas demand calls for more than 5 million tpy of LNG imports for the next couple of years. Brazil will have about 5.5 million tonnes of import capacity when its second offshore LNG terminal at Guanabara Bay is completed later this year (OGJ, Mar. 16, 2009, p. 64).

Chile will become an LNG importer this year. A consortium led by Chilean state-owned petroleum company ENAP will begin commissioning its 2.5-million tpy terminal at Quintero Bay in June. Plateau demand from this terminal is 1.7 million tpy. A second, 1.4-million tpy Chilean terminal at Mejillones owned by GDF Suez and copper producer Codelco should also complete construction by 2009, with start-up slated for January 2010.

Supply

Global nameplate liquefaction capacity will grow to about 240 million tonnes by yearend 2009, an increase from its 2008 level of about 197 million tonnes. "Naturally, these projects will take some time to ramp up to their respective nameplate capacities, and actual production will be somewhat less," the report says.

Most of new LNG export capacity

slated for 2009 start-up is in the Middle East. Two regional export projects will begin exports by yearend: more than 30 million tonnes of capacity in Qatar and another 6.7 million tonnes in Yemen.

Asia will also add to its LNG production capability with the recent start-up of Train 1 of the Sakhalin II project (4.8 million tpy; OGJ Online, Mar. 31, 2009), and Train 2 may come online a few months later, as well as Indonesia's soon-to-be-inaugurated two-train, 7.6-million tpy Tangguh project and completion of Malaysia LNG Dua's debottlenecking.

The Atlantic Basin, on the other hand, will not inaugurate any new production capacity this year.

Few FIDs

LNG players today, says the report, are "living in a time of falling gas demand, plunging prices, and a world awash with LNG." But the slight amount of additional LNG supply coming on line over the next few years should "quell any speculation that the pendulum is swinging from a seller's to a buyer's market again."

While FGE assumes no further delays in new projects under construction and expected online in 2009-12, there could be a drop-off in new capacity additions for 2012-13. After all, the report says, only five projects have reached an affirmative final investment decision since 2006—Algeria's Arzew GLZ3 and the Skikda rebuild; Angola LNG; Australia's Pluto LNG, and Peru LNG.

Combined, these represent only 23 million tpy of greenfield capacity, less than a quarter of how much had been approved in the preceding 3 years. "This translates to modest capacity increases in the medium term," says the report.

While affirmative FIDs are likely this year for Gorgon (Australia) and Donggi (Indonesia), uncertain demand prospects and doubt over the future direction of engineering and construction costs may encourage prospective LNG exporters to exercise caution, say the authors. This "waiting game spells bad news for buyers looking for additional LNG supplies" to bridge their forecast post-2012 demand-supply gaps.

Similar LNG supply trends hold for 2010. The Middle East will commission more Qatari megatrains (Qatargas 3 and 4), while the Pacific Rim will see Peru LNG and Australia's Pluto come online.

The Atlantic Basin will not bring online any new production capacity for 2010. The next regional contributor to the region's capacity will be the single-train 5.2-million tpy Angola LNG project, not scheduled for cool-down until 2012. ✦

Bakken, Barnett, Manitoba fuel EOG's liquids binge

Alan Petzet
Chief Editor-Exploration

EOG Resources Inc., Houston, is emphasizing North American liquids and natural gas plays as it develops and explores unconventional and conventional plays in US and Canadian basins.

A leader in horizontal drilling and multifrac application in shales, the company reminded followers May 5 that its "standard plays" are also performing well and provide a production support base.

The company raised the forecast liquids production 2.5 percentage points to a 5.5% increase in 2009, said Mark Papa, chairman and chief executive officer.

Papa expects company-wide production of crude oil, condensate, and natural gas liquids to grow to 75,000 b/d in 2009 and 90,000 b/d in 2010 compared with 61,000 b/d in 2008 and 43,000 b/d in 2007.

EOG, however, is also poised to capitalize when gas prices improve, Papa said.

"Practically speaking, we can grow our North American gas production at any annual rate between zero and double digit per-year growth for at least the next 7 years by simply deciding what level of capital to deploy each year. We already have the organic inventory captured at early-mover cost levels."

Even so, EOG's $3.9 billion 2009 capital budget is directed towards liquids investments.

EOG RESOURCES DRILLING INVENTORY

Play	Potential net recovery*	Includes proved reserves at Dec. 31, 2008
Barnett shale combo	>200 MMboe	8.4 MMboe
Bakken oil	>80 MMboe	48 MMboe
Barnett shale gas	>5 tcfe	1.8 tcfe
Uinta basin	3.3 tcf	1.4 tcf
Haynesville shale	3-4 tcf	14 bcf
British Columbia shale gas	≈6.0 tcf	28 bcf
South Texas Wilcox	0.5 tcf	94 bcf
Atoka/Cleveland	0.5 tcf	204 bcf
Travis Peak	0.8 tcf	62 bcf
Marcellus	2-3 tcf	2 bcf
Waskada oil	25 MMbo	2.2 MMbo

*Potential, not proved reserves. All except Uinta basin and Travis Peak involve horizontal drilling.
Source: EOG Resources Inc.

Williston basin

A trend of increasing North American liquids production will continue for several years as the company's horizontal oil plays begin to have greater effect, Papa said.

The company's main liquids plays are the North Dakota Bakken, North Texas Barnett combo play, and an emerging play in a tight siltstone at Waskada field in Manitoba, Canada.

Papa said the company's holding of 500,000 net acres is industry's best position in the Bakken Trend.

Coming off of 2008's service and supply price spike, EOG Resources restricted its Bakken oil production for the first 6 months of 2009 due to marketing issues. Initial potential of the Bakken wells it completed in 2008 averaged 1,700 b/d.

The company shrank Bakken drilling to eight rigs from 10 last year and deferred almost all completions until mid-2009 when fracs can be performed more economically and road conditions improve in the Williston basin (OGJ Online. May 6, 2009).

Bakken production is to ramp back up in June and be fully restored in July.

A plan to ship Bakken oil by rail to Cushing, Okla., is to take effect in February 2010. This expected to improve netbacks vs. pipelining the oil to the Clearbrook, Minn., hub.

In southwestern Manitoba's Waskada field, just north of the border with North Dakota, EOG Resources has drilled 29 successful horizontal wells and expects to build production from 1,900 b/d at present to 9,500 b/d by the end of 2012.

The producing formation is a tight siltstone with an underlying water zone, Papa said.

Vertical wells yielded very low recoveries, but EOG Resources has booked 2.2 million bbl of reserves as of the end of 2008 and expects to ultimately recover 25 million bbl from the field due to the technology advance.

Barnett shale

EOG Resources' net liquids production from all Barnett shale plays is to grow from 12,000 b/d at present to 21,000 b/d in 2010 and more than 42,000 b/d by 2012, Papa said.

The company's 2009 plan is to drill 60 wells in the combo play. It averages 11 Barnett rigs this year, down from 24 in 2008.

The average combo well IP is 300 b/d of oil, 940 Mcfd of gas, and 130 b/d of natural gas liquids.

A gas processing plant came on line in February 2009.

Pattern work in the Barnett combo play in Montague County involves drilling and simultaneously completing groups of 4-8 wells, and 12 first quarter 2009 completions turned in 30% direct after-tax rates of return at current Nymex prices. EOG Resources controls the vast majority of the combo acreage.

Other plays

EOG Resources is still finding many successful vertical plays, Papa said.

These plays act as a support base that contributes to company-wide volume growth.

One example is the Travis Peak stack and frac play in East Texas, where the company has captured 800 net bcf of ultimately recoverable gas at $1.65 Mcf direct finding cost. It expects to develop the play in the next few years.

EOG Resources has an inventory of 13,250 drillable locations and 12,250 other probable locations in its North American plays. Papa said 59% of the locations are to be horizontally drilled, and 100% of the locations are horizontal in the Barnett gas and combo plays, Midcontinent area, and Appalachian and Horn River basins. ✦

Indonesia awards blocks, plans new bidding round

To boost its declining production, Indonesia has awarded exploration rights for 11 new oil and gas blocks and is already mapping out its next bid round.

Evita Legowo, director general of oil and gas at the energy ministry, said, "The areas are promising, but we have to wait for the investors to do the exploration so we know the reserves."

The new awards include: South Block "A," North Sumatra (PT Renco, PT Prosys); East Pamai, onshore Central Sumatra (PT Nana Yamano); West Belida onshore South Sumatra (Orchard Energi, Bayu); Terumbu onshore and offshore Madura (Australia Worldwide Exploration Ltd.).

The awards also include: Southeast Madura (PT Bama Bumi Santosa, PT Toba); Pasir, onshore East Kalimantan (PT Archipelago); S. Sesulu, offshore East Kalimantan (Hess); Kofiau, offshore West Papua (Biak Petroleum, Niko Resources); offshore West Papua (Marathon, Komodo Energy, Kumawa Energy); Cendrawasih, offshore West Papua (Esso, ExxonMobil, and Biak Petroleum); Northern Papua, onshore and offshore North Papua (Sarmi Papua, Asia Oil).

Legowo announced plans to offer 24 oil and gas blocks in May. Most will be offshore blocks in the less-explored eastern part of Indonesia. Particulars were specified during the Indonesian Petroleum Association annual conventional May 5-7 in Jakarta. Contracts for the 11 blocks awarded were to have been signed at the convention.

Meanwhile, Legowo said the Indonesian government believes it could find more oil and gas reserves based on historical data that Royal Dutch Shell PLC will return to Indonesia. Under a recent memorandum of understanding, Shell agreed to return all its exploration documents from before 1965.

"We expect the data transfer will be completed in no more than 1½ years," said Legowo.

She said the government proposed that Stanvac and Caltex, now ExxonMobil Corp. and Chevron Corp., respectively, return their exploration documents from before 1965. Legowo said such historical documentation was expected to provide more information about oil and gas potential in the country.

"It is possible that, based on the data, we will find new oil and gas blocks," she said.

Although the government has conducted its own seismic surveys, Legowo said the possibility exists that something may have been overlooked.

"Take the example of Cepu block. PT Humpuss had done exploration in the area, but it could not find big oil reserves. But ExxonMobil later on found a big reserve in the block," she said.

Indonesia is struggling to produce more oil from aging fields. In the first quarter of 2009, production averaged 946,000 b/d, down 14,000 b/d from the government's target of 960,000 b/d.

Last year Indonesia withdrew from the Organization of Petroleum Exporting Countries due to declining production and increased imports of oil. ✦

Australia

Texalta Petroleum Ltd., Calgary, launched a 240 line-km 2D seismic survey on EP 103 and 104 in the Georgina basin in the Northern Territory of Australia.

Shooting is to end by June 21, and interpretation and processing should take 8 weeks, after which Texalta will shoot more seismic or pick exploratory well locations to be drilled in year three of the permits' 5-year term.

Indonesia

Niko Resources Ltd., Calgary, noted that it has been awarded eight exploration blocks off Indonesia since October 2008.

Three blocks awarded in May 2009 cover 1.2 million acres each. They are the Kofiau block in West Papua, the Kumawa block in southwestern Papua, and the Cendrawasih block in northwest Papua.

Kofiau is in a geological setting similar to the nearby Salawati basin, which has more than 500 million bbl of oil discovered in Miocene carbonates. Kumawa has large exploration targets in structural traps with Jurassic age fluvial sandstones. Main exploration targets at Cendrawasih are large Miocene carbonate reefs.

Marathon Oil Corp. operates Kumawa with 25% interest, and Niko has 25%. ExxonMobil operates Cendrawasih, and Niko has 25%. Biak Petroleum operates Kofiau, and Niko holds 67% (OGJ Online, May 4, 2009).

Israel

Zion Oil & Gas Inc., Dallas, has spud the Ma'anit-Rehoboth-2 well on the Joseph license in Israel.

A 2,000-hp rig is drilling the directional well to 15,400 ft or Triassic and then below 18,000 ft into Permian rocks (OGJ, July 5, 2004, p. 41).

Italy

First production from Guendalina gas field in the northern Adriatic is expected by the last quarter of 2010, said 20% interest holder Mediterranean Oil & Gas PLC.

Reserves of the Eni-operated field are 19 bcf proved plus 3 bcf probable.

Italy's environment ministry approved development in early May, and final award of the production concession is expected next quarter.

The reservoir is more than 3,000 m deep in 20 m of water 25 km off Ravenna, Italy. The field is to have a platform and two development wells. Output is expected to be 20 MMcfd.

Northwest Territories

MGM Energy Corp., Calgary, amended its Mackenzie Delta farm-out with Canadian affiliates of Chevron Corp. and BP PLC in Canada's Northwest Territories.

MGM won't be required to drill the final three wells or shoot seismic called for in the original agreement until a decision is made in connection with the Mackenzie Valley gas pipeline.

MGM immediately becomes operator and earns the maximum interest available consisting of a 50% interest in the farmout lands and joint discoveries in the Mackenzie Delta.

Three wells to be drilled after a decision to construct the pipeline may be appraisal or development wells at MGM Energy's option.

Quebec

Corridor Resources Inc., Halifax, NS, deferred until 2010 its application for approval to run a geohazard site survey for a proposed offshore exploration well at the Old Harry prospect in the Gulf of St. Lawrence off Quebec.

The Quebec government's April 2009 budget calls for undertaking a strategic environmental assessment in the gulf to prepare the path for offshore oil and gas exploration and development.

The government's timetable indicates this assessment will be completed in 2½ years. Consequently, the earliest time that a permit could be issued by the Canadian and Quebec governments to drill in Quebec's sector of the gulf would be 2012.

Pennsylvania

Admiral Bay Resources Inc., Centennial, Colo., took a 50% working interest in up to 6,000 acres in Cambria County, Pa., that provide exposure to the emerging Marcellus shale gas play.

Admiral Bay and its partner in the Revloc coalbed methane project in the Appalachian basin said the acreage appears to be in the fairway for Marcellus prospectivity.

Admiral Bay negotiated pipeline right-of-way, and a tap site is in place. Pipeline construction could begin as early as late 2009.

Texas

West

Arena Resources Inc., Tulsa, added $20 million to its 2009 budget, bringing outlays to $85 million, and will activate a second company owned rig in June at Fuhrman-Mascho field in Andrews County, Tex.

The company has drilled 497 San Andres development wells since mid-2005, including 20 in the quarter ended Mar. 31, with 100% success. The two rigs will have drilled 120 wells in 2009. Arena Resources ran as many as five rigs in 2008.

Drilling and completion costs have declined 26% to $480,000 since the fourth quarter of 2008.

The company completed two of four Yates gas wells drilled in late 2008 at encouraging initial rates consistent with expectations and is accelerating Yates development.

Repeated gas gathering system shutdowns resulted in 64 days of lost sales in the first quarter.

SandRidge Energy Inc., Oklahoma City, is operating four rigs in the West Texas Overthrust and one in East Texas compared with a high of 47 rigs in the second quarter of 2008.

The company averaged 10 rigs and drilled 44 wells in the 2009 first quarter, when it completed and brought on production 61 net wells. First quarter production was up 27% year to year to 319 MMcfed.

As service costs have fallen, the cost to drill and complete a typical Warwick thrust well has declined 34% to $2.2 million. The drilling finding cost for the average Warwick thrust well is currently 98¢/Mcfe.

DRILLING MARKET FOCUS

US rig count slumps more rapidly than industry expected

Paula Dittrick
Senior Staff Writer

The US rig count fell much more rapidly than most in the oil and gas drilling industry had forecast, and industry executives say they are uncertain when drilling activity might recover.

Baker Hughes Inc. reported a rig count of 975 working rigs for the week ended Apr. 17 compared with 1,743 rigs drilling during the same period a year ago.

The weekly rig count released Apr. 17 marked the first time since Apr. 30, 2003, that fewer than 1,000 rotary rigs were working in the US and its waters. It also marked the lowest weekly rig count since Apr. 2, 2003, when 972 rigs were drilling.

Halliburton Co. Chief Executive Officer Dave Lesar called the drilling decline "unprecedented" and said it's impossible to say when activity might recover. He believes the downturn came more quickly than in past drilling slump cycles.

Lesar's comments came Apr. 20 when Halliburton of Houston reported first-quarter 2009 net profit of $378 million compared with $580 million for first-quarter 2008. Rival Weatherford International, based in Switzerland, reported first-quarter net profits of $164.8 million compared with $264.2 million for the same period last year.

Diamond Offshore reported Apr. 15 that three of its shallow-water Gulf of Mexico rigs were idled within 1 month.

