Deepwater: Horizontal Openhole Gravel-Pack Completions

First Successful Horizontal Openhole Gravel Pack in Deepwater Stybarrow Field

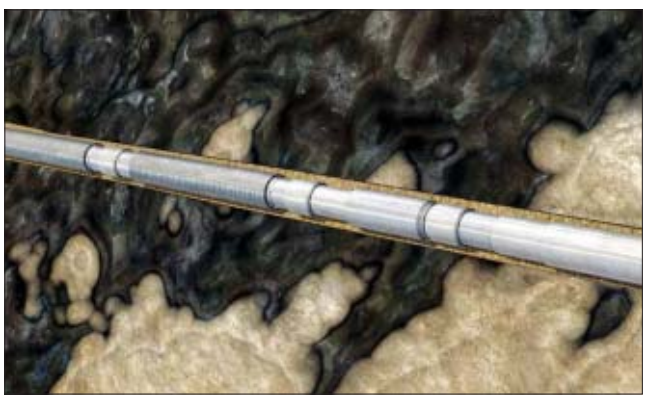
The Stybarrow Field consists of slope turbidite sandstones of the Macedon Formation in the Exmouth Sub-Basin offshore Western Australia. It is one of two fields in Australia's deepest water development, in more than 800 m of water, and was developed entirely by subsea wells connected to an FPSO.

Lateral Reservoir Quality, Sand/Shale Heterogeneities

Lateral reservoir quality variations, difficult sand/shale heterogeneities, and limited in-country technical experience and infrastructure were only some of the obstacles to completing four, near-horizontal production wells in this field. Others included gravel packing across much longer non-reservoir sections, gravel packing out of a milled casing window, narrow pressure margin between circulating pressures and formation fracture pressure, large wellbore washouts, and gravel packing at wellbore inclinations of up to 94°.

Gravel-Pack Design With Ceramic Proppant

To solve these problems, Baker Hughes helped develop an optimized reservoir drilling fluid and gravel carrier fluid design. We also created a gravel pack pumping design that used a 16/20 US Mesh ceramic proppant. This combined with our EXCLUDER2000™ medium-weave premium screen to produce the optimal sandface completion. Baker Hughes engineers sized the screens to retain formation sand. This would ensure sand retention in case of incomplete gravel packs. Slurry and conformance tests with various screen types and a range of sand facies, along with various proppant sizes and types, concluded that inclusion of proppant drastically reduced pressure buildup across the screens as well as the mass of sand particles produced through the screens. The



EXCLUDER2000™ screens like those used in the Stybarrow wells have compiled an outstanding performance record in the world's most extreme conditions.

Baker Oil Tools gravel-pack design also contained contingencies specific to this design in case of poor installation outcomes. Another success factor in the project was continuity of key Baker Hughes personnel and essential equipment from concept through execution.

Near-Record Australian Production Rates

Gravel-pack efficiency factors between 108% and 118% were achieved despite several unforeseen geological and technical challenges. All four Stybarrow production wells achieved maximum sand-free rates per FPSO design capacity. Maximum production rates from all four wells have exceeded 80,000 BOPD, with one well producing at near-record Australian rates of 32,000 BOPD seven months after first oil.

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Enhanced Oil Recovery Survey — Covers active, planned and terminated projects worldwide. Updated biennially in March.
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Worldwide Gas Processing Survey — Gas processing plants worldwide with details.
E1209 Current E1219C Historical, 1985 to current

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

LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO

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

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

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

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
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Oil Sands Projects — Planned Canadian projects in four Excel worksheets. Includes mining, upgrading, in situ projects, and historical table with wells drilled back to 1985.
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Production Projects Worldwide — List of planned production mega-projects.
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Completion Methods

Proposition: global effort to model largest oil fields
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In-line cyclonic remedies compressor liquid ingestion
Integrity management must include failure plans

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OIL&GAS JOURNAL®

June 8, 2009
Volume 107.22

COMPLETION METHODS

REGULAR FEATURES

COVER

The two pipe skids are next to a field compression station and are part of the gas-gathering system in the Williams Exploration & Production-operated part of the Piceance basin in Colorado. An article in the special report on completion methods, p. 41, describes the approach Williams uses for completing and producing the more than 3,000 wells that it operates in the area. A second article, p. 46, discusses a way for determining gas-lift valve behavior in wells completed with this type of artificial-lift technology. Photos by Guntis Moritis.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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June 8, 2009

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General Interest — Quick Takes

IEA: Global upstream budgets already down 21%

Global upstream oil and gas budgets for 2009 have already been cut 21% compared with 2008, according to a report by Paris-based International Energy Agency.

This is almost $100 billion, said IEA in a report on the impact of the financial crisis on energy investments worldwide, prepared for the G8 Energy Ministers Meeting in Rome May 24-25.

The investment drop will continue into 2009, especially in the Organization for Economic Cooperation and Development region, and will impact both supply and demand, IEA reported.

From October through April, more than 20 planned large upstream oil and gas projects were either postponed indefinitely or scrapped. The projects were valued at more than $170 billion and involved 2 million b/d of oil capacity and 1 bcfd of gas capacity. A further 35 projects amounting to 4.2 million b/d oil capacity and 2.3 bcfd gas capacity were delayed by at least 18 months.

Oil projects in Canada account for the bulk of the postponed oil capacity. Investments in non-OPEC countries are expected to drop the most as upstream spending has fallen mainly in high-development-cost regions and in areas where small players and projects dominate investments. Supermajors, on the other hand, plan to cut spending by only 5%.

The report said spending cuts on existing fields could accelerate decline rates. It said exploration spending will be reduced sharply in 2009 as investments are diverted to complete development projects launched before prices slumped.

Iraq wants 'coordination' with Kurdish oil deals

The Iraqi oil ministry, while acknowledging the right of semi-autonomous Kurdistan to sign agreements with international oil companies, said it is concerned about the lack of coordination regarding them.

"The Iraqi oil ministry's objection is to the signing of these contracts without any coordination with it or with the federal government," said Asim Jihad, a ministry spokesman.

"We do not know how many contracts exist, their details, or how much of Iraq's oil is being given to the foreign companies, not to mention privileges," Asim told Dubai's Al-Arabiya television, adding that the Iraqi federal government and the oil ministry have "the right to learn of these details."

Asim said the Iraqi constitution stipulates that the Kurdistan Regional Government (KRG) coordinate with the federal government on all oil-related matters but that "unfortunately, this has not been the case."

Asim acknowledged that Article 112 of the Iraqi constitution does grant the KRG the right to sign oil contracts, but he said the document also stipulates that such matters should be coordinated with the oil ministry of the federal government.

This month, Kurdistan began exporting crude oil for the first time, sending 100,000 bbl from the Taq Taq and Tawke oil fields via the Iraq-Turkey pipeline to the Turkish port of Ceyhan (OGJ Online, June 1, 2009).

GWPC: US state regulations protect water

Current US state oil and gas regulations adequately protect water resources, the Ground Water Protection Council said in a new report on May 28.

The assertion by one of the nation's leading groundwater protection organizations came as congressional discussions intensified on giving the US Environmental Protection Agency authority to regulate hydraulic fracturing, an essential part of producing natural gas from shale formations.

The study focused on eight regulatory aspects: permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. The resulting report was not intended as an evaluation of state programs, but rather, an evaluation of state programs, the GWPC said.

Each state covered in the study was invited to review the report's findings and provide any updated information, it added. Thirteen states provided responses, which were incorporated in the report, the council said.

GWPC also produced a regulations reference document containing excerpts from each state's oil and gas regulations related to the programmatic areas evaluated in the study, it said.

Oil from Canada's oil sands is also blended, without segregation, with other feedstocks at many US refineries, making it impossible to determine the content of fuels that are purchased, it added. The report and addendums are available online at www.gwpc.org.

Oil and gas organizations responded favorably. "The study confirms what the industry has been saying: Regulation of oil and gas field activities, including hydraulic fracturing, is best accomplished at the state level where regional and local conditions are best understood, and where state regulators are on hand to conduct inspections and oversee specific applications like well construction and testing and plugging as well as hydraulic fracturing," the American Petroleum Institute said in a statement.

"Hydraulic fracturing is a tried-and-true, more than 50-year-old technology, increasingly essential for producing the nation's natural gas," API added.

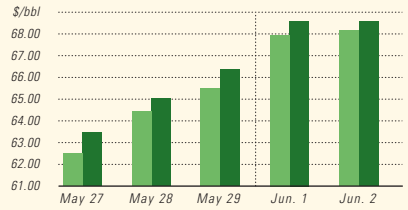
Libya, Cyprus to sign energy agreements

Libya plans to sign agreements with Cyprus concerning the supply of oil and natural gas, according to a senior Libyan official.

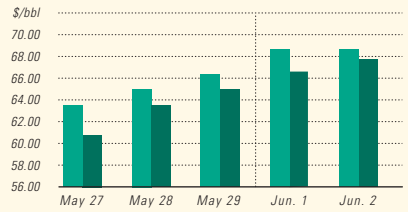
"We look forward to signing agreements with Cyprus in the fields of oil and natural gas," said Libya's Minister of Justice Mustafa Mohamed Abdel Jalil.

Industry Scoreboard

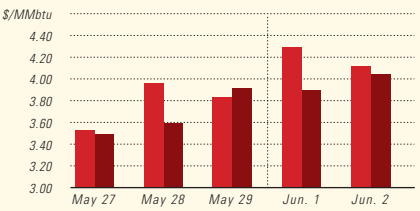
IPE BRENT / NYMEX LIGHT SWEET CRUDE



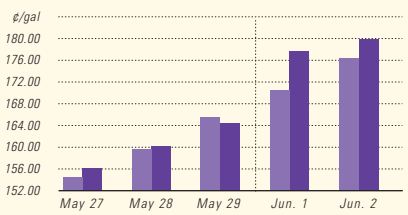
WTI CUSHING / BRENT SPOT



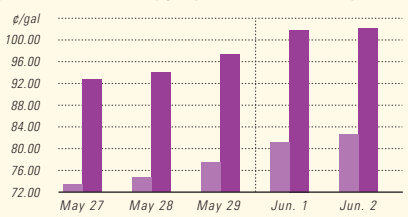
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



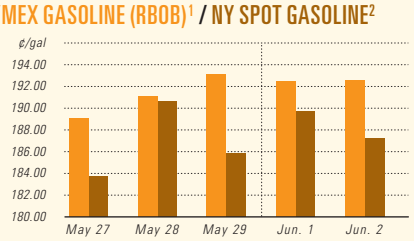
IPE GAS OIL / NYMEX HEATING OIL



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.

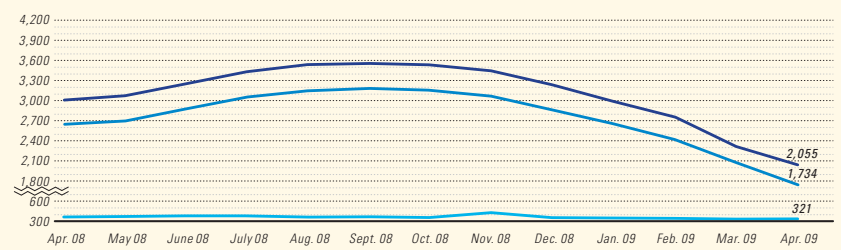
US INDUSTRY SCOREBOARD — 6/8

Latest week 5/22	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	9,151	9,191	–0.4	8,946	8,999	–0.6
Distillate	3,587	3,979	–9.9	3,812	4,141	–7.9
Jet fuel	1,428	1,571	–9.1	1,404	1,554	–9.7
Residual	440	667	–34.0	542	626	–13.4
Other products	3,686	4,331	–14.9	3,985	4,513	–11.7
TOTAL DEMAND	18,292	19,739	–7.3	18,689	19,833	–5.8
Supply, 1,000 b/d						
Crude production	5,326	5,165	3.1	5,318	5,133	3.6
NGL production[2]	1,848	2,378	–22.3	1,816	2,219	–18.2
Crude imports	9,049	9,694	–6.7	9,417	9,753	–3.4
Product imports	2,727	3,236	–15.7	3,012	3,192	–5.6
Other supply[3]	1,649	1,358	21.4	1,653	1,411	17.2
TOTAL SUPPLY	20,599	21,831	–5.6	21,216	21,708	–2.3
Refining, 1,000 b/d						
Crude runs to stills	14,286	15,483	–7.7	14,286	14,777	–3.3
Input to crude stills	14,618	15,528	–5.9	14,618	15,092	–3.1
% utilization	82.9	88.2	—	82.9	85.8	—

Latest week 5/22	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	363,111	368,524	–5,413	311,559	51,552	16.5
Motor gasoline	203,417	203,954	–537	206,155	–2,738	–1.3
Distillate	148,375	148,127	248	109,431	38,944	35.6
Jet fuel–kerosine	40,449	39,665	784	39,581	868	2.2
Residual	38,468	36,961	1,507	39,185	–717	–1.8
Stock cover (days)[4]			Change, %		Change, %	
Crude	25.0	25.6	–2.3	20.7	20.8	
Motor gasoline	22.2	22.5	–1.3	22.1	0.5	
Distillate	41.4	41.9	–1.2	26.4	56.8	
Propane	58.5	58.5	0.0	36.9	58.5	
Futures prices[5] 5/29			Change		Change	%
Light sweet crude ($/bbl)	64.32	60.69	3.63	130.46	–66.14	–50.7
Natural gas, $/MMbtu	3.72	3.83	–0.11	11.50	–7.78	–67.7

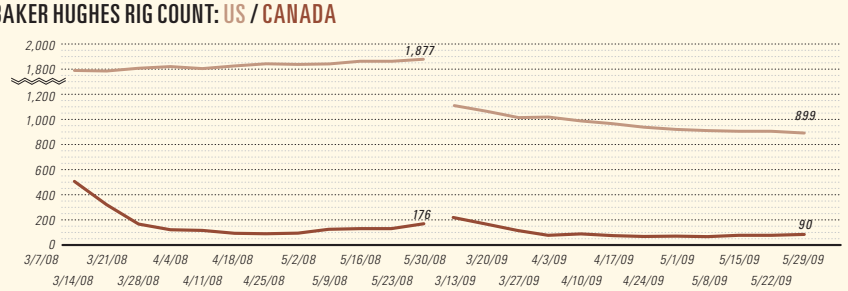
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

"There are many areas of cooperation that are vital for both countries," Jalil said after meeting with Cyprus Minister of Commerce, Industry, and Tourism Antonis Paschalidis.

Libya has sufficient quantities of oil and natural gas it can supply to others, Jalil said, adding that his country will give priority to neighboring countries such as Cyprus.

In April, Libya's National Oil Corp. Chairman Shukri Ghanem, following talks with Paschalides, said the company is considering investing in oil and natural gas exploration off southern Cyprus (OGJ Online, Apr. 30, 2009). ✦

Exploration & Development — *Quick Takes*

Companies ramp up Bakken participation

Several companies increased ownership in North Dakota Bakken well and production interests under an existing joint venture with Slawson Exploration Co., a private Denver operator.

Northern Oil & Gas Inc., Wayzata, Minn., acquired certain North Dakota Bakken assets from Windsor Bakken LLC as part of a syndicate led by Slawson. Northern purchased a 5% interest in the undeveloped acreage, including 60,000 net acres. Price is $7.3 million.

Northern also acquired 14% of the existing 59 gross Bakken and Three Forks well bores in North Dakota including 1,200 b/d of oil production. It also purchased 300,000 bbl of proved producing reserves and 3,000 net undeveloped acres.

GeoResources Inc., Houston, acquired a 15% interest in 60,000 net acres and 15% of varying working interests in 59 producing and productive wells, adding more than 300,000 boe of proved producing reserves. Cost was $10.4 million.

Lario Oil & Gas Co., private Denver operator, also participated in the revised joint venture on undisclosed terms, GeoResources said.

Slawson, responsible for all operations, is expected to drill as many as 45 gross Bakken wells on the newly acquired acreage through 2010.

The joint venture, running one rig, expects to add two more in July and possibly a fourth by the first quarter of 2010, GeoResources said.

Shell-led group to start drilling in the Philippines

Shell Philippines Exploration BV and its partners Kuwait Foreign Petroleum (Kufpec) and South China Resources Ltd. (SCR) will start drilling activities at their Service Contract 60 (SC 60) in Northeast Palawan.

The partners have commissioned the services of the Frontier Phoenix drillship for oil and gas exploration in SC 60, according to filing by SCR with the Philippine Stock Exchange (PSE).

David Baladad, SCR vice-president of operations, told PSE that the drillship will proceed to Northeast Palawan later this year upon completion of its five-well program in Malaysia.

SC 60 is one of the country's most promising areas in terms of potential for large accumulations for petroleum, according to SCR, which said that a rigorous study of the 3D seismic data was conducted and highlighted a number of leads, several of which have been elevated to "prospect status."

"The objective is to continue and further the exploration of the block with a commitment to drill one well during the subphase," SCR said, adding that the second subphase is valid until Feb. 10, 2010.

The consortium partners signed their agreement for SC 60 in 2005. Under terms of their 7-year agreement, the consortium committed a minimum of $24 million (1.27 billion pesos) for the project.

According to the agreement, the consortium is to conduct seismic and exploration work to find petroleum and optional exploration drilling within the first 7 years. SC 60 also includes a 25-year production term in the event of a commercial discovery of petroleum.

The SC 60 partnership is comprised of Shell 55%, Kufpec 30%, and SCR 15%. ✦

Drilling & Production — *Quick Takes*

San Leon to test oil shale technology in Morocco

San Leon Energy PLC has been given 3 years to test its In Situ Vapor Extraction (IVE) oil shale technology on the Tarfaya oil shale exploration project in Morocco with first tests scheduled for mid-to-late-2010.

The company signed a memorandum of understanding with Morocco's National Office of Hydrocarbons and Mining (ONHYM) for the project and site testing will begin later this year. The location will be 200 m above the high oil-yielding zone within the Tarfaya oil shale.

San Leon signed an exclusive agreement with Mountain West Energy LLC to use IVE to extract oil from the acreage that encompasses 6,000 sq km. This method is easier on the environment than open pit mining.

ONHYM approved the feasibility study and work program. San Leon produced 62 l./tonne of oil under lab conditions. "This is similar to the yield reported by Shell when they were testing in the Tarfaya area from 1981 until 1986," the company said.

Shell drilled 55 shallow boreholes, all of which were petrophysically logged, in 1982, encountering the Cretaceous and organic rich Tarfaya oil shale within the San Leon area. Shell established an open pit mine and heated the oil shale in a retort to produce oil. They left the area in 1986 after oil prices plunged to $10/bbl.

San Leon Energy estimates it could produce 500,000 b/d from oil shale reserves in the area. Petrobras is looking at similar developments in the Timhadit oil shale MOU, which is in northern Morocco.

Oil shale reserves in Morocco include an estimated 53 billion bbl in place.

K2 unit expansion tie-back contracts let

Anadarko Petroleum Corp. awarded Technip a contract for tying

back to the Marco Polo tension-leg platform two new subsea completed wells in its operated K2 unit in the Gulf of Mexico.

The contract covers project management and engineering; fabrication and installation of two rigid flowlines; design, fabrication, and installation of four pipeline end terminations; installation of two static umbilicals; tie-ins; precommissioning; and a survey.

Technip's operating center in Houston will execute this contract. The company will weld the flowlines at its spoolbase in Mobile, Ala. and has scheduled offshore installation for third-quarter 2009, using its Deep Blue deepwater pipelay vessel.

The Marco Polo TLP hub, installed in Novembr 2003, is on Green Canyon Block 608 in 4,300 ft of water. Enterprise Products Partners LP and Helix Energy Solutions Group Inc. each own 50% of the TLP while Anadarko is the operator and holds 100% interest in the Marco Polo field that started producing in 2004.

The K2 unit is on GC Block 562 and portions of GC Blocks 518, 561, 563, 605, 606, and 607. Production started in 2005 from subsea completed wells in about 4,000 ft of water.

Current interest owners in the K2 unit are operator Anadarko 41.8%, ConocoPhillips 12.4%, Nippon Oil Exploration USA Ltd. 11.6%, Eni Petroleum US LLC 13.4%, MCX Gulf of Mexico LLC 11.6%, and Ecopetrol America Inc. 9.2%.

Angostura gas project flowline contract let

BHP Billiton Ltd. has let a contract to Technip for the fabrication and installation of a flowline and installation of an umbilical in its operated Phase 2 Angostura gas project off Trinidad and Tobago.

The project lies in about 100 ft of water.

Technip's operating center in Houston will execute the flowline and umbilical contract. Technip will weld the flowline at the group's spoolbase in Evanton, Scotland, and has scheduled offshore installation for 2010 with its Apache pipelay vessel.

In September 2008, BHP Billiton announced that the Phase 2 development of the Greater Angostura field would involve a $400 million investment for the construction and installation of a gas export platform alongside existing facilities within the Greater Angostura field, as well as modifications to existing Angostura facilities and installation of new flowlines.

The company expects the facility, with a 280 MMscfd design capacity, to come on stream during the first half of 2011.

National Gas Co. of Trinidad & Tobago Ltd. (NGC) will take delivery of the gas at the new gas export platform and will transport the gas in its proposed 36-in. Northeastern Offshore pipeline and the 12-in. Tobago pipeline.

First gas production from Angotura started in December 2004 followed by oil production in January 2005. The Greater Angostura field includes oil and gas discoveries at Aripo, Kairi, and Canteen.

Operator BHP Billiton holds a 45% interest in Angostura. Partners are Total SA 30% and Talisman Energy Inc. 25%.

In 2009, Talisman entered into an agreement to sell its assets in Trinidad and Tobago for about $380 million before closing adjustments. It expected to complete the sale in the second quarter. ✦

Processing — *Quick Takes*

EPA cites BP for alleged violations at refinery

The US Environmental Protection Agency has cited BP Products North America Inc. on June 2 for allegedly violating federal air pollution regulations at its Whiting, Ind., refinery over a 5-year period.

EPA's Region 5 office in Chicago alleged that the refiner failed to manage and treat benzene waste from the plant during 2003-08 as required by the Clean Air Act's national emission standards for hazardous air pollutants.

It said that the facility's 2008 report showed that benzene waste was almost 16 times the allowed amount.

The refinery, which was initially established in 1889, is now the third-largest in the US and the biggest outside the Gulf Coast, with more than 400,000 b/d of throughput capacity, according to information on BP America Inc.'s web site.

EPA emphasized that these are preliminary findings of violations. It said, to resolve them it may issue a compliance order, assess an administrative penalty, or sue the company in federal court. BP has 30 days from receiving the notice to meet with the agency to discuss and resolve the allegations, the federal environmental regulator said.

Chevron sells fuel marketing business in Haiti

Medley Capital Ltd. has agreed to buy Chevron Corp.'s fuels marketing business in Haiti for an undisclosed sum. Medley is owned by GB Group, a Haiti-based industrial group with core holdings in energy, steel, and food products.

Under the terms of the agreement, which are subject to various closing conditions, Medley Capital would acquire 58 retail outlets, 120 commercial and industrial customers, and other lines of business.

Brazil committed to biofuels despite presalt finds

Brazil remains committed to developing biofuels despite last year's discovery of giant oil reserves in the presalt area of the Santos basin, according to a government official.

Dilma Rousseff, presidential chief-of-staff, while speaking to sugar and ethanol producers at the Ethanol Summit, said Brazil will continue being the leader in ethanol production and technology development.

Rousseff denied that sugarcane crops would take land from food's rural farmers. "Sugarcane occupies only 0.5% of Brazil's arable land," Rousseff said, adding that technology has allowed Brazilian rural farmers to harvest more sugarcane in the same area.

Rousseff also said the Brazilian government could use ethanol as a substitute for diesel oil to generate electricity in isolated communities in the Amazon region. "In order to prevent diesel oil from being burned in the Amazon we want to burn ethanol," she said.

"We estimate that, via the Eletrobras system, we can adopt it in isolated generation systems in the Amazon, as it's impossible to take transmission networks to isolated communities," she said.

Holly completes link in refinery expansion

Holly Corp. has completed a third 65-mile pipeline to carry

intermediate products between segments of the New Mexico refinery it is expanding and upgrading to handle heavy oil.

Holly Energy Partners LP, 41% owned by Holly Corp., has acquired the 16-in. pipeline, which connects distillation and vacuum units in Lovington, NM, with the main Navajo Refining Co. LP facility in Artesia. The purchase price was $34.2 million.

Holly Corp. is expanding crude capacity of the refinery to 100,000 b/d from 85,000 b/d in a project that also is adding upgrading capacity, including a 15,000-b/d hydrocracker (OGJ, Apr. 28, 2008, p. 30).

The upgraded and expanded refinery will be able to run as much as 40,000 b/d of heavy crude.

The project includes a new 70-mile pipeline connecting Lovington with one of two 16-in. Centurion Pipeline LP lines between Cushing, Okla., and Slaughter, Tex., reversed to carry heavy crude.

Another part of the project is a new 37-mile pipeline linking Holly Energy's Artesia gathering system with Lovington. ✦

Transportation — *Quick Takes*

SemGroup crude pipeline begins operations

SemGroup LP announced its 12-in. OD, 525-mile White Cliffs crude pipeline began commercial operations. The pipeline extends from Platteville, Colo., to SemGroup's storage at Cushing, Okla., from which it could be shipped to major US refining centers.

White Cliff's current capacity is about 30,000 b/d, expandable to more than 50,000 b/d. It includes a 100,000 bbl tank at Platteville to aggregate DJ basin-Wattenberg field production.

Production efforts at Wattenberg increased during 2008, with Anadarko Petroleum Corp. running 1,102 frac jobs in the gas and oil field, 60% more than in 2007 and a record for the field (OGJ Online, Feb. 6, 2009).

SemGroup owns 99.17% of White Cliffs Pipeline. Other partners are Anadarko Wattenberg Co. LLC 0.415% and Samedan Pipeline Corp. 0.415%

On May 15 SemGroup filed its plan of reorganization under Chapter 11 bankruptcy proceedings. The plan called for the distribution of about $2.27 billion in value to creditors, which would become owners of the reorganized company. SemGroup filed for Chapter 11 bankruptcy July 22, 2008, and expects to exit bankruptcy in the third quarter.

France discusses TransMed pipeline extension

France expressed interest in receiving gas from the Galsi pipeline, which will import 8 billion cu m/year of Algerian gas to Italy.

Chakib Khelil, Algeria's energy minister, said France wants to add a branch to the proposed 850-km line, which will link Algeria to Sardinia to Tuscany. He told reporters construction of the pipeline would begin next year. "All of the studies concerning the pipeline have been completed, and the two partners in the project, Algeria and Italy, have decided to begin investment in 2010," he said.

Khelil met with Italian Economic Development Minister Claudio Scajola over the weekend. With Europe keen to lessen its dependence on Russian imports, Scajola described Transmed as a "strategic project for the energy security of Europe."