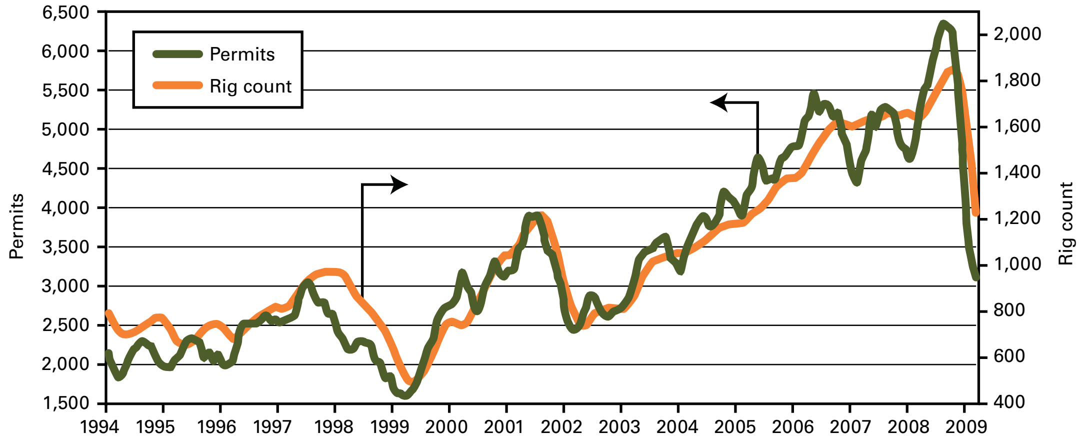
Producers shut in gas

Some operators temporarily are shutting in wells. Chesapeake Energy Corp., Okalahoma City, said Apr.16 that it shut in natural gas production by 400 MMcfd. Production cuts primarily involved the Midcontinent and Barnett shale.

Until gas prices strengthen, Chesa-

Range Resources Corp. is using custom-designed crawler rigs in the Marcellus shale. These rigs can traverse a drill pad in a matter of hours, saving time and money for Range, which is drilling multiple laterals from a single pad. Photo from Range Resources.

DRILLING PERMITS VS. RIG COUNT*



*30-state total based on 3-month average (January-March).
Source: Barclays Capital after various state agencies and Baker Hughes Inc. rig count

peake plans to limit production from most newly completed wells in the Barnett and Fayetteville shales to 2 MMcfd. Production in the Marcellus shale will be limited to 5 MMcfd and Haynesville shale production limited to 10 MMcfd.

Aubrey K. McClendon, Chesapeake's chief executive officer, blamed soft gas prices on "recession-related reduced demand and abundant US production." Lower drilling activity and natural reservoir depletion will rebalance the gas market by early 2010, he said.

J. Marshall Adkins, analyst with Raymond James & Associates, said US gas production rates have yet to reflect the plummeting US drilling activity.

"Unfortunately, we still do not believe the US gas supply rollover will come soon enough or be large enough to save the natural gas market from further meltdown in 2009," Adkins said.

He expects the current slump in drilling rig activity will hit bottom by the end of second quarter.

Having slashed his US rig count forecast for 2009-10 since early February, Adkins said Apr. 20 that he anticipates the US rig count will bottom at around 700 rigs—down from his earlier February forecast of 800.

"The US gas rig count will bottom close to 500 rigs (down nearly 70% from the peak), and year-over-year US gas supply will be down about 6 bcfd by late 2009," he said.

Natural gas producers recently have been drilling but not completing wells, Adkins said. Based upon his conversations with industry, he estimates that as many as 1,000 wells were drilled but not completed during first quarter.

"This equates to roughly 10-20% of the well count and could delay 10-20% of expected new production," or up to 1.5 bcfd, he said. Operators delay completions of newly drilled wells because:

• They can save cash and eliminate some well costs.

• They can hold leases by drilling only a vertical well and producing only a small portion of gas vs. drilling a horizontal well

• They are waiting for oil and gas prices to recover before they complete wells.

• Limited take-away capacity has prevented completion and production of wells in some areas, particularly in the Barnett shale recently.

The rig count in shale plays has held up better than the total fleet average, Adkins said, noting that the percentage of active rigs drilling shale plays has moved higher during the past 6 months.

Range Resources Corp., Fort Worth, said its production continues to grow despite a reduced capital program. Range attributes its production growth to the Marcellus shale in Pennsylvania, Nora field in Virginia, and the Barnett shale in North Texas.

Range Resources had 15 rigs operating as of Apr. 16 compared with 33 rigs for the same time last year.

Oil drilling to recover first

Pritchard Capital Partners LLC expects the rig count will bottom at 800-1,000 rigs by June 30, said Pritchard analysts in an Apr. 20 research note. They suggested rigs drilling vertical wells for oil will be among the first to go back to work.

In April, Chesapeake said it had resumed 7,000 b/d of production from previously shut-in oil wells.

Barclays Capital analysts in New York monitor the number of drilling permits issued by 30 states. They report a "very strong relationship" between drilling permit issuance and US rig count.

In March, the 30 states issued 2,753 drilling permits, down 11.2% from February and adjusted for comparable number of filing days. The decline was broad-based. California was down 99 permits, Montana was down 43 permits, and New Mexico was up 69 permits (see chart).

"We believe the ongoing weakness in aggregate permitting activity points to further erosion in drilling demand during the second quarter," Barclays analyst James Crandell said. ✦

Biocides control Barnett shale fracturing fluid contamination

J.K. Fichter
K. Johnson
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Baker Hughes Inc.
Sugar Land, Tex.

R. Oden
EOG Resources Inc.
Fort Worth

Production

A team, composed of the operator and service company staff, tested various biocides to determine the best chemical for controlling bacteria in fluids used for fracturing Barnett shales in the Fort Worth basin of Texas.

The selected biocide provided consistent performance in the quick kill of aerobic, fermentative, and sulfate-reducing bacteria as well as the long-term preservation of the produced fluid.

Operators commonly use hydraulic fracturing with varied proppant concentrations for extracting gas from shale formations. The fracturing fluid consists of water and polyacrylamide or sugar-based polymers.

Bacteria typically contaminate water obtained from local rivers, lakes, or oil field wastewater. Polyacrylamide and other organic compounds can serve as food for the bacteria. As a result, the frac fluid is a fertile breeding ground for sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB).

If SRB and APB become established in the wellbore, production of hydrogen sulfide, iron sulfide, and microbial induced corrosion can damage production lines, surface equipment, and gas-gathering systems.

Bacterial contamination

Because the Barnett shale has very low hydraulic permeability, the water volumes used to frac wells have ranged from less than 1 million gal on early vertically completed wells to more than 5 million gal on recently completed horizontal wells.

The water used comes from several sources, including freshwater supply wells, chlorinated city water, rainwater, pond water, and lake water. Each water source contains some bacterial contamination.

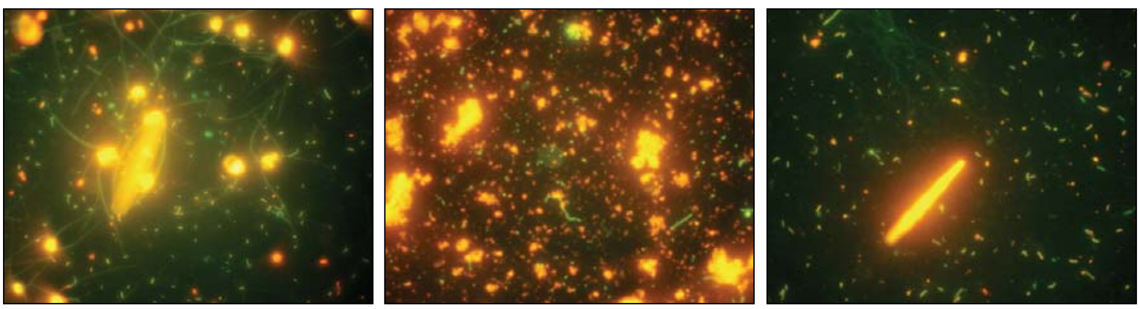
During droughts or to reduce water-hauling expenses, operators on occasion will reuse flowback water from previous frac jobs. This practice usually increases bacterial contamination and solids loading.

The initial slick-water fracs used 500-bbl portable tanks for storing source water on location. These tanks provide a relatively easy way for controlling water quality because service companies could easily clean the frac tanks and water-hauling trucks and chemically treat the water in the tanks.

As frac jobs grew larger, it became uneconomical to use frac tanks to store water. The most common solution placed the frac water in lined or unlined earthen pits that are open to the atmosphere. As a result, dust, rain, and surface runoff can contaminate the water. The water can remain dormant in the pit for days to months before a frac job, leading to stagnant, highly contaminated water. Often, the jobs require a mix of several different water sources that may result in scale formation and increased bacterial activity.

Seasonal temperature fluctuations will affect bacterial activity in the frac fluids, resulting in higher bacteria concentrations in the warmer spring and summer months and lower activity in the cooler fall and winter months. Consequently, success in the winter may not translate to a successful frac biocide program in the summer without adjustments to the biocide loading rates.

Frac jobs pump large volumes of water downhole under high pressure, resulting in near-wellbore cooling that provides a favorable temperature for bacterial growth. In addition, the operator may shut in the wells for days to weeks following the frac job to



The water source survey indicated high bacterial contamination, as shown under 1,000X magnification (Fig. 1).

Based on a presentation to NACE International Corrosion 2008 Conference and Expo, Mar. 16-20, 2008, New Orleans.

await installation of surface processing equipment and flowlines.

Without a proper biocide treatment, frac-water bacteria can become established downhole and near the wellbore during the frac job and subsequent shut-in period. These bacteria then can contaminate separators, water tanks, flowlines, and disposal facilities downstream.

Sampled water quality varied widely (Fig. 2).

Bacterial contamination can produce biogenic sulfide (souring), form iron sulfide (black water), cause plugging, and result in corrosion failures of downhole equipment, surface separation and storage tanks, and flowlines.

Preventing contamination requires a good biocide program to prevent system souring, solids formation, and bacteria-related corrosion failures.

A good program has several key stages, including analysis of various water sources, biocide selection, implementation, monitoring, and optimization.

Source water analysis

Source water analysis requires proper sample collection. The Barnett shale program included collection of source water samples in clear, 8-oz plastic bottles from the source well, pond, lake or pit, flowback water, separator, and produced water storage tank. The procedure involved:

- Rinsing out the bottles with system water before collecting the sample.
- Leaving head space in the bottles in the oxygenated source well, pond, lake, and pit water samples.
- Filling the bottles to overflowing and capping them off immediately to maintain an anaerobic environment for the separator and produced-water tank samples.

The water analysis used the serial dilution enumeration technique for semiquantitative enumeration of viable general aerobic APB, and SRB. The technique included serial dilutions with culture media adjusted to system water salinity in accordance with the NACE Standard Test Method 0194-2004.[1]

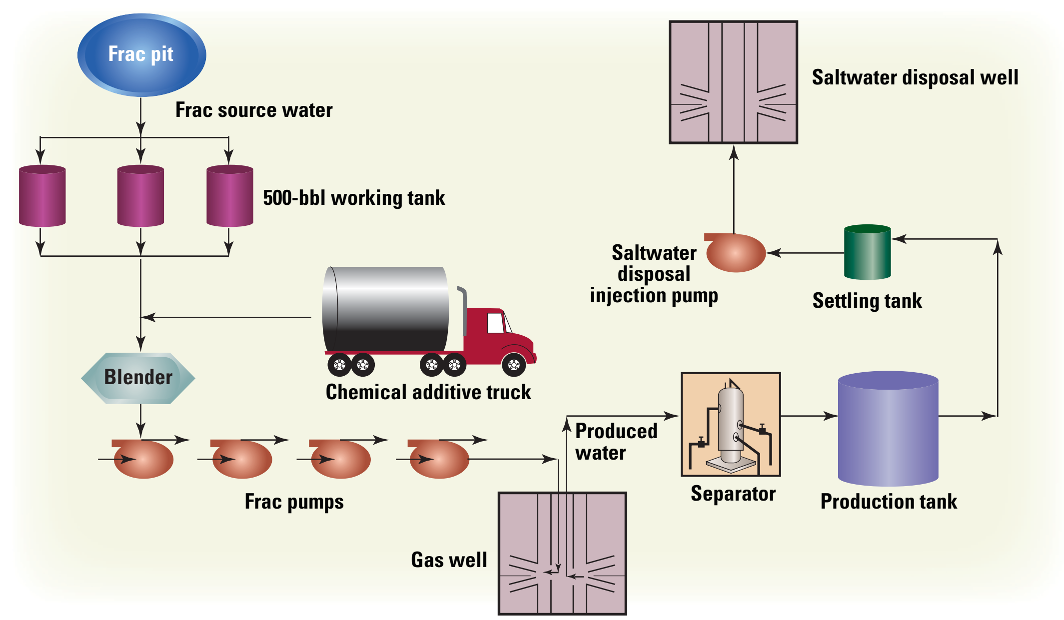
The salinity of the culture medium was adjustedto match the salinity of the water tested. The APB enumeration used modified phenol red dextrose while the SRB enumeration used a proprietary self-adjusted SRB medium. To simulate summer fracturing conditions, the culture media was incubated for 28 days at 85° to 90° F.

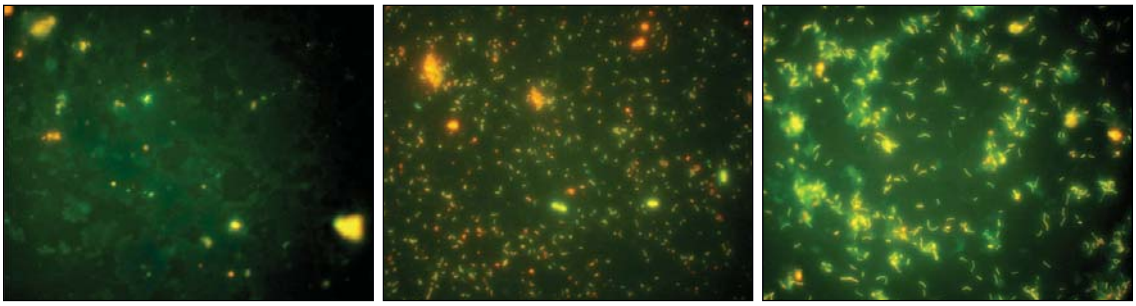
For quantitative enumeration of total bacteria, the analysis included the observation of samples through a microscope equipped with a fluorescence epi-illuminator in accordance with the NACE Standard TMO-194-2004.[1]

Preparation of the samples involved filtering them through black, 25-mm

WELLSITE WATER FLOW

Fig. 3

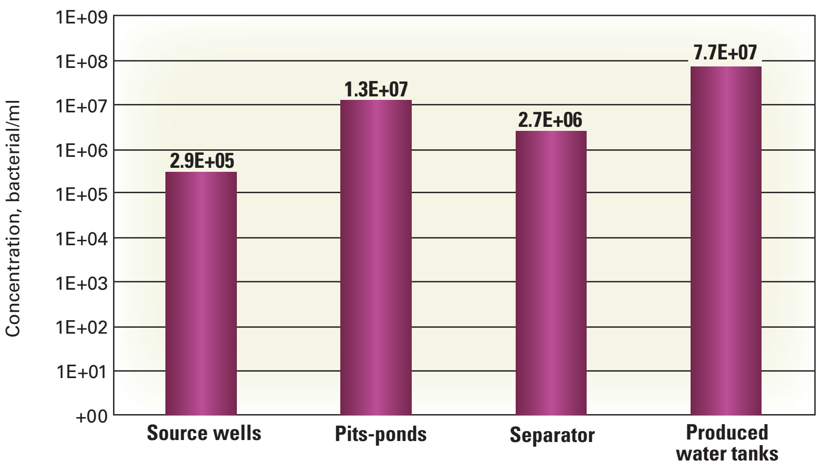




These microscopic photomicrographs from left to right are of the source well waste, pit water, and produced water storage (Fig. 4).

Average bacterial concentrations

Fig. 5



Microbiological survey of fracturing water sources

Table 1

Sample	– Microscopic analysis – Bacteria/ml	Algae/ml	– Bacterial culture media – APB/ml	SRB/ml	Water quality
Pond 1	5 × 10^6	Occasional	≥10^6	10^4	Tan water with solids, natural stock pond
Lined Pit 1	9 × 10^6	BD	≥10^6	10^3	Opaque water
Pond 2	2 × 10^6	3.4 × 10^4	≥10^6	10^4	Opaque water
Pond 3	4 × 10^5	Occasional	10^5	10^2	Opaque water
Lined Pit 2	9 × 10^7	BD	≥10^6	≥10^6	Black water, lot of sediment
Lined Pit 3	3 × 10^5	BD	10^5	10^2	Clear water
Lined Pit 4	3 × 10^7	BD	≥10^6	≥10^6	Dark brown water

diameter, 0.2-μ pore diameter polycarbonate filters, and then staining the bacteria trapped on the filters with acridine orange, a chemical that binds to nucleic acids contained within all bacterial cells.

The tests used an epifluorescence microscopy at 1,000-times magnification to analyze the filters mounted on microscope slides.

Enumeration of bacteria involved averaging the number of bacteria counted over numerous microscopic fields and then calculating bacteria/ml of sample based on the amount of sample filtered, the filter size, and the microscopic field size.

Planktonic kill tests

To determine the best biocide for treating the fracturing fluid bacterial populations, the analysis studied the planktonic bacterial kill on several different chemically free-water sources.

The test involved inoculating the water with previously cultured indigenous bacteria, weighed out into clean 8-oz glass prescription bottles, and dosing with biocides at various concentrations. In addition, a control sample only had indigenous bacteria inoculated.

The analysis exposed the bacteria in each samples to the biocides for various contact times, such as 1 hr, 24 hr, 1 week, and 3 weeks. The longer contact times simulated the fracturing fluid water retained by the reservoir during the flowback period.

A serial dilution technique enumerated the surviving bacteria in each biocide-treated and control sample. The APB enumeration used samples diluted into a freshwater phenol red dextrose medium, while the SRB enumeration used samples diluted into a freshwater proprietary SRB medium.

To simulate summer conditions, the tests incubated the serially diluted culture vials for 28 days at 90° F.

The tests involved a six-vial serial dilution for the biocide-treated samples and an eight-bottle serial dilution series for the control samples.

The analysis also compared the results with other Barnett shale operator kill studies.

Water-source survey

A water-source survey indicated that each fracturing water source was highly contaminated with bacteria (Table 1 and Fig. 1). The general aerobic and acid-producing bacteria were the predominant bacterial population in most pits and ponds. Fig. 2 shows the quality variation of the samples.

Pits 2 and 4, however, contained very large SRB populations as well (greater or equal to 1 million SRB/ml). The amount of turbidity and discoloration in the water correlated with the SRB concentrations, with the highest SRB concentrations observed in the pit waters that were black and dark brown in color.

Typical Barnett shale pit profile

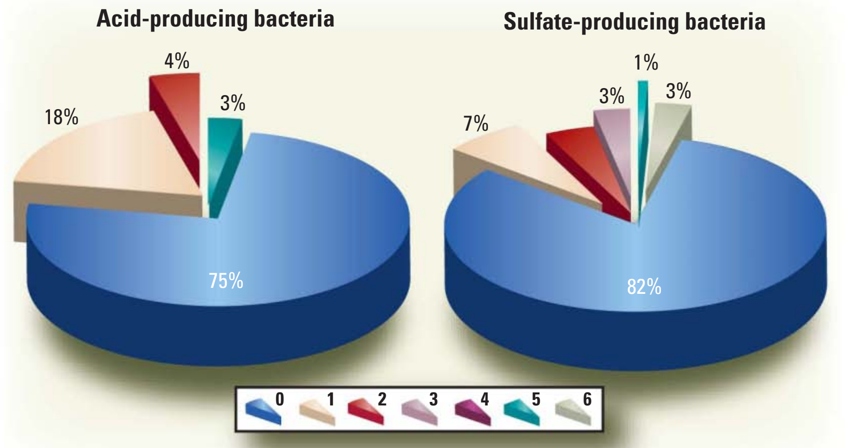
Table 2

Company	Operator
Pit name	Unlined pit
County	Johnson
Sample date	May 30, 2006
Water quality visual	Yellow color
Water temperature, °F.	71
SRB/ml	105
APB/ml	108
Specific gravity	1.003
Total dissolved solids (TDS), mg/l.	4,638
pH	7.10
Iron, mg/l.	0.27
Manganese, mg/l.	0.00
Chlorides, mg/l.	2,300
Calcium, mg/l.	160
Barium, mg/l.	0
Sulfate, mg/l.	521

Comments: This pit contains fresh water and high levels of bacteria.

After 46 ppm biocide A treatment

Fig. 6



Note: Results expressed as the number of positive culture media bottles in a serial dilution series.

The pits and ponds that contained tan or opaque water had moderate concentrations of SRB (10-10,000 SRB/ml). Lined Pit 3 contained clear water and had the lowest concentration of APB and SRB. The natural pond samples had algae.

The pit with black water was a mixture of flowback and fresh frac water. This mixture provided the proper nutrient balance to stimulate SRB activity, resulting in biogenic sulfide production and black water.

Wellsite survey

The survey evaluated several sites at newly drilled and fractured gas wells. At each wellsite without a nearby naturally occurring pond, the operator drilled freshwater source wells for supplying water for the frac job. The job required placing the water from the source well, either pumped or hauled by truck, into a lined pit near the well location.

Upon completion of the frac job, the operator shut in the well from a few days to several months while waiting for installation of the surface equipment. Upon installation, flowback of the initial surge of frac water and sand was routed to the frac tanks.

After flowing back for several days to the frac tanks, the operator rerouted the produced fluids to the separator for separating the produced water and condensate from the natural gas. The separated condensate and water go to storage tanks on location. From the tanks, trucks haul condensate to a sales point and the water to a saltwater processing facility for disposal into an isolated formation downhole.

The wellsite survey collected samples from the water source well, the fracturing water pit, the production separator, and the produced-water storage tanks (Fig. 3).

Despite the lining of the frac pit, the total bacteria count increased by 1.5 log units if the source-well water was in an open frac pit. The majority of frac pits had measurable SRB concentrations.

The separator sample showed high bacteria concentrations in the microscopic analysis, but bacterial culture media indicated that the majority of the bacteria observed by microscopy were not viable, with only 100 viable APB/ml recovered.

As the water proceeds downstream into the produced-water storage tank, bacteria concentration increased with the viable APB and SRB populations exceeding 1 million bacteria/ml. Microscopic analysis (Fig. 4) showed masses of bacteria surrounded by exopolysaccharides (slime) indicating the formation of sessile (attached) bacterial biofilms in the tank bottoms.

Early Barnett shale operators experienced produced-water storage tank and flowline failures because of the stagnant conditions and solids deposition in the storage tanks. The water sat relatively stagnant in the storage tanks for weeks to months before removal and transportation to a water-disposal facility.

Fig. 5 shows the average bacterial concentration observed at each sample location during the field survey. Fig. 4 shows representative microscopic photomicrographs of each sample location analyzed during the field survey.

Biocide selection

In the last 4 years, Baker Hughes Inc. has run planktonic kill studies on at least 20 different Barnett shale fracturing water sources collected from six different operators. Because each bacterial control product contains different biocidal active ingredients, chemical activity levels, and product costs, our analysis evaluated a range of

Wellsite bacteria survey

Table 3

Sample location	Microscopy, bacteria/ml	Bacterial culture media APB/ml	Bacterial culture media SRB/ml
Source well	2×10^5	10^5	BD
Frac pit	7×10^6	$\geq 10^6$	10^2
Separator	2×10^6	10^2	BD
Produced-water storage tank	2×10^7	$\geq 10^6$	$\geq 10^6$

PLANKTONIC TIME KILL TEST RESULTS — Table 4

Biocide	Concentration, ppm	10-hr contact time APB/ml	10-hr contact time SRB/ml	24-hr contact time APB/ml	24-hr contact time SRB/ml
Biocide A	30	10^5	10^5	10^5	BD
	50	10^3	BD	10^2	BD
	75	BD	BD	BD	BD
	100	BD	BD	BD	BD
Biocide B	50	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	100	$\geq 10^6$	10^4	10^5	$\geq 10^6$
	150	10^5	10^3	10^4	10^4
	200	10^2	10^2	10^2	10^2
Biocide C	50	10^5	10^5	10^5	10^2
	100	10^2	BD	10^3	BD
	150	BD	BD	BD	BD
	200	BD	BD	BD	BD
Biocide D	30	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	50	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	75	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	100	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
Biocide E	25	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	50	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	100	$\geq 10^6$	$\geq 10^6$	10^4	10^4
Biocide F	25	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	50	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$	$\geq 10^6$
	100	$\geq 10^6$	$\geq 10^6$	10^5	10^3
Untreated control	—	10^8	10^8	10^8	10^8

Note: Results are expressed as number of positive bottles in a serial dilution series. The untreated control was with an inoculated nine-bottle series, while all treated samples were with an inoculated six-bottle series. For ≥6, all six bottles in the serial dilution series were positive. BD = below detection.

treating concentrations for each biocide in an effort to provide a cost-equivalent comparison of the different chemistries.

The kill study discussed in this article evaluated six different biocides at various concentrations. The study exposed bacterial populations in the frac fluid sample to the biocides for 1 hr and 24 hr before quantifying the concentration of viable APB and SRB in each sample as compared to an untreated control.

In this study, 50 ppm Biocide A and 100 ppm Biocide C provided a 5-6 log reduction in the SRB and APB populations after 1 and 24 hr of contact time with the biocides. Biocide B required 200 ppm to obtain similar reductions in the APB and SRB populations.

A 75-ppm concentration of Biocide A and 150-ppm concentration of Biocide C reduced the APB and SRB populations below detectable limits. No other biocides evaluated provided substantive reductions in the APB and SRB populations at the evaluated concentrations.

Table 5 shows a cost-equivalent comparison of 22 planktonic kill studies performed by Baker Hughes with Barnett shale frac waters. The products shown represent the biocide classes most commonly used for fracturing operations in the Barnett shale.

The average APB populations in the untreated control sample are four log units higher than the average SRB populations. The kill study results indicate that it is more difficult to kill APB than SRB. For the same relative cost, Product A provided 1,000 times greater kill of the APB populations than Product B and 100 times greater kill than Product C.

BIOCIDE COST-EQUIVALENT COMPARISON — Table 5

Product	Test concentration, ppm	Average APB/ml	Average SRB/ml
Product A	75-100	10	<1
Product B	250-300	10^4	<1
Product C	150-200	10^3	<1
Untreated control	—	10^9	10^5

Bacterial populations in the frac water sources generally have become more difficult to kill over time, requiring increased concentrations of biocide. The analysis attributed this observation to increasing age and reuse of the pit waters.

Biocide A was the preferred biocide for the Barnett shale frac fluid treatment due to:

- Consistent, cost-effective performance in the planktonic kill studies.
- Compatibility with the frac fluid friction reducers and other frac fluid additives.
- Passage of the Barnett shale core compatibility studies.
- Absence of foam. Some operators have reported undesirable foaming issues with the addition of glutaraldehyde and quaternary ammonium-blend biocides.
- Noncorrosive at typical frac loading rates.
- Thermal stability at reservoir conditions.

Newly built dedicated frac chemical-injection trucks ensured that the frac fluids were treated with the appropriate biocide concentrations. The frac chemical trucks tie into the blender and flowmeter of the fracturing operation, allowing for injection of the biocide and other production chemicals, such as oxygen scavengers and scale inhibitors, on the fly into the fracturing fluid as it is pumped downhole.

This procedure ensures treatment of all fracturing fluid at the desired biocide concentration. Separate measurement of the chemical additives through a closed manifold system ensures adequate mixing of the chemicals with the frac fluids and minimizes oxygen entry into the frac fluids during chemical injection.

The jobs adjust chemical loading rates based on prefrac and postfrac monitoring results and visual water quality.

Biocide monitoring

Table 6 breaks down the frac biocide program monitoring results for 300 wells treated during the last 4 years. It categorizes the wells by operator, biocide-loading rates, lining of the frac pits, and county. Columns 2 and 3 show the percentage of wells in each category that have low levels of viable SRB or

APB. This study defines low level as 1,000 or less viable SRB or APB/ml in the frac flowback sample.

Operator 2 was one of the first operators in the Barnett shale. In its early frac biocide treatment programs, Operator 2 used 37 ppm of Biocide A. Based on the poor monitoring results (only 35% and 48% efficacy rates for SRB and APB, respectively), it increased its biocide-loading rate to 60-100 ppm with the loading rate dependant on the visual water quality and seasonal temperature variation.

Operator 1 had the best overall biocide performance, despite using identical or lower biocide concentrations than the other operators. Figs. 6 and 7 break down the frac biocide program monitoring results for Operator 1. One can attribute this high-level performance mostly to lined frac pits, which will provide lower sediment loading in the water.

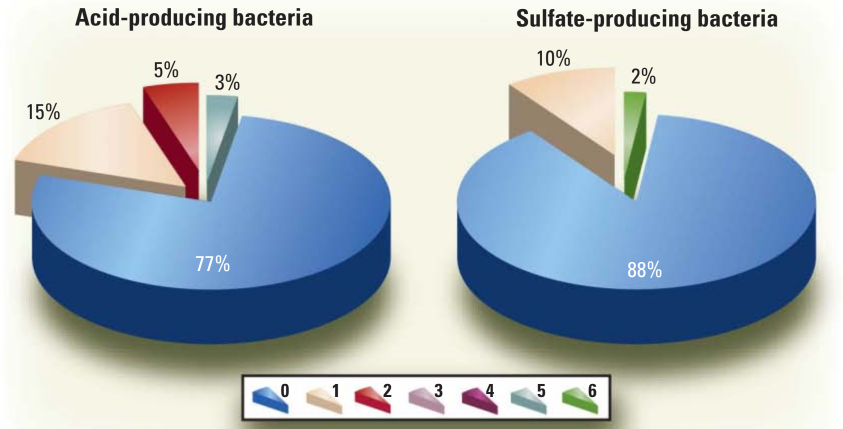
In addition, Operator 1 has its flowback sample monitoring point at the wellhead. Many other operators do not have a sampling point at the wellhead. Therefore, they have to take the flowback sample from the separator, which can result in aberrant readings due to stagnant fluid or solids deposition in the separators.

The first area of the Barnett shale developed was in Denton and Wise counties. Because of this, this area has older frac pits and a pond that have been in use for a much longer time and have had much more fluid mixing.

These factors eventually led to higher bacterial loading and poorer water quality in these pits. A comparison of equivalent biocide loading rates from different operators shows that the frac biocide performance in Denton and Wise counties is slightly lower than for the other counties, such as Johnson and Hood counties where development has just started.

Table 7 compares the effect of seasons on biocide performance for the same 300 wells. The poorest biocide performance (54% and 38% for APB and SRB, respectively) is in the warmest quarter of the year, an average of 82.5° F. during July to September. This information prompted recommendations to increase the biocide loading rates in the warmer late spring, summer, and early fall months.

AFTER 60 PPM BIOCIDE A TREATMENT Fig. 7



Note: Results expressed as the number of positive culture media bottles in a serial dilution series.

BIOCIDE PROGRAM PERFORMANCE COMPARISON Table 6

Operator	Biocide load rates, ppm	Low levels SRB (% of wells)	Low levels APB (% of wells)	Lined pits	Counties
1	46	95	95	Yes	Eastern Johnson
1	60	99	100	Yes	Western Johnson
2	37	35	48	No	Wise, Denton
2	60	78	78	No	Wise, Denton
2	75 to 100	92	88	No	Parker, Hood, Johnson
3	75 to 100	88	88	No	Tarrant, Denton, Wise, Johnson, Parker
4	60	91	91	No	Hood

Control program optimization

Design of a proper bacterial control program requires a thorough understanding of system operations. Gaining this knowledge requires a survey of the various types of fracturing water sources and the frac fluid flowback process to assess the severity of the microbial contamination. One cannot overlook a bacteria problem because a frac water source is chlorinated or of drinking-water quality.

Also needed is the assessment of the bacteria-related problems encountered during standard operating procedures and recognition, simulation, and evaluation of the situations that cause deviations from procedures so as not to overlook additional bacterial and solids loading.

Mixing of frac waters from different sources and reuse of flowback waters can cause elevated bacterial contamination and scaling issues. Eliminating these problems requires compatibility mixing studies with various waters before blending them in the field. The study should evaluate each frac water source multiple times throughout the year to assess

SEASONAL BIOCIDE PERFORMANCE Table 7

Month	Low levels SRB (% of wells)	Low levels APB (% of wells)	Avg. temp. for time period, °F.
January-March	80	78	49.3
April-June	81	76	73.1
July-September	54	38	82.5
October-December	100	100	56.8

how seasonal variations affect bacterial activity and water quality.

These practices provide information on the severity of bacterial contamination and solids loading in the frac water sources, allowing for an adjustment of the biocide loading rates.

When designing a biocide program, one should consider several different factors. First, it is imperative that biocide selection testing include waters representing each type of frac water source. One should only consider broad-spectrum biocides to ensure control over the heterogeneous microorganism population present, such as SRB, APB, algae, and fungi.

After the generation of a list of products that perform well against the frac water microbial populations, it is important to assess if the frac water contains components such as H_2S, iron sulfide, ammonia, or dissolved oxygen that might degrade biocide performance. It is essential to assess compatibility of the biocides with the frac-fluid additives, such as polymers and any other chemicals including oxygen scavengers, scale inhibitors, corrosion inhibitors, and friction reducers.

Planktonic kill studies provide two important pieces of information required for killing bacteria:

1. Concentration of biocide required to kill the target microorganisms in the water source.
2. The amount of contact time required for the biocide to kill the target microorganisms.

Controlling bacteria in frac programs requires storage and treatment of all frac fluid at the predetermined biocide dosage rate in frac tanks or application of the biocide at the desired concentration continuously on the fly, as the frac fluid is pumped downhole.

In frac-tank applications, the jobs should retain the frac fluid in the tanks for the required biocide contact before the fluid is pumped downhole. In on-the-fly applications, one should ensure that the biocide-treated fluid is shut in downhole for the required amount of contact time.