Galsi is an 840-km pipeline and in 2,800 m of water will be one of the deepest offshore pipeline ever laid. It will deliver Algerian gas into Italy starting in 2013, a year later than originally scheduled due to technical difficulties (OGJ Online, Dec. 15, 2008). The final investment decision will be made June 30, 2010.

"We will try to accelerate things on the Galsi project," Khelil said. Sonatrach is leading the project along with Snam Rete Gas SPA, Edison SPA, Enel SPA, and the Hera Group.

The ministers agreed to increase capacity of the TransMed pipeline by 7 billion cu m by the end of this year. Its current capacity is 27 billion cu m/year of gas. It delivers gas from Algeria via Tunisia to Sicily.

Once the Galsi and upgrades to the TransMed pipeline are completed, Algeria's export capacity to Italy will rise to nearly 40 billion cu m/year. But some industry experts have expressed concerns whether Algeria can boost production to fill these pipelines as Algeria's recent gas finds have been relatively small, and there was little interest from foreign energy majors to develop Algeria's fields under the last licensing round.

Algerian officials attributed the lack of interest in its energy sector to the global economic slowdown.

Kogas, Kitimat LNG sign gas supply agreement

Kitimat LNG Inc. has signed a memorandum of understanding to supply Korea Gas Corp. (Kogas) with as much as 40% of Kitimat LNG's production along with an option to acquire an equity stake in Kitimat LNG's export terminal.

Kitimat LNG said Kogas plans to purchase 2 million tonnes/year of LNG from the proposed terminal over 20 years at a total purchase value of more than $20 billion.

Kitimat LNG also said it is progressing with discussions with other potential terminal users and investors for terminal capacity, offtake from the terminal, and equity in the 5-million tpy project, which lies in Kitimat, BC.

Kitimat LNG and Mitsubishi Corp. earlier this year signed a heads of agreement under which the Japanese firm also will acquire terminal capacity and an equity stake in Kitimat LNG's proposed LNG export terminal.

Under terms of that agreement, Mitsubishi will buy 1.5 million tpy of terminal capacity and acquire a minority equity interest in Kitimat LNG's project.

Since then, the government of British Columbia has announced plans to help facilitate the participation of a number of First Nations in the Kitimat to Summit Lake Pipeline Looping (KSL) project.

The $1.2 billion (Can.), 1 bcfd KSL system, which was approved by Canada's federal agencies in March, would extend 290 miles from Summit Lake to the Kitimat LNG export project.

Under the agreement with the British Columbian government, First Nations will secure a direct interest in Pacific Trail Pipelines LP, developer of the KSL system.✦

Calendar

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

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2009

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

✦The Global LNG Congress, Istanbul, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 23-25.

Moscow International Oil & Gas Exhibition (MIOGE) & Russian Petroleum & Gas Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 23-26.

✦Pipeline Integrity Management Seminar, Calgary, Alta., (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org/conferences/pims2009/index.asp. 24-25.

JULY

Rocky Mountain Energy Epicenter Conference, Denver, (303) 228-8000, e-mail: conference@epicenter2008.org, website: www.denverconvention.com. 7-9.

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

✦Petroleum Association of Wyoming (PAW) Annual Meeting, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: suz@pawyo.org, website: www.pawyo.org. 18-19.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

Journally Speaking

Anticipating the rebound

Marilyn Radler
Senior Editor-Economics

In April, OGJ published its annual oil and gas capital spending outlook, which reported a cut in spending worldwide (OGJ, Apr. 27, 2009, p. 26). This contraction in spending plans was brought on by the rapid decline in global oil demand and the resulting fall in oil prices.

A new analysis, however, finds that substantial spending will still take place this year, in spite of the economic downturn. Ernst & Young has released an analysis that looks at investment plans and concludes that the world's largest national oil companies (NOCs) and the supermajors plan to invest more than $375 billion this year, despite ongoing concerns surrounding demand.

The level of uncertainty about the path of future demand is probably now at its highest in decades, driving most oil and gas producers to monitor their spending commitments closely, writes Andy Brogan, global oil and gas transaction advisory services leader for E&Y. Brogan warns that when future demand becomes more certain, spending plans could change very quickly and materially from those currently public, but many companies appear wary of having to play catch-up when the upturn materializes.

In 2009, the largest NOCs collectively plan to invest more than $275 billion on hydrocarbon development at home and abroad, according to E&Y's report, which concedes that because many state-owned oil companies keep their spending plans private, the actual level of investment is likely to be higher.

The analysis finds that many supermajors—ExxonMobil Corp., Royal Dutch Shell PLC, BP PLC, Chevron Corp., and Total SA—collectively plan to invest as much as $100 billion in oil and gas activities this year. This compares with the $122 billion invested in 2008, but with better terms now available for equipment and services, oil companies may find that they get more for their investment.

Cautious investments

Oil and gas producers are being more cautious with investment in some subsectors and regions. When internal business units compete for capital, higher-cost or riskier projects will struggle to win approval in the current economic climate, according to Brogan. The regions most likely to see a decrease in investment in the short term include mature basins where costs are typically higher, countries with unstable fiscal regimes, and countries or regions where security concerns raise operating costs.

Reduced availability of capital and tougher credit terms will impact the ability of smaller producers to fund ongoing operations and bring assets into production. Many smaller, independent companies, making significant reductions in their planned investment for 2009, are prioritizing their most advanced or promising projects to minimize investment risk and increase revenue streams.

And because independent oil and gas companies typically own or control reserves in countries where large international oil companies (IOCs) are not active or have a limited presence, cutbacks in spending by independents could impact the longer-term viability of oil and gas production in less-developed regions, the report says.

Cost-control keys

Brogan says that in light of economic turbulence and oil price volatility, cost containment has become a strategic priority for companies, and companies that achieve successful project results are likely to possess some key attributes that keep costs in check.

One key is an effective risk-management process with a clear line of sight between project, portfolio, and strategic risk management such that strategic objectives are supported by tactics that address operational, business-specific, and macroeconomic threats.

Also, companies must undertake rigorous portfolio management, give greater scrutiny to project selection, and provide more certainty during the feasibility phase to project costs and human resource requirements. In a challenging environment, companies need to consider more carefully where best to allocate finite resources.

A third key to cost control is to invest wisely in enabling technology, processes, and systems to deliver a seamless, effective global operation and knowledge transfer. Also, standardized processes and systems will help underpin greater governance and enhanced oversight, enabling improved transparency and allowing strategic hubs to control worldwide projects without jeopardizing quality, cost, or schedule, according to the E&Y report.

Organizations also will need to have active stakeholder management plans, Brogan says. At the highest level, these plans address relationships between NOCs and IOCs and influence how they effectively interact with governments, local communities, joint venture partners, and the supply chain in a manner that not only supports successful project execution but also promotes a responsible corporate brand image. ✦

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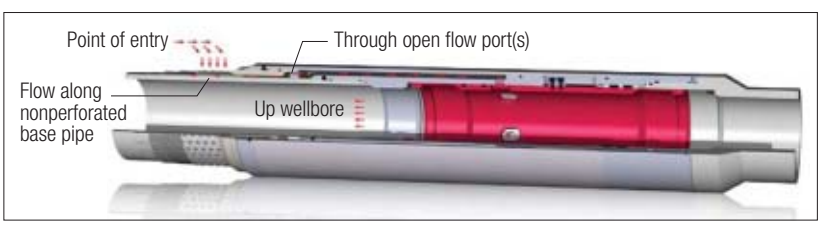

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Editorial

SECOND OF TWO PARTS

The climate bill's costs

In case anyone missed the National Petrochemical & Refiners Association estimate for costs awaiting US refiners from climate-change legislation approved last month by a key House committee, here it is: $58 billion/year. That's "billion" with a "b." And it's not $58 billion over a decade or two. It's $58 billion every year. And it would grow.

HR 2454, the American Clean Energy and Security Act, would hit refining harder than most other US industries. Refiners would face the earliest possible compliance mandate and receive disproportionately low emissions allowances under the bill's cap-and-trade scheme. And they'd have to meet limits on emissions not only from their operations but from use of their products as well.

Heavy burden

At a carbon value of $26/ton, NPRA calculates, a 100,000-b/d refinery would have to spend about $330 million/year if required to purchase emissions allowances for its products. Extrapolation to total US capacity yields an aggregate annual cost of about $58 billion. That's more than twice what major energy companies tracked by the Energy Information Administration earn from US refining and marketing in total every year.

The burden would force some refineries to close, crimping supplies of oil products, raising prices, and increasing US imports. But it fits a strategy. As noted in the first part of this editorial series last week, the federal government has expressed the eerie suspicion that the US produces too much oil and gas and compromises energy security as a result (OGJ, June 1, 2009, p. 18). A government so deluded may be incapable of comprehending the cost of energy mistakes.

Yet the costs of mistaken climate legislation would be monstrous. The conservative Heritage Foundation recently estimated that HR 2454, sponsored by Reps. Henry Waxman (D-Calif.) and Ed Markey (D-Mass.) and approved by Waxman's Energy and Commerce Committee on May 21, would, by 2035:

- Cut aggregate gross domestic product by $9.6 trillion.
- Destroy 1.105 million jobs on average, peaking in the worst years at 2.476 million jobs.
- Raise electricity rates 90% after adjustments for inflation.
- Raise inflation-adjusted gasoline prices by 74%.
- Raise residential natural gas prices by 55%.
- Raise the average family's energy bill by $1,500/year.
- Increase the inflation-adjusted federal debt by 26%.

And these costs are for only the cap-and-trade provisions. Clean-energy mandates of the Waxman-Markey bill would intensify the pain. "Though the proposed legislation would have little impact on world temperatures," the study says, "it is a massive energy tax in disguise that promises job losses, income cuts, and a sharp left turn toward big government."

For such warnings, supporters of the bill have no patience. To them, conservative utterances lack credibility. Costs don't matter. The inability of the measure to alter global average temperature doesn't matter. Waxman-Markey supporters want the US to claim the lead in a frenzied response to global warming fear, whatever the cost.

Already, the cap-and-trade method for lowering emissions of greenhouse gases smells foul. Waxman made big compromises. Instead of auctioning emissions credits, as President Barack Obama proposed, HR 2454 allocates allowances categorically. Suddenly, industries favored with high allowance rates consider cap-and-trade a wonderful plan. Their buy-off only hints at the opportunism and corruption that await emission-credit trading and administration.

Wispy goals

The US government has interwoven the wispy goals of displacing hydrocarbons with renewable energy and manipulating global temperature measurements. Americans will pay heavily for the resulting assault on markets. They'll pay as taxpayers through the heavy and growing subsidization of uneconomic fuels. And they'll pay as consumers through energy costs hiked severely in what can be only a token step toward meaningful management of the climate.

In a program of energy reform that will asphyxiate itself with unreasonable ambition and governmental excess, a crushing paradox is at work. When markets raise the price of gasoline, Americans throw a political tantrum. When their government hikes the costs of energy as a matter of policy, they grovel in economic mire that's fast becoming toxic.

Or are they just asleep? ✦

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Proposition: global effort to model largest oil fields

Wayne L. Kelley
D. Ron Harrell
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Houston

Oil is the world's most important commodity, and the need to understand the long-term supply is widely recognized. In some way, all energy projects—whether they involve conventional or green alternatives—will be measured against oil. Some of the most pressing questions facing the future of oil supply are:

- What is the future global delivery capacity?
- When and at what volume will oil fail to meet the need?
- How can the future price of oil be predicted, and how reliable is the price prediction?
- How can the oil price be maintained at levels sufficient to assure adequate investment to maximize exploitation of oil resources concurrent with timely and adequate investment in alternative energy sources?

A second tier of questions is tied to the best use of oil when supply cannot meet demand. The proposal made in this article will be essential to addressing those questions as well.

Answers to any of these questions are predicated upon a reliable and credible forecast of global delivery capacity. The need for answers becomes more urgent as excess productive capacity shrinks and oil remains the primary and cheapest source of energy (Fig. 1).[1] Primary contributing factors to the present inadequacy of energy investment are price volatility and uncertainty of future delivery capacities, which are the by-products of tightening supply.

The authors confirm the work of others that the energy future depends upon a handful of irreplaceable and aging fields, many of which are in unknown states of depletion. It is time for the world to better understand global oil productive capacity in order to take appropriate measures.

Modeling giants

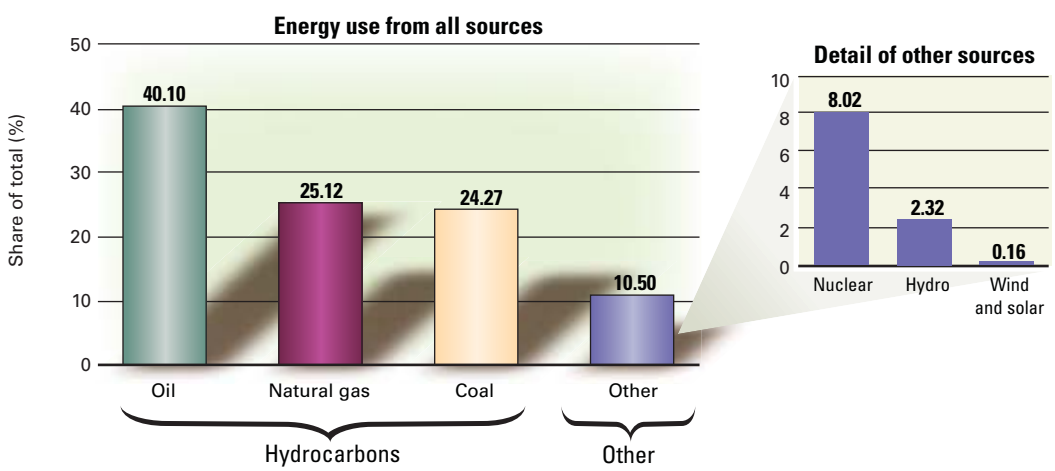
The authors propose that the key to this understanding is the modeling of the largest fields. Should government and industry fail to understand the future supply from these fields, there is a potential for large shortfalls of productive capacity without adequate alternative replacements having been put in place. As the world has experienced on several occasions, even small shortfalls can cause large price increases. Failure to understand when and at what volume oil supply will be insufficient is not acceptable.

The key observation behind this proposal is that over time the proportionate contribution of large fields to world oil supply has been generally consistent. Fig. 2 illustrates the percent of the cumulative daily production through time from giants. For the past 3 decades, the giants have represented around 60% of the total.

The authors propose that modeling the range of productive capacity from the

US ENERGY USE BY SOURCE IN 2008

Fig. 1



Source: Data from Reference 1

largest fields in the world (321 of the top fields) provides the basis to answer the questions posed at the opening of this article. The scale of the proposed undertaking is easily managed. This model would provide a high degree of reliability for 50% of the world's production—the portion that is assumed irreplaceable and the primary driver for future deliverability. As these largest fields diminish in productivity there is little prospect that the loss of their capacity will be offset by new discoveries. The historic trend is that new discoveries do little more than keep pace with depletion of nongiant fields.

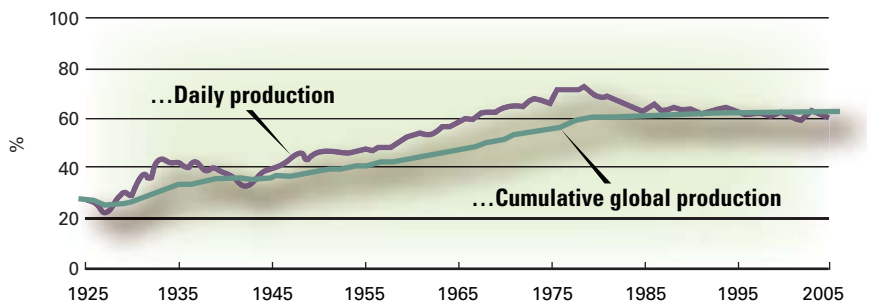
Today there is an overreliance upon historical methods to predict future production. The focus on understanding the whole of the reserves and production picture from an historical perspective, such as the Hubbert model, may be misplaced. Hook et al.[2] and Robelius,[3] as well as Nehring[4] and Klemme,[5] have shown that the world's giant and supergiant fields, deliver over 50% of the world's supply.

In Fig. 3, the largest 19 fields (the lowest curve) and the 321 largest fields (the middle curve) are nearly parallel in the last 20 years to the top curve, which is world total production. Compared to the period between 1940 and 1980, when 70% of the reserves of the largest fields were discovered (Fig. 4), the 3 subsequent decades have contributed only 12%, even with the advantage of greatly advanced technology and access to a large portion of the world's prospective areas.

Giants critical

Considering the advanced depletion and large portion of global supply coming from the few giants and supergiants of the world, a sensitivity analysis will identify these fields as the critical variables in the future delivery of oil. The unanticipated decline of the largest fields poses the greatest risk to future delivery, and the loss of their production without replacement or energy alternatives would be economically catastrophic.

GIANT FIELDS' SHARES OF… Fig. 2



Source: Reference 2

The contribution of the smaller fields and future additions will not have the capacity to mitigate the significant disruption of the global economy brought on at some point by the decline of the largest fields. Therefore, a widely accepted method of forecasting supply is required.

In response, this article proposes building reservoir models of the world's largest fields to gain insight to their possible supply rates. These rates would not be unique answers but would model different scenarios of reservoir development from high investment to low or no investment while giving full consideration to the limitations of remaining oil in place within each field. Further, all producers might join in this effort because it is in everyone's interest to do so. The reliability of the forecast will improve along with increasing cooperation from producers. While the use of a black-oil model of the largest fields does not provide an absolute prediction (one does not exist), it does offer a means of establishing more robust and explainable boundaries than before.

Others (e.g., Simmons,[6] Khadduri,[7] and Laherrere[8]) have recognized the production profile of the largest fields as a better solution than historical data, but no one has done it for a variety of reasons. Constraints include not only availability or access to data but also project funding, size of the undertaking, and a lack of an organization willing to take on the task.

Nonetheless, the role of the supergiants and giants is so compelling that it is now time to start this project.

Prior efforts

Numerous efforts by highly qualified, skilled, and adequately funded persons and groups have produced supply forecasts, but they still have a lot of uncertainty and some controversy. The uncertainty is exacerbated by a lack of transparency in the reporting of much of the world's reserves, inconsistent reporting standards, and the lack of independent, third-party verification. Beyond the lack of transparency, the core reasons for this situation are the lack of a single repository for the primary data on fields and reliance upon historic data with their inherent limitations.

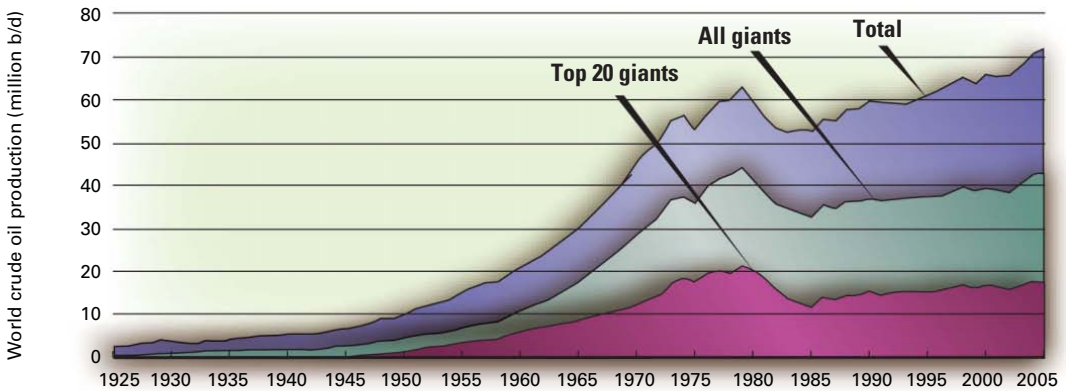
While some countries require the release of such data, others treat it as a state secret. Consequently, there has been no cooperation within industry to create such a repository. Even when reserve data are available, they are often fraught with uncertainties of reporting (they can be 1P, 2P, 3P, or simply not defined).

Beginning with reserves reports first due in the spring of 2010, the US Securities and Exchange Commission will accept reserves estimates beyond 1P, or proved reserves. Even then, reporting of less certain reserves categories will remain optional. Such a lack of international standards clearly leads to difficulties of analysis.

When considering the application of

HOW PRODUCTION DEPENDS ON GIANT FIELDS*

Fig. 3



*Note correlation in last several decades between total production and production from the giants.
Source: References 2 and 3

historic methods, there is an emerging view that the "peak" and "postpeak" periods will not be easy to recognize and will not follow smooth declines as modeled mathematically. Instead, the decline period will likely be slower than modeled by the Hubbert curve and a lot "bumpier" as a result of continued management and investment.

The data used by King Hubbert and the majority of subsequent investigators to forecast future oil supply is essentially historical field-size data with a touch of "growth to known." While suffering from the usual inconsistencies of such data, the Hubbert method provided a prediction of "peak" oil in the US correct in time but somewhat off in volume.[8] The extrapolation to the future using symmetry to predict decline, however, was not nearly as close in time or volume. What the Hubbert model does not accommodate well is the impact of variables such as oil price and the pace of development, which results in a wide range of uncertainty, making it inadequate as a tool to plan the transition from oil.

Complicating the picture is the necessity of dealing with a nonunique number for future production volumes rather than "snapshot" quantities related to a specific date and economic conditions existing at that time. The only time a reserves value is a unique number is when the field is abandoned and the wells are plugged. And, even then, it can return to life with advances in technology and improvements in economics.

Alternative approach

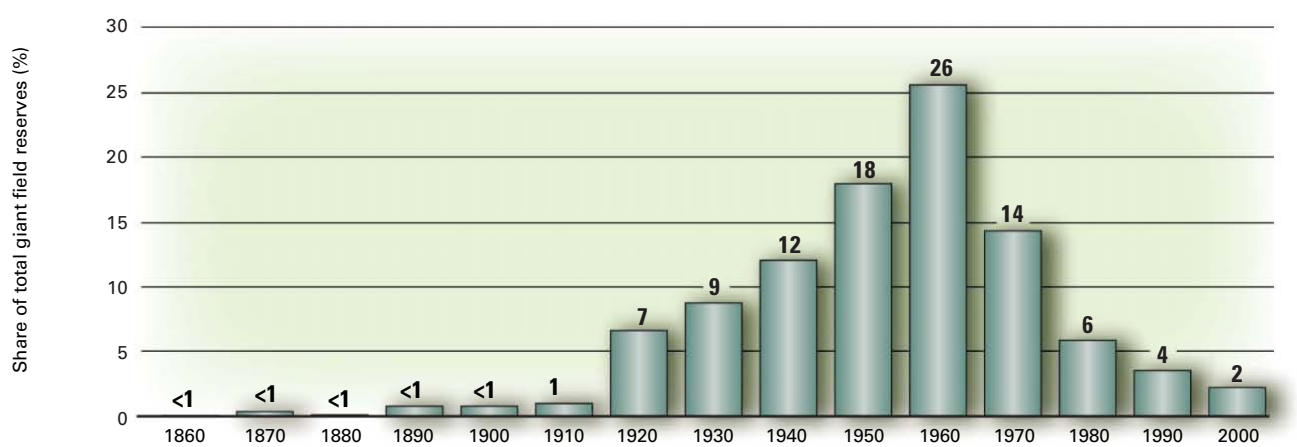
The authors' approach is to simplify the task and improve the reliability of forecasting crude delivery capacity. This is done by modeling the largest fields in the world.

This method has the built-in flexibility to forecast deliverability with ranges of outcomes subject to the sensitivity of production to investments and timing. Additionally, the model can be used to place in context the role of new fields, potential new reservoirs, and field extensions. It is not proposed to model heavy oil deposits, but that could be included.

This production forecast will not provide a unique answer to "peak oil" or rate of production decline, but it is a tool that will define the upper and

GIANT FIELD DISCOVERIES VS. PRESENT RESERVES*

Fig. 4



*Reserves discovered over time in giant fields as share of present day volumes in giant fields.

lower boundaries that are dependent on investment in the fields (Fig. 5). Underlying the tool will be a library of hard and soft-copy data that would be updated regularly. The library would consist of both static and dynamic reservoir models of the giant and supergiant fields using industry standard software, which would allow for scenario analysis.

Fig. 5 is a conceptual diagram of production rate versus cumulative volume. The cumulative volume is a nonunique answer and depends upon price, investment, and the applied technology. The end members of no investment and high investment are shown. This is the core output. The proposal here is to model these two production profiles for the giants and supergiants of the world.

The benefits

The benefits of a reliable forecast of future oil productive capacity are:

- Confidence and agreement by industry, government, and financial markets in the timing and scale of oil shortfalls.
- A forecast suitable for use in estimating the price of oil.
- A forecast suitable for determining the rate for deployment of oil replacements.
- Economic stabilization as a result of reduced oil price volatility and appropriate levels of energy investment.
- Defining timing and needs for energy alternatives in the public debate between industry, regulators, and proponents of oil replacements.
- Providing the core basis for formulation of energy and environmental policies, a significant input to monetary policy.

Of course many factors in addition to the amount of spare capacity influence the price of oil, including demand for specific crude types, the size of inventories, secrecy, disinformation, and the impact of trading. Recent oil pricing demonstrates that volatility is disproportionate to changes in demand and in part reflects the uncertainty of delivery capacity.[9]

Currently, there is a high probability that the energy sector will be short of capital in the near term. Irrational oil pricing combined with vast uncertainty regarding reserves and future deliverability have a chilling effect on lenders and investors in all energy projects, both oil and alternatives. In contrast to popular belief, most oil companies do not have large amounts of cash on hand; similarly, there is no ready pool of capital for alternative energy technology.

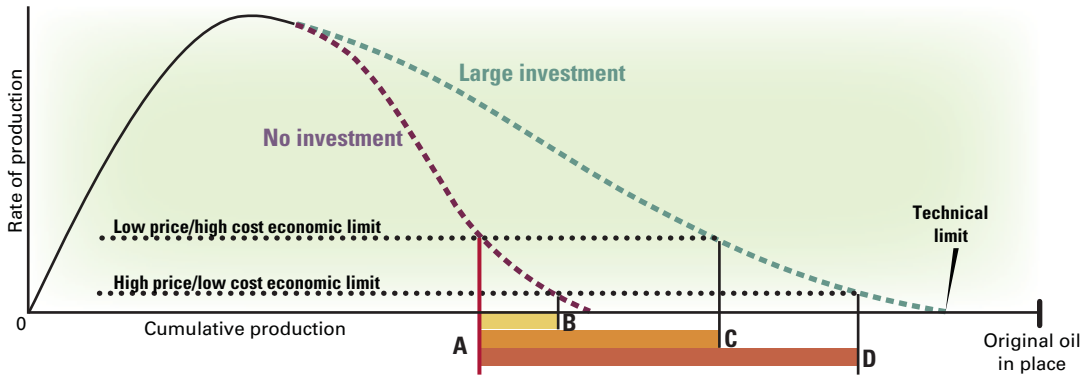
Future energy security depends on the level of participation of capital markets. The current murkiness of global reserves and delivery capacity makes an increase in the amount of available capital unlikely. Even companies with large cash reserves, such as Saudi Aramco and ExxonMobil, will be reluctant to deploy capital to expand capacity. This is especially applicable in today's markets. A common understanding of reserves and future delivery capacity would help operators, lenders, and investors decide if, when, and at what amounts to invest.