For Barnett shale applications in which the biocide is injected on the fly at the blender, the operator should shut in the wells for at least a 24-hr contact time before bringing the well online.

The jobs should use EPA-registered biocides according to the label specifications. For example, application of an EPA-registered biocide into an open pit is illegal because of the potential for leaching into the groundwater and other surface waters, aquatic organism toxicity, and terrestrial hazards due to animal consumption.

One needs to consider the biocide half-life and recalcitrance to ensure that the biocide will maintain bacterial control in the frac waters throughout fracturing, shut-in, and flowback.

An aggressive monitoring program is instrumental in assessing the performance of the biocide program. Monitoring can allow an operator to verify the merit of various costly operational practices, such as lining of pits.

Monitoring can reveal issues with sampling points. For this type of application, a sampling point at the production wellhead is necessary to assess properly the biocide performance and monitor product residuals. One should use the information gained from the monitoring program to optimize a biocide program and assess system conditions that would require an adjustment of the biocide-loading rate.

When frac pits are filled at the last minute, bacteria enumeration techniques are unable to provide information on bacterial activity before proceeding with the frac job. When flowback waters are reused and mixed with fresh waters as the water source for fracturing operations, a water chemistry check must be done first to insure that the salinity of the culturing media matches the salinity of the frac source water.

Operators have used several different biocides in the Barnett shale gas play. They have incorporated the biocide into slick-water fracturing packages to reduce the chance of bacterial contamination downhole that could cause microbial-influenced corrosion and biogenic souring of the reservoir.

The risks associated with an ineffective microbiocide program reach across all phases of production operations.

Acknowledgment

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Reference

1. NACE Standard Test Method 0194-2004, "Field Monitoring of Bacterial Growth in Oil and Gas Systems," 2004.

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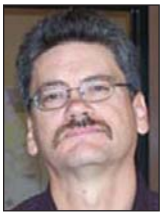

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LIQUIDS ENTRAINMENT—1

Changing operating conditions lead to compressor damage

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This is the first of three articles that describe BP's experience with reciprocating compressor damage from liquids intrusion at two facilities, in Oklahoma and Alaska. Due to the different damage mechanisms, facility constraints, underlying causes, and site-specific factors, the specific actions required were quite different for each installation.

Operators of reciprocating compressors are generally aware of the danger to their equipment from ingestion of liquids. At a basic level, the solution is simple: Provide compressors with a clean, dry suction stream.

The GPSA Data Book provides this summary: "Reciprocating compressors should be supplied with clean gas as they cannot satisfactorily handle liquids and solid particles that may be entrained in the gas. Liquids and solid particles tend to destroy cylinder lubrication and cause excessive wear. Liquids are noncompressible and their presence could rupture the compressor cylinder or cause other major damage."[1]

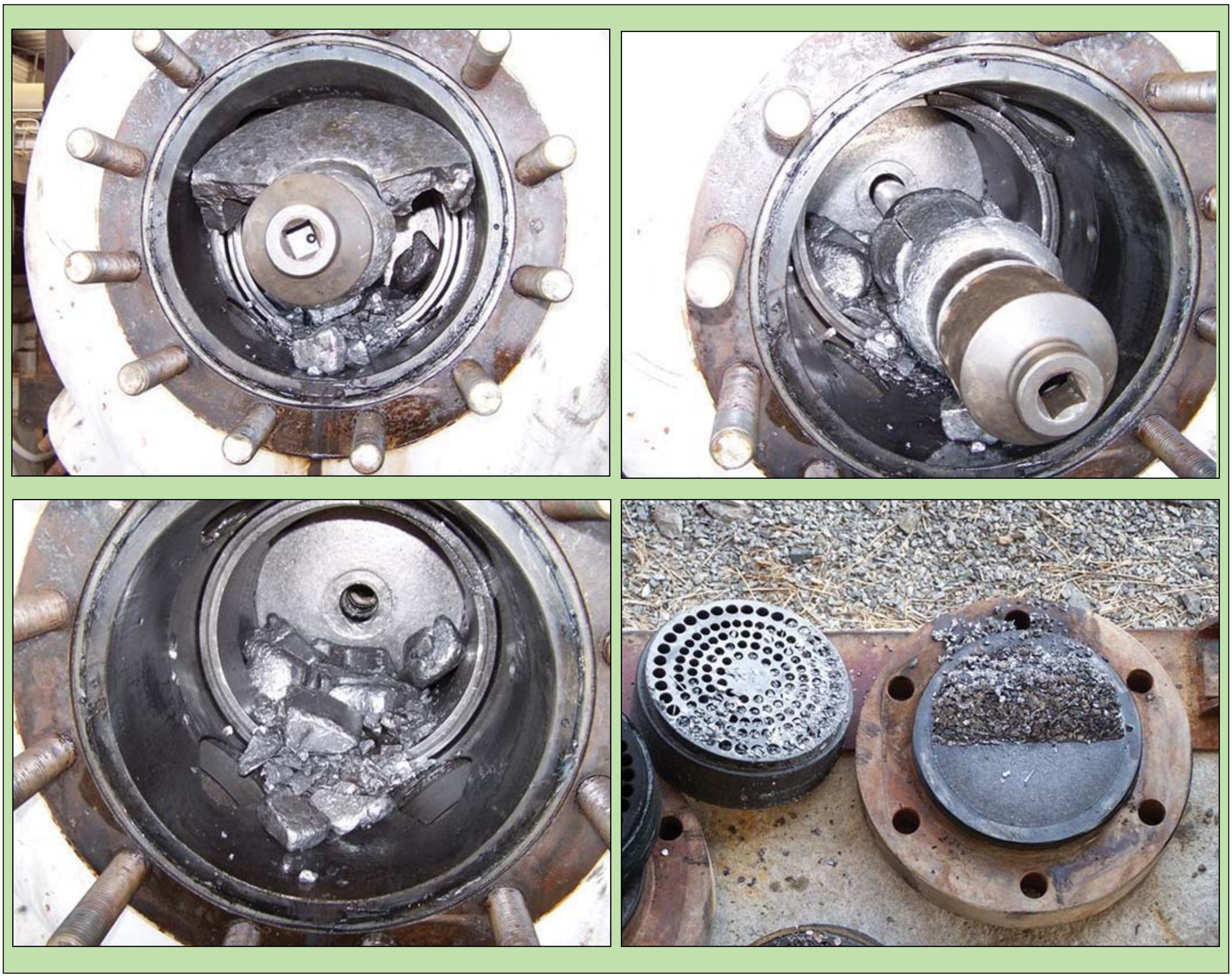
In reality, however, that damage to reciprocating compressors from liquids ingestion is not uncommon reliably indicates the difficulty operators often face in providing clean, dry gas to their units.

BP owns and operates the Milne Point oil production facility on Alaska's North Slope where processing facilities are enclosed in heated, adjoining modules. The gas compression module houses two 3,450-hp reciprocating compressors.

Over time, the frequency and severity of compressor component failures have increased. Intense examination identified both mechanical and process-related causes for the failures, including entrainment of water and NGLs in the compressor suction. Damage caused or exacerbated by ingested liquids included bearing failures, damaged cylinder lining, sheared wrist pins, sheared cylinder attachment bolts, and cracked pistons.

A separate liquid slugging incident at an Oklahoma compressor station resulted in three damaged pistons on two out of six 1,000-hp reciprocating compressors. In this case, the problem was solved with additional pipeline pig-

Based on a presentation to the Laurance Reid Gas Conditioning Conference, Feb. 22-25, 2009, Norman, Okla.



Liquids ingestion at the Oklahoma compressor station caused this damage (Fig. 1).

ging capability and new, more reliable vertical inlet separators.

At Milne Point, poor separation performance of existing suction scrubbers was predicted by computational fluid dynamics (CFD) modeling and confirmed by laser isokinetic probe sampling to quantify liquid entrainment. Analysis of operating data also indicated condensation of liquids in suction piping downstream of the scrubbers.

A multifaceted solution was required, including:

- Reconfiguration of suction cooler temperature control logic.
- Upgrades to suction scrubber level control, alarm, and shutdown systems.
- Installation of in-line, axial flow cyclonic demisters immediately upstream of compressor suction bottles.
- Heat tracing and insulation of piping and suction pulsation bottles downstream of the new demisters.

Other options were considered but rejected for various reasons.

This three-part series will discuss several noteworthy aspects of these two repairs, including the role of changing operating conditions in leading to compressor damage (Part 1), the validation of CFD modeling by on line laser isokinetic probe sampling for liquid entrainment and impact of NGL solubility in compressor lube oil (Part 2, May 25, 2009), and use of state-of-the-art in-line cyclonic separation technology to mitigate liquid entrainment (Conclusion, June 8, 2009).

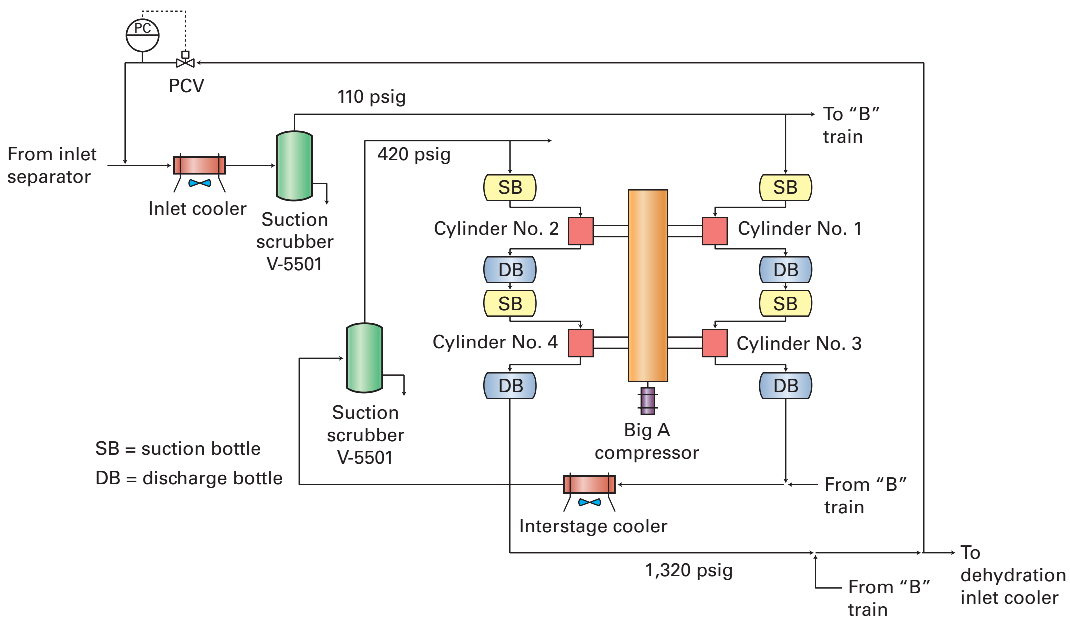
Oklahoma incident

In late 2006, a field compression facility in Oklahoma lost two reciprocating compressors when well fluids, primarily produced water, flowed past the inlet separator and the compressor scrubber and into the compressor cylinders.

The incident damaged two pistons from the first stages of one machine and one piston from a second machine. Fig. 1 shows some of this damage. The

MILNE POINT BIG A/B COMPRESSORS

Fig. 2



separators at both compressor stations designed with high-level switches that would shut down the compressors and prevent reoccurrence.

The switches were LOPA classified, were tagged as safety-critical equipment, and would undergo function testing outlined according to LOPA requirements. Additionally, operations also added pipeline pigging capability in the gathering system to reduce the volume of slugs entering the facility.

These modifications have reduced the cost for compressor valve repairs. After the 2006 incident and subsequent installation of new separators and liquid-level switches, the compression station has experienced no more problems related to liquids in the compressor cylinders.

resulting failures would have resulted in significant downtime if the facility had not planned for spare compression.

The processing facility contains six reciprocating compressors that boost wellhead pressures to a delivery pressure of nearly 900 psig from suction of 60 psig. After compression, the gas undergoes sweetening and dehydration before entering a third-party pipeline as sales gas.

These compressors are Ariel frame 4 (JGK) with Caterpillar drivers (Model 3516 3RC) rated for 1,000 hp. The facility has the luxury of spare compression, which was of great benefit in minimizing the cost of this incident.

The facility had been in service for several years. With time, produced fluids from the wells have increased, both from additional wells coming on production as well as from aging wells now producing more water.

Several times before the incident, the inlet separation equipment was overwhelmed with produced fluids slugging into the facility. The compressor shutdown devices were able to protect the machine by shutting down the compressors.

During a heavy liquid slugging incident in 2006, however, the well fluids overwhelmed the inlet separators, and the compressor safety devices did not react quickly enough to shut down the machines. The liquids entered the cylinders and damaged three pistons in two machines.

Interestingly, during hazardous operations (HAZOP) and layer of protection analyses (LOPA) review of this facility a month before the incident, the engineering and operation team identified this scenario as highly likely with compressor damage a result. The team recommended that either additional fluid separation be installed to collect produced fluids entering the facility or that additional faster-acting shutdown devices that were LOPA rated be installed to prevent the incident.

Before the final LOPA analysis and LOPA verification were completed, the incident occurred. The final LOPA report recommended immediate action to prevent reoccurrence. Engineering accelerated the program to add additional separation.

As a result of this incident, engineering installed new vertical inlet

North Slope repair, upgrade

The self-contained Milne Point oil production facility on Alaska's North Slope, 30 miles west of giant Prudhoe Bay field includes power generation and all processing equipment necessary to produce, treat, and deliver more than 30,000 b/d of sales oil to the Trans-Alaska Pipeline.

To prevent melting the North Slope permafrost, all process facilities are housed in elevated, adjoining modules. All compressors and associated scrubbers and coolers are in a single module.

Unlike Prudhoe Bay facilities, which use centrifugal compressors to handle much higher gas volumes, most of Milne Point's compression needs are met by two parallel low-speed reciprocating compressor trains (A and B

Shown at left is the sheared wrist pin from the Milne Point Big A compressor; at right appears one of the cracked No. 3 pistons (Fig. 3).

trains). Each train includes two large compressors (Big A and Big B) for bulk compression and two small compressors (Little A and Little B) for handling low-pressure secondary and tertiary production-separator vapor and high-pressure injection gas.

The remainder of this discussion will focus entirely on the Big A/B compressors (Fig. 2).

Each of the Big A/B compressors is a 327 rpm, four-throw Clark CLRA compressor driven by a 3,450-hp electric motor. Each unit compresses 18 MMscfd of produced gas to 1,320 psig from 110 psig inlet pressure for delivery to field gas lift and gas injection systems.

During normal operation, both compressors are running, with no spare capacity. Suction scrubbers and coolers are common to both compressors. Fig. 2 provides a simplified process flow diagram of the Big A/B compression system; only the Big A unit is shown, but the Big B unit has an identical configuration.

History

The Milne Point facility began operation in 1985; BP acquired it in 1994. The following year saw completion of a major plant expansion to increase fluid-handling capacity. The Big A/B compressors were recylindered to increase maximum gas capacity to 45 MMscfd from 32 MMscfd, but no corresponding changes were made to the compression train's piping.

The two original suction scrubbers, V-5501 and V-5511, were not replaced, but their original vane packs were, with higher capacity vane pack assemblies. The new vane pack units were equipped with mesh pads on the inlet side to improve flow distribution into the vanes.

Compressor maintenance records show that since the 1995 expansion, the Big A/B compressors have experienced increased mechanical failures and required more frequent maintenance.

Within the last few years, the failure rate has accelerated, with more serious damage including two Big A cracked pistons on cylinder No. 3, damaged cylinder linings, and a sheared wrist pin on each compressor. Main and connecting rod bearings have failed within a few weeks to months of installation (Fig. 3).

In February 2007, Big A experienced multiple mechanical failures, including main bearing failure, sheared cylinder attachment studs, and a bent crankshaft. A complete rebuild of this machine was necessary. Fig. 4 illustrates the impact of this major repair on total compressor throughput.

Initial attempts to resolve the increasing compressor problems focused on reducing excessive vibration caused by lack of adequate compressor support. Most low-speed reciprocating compressors are mounted on massive concrete bases to prevent compressor movement by absorbing shaking forces inherent in reciprocating compressors.