Monetary policy, whether by taxation or incentives, plays a large role in investment decisions. The International Energy Agency has forecast that the energy industry will require $20 trillion over the next 20 years in order to meet current and forecast growth of demand. A reliable supply forecast would greatly assist not only government policy-makers but also bankers, fund managers, and energy companies themselves.

A forecast based upon transparency is the foundation to formulate energy policy and mobilize large scale energy investment. Mike Bray of KPMG correctly argued in his 2004 paper delivered to the World Energy Council (WEC) community at the Sydney World Energy Congress "….that a critical success factor to raising sufficient energy capital through to 2030 is the visibility and clarity of attractive and viable investment propositions, enabled by an effective business-reporting and communications (BRAC) toolkit. This toolkit allows capital providers to differentiate between competing investment propo-

KEY VARIABLES OF ESTIMATED ULTIMATE RECOVERY*

Fig. 5



*The volume range shown by line AB is driven largely by low price; by line ABC, a combination of intermediate investment and intermediate price; and by line ABCD, high investment and high product prices.

sitions and allocate capital with precision based on merit."

Bray's comments then and subsequently at the 2007 WEC in Rome are made in the context of his and others' concerns about raising the $20 trillion forecast by the IEA as needed to meet expected energy demand in the next 2 decades. Taking the point one step further, the effective business reporting referred to in Bray's papers requires that all of the oil sector report in auditable numbers derived from primary data. By whatever means, it is essential to create a reliable reporting of global reserves and forecasting of delivery capacities.

Call for cooperation

The authors propose that industry and government cooperate by the formal establishment of a global body mandated to:

- Establish a library that minimally collects primary data (logs, seismic data, production histories) for the 321 largest fields.
- Acquire the necessary expertise to validate the interpretation of the data and create the static and dynamic models.
- Issue forecasts of the production of the fields in the database, and extend the forecast to total global capacity.
- Periodically update the models and issue updates to the forecast.
- Issue price expectations in coordination with other similar bodies, such as IEA and the Joint Oil Data Initiative (JODI).

This proposal requires industry and producing countries to contribute financing and data to the library. Much of the data already is available, but this is an offer of encouragement to those countries who have not released the data to do so.

To implement the proposal, potential contributors could convene to do the planning through the auspices of professional organizations that have demonstrated an interest in the subject in venues such as American Association of Petroleum Geologists Hedberg conferences and Society of Petroleum Engineers applied technology workshops. JODI, launched in May 2004 by the Organization of Petroleum Exporting Countries, IEA, Asia Pacific Energy Cooperation (APEC), Statistical Office of the European Communities (Eurostat), Latin American Energy Organization (OLADE), and United Nations Statistical Division, provides precedence for such a body.[7] JODI broadly accumulates production, refining, and storage statistics from over 90 countries, and grades the statistics for their quality. JODI claims its data represents 94% of global production and 95% of global demand, but these data are not forecasts of future productive capacity.

How do the authors propose to overcome objections to the proposal?

Confidential primary data could be used to reliably model deliverability without compromise to the source. Results could be aggregated to protect the information provided by individual members and other interested parties. What is most important is that all parties have confidence in the forecasts.

There will be naysayers attacking the formation of a cooperative body to coordinate energy policy and pricing saying it lacks adequate transparency, contradicts the inherent advantages of a free market, does not accommodate the needs of the poorest of nations, and is beneficial only to a few. No method is perfect. But the lack of a coordinated policy and stable pricing puts all countries at risk, the richest and poorest.

Changing tactics

Continuing to do what has been done before will not secure future global oil deliveries or deploy alternative technology on a large scale. Continued delay makes solutions increasingly difficult. By changing tactics, it is possible to create a world body with the mandate to forecast oil deliverability.

The authors have proposed conventional modeling methods that require access to primary data that can reliably forecast future oil supply. Though the World Energy Council has taken tentative steps in this regard, a higher profile body with the capacity to cause appropriate cooperation is warranted.

In the US, the Obama administration has the opportunity to take the initia-

tive in calling for such a world body. In addition to the US, the OPEC countries, Japan, China, India, the Euro zone, Brazil, and Russia need to cooperate.

Energy industry leaders can raise the level of awareness of the world's energy peril and the need for a new approach. The inevitable transition from an oil-based economy is one of the greatest global challenges and deserves a similar level of attention to nuclear proliferation, global warming, and the current economic crisis. The stakes are too high to choose inaction or further delay. ✦

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API opposes efforts to federally regulate hydraulic fracturing

Nick Snow
Washington Editor

Proposed federal regulation of hydraulic fracturing under the Safe Drinking Water Act could add $150,000 to deep-well costs and reduce drilling, American Petroleum Institute officials warned on June 3.

Requiring producers using hydraulic fracturing to comply with the SDWA's underground injection control provisions would add another regulatory layer that many states' water laws already cover, API members told reporters in a teleconference.

"An estimated 60-80% of onshore wells drilled in the Lower 48 states involve hydraulic fracturing," said Richard L. Ranger, a senior policy advisor at API. "It has played a significant part in the Bakken shale oil play. Virtually all the wells extracting gas from shales in the Midcontinent and tight sands in the Intermountain West use it," he said.

Ranger said the estimated $150,000 of additional regulatory compliance costs under legislation that Rep. Diana DeGette (D-Colo.) is apparently planning to introduce would include $100,000 for UIC regulations, $25,000 for stormwater permits, and $15,000 for waste permits under the federal Resource Conservation and Recovery Act.

DeGette introduced a bill, HR 7231, on Sept. 29, 2008, to repeal hydraulic fracturing's exemption under the SDWA. She has not reintroduced it this year, but plans to so soon, a spokesman told OGJ on June 3. The House Natural Resources Committee's Energy and Mineral Resources Subcommittee will also probably examine hydraulic fracturing as part of its June 4 hearing on shale gas potential.

Work ahead

"We're opposed to Rep. DeGette's bill that's being discussed now. We have a lot of work ahead of us to explain why. We see this as an education effort and part of what we do at API," said Ranger, who was joined in the teleconference by two other API senior policy advisors, Andy Radford and Stephanie Meadows.

States are better qualified to regulate oil and gas drilling because their agencies are better acquainted with each drilling site's unique characteristics, they explained. "Technical professionals at state agencies who have experience in each area's unique characteristics are the best qualified," said Ranger. Alaska's comprehensive regulations cover steps from the drilling engineer's blue-line drawings to well site operations, while Colorado recently changed its rules to provide more consultation among agencies but retained their strong technical history, he said.

UIC provisions under the SDWA aren't appropriate for hydraulic fracturing, Meadows said. "Producers aren't actually storing anything in the well, which UIC provisions cover. The water is being temporarily used and brought back to the surface with the oil or gas that's produced," she said.

State regulations also go beyond water, Ranger continued. "There really isn't any such thing as a 'clean, vanilla drilling operation,' nor would that necessarily be desirable. A drilling operation deals with unique conditions at each site under state regulations which try to assure that operations there are conducted with the utmost safety," he said.

"These commissions don't exist in a silo, but meet frequently depending on the amount of drilling that takes place in the state. In Texas, for instance, they meet twice yearly whereas in Ohio, where there's much less activity, they meet less frequently," Ranger said.

Questions raised

Other US House members share DeGette's view. During a May 19 House appropriations subcommittee hearing on the US Environmental Protection Agency's fiscal 2010 budget request, Rep. Maurice D. Hinchey (D-NY) asked EPA Administrator Lisa P. Jackson if she would have the agency review risks to drinking water posed by hydraulic fracturing. Jackson responded that EPA should review the matter in light of cases across the country that raised questions about the drilling technique's safety, Hinchey said following the hearing.

"It's imperative that we protect our drinking water supplies from harmful chemicals that are being pumped into the ground by oil and gas companies looking to produce on more and more land in New York and across the country," Hinchey said. He added, "We are in a much stronger position to protect our drinking water now that we have an administration in place that is committed to environmental protection. While there is value in drilling for natural gas, it's imperative that we do so in a manner that doesn't have long-term environmental consequences on our drinking water, a resource that is critical to human health and survival."

Ranger conceded during the teleconference that some landowners have complained that hydraulic fracturing nearby has damaged their property, but added: "We believe that the incidents that have been brought forward associated with contamination of soil and water have been associated with handling fluids on the surface and not with hydraulic fracturing underground. That does not excuse them, but they should not be used to condemn hydraulic fracturing." ✦

US House panel studies proposal to alter federal leasing

Nick Snow
Washington Editor

A legislative draft that would substantially change federal oil and gas leasing has been circulating around the US House Natural Gas Resources Committee since last May.

The proposal by the committee's majority would consolidate the US Bureau of Land Management and US Minerals Management Service, according to a copy that OGJ obtained on May 29. It would shorten lease periods from 10 to 5 years, increase onshore royalty rates to 18.75%, require diligent development of leases, and impose best management practices on new leases.

"By our calculations, natural gas provides approximately 4 million American jobs. This legislative proposal will put those jobs at risk."
—Natural Gas Supply Association Pres. R. Skip Horvath

Offshore, the proposed legislation would institute a "no discharge" requirement for new leases. It also would establish what the draft calls "a production incentive fee" on existing onshore and offshore leases that are not producing in their later years to encourage production and discourage speculative holding of federal resources.

The bill's draft also would change the federal royalty program in several ways including elimination of royalties in-kind, ending federal reimbursement of interest accrued on overpayments lessees erroneously make, revision of several ambiguous legal provisions that the bill's proponents say hinder accurate accounting, and increased penalties for inaccurate royalty reporting and payments.

The draft also would establish regional ocean councils and onshore statewide teams modeled on existing voluntary collaborative management efforts such as the Northeast Regional Ocean Council and the Western Gover-

nors Association's Renewable Energy Zones project.

> "We need more energy. Provisions of this draft bill will not provide us with more energy. Instead, the draft bill will impose hurdles, drive up costs, and stifle investments, which will lead to less energy."
> **—American Petroleum Institute Pres. Jack N. Gerard**

OCS planning councils

OCS regional planning councils would be established for the Atlantic, Pacific, and Gulf of Mexico regions. These councils would prepare marine spatial strategic plans to guide OCS energy development amid other activities. The plans would then incorporate into the 5-year OCS leasing plans that are already being developed under the OCS Lands Act.

Onshore, the draft proposes creating federal-state-stakeholder teams to develop comprehensive energy plans for each public lands state. The plans would be used to guide federal land management and leasing decisions. The bill also would create federal leasing programs for wind, solar, and uranium on public acreage to create a basic framework for the various kinds of energy development.

The draft proposal also would create an oceans trust fund, which would dedicate a portion of OCS revenues to grants for coastal states and regional collaborations to protect, maintain, and restore ocean, coastal, and Great Lakes ecosystems.

Oil and gas industry association leaders immediately criticized the proposals. American Petroleum Institute Pres. Jack N. Gerard said on May 29 that the draft poses a major threat to US energy security, and to the jobs, revenues, and secure energy supplies that would result from more domestic oil and gas development. "We need more energy. Provisions of this draft bill will not provide us with more energy. Instead, the draft bill will impose hurdles, drive up costs, and stifle investments, which will lead to less energy," he maintained.

The Natural Gas Supply Association plans to send a letter to House Natural Resources Committee Chairman Nick J. Rahall (D-W.Va.) and the majority staff, "letting them know that this legislation eliminates jobs, reduces domestic supply, and puts upward pressure on natural gas prices at a time when people are worried about jobs and prices," said NGSA Pres. R. Skip Horvath on May 29.

Payments in billions

Horvath noted that gas producers remitted $2.9 billion to the federal government in royalties, rents, and other payments in 2007, and more than doubled such payments to $7.2 billion in 2008. "Those numbers don't even include the taxes we pay," Horvath said, citing US Energy Information Administration figures showing that major gas producers had an effective income tax rate of 40.3% in 2007, significantly higher than the 35% US statutory rate and the 26.6% effective rate for all US manufacturers.

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Smart policies key to gas

Natural gas utilities often face different issues than producers and pipelines. But keeping domestic supplies abundant and affordable by resisting rash legislative proposals was very much on Chris McGill's mind as he prepared to visit Houston.

"It's an interesting contrast," he told me during a June 2 interview at the American Gas Association, where he's managing director of policy analysis. "In the short-to-medium term, if we are pushed legislatively in the direction of encouraging alternative and renewable energy sources and dealing with global climate change, natural gas will be very important."

The US market has clearly grown in the last 3-4 years, McGill said. Technology, discovery rates, and economics all have improved. The US supply picture is very solid, and that's before including LNG imports.

"It's an abundance message, but diversity also is important. You have to have policies that support developing these resources. If you start picking off options, whether in the Intermountain West or on the Outer Continental Shelf, this abundant resource could become limited," McGill warned.

Constant advocates

Gas should be viewed less as what he termed "a carbon fuel impediment" and more as part of the US global climate-change strategy, McGill said. Producers, pipelines, and utilities all need to be constant advocates, he said.