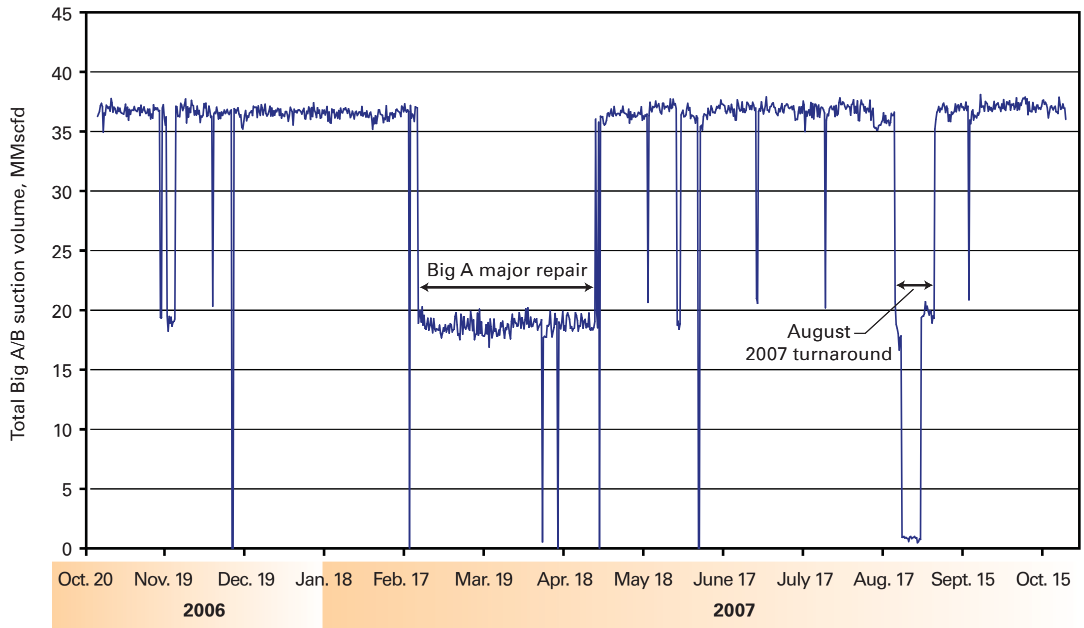
Big A/B compressors, however, are secured to the base of an elevated steel module with no underlying concrete mass to dampen vibration. These early efforts were only partially successful, often resulting in shifting vibration and shaking forces from one part of the compressor module to another.

In response to the rapidly deteriorating mechanical integrity of these machines, BP initiated a project in early 2006 to design new compressors to replace Big A/B. Concurrent with the compressor replacement project began an intensive effort to determine whether the existing machines could be adequately repaired and upgraded to allow for safe, long-term operation.

This effort concluded that the main driving forces responsible for the excessive mechanical failures were subframe flexibility (of the steel module), inherent compressor weight imbalance, and liquids ingestion. Specific recommendations were made to correct each

IMPACT OF MECHANICAL FAILURES OF BIG A/B THROUGHPUT

Fig. 4



of these underlying causes to allow for safe, reliable operation of Big A/B for several more years.

Most have now been implemented, with positive results. The last major recommendation to be implemented is installation of four in-line axial-flow cyclonic demisters, one upstream of each Big A/B compressor suction bottle on the Nos. 1 and 2 cylinders. These units are currently scheduled to be installed this summer during the Milne Point turnaround.

Unlike the Oklahoma incident, in which compressor pistons were destroyed by a single known liquid slugging event, no absolute cause and effect relationship between liquids ingestion and compressor damage could be established for the Milne Point machines. But liquids were determined to be a significant factor contributing to much of the damage that has occurred in the past.

Even after completion of the Big A rebuild in April 2007, connecting-rod bearing have continued to fail at an abnormally high frequency. Until the demisters are installed, there will continue to be loss of lubrication due to persistent ingestion of entrained NGLs.

Evidence of entrainment

After Big A sustained major damage in February 2007, the only viable option to restore compressor capacity in the short term was to rebuild this machine completely. A new compressor could not have been operational for at least 18 months.

Visual detection

Beginning in late February 2007, Big A was disassembled and rebuilt over the next 10 weeks. When Big A was opened, liquids were found in the suction bottles, discharge bottles, and distance pieces. For the Nos. 1 and 2 cylinders, the liquids found in the suction bottles and distance pieces were clear to amber colored. These liquids had the smell and appearance of natural gas condensate.

Later analysis confirmed them to be a mixture of water and NGL, typical of suction-scrubber liquid dropout. Liquids found in the discharge bottles of Nos. 1 and 2 cylinders and the distance pieces and suction bottles of the Nos. 3 and 4 cylinders appeared very thin lube oil. Lab analysis confirmed that these liquids were lube oil diluted with NGL.

Knock-sensor indications

In 2006, each of the Big A/B cylinders was equipped with knock sensors to monitor the relative magnitude of forces generated within each cylinder. These sensors were initially monitored to detect impending mechanical damage. More information about the presence of entrained liquids, however, revealed a correlation between liquids ingestion and knock-sensor indications.

In particular, whenever changes in operating conditions caused a significant increase in the rate of liquid dropout in the suction scrubbers, operators noticed elevated cylinder knocking. This generally continued until the scrubber liquid formation returned to normal.

LIQUIDS DRAINED FROM BIG A/B SUCTION BOTTLES

	Big A compressor				Big B compressor			
	Cyl. No. 1	Cyl. No. 2	Cyl. No. 3	Cyl. No. 4	Cyl. No. 1	Cyl. No. 2	Cyl. No. 3	Cyl. No. 4
	Daily average vol., ml							
April 2007	—	—	—	—	30	2	76	5
November 2007	236	11	111	0	25	0	16	0

Elevated knock-sensor activity also occurred immediately after a large manual increase of the discharge temperature set points for the gas coolers upstream of the suction scrubbers. This was later determined to result from increased condensation of liquids downstream of the scrubbers as warmer, richer gas came into contact with cooler suction piping and pulsation bottles.

Suction bottle drains

After discovering liquids in the suction and discharge bottles of Big A, operators installed manual drain lines on all pulsation bottles on Big A and Big B, with the exception of the Nos. 3 and 4 cylinder discharge bottles. These drain lines were plumbed to the closed hydrocarbon drain system but equipped with connections for collecting samples of the liquids drained from each bottle.

During the Big A rebuild, operators drained liquids daily from the Big B suction bottles to quantify volumes and verify appearance of the drained liquids. They repeated this experiment in November 2007 with both Big A and Big B operating. In all instances, the liquids drained from the Nos. 1 and 2 bottles were clear and smelled like gasoline. Likewise, all liquids drained from the Nos. 3 and 4 bottles appeared as thin lube oil.

These visual results were consistent with earlier observations of liquids discovered during the Big A teardown. The table shows the average daily volumes of liquids drained from each suction bottle during the April and November tests.

A notable aspect of these results is the larger quantity of liquids drained from Big A than from Big B. The compressors are virtually identical and the main suction line from each suction scrubber tees into the compressor suction header right in the middle, at an equal distance from each Nos. 1 and 2 suction bottle. Piping geometry directly upstream of this tee is presumed to be the cause of the preferential flow to the A machine.

This difference in liquid volumes is entirely consistent with both operating data and historical mechanical failure records. Bearing failures and cylinder knocking related to liquids ingestion are more frequent and severe on Big A than on Big B.

Also, both of the No. 3 piston failures occurred on Big A. These failures were most likely related to liquids ingestion, as described in the next article in this series. ✦

Reference

1. GPSA Engineering Data Book, 12th Edition, Tulsa: Gas Processors Suppliers Association, 2004.

The authors

Paul Tenison (Paul.Tenison@bp.com) is a facility engineer at BP Alaska's Lisburne production center on the North Slope. Previously, he worked in Anchorage as a senior process engineer assigned to several projects, including the Milne Point Compressor upgrade and repair project. His career in process and facility engineering began in 1979 with ARCO Oil & Gas Co., Dallas. He has worked in Bakersfield, Calif., Denver, and for the last 21 years in Alaska. Tenison graduated from Oklahoma State University in 1979 with bachelor and master degrees in chemical engineering.

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Study sets parameters for using direct assessment on networks

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Structural Integrity Associates Inc.
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Pipelines

Dry gas internal corrosion direct assessment (DG-ICDA) can be an effective means of evaluating networks of pipe for internal corrosion. Evaluating large networks of pipe in a single assessment results in reduced project time requirements.

In cases where in-line inspection was used as the integrity assessment method addressing internal corrosion on a trunkline and where no gas additions between purchase points and no history of internal corrosion in any of the laterals or the common trunkline, multiple laterals that tap off the same trunkline can be combined into one ICDA region. This method achieves the objectives of DG-ICDA while eliminating unnecessary digs and project reporting, ultimately decreasing project scope.

Evaluating the typical system operating conditions for an extended period and evaluating the effects of changing pipeline operating conditions on calculated critical angles can reduce error in determining places along a pipeline where fluid or other electrolyte may reside.

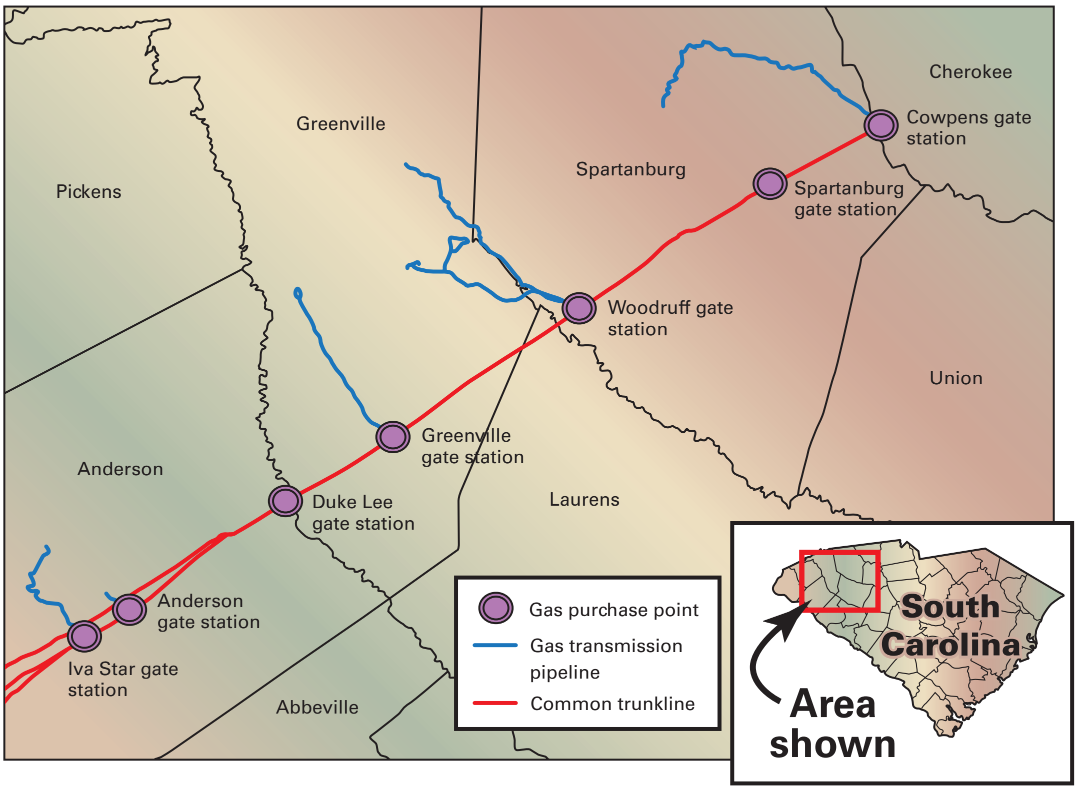
Based on presentation to NACE Corrosion 2009 Conference, Atlanta, Mar. 22-26, 2009.

Background

DG-ICDA identifies areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, then focuses direct examination where internal corrosion is most likely to exist. ICDA seeks to identify the potential for internal corrosion, allowing an operator to prevent any discovered internal corrosion defects from growing to a size that threatens the structural integrity

SOUTH CAROLINA TRANSMISSION PIPELINE SYSTEM

Fig. 1

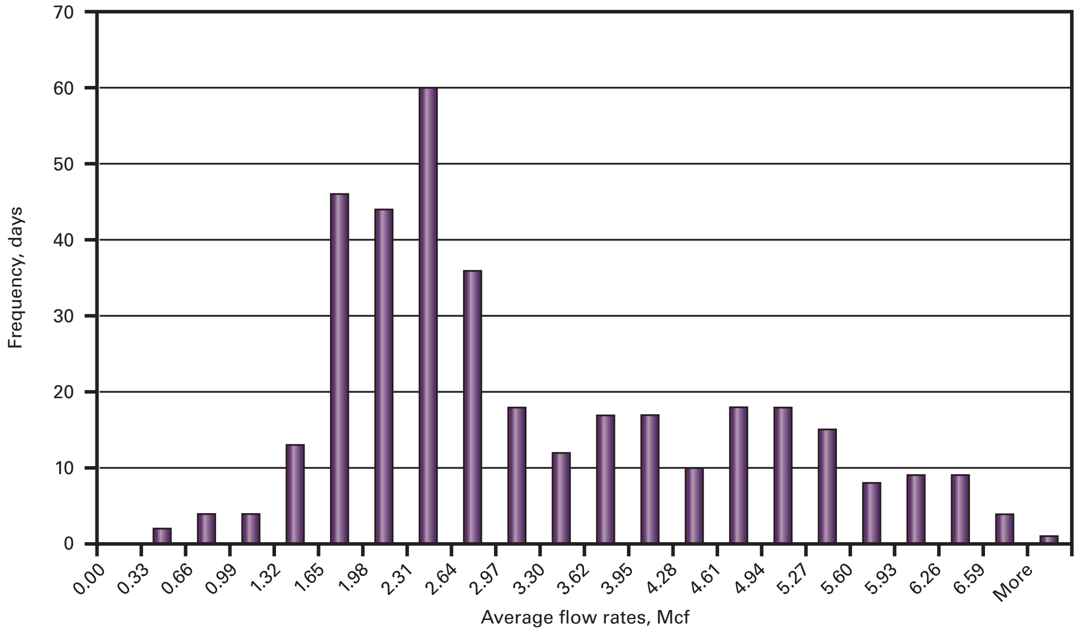


of the inspected pipeline segments.

Operators of gas transmission pipelines, in accordance with 49 CFR 192.921, must assess the integrity of their pipelines in each covered segment based on the threats to which the covered segment is susceptible.[1] Piedmont Natural Gas chose DG-ICDA as the assessment method to identify if the threat of internal corrosion existed in its South Carolina transmission pipeline system.

DAILY FLOW RATES

Fig. 2



The company's system in South Carolina consists of 35 named pipeline segments comprising about 136 miles of pipe. Fig. 1 shows the system's 14 primary laterals, originating from 7 gas purchase points along a common trunkline. Gas in the trunkline travels from south to north, supplying each of the company's seven purchase points.

This project followed requirements of the company's written ICDA plan. The plan used in this project accorded with the Department of Transportation 49 CFR 192 Subpart O, Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Final Rule. The plan also used procedures and protocols developed by Northeast Gas Association (NGA), Gas Technology Institute (GTI), National Association of Corrosion Engineers International (NACE), and the efforts of outside consulting services (Structural Integrity Associates Inc.).

Region identification

An ICDA region extends from where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed.

The criteria for determining the endpoint of an ICDA region as defined by the company's written DG-ICDA plan are:

- Entrance point of gas at a purchase point (i.e., gate station).
- End of transmission gas flow (i.e., into an intermediate high pressure or low-pressure regulator station).
- Gas flow null point from two different gas sources.

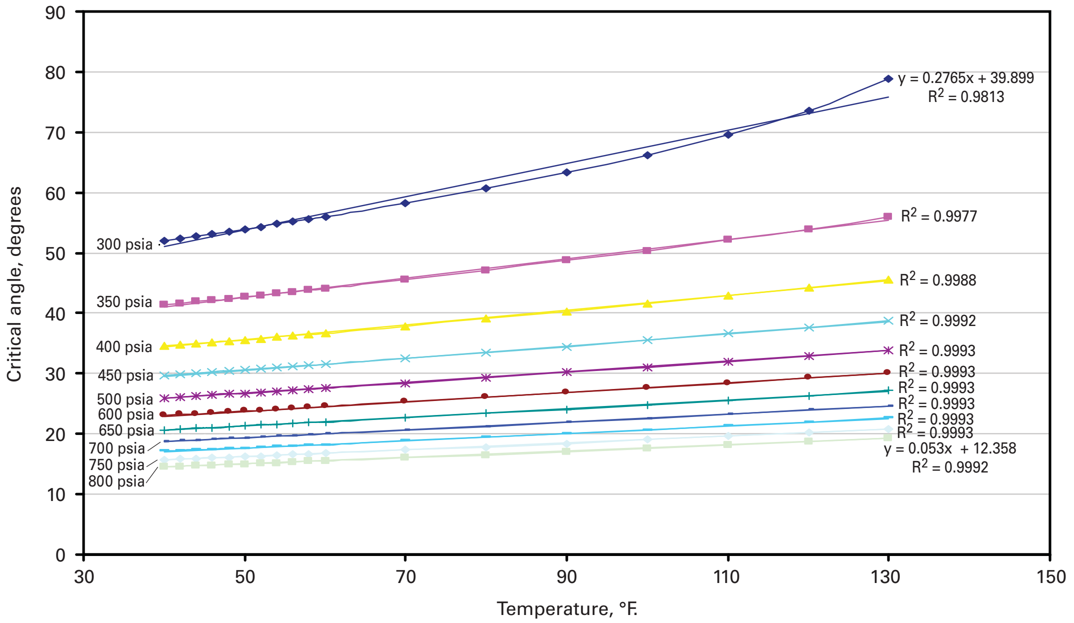
Based on these criteria, the company could consider each lateral or purchase point off the common trunkline in its South Carolina system as an individual DG-ICDA region. This method would result in unnecessary digs and increased project reporting needs, ultimately increasing project scope. Several laterals in the system also are relatively short and completing the necessary digs would not be feasible. These circumstances required development of an alternative approach.

The company's written DG-ICDA plan bases identification of ICDA regions on the source of gas. If liquids are not present at the gas source they would likely be absent in downstream laterals. If two lines therefore have the same gas source, they can be considered one ICDA region. The same philosophy can apply to multiple laterals originating from a common trunkline. In cases that used in-line inspection as the integrity assessment methodology to address internal corrosion on the trunkline on which there are neither gas additions between purchase points nor a history of internal corrosion in any of the laterals or the common trunkline, multiple laterals tapping off the same trunkline can be combined into one ICDA region.

The company's system has 14 primary laterals originating from 7 separate purchase points. The purchase points receive gas from a trunkline network of 4 mainlines. The company asked the upstream gas supplier whether it had seen internal corrosion on the 4 mainlines supplying the system and whether the gas in the 4 mainlines is commingled. The upstream supplier reported completing ILI on sections of 3 mainlines without finding internal corrosion. It

PIPELINE: 6.625-IN. OD, 0.219-IN. WT, 15 MMCFD

Fig. 3



also reported no gas additions in South Carolina and commingling of the gas within the 4 mainlines.

Since gas in the mainlines is commingled and neither the supply gas pipelines nor pipelines in the company's system has a history of internal corrosion, the system was evaluated as one ICDA region.

Representative flow

Technicians must establish flow conditions that represent typical system operation for each DC-ICDA region to calculate critical angles. Corrosion's state as a time-based phenomenon requires consideration of the days per year a system operates at a given set of conditions.

Selecting flow conditions based on preestablished system conditions (i.e., maximum, minimum, or mean conditions) does not consider actual system operation. Conditions such as maximum or minimum typically occur on a few days each year. Observers would not expect to find extensive internal corrosion at sites determined by these conditions.

A statistical analysis approach evaluating system operation for an extended period serves as a preferred method for determining representative operational flow conditions. Such an analysis evaluates how long the system operates at a given set of conditions and allows the user to select conditions (maximum, minimum, mean, etc.) based on duration and system operation rather than a preestablished condition.

The company's system underwent a statistical analysis with daily average flow rate information for 1 year at each of the seven purchase points, creating histograms plotting the daily average flow rate data at each of the seven purchase points. This analysis identified the characteristics (i.e., unimodal, multimodal, etc.) of the distributions as well as determining the mean flow condition and establishing delta flow conditions at 1 standard deviation (σ).

Fig. 2 shows a sample daily average flow rate histogram. During normal operation of the system any liquid will likely migrate to positions predicted by the mean and mean+1σ flow conditions. Mean and mean+1σ flow rate data provided the basis for calculating critical angles and direct examination sites.

Critical angles

Determining locations along a pipeline where fluid or other electrolyte may reside is critical in the DG-ICDA process. This determination requires calculation of critical angles based on pipeline operating conditions. The company's written ICDA plan states either the standard GRI 02/0057 model equations or the modified GRI 02/0057 model can be used to calculate critical angles. The typical system operating conditions and the discrete pipeline information available prompted selection of the modified GRI 02/0057 model. This model allows calculation of the critical angle over a continuous range of flow conditions with a single equation (see box).

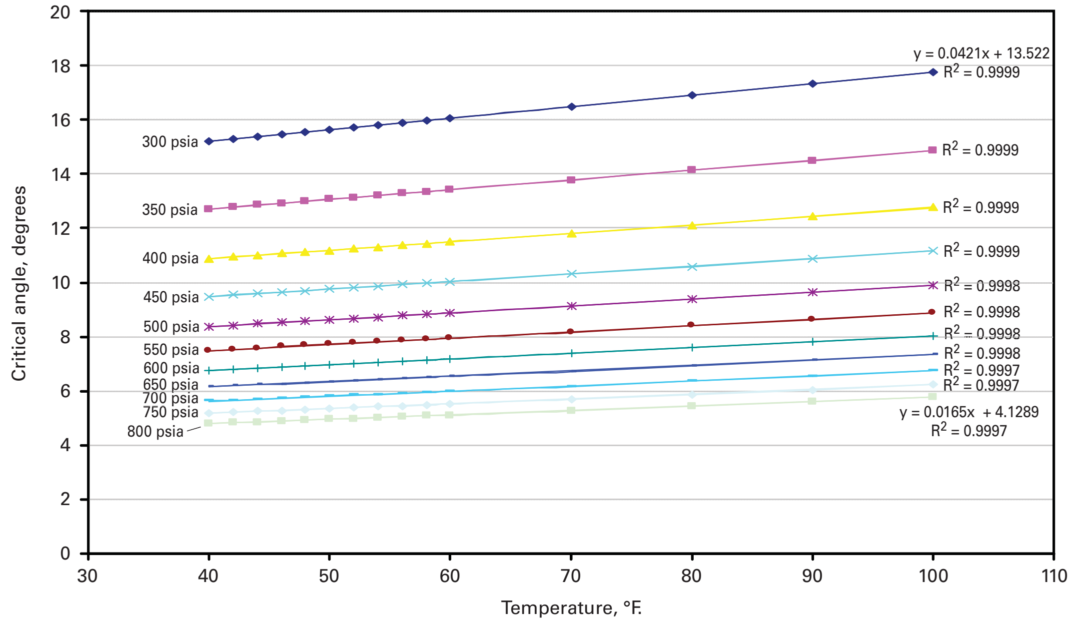
EQUATION

$$\Theta = \arcsin\left[\left(0.675\frac{\rho_G}{\rho_L - \rho_G} * \frac{V_g^2}{g * ID}\right)^{1.091}\right]$$

Reducing errors in determining locations along a pipeline where fluid or other electrolyte may reside requires understanding the effects of changing pipeline operating conditions. The modified GRI 02/0057 equation shown in the accompanying box allowed a parametric study in which temperature, pressure, diameter, and flow rate conditions were varied to better understand the effect of data variability on the calculated critical angle.

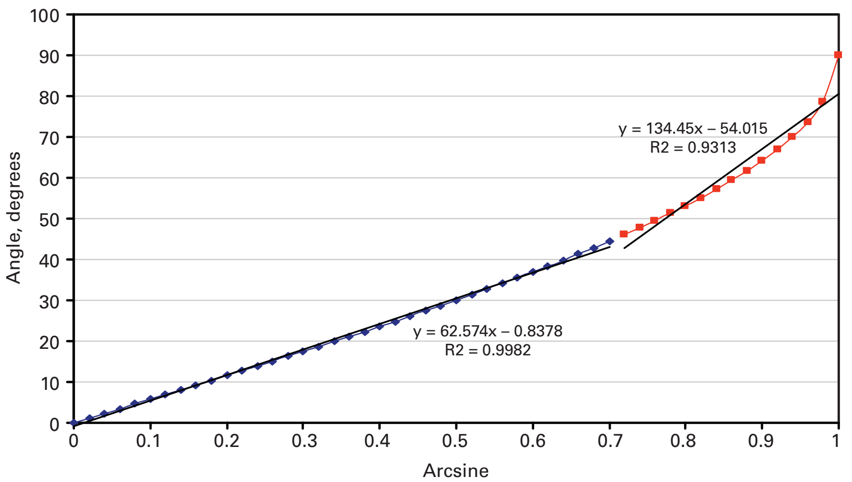
PIPELINE: 12.75-IN. OD, 0.25-IN. WT, 50 MMCFD

Fig. 4



ARCSINE PLOT

Fig. 5



Figs. 3 and 4 show plotting critical angle vs. temperature results in the appearance of a linear relationship with a slight parabolic trend for relatively high critical angles. For a given set of operating conditions with critical inclination angles less than 45°, the relationship is roughly linear and the rate of change in critical angle due to temperature fluctuations can be considered constant. For a given set of operating conditions, therefore, a 20° F. temperature fluctuation from 60° to 80° F. would result in the same change in critical angle as a fluctuation from 80° to 100° F. The arcsine function in the equation suggests this relationship.

The rate of angular change is minimal at low critical angles and becomes increasingly important approaching 90°.

Plotting the arcsine function (Fig. 5) yields a linear trend for angles up to about 45°. Angles greater than 45° have a less linear relationship and a more parabolic slope.

As the critical angle decreases, the rate of change in critical angle with respect to temperature also decreases (Figs. 3-4). Plotting the arcsine function from 0° to 30° (Fig. 6) shows that for critical angles less than 30° the slope increases by 3% between 10° and 20° and 7% from 20° to 30°.

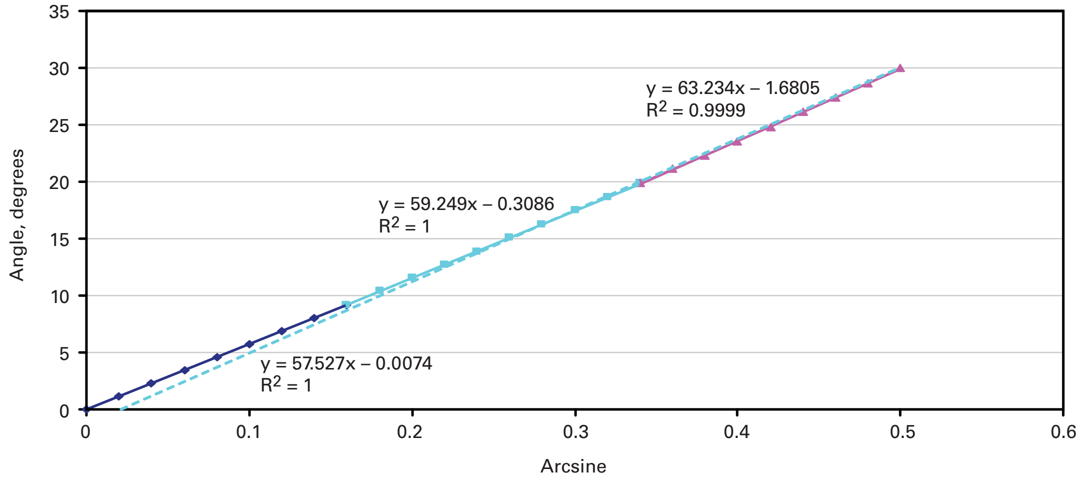
Plotting critical angle vs. temperature for a range of operating pressures shows that an increase in pressure results in a decrease in critical angle. Since flow rate data are calculated in million cubic feet per day, pressure is part of the conversion to determine actual gas flow and the resulting superficial gas velocity (at operating temperature and pressure). For a fixed superficial gas velocity, a change in pressure only affects the density of the gas, and therefore critical angle increases with pressure.

Similarly, plotting critical angle vs. temperature for a range of operating pressures shows that the change in angle with respect to temperature increases with a decrease in pressure. Fig. 3 shows at 300 psia a temperature change of 1° F. results in a 0.28° change in critical angle. At 800 psia, however, a temperature change of 1° F. results in a 0.05° change in critical angle.

The derivative of the modified GRI 02/0057 equation with respect to temperature not eliminating the effects of pressure suggests this trend.[2 3] The change in critical angle with respect to temperature depends on pressure.

Arcsine plot, 0°-30°

Fig. 6



Decreases in flow rate or increases in ID result in decreasing critical angles. Similar to changes in pressure, decreases in flow rate and increase ID also result in a decrease in the rate of critical angle change with respect to temperature.

Pressure, diameter, and flow rate are interdependent variables with nonlinear responses to temperature changes. An increase in pressure has the greatest effect on critical angles at low pressures. Fig. 4 shows that at 300 psia and 70° F., an increase of 50 psi results in a change in critical inclination angle of 2.7°. At 750 psia, however, the same shift results in a change in critical inclination angle of 0.4°. The percentage change in pressure partially explains this difference. The shift from 300 to 350 psia results in a 17% pressure change. But the shift from 750 to 800 psia results in a 6% change.

A dependent effect is associated with the relative inclination angle as a function of pressure. At lower pressures, the relative inclination angle is greater and the corresponding rate of change of critical angle greater than at higher pressures, for the reasons discussed.

Detailed examination

The detailed examination site selection process used a combination of regulatory required sites and additional sites predicted by flow modeling to have a potential for internal corrosion. The company's written DG-ICDA plan requires a minimum of four sites be selected for first-time assessment. When multiple laterals originating from a common trunkline are combined as a single DG-ICDA region, it recommends selecting detailed examination sites on each of the laterals. This method accounts for variability in gas velocity in each of the laterals and verifies the definition of the entire system as a single ICDA region.

Seven sites in the company's system were selected for detailed examination:

- The first inclination greater than critical in the first HCA in the DG-ICDA region.
- An inclination location greater than critical in an HCA in the second half of the DG-ICDA region.
- The first critical inclination angle in the DG-ICDA region.
- A drip receiver at the end of line in the first half of the DG-ICDA region.
- A 90° inclination inside the station at a gas purchase point.
- The first inclination in an HCA after a purchase point at the end of the first half of the DG-ICDA region.
- A critical inclination angle near the end of the DG-ICDA region.

Detailed examination at five of the seven selected sites revealed no internal corrosion. B-Scan inspection at Site 6 identified internal metal loss. Evaluation of an additional detailed examination site 50 ft upstream of the original dig location occurred based on potential indications discovered during the inspection screening process. This site identified a field bend with no internal corrosion on the upstream side of the bend and internal metal loss on the downstream side of the bend. B-Scan inspection of the drip at Site 4 also identified internal metal loss.

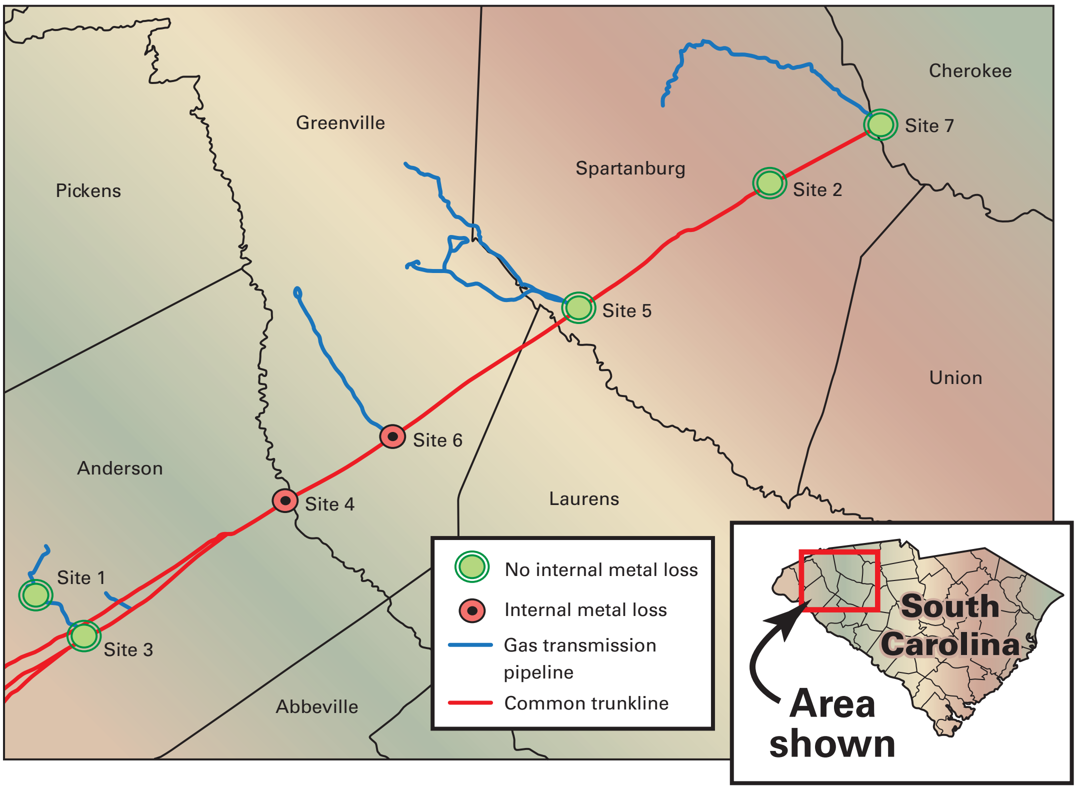
When metal loss is discovered at detailed examination sites, additional sites must be identified to assess the extent of the affected area and confirm the most severe damage has been found. The project team reviewed the seven sites where direct examination took place and decided, based on internal metal loss identified at Site 4 and Site 6, additional examination sites were necessary.