"There's an untold technology story too. Gas gets short-changed and is not viewed as high-tech. Yet we've had progress in burner-tip efficiency and in securing new supplies in the past few years," he said.

"More important, gas is available right now. What's more, we have the domestic supplies to meet foreseeable demand," McGill said.

In a week when a House Natural Resources subcommittee was holding a hearing on hydraulic fracturing and the American Petroleum Institute scheduled a teleconference with reporters on the technology, McGill also acknowledged the controversy surrounding the process for producing gas from shale formations.

An inappropriate link

One problem in the debate is linking hydraulic fracturing to water problems associated with coalbed methane production, which occurs much closer to the surface and is likelier to pose challenges in keeping impurities out of potable aquifers, McGill said.

"A frac job at 7,000 ft below the surface, if it's properly done, will be separated by thousands of feet from an aquifer. If the well is properly drilled and cased, production should not disturb drinking water supplies," McGill said.

Shale gas recovery also requires millions of gallons of water, he continued. "These problems need to be addressed locally, but producers, states, and communities already are discussing specific questions," he said.

Not every producer behaves in exemplary ways, McGill conceded, but most recognize that it's in their best interests to be candid with landowners and nearby communities. ✦

"At a time when unemployment is running in the double digits in states like California and Michigan, now is not the time to raise taxes or create uncertainty in the energy market. That hurts consumers on both the job front and in the pocketbook. By our calculations, natural gas provides approximately 4 million American jobs. This legislative proposal will put those jobs at risk," Horvath said.

Other trade association officials tried to quantify impacts and resolve uncertainties in the legislative draft. "The bill, as a package, seems to express an anti-oil, anti-natural gas bias. We've completed a review and are waiting to discuss it with member companies," Richard L. Ranger, a senior policy advisor at API, told OGJ on May 29.

Kathleen Sgamma, government affairs director at the Independent Petroleum Association of Mountain States, said, "It's clear that they're trying to boost renewable energy development on public lands. At the same time, they're making it more difficult to produce natural gas, which we need to enable those renewable energy resources and tackle climate change. On the one hand, the government is trying to increase renewable energy production. On the other hand, it's making it more difficult to develop the natural gas that will be needed to back up intermittent renewable sources."

Daniel T. Naatz, vice-president of federal resources and political affairs at the Independent Petroleum Association of America, said, "We need to look more closely at these proposals, which are only a draft. Our main concern is that it will create further delays. We've seen from the environmentalists' playbooks that the more opportunities there are, the more they'll make it difficult to actually do work. The idea of planning councils sounds reasonable on its face, and we may not be opposed to it. But our experience suggests that it simply could create a more efficient way to slow things down."

Proposing to cut onshore lease periods in half suggests that no effort was

made to consider the time necessary to move from leasing to development to production in frontier US areas that are being leased now, API's Ranger said.

> *"The bill, as a package, seems to express an anti-oil, anti-natural gas bias. We've completed a review and are waiting to discuss it with member companies."*
> ***—Richard L. Ranger, a senior policy advisor at API***

'Often takes longer'

Ranger said, "If you roll up the deep gas plays in the Intermountain West and the work in the Gulf of Mexico in deep water, you're looking 4-9 years before production begins. Each of these prospects and plays brings its own challenges. As we move to frontier areas and drill deeper to pursue projects in more challenging regimes, it often takes longer. The idea of a 5-year lease term would have worked a generation ago when you were chasing basic sandstone gas plays on 160-acre tracts in western Oklahoma, but it won't work now."

Land ownership patterns also pose challenges for producers, IPAA's Naatz told OGJ. "It is important to recognize that in the Intermountain West, a producer often has to work with federal, state, and private landowners to put acreage together to secure credit. In and of itself, this won't put people out of business. But it will make it more difficult for independent producers," he said.

IPAMS's Sgamma said the association is more concerned about the proposal to increase fees and royalty rates, which she said would result in less gas produced from federal lands. "When costs go up, a producer has less money to spend on actually developing the resources," she said.

Ranger said he was most troubled by the draft's proposed requirement that a lessee supply the government information every couple of years that he has been pursuing development diligently troubled him most. "The bill is silent by what benchmarks this will be determined. It also doesn't consider how government employees will look at reams of paper and electronic filings they would receive in response to this requirement," he said.

Ranger added, "Finding oil and gas requires ongoing judgment calls, comparing leases and prospects. Somehow, there's to be some arbitrary standard to determine leases are diligently being developed. We have it already with the existing leasing system, where companies have to risk additional capital to determine if the lease has commercial properties. We've been finding real oil and gas. What this process is going to add in administrative burdens will make it that much harder."

'Every incentive already'

Production incentive fees also are unnecessary, Naatz said. "Operators are part of a competitive bid process when they bid for leases. They pay bonuses and rental rates. No company I know simply doesn't lease land and sit on it. They're conducting seismic work, putting land packages together, and otherwise trying to move ahead. Companies have every incentive to produce already. This will simply add more costs and, certainly, for marginal areas when prices are low make it that much harder to produce," he said.

Sgamma said, "Why wouldn't they figure out what due diligence is before they propose punitive measures? Shouldn't they be looking harder at data inconsistencies and problems the Interior Department has? They propose additional fees, but show no appreciation for the exploratory work, environmental analysis, and permitting companies do on their leases."

The three oil and gas association officials also questioned the rationale behind combining BLM and MMS. "I don't understand what a bureaucratic organization is going to do when institutions have been in place for half a century. It's hard to tell from the proposals what the impacts would be. At a time when there's so much change being proposed, I think a major reorganization would delay positive gains in improving energy security and developing renewable resources," Sgamma told OGJ.

"I don't understand what a bureaucratic organization is going to do when institutions have been in place for half a century," she said, adding, "It's hard to tell from the proposals what the impacts would be. At a time when there's so much change being proposed, I think a major reorganization would delay positive gains in improving energy security and developing renewable resources."

Ranger said, "The draft's proposal to create a new single office of federal energy mineral's leasing has great potential to be a totally wasted exercise. There are functions performed by BLM and MMS that are unique. The loss of efficiency and expertise that would be lost would be considerable."

Withdrawals, delays

The association officials also questioned whether creating new planning councils would be effective in producing more energy domestically. Ranger said, "The legislation is silent as to whether this new committee-driven planning effort will stop all other processes until it delivers its findings. It also, particularly offshore, seems to invite the planning councils to identify new areas to be withdrawn."

He said, "Overall, this approach seems destined to change and transform a decision-oriented approach with accountabilities and expectations with endless planning creating new opportunities for special interest groups to insert themselves into

> *"It's clear that they're trying to boost renewable energy development on public lands. At the same time, they're making it more difficult to produce natural gas, which we need to enable those renewable energy resources and tackle climate change."*
> ***—Kathleen Sgamma, government affairs director, Independent Petroleum Association of Mountain States***

the process to stop energy development. It's possible that even if these planning groups produce a recommendation for leasing, one of these groups will sue to force consideration of one of their recommendations."

Ranger said, "It seems tailor-made to throw new roadblocks in the way of America's energy security in places out west and in deepwater frontiers. It will create new burdens on both government and industry at a time when we're concerned about jobs, about revenues, about investment and about sustainable energy supplies and energy securities. This bill works against every one of these objectives."

Sgamma said, "It's impossible to say from the bill how that would interact with the already existing land use planning processes. BLM has spent hundreds of man-years and millions of dollars developing these processes over several decades. It spent $35 million in Utah over the last 6 years. That's just one state. The bill is unclear how this new structure would interact with this."

The officials emphasized that the proposals could change before the bill is introduced, but are troubling just the same. "Taken in total, they go exactly against efforts to increasing energy, and oil and gas in particularly, on federal lands," Naatz said, adding, "All of these provisions are going to make it more difficult for independent producers in particular to explore for oil and gas in the Intermountain West and across the country." ✦

"We need to look more closely at these proposals, which are only a draft. Our main concern is that it will create further delays. We've seen from the environmentalists' playbooks that the more opportunities there are, the more they'll make it difficult to actually do work."

—Daniel T. Naatz, vice-president, federal resources and political affairs, Independent Petroleum Association of America

Georgia objects to Rosneft agreement with Abkhazia

Eric Watkins
Oil Diplomacy Editor

The government of Georgia has criticized Russia's OAO Rosneft for signing an exploration and development agreement with the breakaway Republic of Abkhazia, calling the document a violation of Georgia's laws and territorial integrity.

"This step of the Russian national company Rosneft is yet another proof evidencing Russia's aggressive policy against Georgia," the Georgian foreign ministry said in a statement.

The Georgian statement was referring to the 5-year agreement signed by Rosneft and Abkhazia on May 26 under which two companies will be established: one to manage upstream operations and the other to focus on downstream operations.

"The Russian authorities, as well as representatives of both public and private structures, need to be reminded that any deal or agreement…is a violation of Georgian law…and will be declared null and void," the Georgian foreign ministry said.

"When the territorial integrity of Georgia is restored, operations of such companies as Rosneft as well as of other Russian companies in Abkhazia and South Ossetia will be annulled," said Georgia's Minister of Economic Development Lasha Zhvania.

"They will suffer significant financial losses," said Zhvania, referring to Rosneft's agreement with Abkhazia as well as an earlier one under which Russia's OAO Gazprom is building a natural gas pipeline directly connecting Russia with South Ossetia.

Georgia considers both Abkhazia and South Ossetia as parts of its territory, while Russia stands accused of helping both regions rebel from central government control—a point underscored by Rosneft.

Rosneft responds

In response to the Georgian criticism, Rosneft openly acknowledged that it is an arm of Russian state policy and said it intends to work in Abkhazia as in a sovereign state.

"As a state company, Rosneft is a 'carrier' of the Russian Federation's official policy in the fuel and energy sector," a company source told Russian state media. "We have been selected as a state company to work in Abkhazia which Russia has recognized as a sovereign state."

Rosneft Pres. Sergey Bogdanchikov played down the political aspect of the agreement, however, saying it represented a sound business decision.

"We don't want to expand to Abkhazia to take over someone else's businesses, but to promote their development," Bogdanchikov said. "We see booming development in the republic and its exceptionally mild tax climate, which determines an investor-friendly environment."

"Rosneft will start oil prospecting and drilling on Abkhazia's shelf to appraise its oil reserves," said Abkhazia President Sergei Bagapsh. "If the reserve of oil is sufficient for commercial extraction, a separate agreement will be signed to define the principles of oil extraction."

Abkhazia's view

Even before any formal exploration, Abkhaz officials were speculating on the amount of oil in the region. "Oil reserves on the Abkhaz shelf total 350-500 million tonnes according to preliminary estimates," a source in the Abkhaz government told Russia's Inter-

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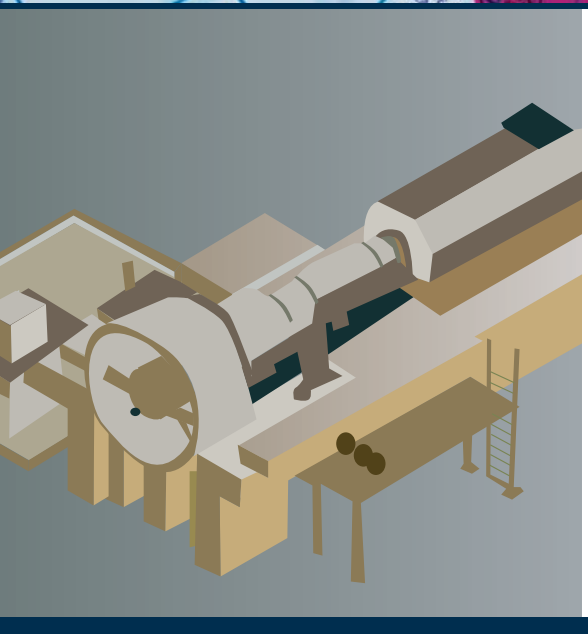

Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment.

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

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

Four 58-MW Rolls-Royce Trent GTGs Available for Delivery Within 120 days

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

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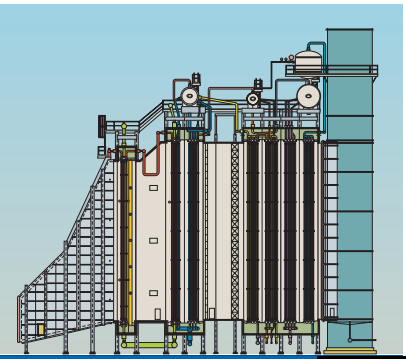
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Three New Vogt F-class HRSGs Now Available for Completion and Delivery by Vogt Within 14 Months



- Product type: natural circulation – unfired, triple pressure reheat heat recovery steam generators (HRSGs) designed for F class gas turbines.
- The HRSGs are designed for duct firing and feature a horizontal gas path; three pressure levels and reheat unfired.
- The buyer will have some flexibility to incorporate certain modifications before final completion by Vogt.
- Units come complete with all normally supplied auxiliaries.

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WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Pouring oil on rebellion

The oil and gas industry is not often thought of as a vehicle for making peace. But in Turkey these days they are thinking otherwise following the start of oil exports from Iraqi Kurdistan.

One commentator said fostering ties between Turkey and Iraq's Kurdish Regional Government (KRG), marked by oil exports via the Iraq-Turkey pipeline, could give Ankara an upper hand in its fight against terror.

That fight is the one waged by Turkey against the outlawed Partiya Karkeren Kurdistan (PKK). According to Ankara, the PKK is a Kurdish secessionist organization that uses terrorism against civilian and military targets to achieve its political goal of an independent Kurdish state.

Diplomats said steps taken by the KRG to combat the PKK would boost bilateral ties, giving the Turkish regime an edge over the PKK.

Boosting trade?

"The [KRG's] contributions to our fight against terrorism would reflect positively on our bilateral trade. Turkey is in close dialogue with all the groups in Iraq and we have already seen the fruits," a Turkish diplomat told local media.

"The PKK does not have the strength it once had and has been losing ground. The [KRG] has seen that cooperation against the PKK will have positive impacts on bilateral ties with Turkey, and it will sell out the PKK and prefer Turkey," the diplomat said. The debate was triggered last week after the KRG officially started transporting crude oil to the international market, with an initial shipment of 100,000 bbl to Ceyhan from the Taq Taq and Tawke fields.

Essentially, the thinking behind the diplomat's words suggests that the pipeline connection between the KRG and Turkey will be stronger than any relationship between the KRG and the PKK.

Ultimately, the Turkish diplomat is suggesting that with its oil now in Turkish hands, the KRG would not be willing to support any action of the PKK against Turkey. After all, it would not take much for the Turks to shut down the line.

Stability important

However, another observer, Kurdish journalist Rebwar Karim Wali, warned that the KRG could not do much against the PKK. "Neither the Unites States nor Turkey would want a source of instability in the north that could risk economic interests here," he said.

But consider something else: the Iraqi government. While it has countenanced the flow of oil from Kurdistan to Turkey, there's no reason to think it will allow the flow to continue unabated—especially if Iraqi Kurds prove too independent.

"How these oil revenues and contracts will be handled isn't clear," said Hazim al-Nuaimi, a political analyst.

"The reason exports were allowed was because of (financial) pressure on the government, but it is obvious it is not comfortable and disagrees," al-Nuaimi said, adding, "This lays political and economic landmines for the future."

Baghdad's political and economic landmines, of course, are being laid right under the KRG's pipeline to Turkey. ✦

fax news agency.

At the same time, concerns have already been voiced over the potential impact of exploration and development on Abkhazia's environment—an issue addressed by the country's Minister of Economy Kristina Ozgan.

"Rosneft promises to employ advanced methods and technologies in developing offshore deposits," said Ozgan. "When the implementation of specific projects begins, the parties concerned will determine the rules, the legal form and the payment terms—everything that concerns ecological security."

"All project documents are to undergo examination by experts and Abkhazia's state ecological service will have a say in this," Ozgan said.

Earlier this year, Georgia and the US, concerned over Russian aggression, agreed to step up physical security of energy transit across the trans-Caucasus to European markets as part of the US-Georgia Charter on Strategic Partnership signed on Jan. 9 (OGJ, Jan. 19, 2009, Newsletter).

Russia invaded Georgia in August 2008 after the Tbilisi government tried to retake the breakaway region of South Ossetia by force. The conflict saw considerable disruption in the transit of oil and gas across the region, with Russian warplanes said to have targeted pipelines and railways. ✦

Brazil, Venezuela see end to impasse over joint projects

Eric Watkins
Oil Diplomacy Editor

Major disagreements preventing joint projects by Brazil's state-owned Petroleo Brazileiro SA (Petrobras) and Venezeula's Petroleos de Venezuela SA (PDVSA) will be cleared up in 3 months, according to the presidents of the two countries.

"I am optimistic we can deliver good news in 90 days," said Brazil President Luiz Inacio Lula da Silva following his meeting with Venezuela President Hugo Chavez. "In that period we will be able to define all the details, not only of the [Abreu e Lima] refinery, but also of Petrobras's participation in the Orinoco belt," Lula said.

Earlier in a private session accidentally broadcast to reporters, the two presidents expressed their irritation with the continued breakdown of negotiations between Petrobras and PDVSA.

"I confess my frustration, but it's the fault of both countries that we haven't been capable of reaching an accord," Chavez said, referring to talks between the two oil companies that began in 2005. The Venezuelan president also expressed regret that Petrobras is one of the few important international oil companies without any operations in the Orinoco belt. Referring to the Abreu e Lima refinery project, Lula joked, "The accord was not possible because Petrobras and PDVSA are two very pretty and vigorous young ladies who fight over any problem."

Extended agreement

In the absence of a new agreement, Petrobras and PDVSA executives decided on a 90-day extension of the agreement they signed last year, which calls for joint participation in the refinery now under construction by Petrobras.

When built, Abreu e Lima will be capable of processing 200,000 b/d of oil, with Petrobras and PDVSA each supplying half of the required crude.

But the project has been delayed by a dispute over how much the joint venture will pay for the crude from Venezuela, according to Petrobras Chief Executive Jose Sergio Gabrielli. He said he also objects to PDVSA's bid for Brazilian distribution rights to the fuel produced by the refinery.

Gabrielli's remarks echoed earlier statements by Petrobras supply and refining director Paulo Roberto Costa. In February, Costa said PDVSA needed to change its position on the price of

crude to be imported from Venezuela and drop its demand that its 40% of the oil refined at the site be put into the consumer market of northeastern Brazil (OGJ Online, Feb. 13, 2009).

The role of the Petrobras executive in the disagreement with PDVSA was highlighted by Lula who said, "Chavez is even ready to invite Gabrielli to a meeting to see why he has such a hard heart." The Brazilian president went on to say: "One of the two (Gabrielli or his PDVSA counterpart) has one [hard heart], because the negotiation is proceeding by millimeters."

Earlier in May, Petrobras said it would restart the tender process for the Abreu e Lima refinery, seeking lower bids on work to be done at the facility in order to cut costs. Original bids for the refinery came in at 23 billion Brazilian reals ($10.9 billion), more than double the BRL9 billion budget. Under the preliminary shareholders' contract, Petrobras owns 60% of Abreu e Lima while PDVSA holds the remaining 40%. ✦

Deloitte: UK Continental Shelf to see activity drop in drilling

Uchenna Izundu
International Editor

Drilling activity on the UK Continental Shelf may fall by half in 2009 and drop again in 2010 despite the new incentives and tax changes introduced by the Chancellor in April, Deloitte LLP has warned.

The advisory firm said high operating costs and tax burdens are affecting drilling with investment in new and existing fields expected to fall to £3.5-4.5 billion this year and dropping again to £2.5-4 billion in 2010.

The analysis was given at a briefing in Aberdeen in partnership with trade association Oil & Gas UK, which lobbied for major changes in the fiscal regime to improve activity on the UKCS, especially with low oil prices.

"Merger and acquisition activity is expected to rise within the next 12-18 months; however equity will be needed for survival," said Deloitte.

"We are back to being an oil economy," said Andrew Ogram, tax partner at Deloitte. "Oil and gas contributed 28% of corporate tax in 2008-09 and although the tax take from the North Sea is expected to almost halve in 2009-10, it is still predicted to contribute one fifth of corporate tax revenues.

The views about the impact on the UK North Sea are also shared by North Sea consultancy firm Hannon Westwood. Partner Chris Bulley said the firm expected activity to fall as companies rein in unnecessary expenditure and discretionary drilling plans are put on hold. "By the end of first quarter 2009 there were 7 new well spuds and 10 sidetracks compared with 20 and 8, respectively, for the same period of 2008."

The drop in activity this year contrasts significantly with that of 2008 where according to data collected by Hannon Westwood, the UK saw its highest exploration and appraisal drilling since the last peak in 1997. Operators added 841 million boe to reserves from the 18 exploration and 19 appraisal successes last year against 1.08 billion boe produced in the year.

However, the effect of the current downturn is not reflected in 2008 drilling activity because many of the 2008 wells were already contracted to rig companies and drilling budgets allocated.

The Central North Sea proved again to have the largest number of exploration wells and the majority of successes. "The northern North Sea, West of Shetland, and southern North Sea all recorded exploration drilling success, while there was no drilling in 2008 in the East Irish Sea, English Channel, or Southwest Approaches. A multiwell, multioperator drilling program is, however, scheduled for the East Irish Sea in 2009," said Hannon Westwood.

However, the central and southern North Sea had the most appraisals, with the gas prone latter area having seven successes. Sterling Resources discovered that its Breagh field had an east and west extension, which was confirmed by two wells on Block 42/13.

Hannon Westwood estimates that the 18 successful exploration wells found 488 million boe (an average finding rate of 27.1 million boe/well), while 353 MMboe was found by 20 successful appraisal wells (an average rate of 17.7 MMboe/well).

Finding costs reflect the wide variety of well types, with an overall UKCS average of $2.80/boe for appraisal and $2.30/boe for exploration. ✦

COMPANY NEWS

Shell plans major organizational revamp

Royal Dutch Shell PLC announced plans for major restructuring of its organization, with its 200 most senior managers initially affected (see Personnel Moves, p. 36).

Effective July 1, the company will merge its exploration and production, gas and power, and oil sands units into two new divisions to improve operating performance and technology. With 22,000 people working in the three segments, thousands of jobs are potentially at risk with the overhaul. Officials said the 2,000 employees at

Shell's headquarters in The Hague will be strongly affected.

In other recent company news:

• Eni SPA and Enel SPA will assign to OAO Gazprom a 51% stake in SeverEnergia, a Russian holding company with exploration and production licenses. The deal is expected to close in June.

• China National Petroleum Corp. subsidiary PetroChina, taking a first-ever step away from its parent company, has agreed to pay $1.02 billion to Keppel Corp. for a minority stake in Singapore Petroleum Co.

• Valero Energy Corp. agreed to acquire Dow Chemical Co.'s 45% interest in the Total Raffinaderij Nederland NV (TRN) for $725 million.

Shell revamp

The restructuring measures are intended to simplify Shell's company structure, improve project implementation, and cut costs. They are similar to recent initiatives by BP PLC and ExxonMobil Corp.

A Shell spokesman told OGJ no figures had been given on job cuts or potential economic savings. "Some people will have to internally apply for their jobs as it will be redefined; others will have to leave."

The revamp began with the abrupt resignation of Linda Cook, head of gas and power, whose division will be subsumed with oil sands and with exploration and production into two new streamlined units. She left by "mutual agreement," Shell said.

Cook's departure was June 1, prior to new chief executive Peter Voser succeeding Jeroen van der Veer on July 1. Cook had competed for the position; she has been with the company 29 years, the last 5 as executive director of gas and power, Shell trading, global solutions, and technology. Under her tenure, Shell's LNG capacity increased over 60% in the last 5 years.

Analysts welcomed Voser's plans that stress cost-cutting and operational performance, but they have concerns about subdividing the upstream between two directors. David Thomas, analyst at Citigroup Inc., said, "[T]he level of financial disclosure under the streamlined reporting lines may be less than has been the case to date."

Upstream will consist of two businesses: upstream Americas covering North and South America, and upstream international, covering the rest of the world.

Shell's high upstream costs are a major issue because it is developing unconventional production, such as Canadian oil sands, GTL, and LNG. The company expects to invest up to $32 billion this year.

Shell's downstream division will contain the refining, marketing, and chemicals businesses and will be expanded to include trading and alternative energy activities in Shell, excluding wind, which will be part of upstream. Mark Williams will be the director of downstream.

"A new business—projects and technology—will combine all of Shell's major project delivery, technical services, and technology capability covering both upstream and downstream. It will also oversee Shell's safety and environment performance," said Shell.

Gazprom-SeverEnergia

Enel and Eni have given Gazprom until 2010 to pay the $1.5 billion for the stake in two tranches. "As a result of the transaction, Eni and Enel's equity will cash in $900 million and $600 million dollars, respectively," said Eni.

The new shareholding in SeverEnergia will be Gazprom holding 51%, the Italian partners, 49% (via a joint venture between Eni and Enel holding 60% and 40%, respectively).

This agreement builds upon a deal that was signed in April giving Gazprom until May 30 to implement its option to buy the stake (OGJ Online, Apr. 11, 2009). SeverEnergia was formerly known as EniNeftegaz and was two production companies belonging to the defunct OAO Yukos.

By 2013, SeverEnergia hopes to produce at least 150,000 boe/d focusing on west Siberian fields. SeverEnergia has the Arcticgaz, Urengoil, and Neftegaztechnologia E&P licenses, which hold an estimated 5 billion boe.

"The parties also agreed to produce first gas by June 2011 from the Samburskoye field. The parties have 90 days to define the plan and obtain all the necessary authorizations, including the extensions of the licenses by Rosnedra, the Russian authority regulating the exploitation of the country's mineral and oil resources," said Gazprom.

Enel Chief Executive Officer and General Manager Fulvio Conti said this partnership would enable Enel to grow in the Russian market throughout the entire value chain, from gas fields to generation and sale of electricity. "From this perspective, the entry of Gazprom provides us with a guarantee of being able to continue contributing a reliable supply of gas to our Russian power plants at advantageous conditions through our SeverEnergia gas quota."

PetroChina-SPC deal

"SPC will become a new platform for the implementation of our international strategy and will provide a broader foundation and stable path for development," PetroChina said of the agreement signed by PetroChina International (Singapore) Pte. Ltd., and Keppel Oil & Gas Services Pte. Ltd.

PetroChina said it purchased 45.51% of the Singaporean company's issued share capital, adding that it also intended to make an offer for the remaining shares upon completion of the agreement.

The Chinese firm said that SPC is a regional energy company with interests in petroleum refining and marketing and that it owns a 50% stake in SPC, one of the island nation's three major refiners.

SPC also is engaged in oil and gas exploration, with production properties in China, Indonesia, Vietnam, Cambodia, and Australia.

The agreement marks a first for PetroChina, which has previously relied on support from CNPC for overseas agreements, with all business handled via a

joint venture known as CNPC Exploration & Development Co.