Site 4 lies at an aboveground pressure vessel with a drip leg at the end of the line. Inspection identified internal metal loss and liquids in the drip leg of the pressure vessel. Subject matter experts noted that about 5 years before inspection, the upstream gas supplier notified the company of a slug of liquids traveling through its line. Station maintenance personnel stated the drip leg had not been drained following this notification. Liquids and internal metal loss identified here are believed to result from a one-time liquid upset from the gas supplier.

Further verification used an additional examination site at a low spot immediately upstream of the pressure vessel. The depth of the line at the

DG-ICDA DIG LOCATIONS

Fig. 7



location and its proximity to a creek rendered this work unsuccessful. The company instead commissioned an in-line inspection of the line to determine if and to what extent additional metal loss was present.

Site 6 lies at a pipeline inclination angle greater than critical. This site has three parallel lines (4-in., 6-in., and 12-in.) in the pipeline right-of-way. Internal metal loss had occurred on the oldest of the three lines, a 4.5-in diameter line installed in 1952. Current flow conditions made it unlikely liquids would reach this location.

Subject matter experts verified that before installation of the 12-in. line (1970), flow was high enough to push liquids to the inspection location. As a result, internal metal loss identified at this location is likely historical and not active. Further verification used an additional examination site upstream of Site 6. This site lies immediately after the gas purchase point at the first pipeline inclination angle greater than the calculated critical angle determined by current system flow parameters. Detailed examination of all three parallel lines found no internal metal loss.

Acknowledgments

The authors thank Piedmont Natural Gas Co. for allowing us to publish this work and Robert Bratcher, Benji Vess, and Martin Boiter for their assistance. Additional thanks go to Steve Biagiotti and Cheryl Janicek for their efforts in making this project a success and to Oliver Moghissi and Jose Vera for insight regarding the modified GRI 02/0057 equation. ✦

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2. Moghissi, O., Norris, L., Dusek, P., and Cookingham, B., "Internal Corrosion Direct Assessment of Gas Transmission Pipelines," NACE International CORROSION/2002, Paper 02087, Denver, Apr. 7-11, 2002.

3. Moghissi, O., Vera, J., and Norris, L., "Improved Critical Angle Equation Broadening Direct Applicability of ICDA for Normally Dry Natural Gas Pipelines," NACE International CORROSION/2006, Paper 06183, San Diego, Mar. 12-16, 2006.

New release of steady state simulation software

A new release of this firm's steady state simulation software—ProSimPlus—is now available.

The software is used in design and operation of existing plants for process optimization, units troubleshooting or debottlenecking, plants revamping, or for performing front-end engineering analysis. It provides a thermodynamic module and a comprehensive unit operations library that allow the modeling of a variety of processes. It's suited for chemical, petrochemical, refining, and gas treatment operations.

Improvements to this new release focus on its thermodynamic package, comprehensive set of unit operation models, and convergence methods. Additionally, a new an easy to use and learn graphical interface helps ensure quick learning and optimize access to simulation results.

Simulis Thermodynamics, the firm's thermodynamic server, is fully embedded in ProSimPlus. Beside flexibility in the definition of thermodynamic profiles used in the process, this module offers a full set of functions for the detailed analysis of the thermophysical phenomena that can occur in a process. In particular, transport or thermodynamic properties and phase equilibria on streams can be calculated in only a few clicks. The thermodynamic model library was enriched with equations of state PR78 and PR78BM and with several calculation services in particular for Reid vapor pressure, equilibrium constants, and surface tension or residue curves plotting.

Several unit operation modules such as the pipe segment or the heat exchanger were enhanced with additional configuration options or new calculation methods. In particular, a new interface was built for the optimization module allowing the user to configure the calculation parameters more easily.

Source: **ProSim,** Stratege Batiment A, BP 27210, F-31672, Labege Cedex, France.

New mass flow controller

The B-Series mass flow controller is a new family of mass flow products designed to be insensitive to fluctuations in pressure and temperature.

Built on a standard 1.125-in. wide platform with a powerful user interface and local digital display, the B-Series provides a compact flow measurement and control solution that the company says eliminates the need for costly temperature and pressure control devices and systems.

The B-Series is designed to minimize all sources of gas flow inaccuracy. It promises accuracy, fast response, stability, and resistance to flow variation due to pressure and temperature fluctuations.

The B-Series is a pressure and temperature-insensitive device. The mass flow controller actively measures line pressure and adjusts the control valve to virtually eliminate actual flow and flow signal changes as a result of pressure fluctuations.

Source: **Brooks Instrument LLC,** 407 W. Vine St., Hatfield, PA 19440.

Schlumberger,

Paris, has announced a series of key management changes targeting technology integration and enhanced service delivery. With these changes, the Schlumberger Product Group technology portfolio will be further streamlined while backed by a closely linked Research, Engineering, Manufacturing, and Sustaining organization. In addition to this change in technology development and deployment, closer integration will also improve efficiency across Area and GeoMarket field operations. Reporting to Chakib Sbiti, executive vice-president, will be Product Group presidents Paal Kibsgaard, Reservoir Characterization; Doug Pferdehirt, Reservoir Production; and Jeff Spath, Reservoir Management. Also reporting to Sbiti are Charles Woodburn, vice president, Engineering, Manufacturing, and Sustaining; and Satish Pai, vice-president, Operations. Reporting to Pai are area presidents Mark Corrigan, Europe, Africa, and CIS, with headquarters in Paris; Bill Coates, North America, and located in Houston; Cesar Jaime, Latin America, and based in Rio de Janeiro; and Aaron Gatt, Florida, Middle East, and Asia and headquartered in Dubai. In addition, Miguel Galuccio, president of Schlumberger Integrated Project Management, reports to Pai.

Schlumberger is the world's leading supplier of technology, integrated project management, and information solutions to the global oil and gas industry.

O'Brien's Response Management Inc.,

Houston, has named Tim O'Leary vice-president of communications to lead its news media and public relations services, a newly created component to its emergency response and crisis management business. O'Leary previously worked at Shell Oil Co. for nearly 8 years, where he provided communications services to a variety of Shell business units and served as a company spokesperson. He was also the crisis management focal point for Shell in North America. O'Leary is a retired US Navy commander and qualified as a US Navy surface warfare officer. He served on a variety of ships and shore stations and was also designated with a subspecialty in public affairs, a field in which he worked most during his 20-year Navy career.

O'Leary

O'Brien's is a global provider of environmental compliance, emergency preparedness, response management, disaster services, and crisis management for numerous industry sectors and government agencies.

Subsea 7 Inc.,

George Town, Cayman Islands, has acquired through its subsidiary Subsea 7 Ltd. the exclusive global license rights for a new subsea hot tap technology known as Subsea Grouted Tee (SSGT). SSGT enables intervention activities to be carried out on high- and low-pressure subsea pipelines, without the need for major hyperbaric welding operations. The Grouted Tee technology was first developed by Advantica, now GL Industrial Services UK Ltd., in the 1990s and used on cross-country, high-pressure onshore pipelines and distribution networks worldwide. In 2006, Subsea 7 embarked with GL on an industry-sponsored joint industry project to convert the technology for subsea applications.

Subsea 7 is one of the world's leading subsea engineering and construction companies, offering all the expertise and assets that make SURF (subsea umbilical, riser, and flowline) field development possible.

ITS Group,

Aberdeen, formed ITS Arabia Ltd. following a joint venture agreement with Saudi Arabian services company Shoaibi Group. The JV will be based in Al Khobar, Saudi Arabia, and provide a wide range of drilling equipment and associated services to regional oil and gas companies. Plans are under way to establish a machine shop facility for manufacturing , repair, and inspection activity, which will support further investment in equipment and personnel during the next 18-24 months. The JV offers drill pipe, drill collars, stabilizers, drilling jars, casing running equipment, fishing tools, and pressure control equipment for sale or rent. In addition, ITS Arabia offers fishing, tubular running, and other machine shop services.

ITS, active in Saudi Arabia for 3 years, offers drilling and pressure control equipment, casing running and fishing services, and machine shop manufacturing, inspection, and refurbishment services.

Shoaibi Group provides oil and gas services through strategic partnerships and is also involved in the power, IT, and telecommunications sectors in the Middle East and North Africa.

Mustang Engineering,

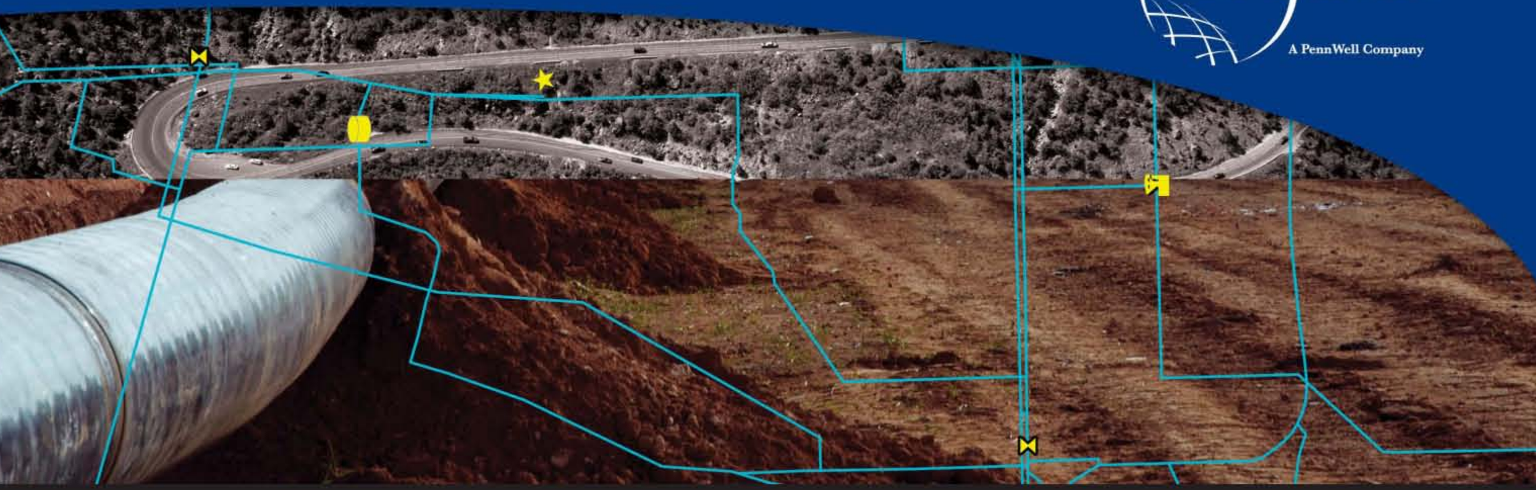
Houston, has appointed A.J. Cortez and John W. Dalton Sr. to the newly created positions of executive vice-presidents. Cortez has worldwide oversight of four of Mustang's six business units: Upstream, Pipeline, Process Plants, and Automation & Control. Cortez has 34 years experience in the design, project, and construction management of oil and gas projects. He is a graduate of Texas A&M University and a member of the National Society of Professional Engineers.

Cortez

Dalton has oversight for global engineering, project services, construction operations, and the Midstream and Process & Industrial Business Units. A graduate of the University of Houston, he has more than 37 years of industry experience and serves as 2009 chairman of the executive committee for the Construction Industry Institute.

Dalton

Mustang, a unit of Wood Group, provides design, engineering, procurement, project management, and construction management services to the upstream oil and gas, midstream, and refining and petrochemicals industries.



Statistics

IMPORTS OF CRUDE AND PRODUCTS

	— Districts 1–4 —		— District 5 —		Total US		
	5-1 2009	4-24 2009	5-1 2009	4-24 2009	5-1 2009	4-24 2009	*5-2 2008
	1,000 b/d						
Total motor gasoline	769	841	54	0	823	841	1,494
Mo. gas. blending comp.	583	680	34	0	617	680	1,098
Distillate	165	123	0	0	165	123	187
Residual	336	327	60	59	396	386	317
Jet fuel–kerosine	79	41	44	15	123	56	131
Propane–propylene	138	168	2	8	140	176	127
Other	277	318	(15)	40	262	358	42
Total products	**2,347**	**2,498**	**179**	**122**	**2,526**	**2,620**	**3,396**
Total crude	**8,157**	**8,836**	**1,763**	**988**	**9,920**	**9,824**	**10,628**
Total imports	**10,504**	**11,334**	**1,942**	**1,110**	**12,446**	**12,444**	**14,024**

*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.

OIL&GAS JOURNAL online research center.

OGJ CRACK SPREAD

	*5-8-09	*5-9-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	64.67	133.50	–68.83	–51.6
Brent crude	54.94	120.92	–65.99	–54.6
Crack spread	9.74	12.59	–2.85	–22.6
FUTURES MARKET PRICES				
One month				
Product value	65.76	136.67	–70.91	–51.9
Light sweet crude	56.00	123.00	–67.00	–54.5
Crack spread	9.76	13.68	–3.91	–28.6
Six month				
Product value	66.04	132.48	–66.45	–50.2
Light sweet crude	61.40	120.91	–59.51	–49.2
Crack spread	4.64	11.58	–6.94	–59.9

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

PURVIN & GERTZ LNG NETBACKS—MAY 8, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	8.14	5.38	6.56	5.28	5.91	6.49
Everett	3.21	1.38	2.90	1.49	1.85	3.46
Isle of Grain	2.89	1.08	2.37	0.99	1.54	2.39
Lake Charles	1.67	–0.01	1.48	0.16	0.36	2.19
Sodegaura	3.57	5.90	3.83	5.29	4.65	3.03
Zeebrugge	4.57	2.57	3.85	2.49	3.01	3.90

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 Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	15,203	57,149	39,643	10,650	55,154	14,790	2,993
PADD 2	85,294	50,096	20,770	7,531	35,012	1,320	15,853
PADD 3	196,835	71,848	41,314	12,930	40,736	15,092	25,042
PADD 4	17,136	5,509	2,044	566	3,258	239	[1]870
PADD 5	60,790	27,843	22,424	8,991	12,373	4,486	—
May 1, 2009	**375,258**	**212,445**	**126,195**	**40,668**	**146,533**	**35,927**	**44,758**
Apr. 24, 2009	**374,653**	**212,612**	**126,734**	**40,188**	**144,105**	**36,282**	**43,119**
May 2, 2008[2]	**325,583**	**211,883**	**106,476**	**38,792**	**105,724**	**38,597**	**29,848**

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

REFINERY REPORT—MAY 1, 2009

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,203	1,213	2,488	82	374	79	52
PADD 2	3,187	3,160	2,044	232	896	59	235
PADD 3	7,626	7,467	2,773	740	2,294	141	613
PADD 4	525	518	258	25	167	11	[1]73
PADD 5	2,536	2,396	1,355	353	476	131	—
May 1, 2009	**15,077**	**14,754**	**8,918**	**1,432**	**4,207**	**421**	**973**
Apr. 24, 2009	**14,612**	**14,334**	**8,790**	**1,442**	**4,153**	**476**	**1,005**
May 2, 2008[2]	**14,948**	**14,649**	**8,677**	**1,400**	**4,239**	**715**	**1,115**
	17,672 Operable capacity		**85.3% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 5-6-09	Pump price* 5-6-09	Pump price 5-7-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	160.2	206.7	372.9
Baltimore	160.8	202.7	359.4
Boston	158.8	200.7	354.4
Buffalo	146.8	207.7	376.8
Miami	152.1	203.7	381.9
Newark	181.3	213.9	346.7
New York	131.8	192.7	363.1
Norfolk	156.4	194.8	345.5
Philadelphia	158.1	208.8	363.9
Pittsburgh	161.2	211.9	362.7
Wash., DC	179.4	217.8	371.2
PAD I avg	158.8	205.6	363.5
Chicago	159.8	224.2	397.3
Cleveland	161.8	208.2	353.5
Des Moines	163.8	204.2	349.7
Detroit	150.8	210.2	363.3
Indianapolis	143.8	203.2	359.6
Kansas City	162.2	198.2	341.9
Louisville	163.3	204.2	370.5
Memphis	163.1	202.9	347.8
Milwaukee	156.9	208.2	375.9
Minn.-St. Paul	163.2	207.2	355.0
Oklahoma City	157.2	192.6	344.6
Omaha	158.6	203.9	352.6
St. Louis	158.2	194.2	359.0
Tulsa	157.8	193.2	339.7
Wichita	155.8	199.2	344.5
PAD II avg	158.4	203.6	357.0
Albuquerque	161.5	197.9	348.7
Birmingham	156.6	195.9	353.8
Dallas-Fort Worth	154.5	192.9	355.5
Houston	154.5	192.9	350.8
Little Rock	155.7	195.9	352.7
New Orleans	153.5	191.9	349.8
San Antonio	152.5	190.9	346.3
PAD III avg	155.5	194.0	351.1
Cheyenne	171.4	203.8	335.3
Denver	166.5	206.9	365.3
Salt Lake City	159.0	201.9	347.2
PAD IV avg	165.6	204.2	349.3
Los Angeles	148.1	215.2	390.4
Phoenix	166.8	204.2	340.1
Portland	181.8	225.2	367.3
San Diego	167.1	234.2	399.0
San Francisco	172.1	239.2	405.8
Seattle	169.3	225.2	376.3
PAD V avg	167.5	223.9	379.8
Week's avg.	**159.9**	**205.5**	**360.4**
Apr. avg.	**156.7**	**202.3**	**339.3**
Mar. avg.	**147.6**	**193.2**	**319.7**
2009 to date	**146.4**	**192.0**	—
2008 to date	**276.1**	**319.7**	—

*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

Spot market product prices

	5-1-09 ¢/gal		5-1-09 ¢/gal
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	143.50	New York Harbor	134.50
Gulf Coast	142.75	Gulf Coast	132.00
Los Angeles	160.50	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	138.81	ARA	138.81
Singapore	NA	Singapore	NA
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	152.13	New York Harbor	109.83
Gulf Coast	149.00	Gulf Coast	117.33
Los Angeles	166.50	Los Angeles	124.38
		ARA	102.36
		Singapore	107.93

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

BAKER HUGHES RIG COUNT

	5-8-09	5-9-08
Alabama	4	6
Alaska	5	5
Arkansas	48	45
California	21	40
Land	20	38
Offshore	1	2
Colorado	43	121
Florida	0	0
Illinois	1	1
Indiana	0	2
Kansas	16	11
Kentucky	10	10
Louisiana	138	150
N. Land	75	51
S. Inland waters	7	22
S. Land	10	21
Offshore	46	56
Maryland	0	0
Michigan	0	1
Mississippi	10	12
Montana	1	10
Nebraska	1	0
New Mexico	34	76
New York	1	8
North Dakota	36	61
Ohio	7	12
Oklahoma	84	210
Pennsylvania	28	19
South Dakota	1	3
Texas	355	889
Offshore	4	10
Inland waters	0	1
Dist. 1	13	30
Dist. 2	11	33
Dist. 3	25	59
Dist. 4	43	93
Dist. 5	87	179
Dist. 6	55	120
Dist. 7B	11	34
Dist. 7C	8	69
Dist. 8	39	125
Dist. 8A	11	23
Dist. 9	23	38
Dist. 10	25	75
Utah	14	40
West Virginia	23	26
Wyoming	35	71
Others—NV-4; TN-3; VA-4; WA-1	12	17
Total US	**928**	**1,846**
Total Canada	**63**	**122**
Grand total	**991**	**1,968**
US Oil rigs	190	361
US Gas rigs	730	1,475
Total US offshore	53	69
Total US cum. avg. YTD	**1,227**	**1,790**

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	5-8-09 Rig count	5-8-09 Percent footage*	5-9-08 Rig count	5-9-08 Percent footage*
0-2,500	42	7.1	83	6.0
2,501-5,000	61	65.5	118	55.0
5,001-7,500	117	12.8	213	14.5
7,501-10,000	197	5.0	418	4.3
10,001-12,500	179	4.4	463	2.5
12,501-15,000	165	—	282	—
15,001-17,500	110	—	117	—
17,501-20,000	48	—	76	—
20,001-over	37	—	37	—
Total	**956**	**7.9**	**1,807**	**7.2**
INLAND	10		28	
LAND	901		1,722	
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]5-8-09	[2]5-9-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	695	695
California	653	653
Colorado	64	65
Florida	5	5
Illinois	28	26
Kansas	103	105
Louisiana	1,435	1,300
Michigan	15	16
Mississippi	61	58
Montana	91	87
New Mexico	163	160
North Dakota	196	153
Oklahoma	175	170
Texas	1,347	1,338
Utah	57	57
Wyoming	150	147
All others	67	76
Total	**5,325**	**5,132**

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

US CRUDE PRICES

	5-8-09 $/bbl*
Alaska-North Slope 27°	42.37
South Louisiana Sweet	58.00
California-Kern River 13°	51.30
Lost Hills 30°	60.05
Wyoming Sweet	47.13
East Texas Sweet	54.50
West Texas Sour 34°	49.00
West Texas Intermediate	55.00
Oklahoma Sweet	55.00
Texas Upper Gulf Coast	48.00
Michigan Sour	47.00
Kansas Common	54.25
North Dakota Sweet	45.75

*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]	5-1-09
United Kingdom-Brent 38°	49.78
Russia-Urals 32°	48.57
Saudi Light 34°	47.91
Dubai Fateh 32°	49.06
Algeria Saharan 44°	49.96
Nigeria-Bonny Light 37°	51.24
Indonesia-Minas 34°	53.13
Venezuela-Tia Juana Light 31°	50.61
Mexico-Isthmus 33°	50.50
OPEC basket	49.76
Total OPEC[2]	48.97
Total non-OPEC[2]	48.84
Total world[2]	48.91
US imports[3]	47.82

[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]

	5-1-09	4-24-09	4-24-08	Change, %
	bcf			
Producing region	831	805	546	**52.2**
Consuming region east	768	710	685	**12.1**
Consuming region west	319	308	196	**62.8**
Total US	**1,918**	**1,823**	**1,427**	**34.4**
	Feb. 09	**Feb. 08**	**Change, %**	
Total US[2]	**1,761**	**1,465**	**20.2**	

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

INTERNATIONAL RIG COUNT

Region	Apr. 09 Land	Apr. 09 Off.	Apr. 09 Total	Apr. 08 Total
WESTERN HEMISPHERE				
Argentina	46	1	47	88
Bolivia	4	—	4	2
Brazil	32	30	62	46
Canada	74	1	74	106
Chile	1	—	1	1
Colombia	27	—	27	40
Ecuador	10	—	10	7
Mexico	99	28	127	102
Peru	5	—	5	7
Trinidad	—	—	—	5
United States	947	48	995	1,829
Venezuela	53	12	65	82
Other	1	—	1	—
Subtotal	**1,299**	**119**	**1,418**	**2,314**
ASIA-PACIFIC				
Australia	9	10	19	30
Brunei	1	3	4	2
China-offshore	—	23	23	19
India	49	22	71	81
Indonesia	54	16	70	65
Japan	3	—	3	5
Malaysia	—	11	11	9
Myanmar	3	1	4	7
New Zealand	3	1	4	5
Papua New Guinea	3	—	3	4
Philippines	3	—	3	2
Taiwan	—	—	—	—
Thailand	4	9	13	10
Vietnam	—	8	8	8
Other	—	—	—	2
Subtotal	**132**	**104**	**236**	**249**
AFRICA				
Algeria	32	—	32	30
Angola	—	2	2	7
Congo	1	1	2	2
Gabon	—	1	1	2
Kenya	—	—	—	—
Libya	10	1	11	15
Nigeria	2	4	6	9
South Africa	—	—	—	1
Tunisia	3	2	5	3
Other	2	1	3	4
Subtotal	**50**	**12**	**62**	**73**
MIDDLE EAST				
Abu Dhabi	8	3	11	12
Dubai	—	1	1	—
Egypt	41	7	48	55
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	1	—	1	—
Kuwait	11	—	11	13
Oman	51	—	51	55
Pakistan	20	—	20	19
Qatar	1	7	8	12
Saudi Arabia	55	12	67	78
Sudan	—	—	—	—
Syria	24	—	24	21
Yemen	10	—	10	13
Other	1	—	1	1
Subtotal	**223**	**30**	**253**	**279**
EUROPE				
Croatia	—	—	—	—
Denmark	—	4	4	3
France	—	1	1	1
Germany	7	1	8	10
Hungary	2	1	3	3
Italy	3	—	3	4
Netherlands	—	3	3	3
Norway	—	22	22	19
Poland	2	—	2	1
Romania	7	1	8	20
Turkey	2	3	5	5
UK	1	18	19	18
Other	6	2	8	6
Subtotal	**30**	**56**	**86**	**93**
Total	**1,734**	**321**	**2,055**	**3,008**

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	—	—
Caribbean	Houston	Resid.	380	61	0.79
Caribbean	Houston	Resid.	500	55	0.71
N. Europe	New York	Dist.	200	119	2.19
N. Europe	Houston	Crude	400	73	1.96
W. Africa	Houston	Crude	910	55	1.70
Persian Gulf	Houston	Crude	1,900	22	1.28
W. Africa	N. Europe	Crude	910	55	1.25
Persian Gulf	N. Europe	Crude	1,900	22	0.89
Persian Gulf	Japan	Crude	1,750	30	1.00

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

WATERBORNE ENERGY INC. US LNG IMPORTS

Country	Mar. 2009	Feb. 2009	Mar. 2008	Change from a year ago, %
	MMcf			
Algeria	—	—	—	—
Egypt	11,670	5,840	0	—
Equatorial Guinea	—	—	—	—
Nigeria	—	—	—	—
Norway	2,890	5,990	2,940	–1.7
Qatar	—	—	—	—
Trinidad and Tobago	22,240	15,990	18,010	23.5
Total	**36,800**	**27,820**	**20,950**	**75.7**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.

PROPANE PRICES

	Mar. 2009	Apr. 2009	Mar. 2008	Apr. 2008
	¢/gal			
Mont Belvieu	65.34	63.82	147.47	159.03
Conway	65.59	64.45	146.63	157.08
Northwest Europe	67.16	60.20	165.01	168.13

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					
Apr. 2009						
Product revenues	61.80	56.76	59.69	61.60	57.55	55.54
Feedstock costs	–55.27	–52.69	–51.25	–47.73	–51.29	–53.03
Gross margin	6.53	4.07	8.44	13.87	6.26	2.51
Fixed costs	–2.13	–2.46	–2.39	–2.79	–2.39	–1.86
Variable costs	–1.34	–1.04	–1.23	–2.17	–2.14	–0.76
Cash operating margin	**3.06**	**0.57**	**4.82**	**8.91**	**1.73**	**–0.11**
Mar. 2009	2.14	–1.12	2.12	5.55	1.76	–0.73
YTD avg.	4.01	1.11	5.16	13.51	3.70	1.45
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

Mar. 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	204.98	186.63	218.59	203.92
Taxes	50.30	38.40	53.58	47.09
Wholesale price	145.44	143.34	152.09	147.50
Spot price	133.96	133.31	148.10	129.60
Retail margin	9.25	4.89	12.92	9.33
Wholesale margin	11.48	10.03	3.99	17.90
Gross marketing margin	**20.73**	**14.92**	**16.91**	**27.23**
Feb. 2009	20.32	28.63	9.88	32.05
YTD avg.	21.09	18.00	9.29	28.17
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		
Apr. 2009			
Product revenues	39.18	58.99	70.21
Feedstock costs	–15.20	–36.52	–68.43
Gross margin	23.98	22.47	1.78
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–3.15	–3.65	–4.78
Cash operating margin	**15.45**	**12.46**	**–10.19**
Mar. 2009	16.23	12.33	–8.88
YTD avg.	15.03	10.54	–7.88
2008 avg.	21.00	22.89	–5.91
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

Apr. 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	3.38	2.55
Liquids	0.70	1.78
Gas purchase cost	3.76	3.43
Operating costs	0.07	0.15
Cash operating margin	**0.26**	**0.75**
Mar. 2009	0.18	0.77
YTD avg.	0.16	0.71
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	59%	55%

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

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Chief executives boost UN program on corruption

An important United Nations fight against corruption received a boost this month from the chief executives of 24 international companies.

The executives signed a letter to UN Sec. Gen. Ban Ki-moon supporting the UN Convention against Corruption (UNCAC) and calling for action on a crucial but slow-moving program element.

Launched in December 2003, UNCAC addresses prevention, criminalization, international cooperation, and asset recovery. So far, 140 countries have signed the convention, and 136 have ratified it.

The Editor's Perspective

by Bob Tippee, Editor

The laggard UNCAC element is implementation review, which the first Conference of States Parties (COSP), held in 2006, described as "of paramount importance."

According to the anticorruption group Transparency International (TI), a UN working group has been trying to define the review mechanism and will meet again on May 11-13 and Aug. 31-Sept. 2. The issue will be a priority agenda item at the third COSP, in Doha the week of Nov. 9.

"Because of the complexity of a decision-making process involving 140 governments," TI says, "unless controversial issues can be resolved well in advance, the prospects for Doha are poor."

Implementation became divisive at the second COSP, held in Bali in January 2008. Warning against the onset of "a holding pattern," a TI press release after that meeting said contentious issues included "the form a country progress review program should take" and "terms of the transparency of the process and the participation of civil society."

Companies probably see trouble in an agreement with potential to compromise their international contracts in any way. At the same time, they must recognize how corruption impedes economic development and weakens the social foundations of expatriate business.

Signatory companies in the letter calling for action on an implementation review mechanism are Anglo American PLC, AngloGold Ashanti Co., BASF AG, Bhoruka Power Corp. Ltd., EADS, Fluor Corp., Fuji Xerox Co. Ltd., GDF Suez, General Electric Co., IKEA Group, Infosys Technologies Ltd., Kanoria Chemicals & Industries Ltd., Li & Fung Group, Newmont Mining Corp., Novartis International AG, Petronas, Royal Dutch Shell PLC, SAP AG, Sinosteel Corp., Solvay, TAQA, Tata Sons, TNT NV, and Zurich Financial Group.

(Online May 8, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

A May rally in energy prices

Energy prices rallied in early May with natural gas climbing above $4/MMbtu and crude at one point topping $58/bbl—a new high for the year—as traders shrugged off bearish inventory reports and focused instead on indications of a possible economic turnaround.

In Houston on May 8, analysts at Raymond James & Associates Inc. said, "Money has been flowing heavy into commodities this week, and it has helped prop up oil prices as big funds are betting that the worst of the recession is over." They noted natural gas prices had rallied more than 30% in less than 2 weeks "despite a string of bearish data points." But they said it looked more like a "short squeeze" rather than a real market bottom.

At KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, analysts said, "Oil fundamentals do not support such a move [to $56-58/bbl] with the year-on-year excess in US oil inventories…together with oil in floating storage amounting to 225 million bbl." In the week ended May 1, US refiners ran more crude and feedstock than in any week since Dec. 5, 2008. "However, total petroleum demand on a 4-week basis was still the lowest since May 1999," said analysts at Pritchard Capital Partners LLC, New Orleans.

Unemployment numbers

Meanwhile, Automatic Data Processing Inc. reported US nonfarm private employment decreased by 491,000 in April on a seasonally adjusted basis, compared with a revised drop of 708,000 in March. The US Department of Labor reported 601,000 new applications for jobless benefits in the week ended May 1, the smallest increase in 14 weeks and a possible indication that layoffs have peaked. Nonetheless, the total number of people receiving unemployment benefits climbed to 6.35 million. In a separate report, the government said US productivity grew at an annual rate of 0.8%—better than economists expected—in this year's first quarter.

Pritchard Capital Partners said, "Recent economic data releases continue to show an increase in economic activity and at some point…we should see an increase in demand for both crude and gasoline."

However, Raymond James analysts said, "We continue to think the fundamentals look pretty poor in the domestic market and that many of the stocks could be getting ahead of themselves."

Olivier Jakob at Petromatrix, Zug, Switzerland, said, "On the fundamental side, a crude oil price of $50-60/bbl should make about zero difference on the demand side of the equation. Retailers have not been passing the entirety of the price drop to the consumer, and Western governments have not been pushing them to do so in order to preserve some of the energy efficiency gains. Hence there is some room for a price increase in futures before the consumer gets hit on the retail side."

Jakob said, "On the supply side a price of $60/bbl rather than $50/bbl could provide some lower compliance [among members of the Organization of Petroleum Exporting Countries], but the main cheaters are already leaking at $50/bbl so the net difference will be hard to immediately measure." He said, "In the end, what will make the sustainability of $60/bbl or of $50/bbl will be the size and the sustainability of the crude oil contango."

Natural gas rebound?

Meanwhile, Pritchard Capital Partners said conference calls by exploration and production companies indicated industry executives expect natural gas will rebound late this year or early in 2010. They reported, "Mark Papa, CEO of EOG Resources Inc., said he sees US natural gas production down 4.5 bcfd [of gas equivalent] by the end of 2009." That, the analysts noted, is in contrast to PIRA [Petroleum Industry Research Associates] Energy Group's estimated decline of 3 bcfed. "If Papa's comments are correct, the bottom for natural gas may be near," said analysts.

They said Bob R. Simpson, founder and chief executive of XTO Energy Inc. in Fort Worth, indicated he expects the price of natural gas to double by next May.

In other news, Raymond James analysts reported China approved a plan to set up 10 million tons of refined fuel state reserves by 2011 as part of its economic stimulus plan. At China's current consumption, it would provide 2 weeks of gasoline, diesel, and kerosine combined. Jakob said, "Early indications are that China in April printed another record in car sales (according to our tracking that would amount to about 25% growth in April sales for all automobiles and 37% for passenger cars) and continues the recent trend of selling more cars than the US."

(Online May 11, 2009; author's e-mail: samf@ogjonline.com)