The agreement between PetroChina and Keppel has prompted comment among oil industry analysts. "This should be a landmark as PetroChina is acquiring overseas stake directly (rather than via its state parent before), and we expect Sinopec Corp. to follow suit," China Merchants Securities analyst Qiu Xiaofeng told the Shanghai Daily.

Analyst Global Insight said, "The purchase through PetroChina…rather than through parent company CNPC could help emphasize the commercial nature

PERSONNEL MOVES AND PROMOTIONS

Shell changes senior management structure

Royal Dutch Shell PLC has made changes to its senior management structure effective July 1 (see Company News, p. 34).

Peter Voser will become chief executive officer.

Marvin Odum, currently executive vice-president for EP Americas, will become director for upstream Americas.

Malcolm Brinded, currently executive director for exploration and production, will become executive director of upstream international.

Matthias Bichsel, who is currently executive vice-president for exploration and production technology, will be the director of projects and technology.

Other moves

ConocoPhillips made several senior management changes.

Ryan Lance, currently president, exploration and production, Asia, Africa, Middle East, and Russia/Caspian, will become senior vice-president, exploration and production, international.

Kevin Meyers, currently president, Canada, E&P, will become senior vice-president, E&P Americas.

Kevin Mitchell, currently general manager, finance, strategy and planning, E&P, will become vice-president, E&P, strategy, administration, and technical services.

Occidental Petroleum Corp. named **Anita Powers** vice-president of Oxy and executive vice-president, worldwide exploration, for Oxy Oil & Gas.

Powers has worked at Oxy for 30 years. Since December 2006, she has served as vice-president, worldwide exploration. Before that she served as director of worldwide geoscience, vice-president of exploration in Colombia, and chief exploration geologist for worldwide exploration.

Hess Corp. appointed **Michael Turner** as senior vice-president, global production, with responsibility for Europe and Asia.

Turner joins Hess from Royal Dutch Shell PLC. In his 28 years with Shell, he held leadership positions in a range of US and international production operations, including its UK North Sea assets.

Turner will succeed **George Sandison**, who will become senior vice-president, global exploration and production services, with responsibility for global drilling, supply chain, environment, health and safety, and social responsibility.

Noble Energy Inc. elected **David Stover** as the company's president. He will also continue to serve as the chief operating officer.

As president and COO, Stover will be responsible for the daily operations of the company including all exploration, production, drilling, and marketing activities.

Prior to joining Noble Energy in 2002, Stover held senior management positions with BP PLC and predecessor companies Vastar Resources Inc. and ARCO.

Newfield Exploration Co. named **Lee K. Boothby** as chief executive officer. He was also elected as a member of the board.

Boothby joined Newfield nearly 10 years ago. Prior to becoming president in February, he served as senior vice-president, acquisitions and business development.

Gary D. Packer was promoted to executive vice-president and chief operating officer. Packer joined Newfield in 1995 and most recently served as president of Newfield's Rocky Mountain division in Denver.

Terry W. Rathert was promoted to executive vice-president and chief financial officer. Prior to this promotion, he served as senior vice-president and chief financial officer since 1994 and also served as secretary of Newfield until May 2008. Rathert is a founding member of the company.

Daryll T. Howard was promoted to vice-president, Rocky Mountains. Prior to this promotion, he had served as East Team Rocky Mountain asset manager since June 2008.

Samuel E. Langford was promoted to vice-president, corporate development. Prior to this promotion, he had served as manager, acquisitions, planning and commercial development of Newfield's Midcontinent division.

Dana Gas PJSC appointed **Ahmed Al-Arbeed** as chief executive officer and **Rashid Saif Al-Jarwan** as executive director.

Al-Arbeed has more than 30 years of experience in the oil and gas industry and was named executive director of upstream in January 2008.

Al-Jarwan joined Dana Gas as general manager in February 2006, bringing with him oil and gas industry

of the transaction in order to deflect criticism that PetroChina is pursuing a nationalist grab for energy supplies."

Valero-TRN deal

TRN owns a 190,000 b/d refinery in the Netherlands' Zeeland region on the Scheldt River. TRN also owns an interest in the Massvlatke Olie Terminal in Rotterdam, one of the world's largest oil terminals.

The transaction is subject to regulatory approval as well as a right-of-first refusal held by Total SA, the refinery operator and owner of the remaining 55% interest in TRN, Valero said. The transaction is expected to close in the third quarter.

TRN's refinery, built in 1973, received major upgrades in the mid-1980s, mid-1990s, and throughout this decade. The refinery has a large, distillate-hydrocracking unit with capacity of 68,000 b/d.

Bill Klesse, Valero chairman and chief executive officer, said the acquisition represented an exceptional entry point into the European market, especially since TRN's refinery can process a variety of discounted feedstocks primarily into diesel and jet fuel within the world's strongest diesel market. ✦

experience from 30 years in the ADNOC group of companies.

Continental Energy Corp. named **Andrew Eriksson** as president and chief operating officer of the company.

Eriksson has worked for Continental in its Jakarta office since 2003 and will continue to serve as the company's exploration manager.

Steven B. Hinchman assumed duties as executive vice-president and chief operating officer of Callon Petroleum Co., Natchez, Miss.

Hinchman served as executive vice-president of technology and services at Marathon Oil Corp., a position he held since April 2008. He joined Marathon in 1980 as a field engineer and had been a member of its executive committee since October 2000.

Callon operates in the Gulf of Mexico.

Finley

The Society of Independent Professional Earth Scientists (SIPES) named **William R. Finley** as president for 2009-10.

Finley is an independent petroleum geologist and participating partner of Rozel Energy LLC and is involved in onshore and offshore petroleum exploration and exploitation in the Louisiana Gulf Coast area.

Other 2009-10 officers are **Marc D. Maddox**, vice-president; **Kenneth J. Huffman**, vice-president of national energy; **J. Phil Martin**, secretary; and **Bobby M. Greenwood**, treasurer.

New members of the SIPES board of directors include **Donna Balin**, **Dennis Gleason**, and **Larry Rairden**.

ExxonMobil group outlines Hebron development details

The Hebron project on the Grand Banks off eastern Canada should start producing by the end of 2017 and recover 566 million bbl of oil over a 30-year productive life, said project operator ExxonMobil Canada Properties.

The partners expected to decide in the first half of 2009 whether they will predrill wells, the company said in a project description filed with the Canada-Newfoundland and Labrador Offshore Petroleum Board.

The project will involve development of Hebron, Ben Nevis, and West Ben Nevis fields in the Hebron Unit in 289-335 ft of water in the Jeanne d'Arc basin 211 miles east-southeast of St. John's, Newf., and 5½ miles north of giant Terra Nova oil and gas field (Fig. 1).

The province previously said production would begin as early as 2016 and build to 150,000 b/d in 2 years (OGJ Online, Feb. 2, 2009).

Development outline

Initial development will involve Hebron field only, but the unit includes four significant discovery license areas, 1006, 1007, 1009, and 1010.

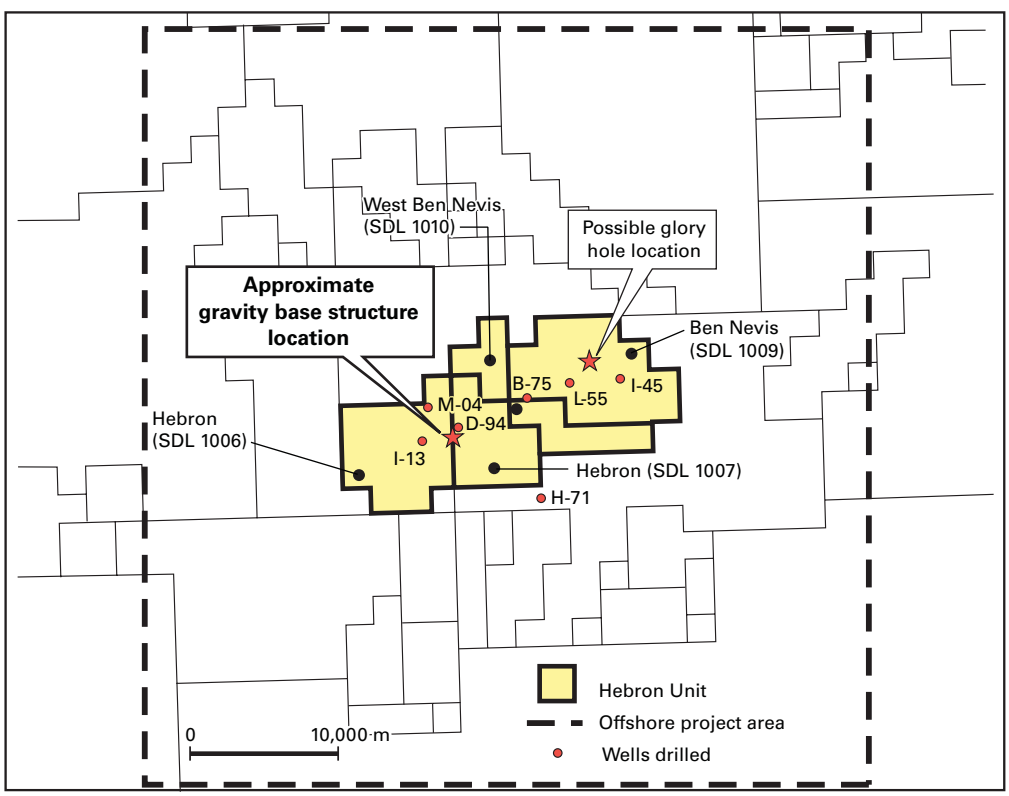
The four SDLs contain the most likely extent of the oil for the delineated pools in the Hebron Unit, said the project description, filed in part to support environmental studies.

"The Hebron Unit could be expanded if additional studies, seismic or exploration and/or delineation drilling proves that economically recoverable oil pool accumulations extend beyond the currently envisioned boundaries" of the unit, the company said.

A stand-alone, reinforced gravity-based structure would be used to develop the giant field with water injection as the main drive mechanism. That facility would be built at Bull Arm on Trinity Bay 130 km northwest of St. John's.

HEBRON OFFSHORE PROJECT AREA

Fig. 1

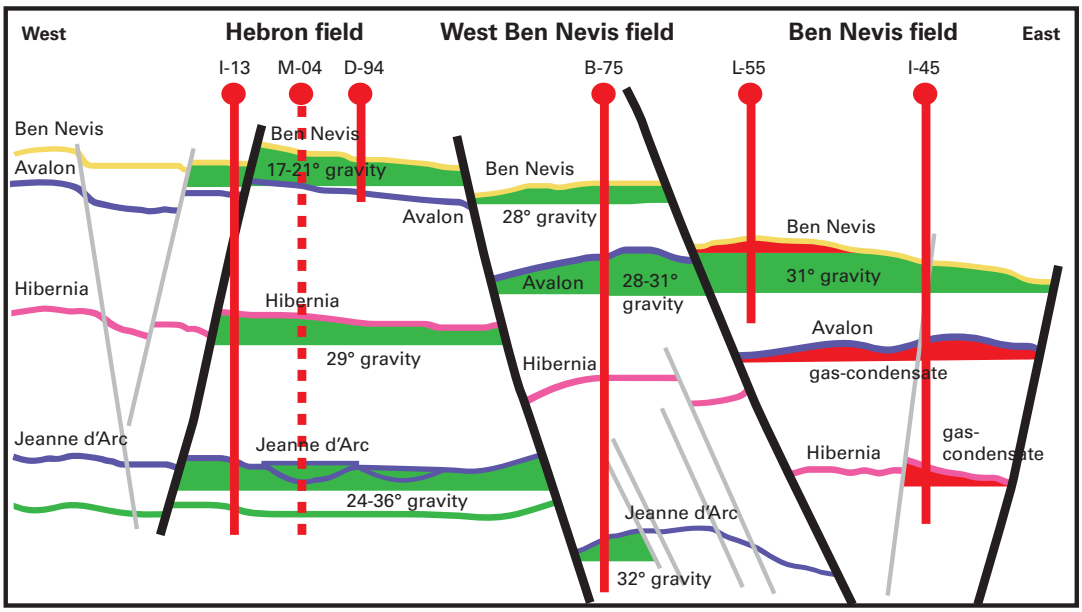


Produced gas could be used for artificial lift, production assist in secondary oil reservoirs, and for water-alternating-gas injection to improve recovery in primary producing intervals.

Interests in the four SDLs that comprise the Hebron unit are ExxonMobil Canada Properties 36%, Chevron Canada Ltd. 26.7%, Petro-Canada 22.7%, and StatoilHydro Canada Ltd. 9.7%. The government's 4.9% stake is held by Nalcor Energy-Oil & Gas Inc., formerly Oil and Gas Corp. of Newfoundland and Labrador.

SCHEMATIC CROSS-SECTION OF HEBRON PROJECT AREA

Fig. 2



Not to scale. M-04 location projected into the plane of the section.

Hebron reservoirs

Unit wells have encountered several reservoirs (Fig. 2):

Hebron field: Ben Nevis reservoir, including the fault block penetrated by the D-94 and M-04 wells, and the fault block penetrated by the I-13 well; the Lower Cretaceous Hibernia reservoir, defined by the I-13 and M-04 wells; and the Upper Jurassic Jeanne d'Arc reservoir, including the isolated B, D, G, and H hydrocarbon-bearing sands, defined by the I-13 and M-04 wells.

West Ben Nevis field: Ben Nevis reservoir, penetrated by the B-75 well; Lower Cretaceous Avalon reservoir, defined by the B-75 well; and Jeanne d'Arc reservoir, penetrated by the B-75 well.

Ben Nevis field: Ben Nevis reservoir, defined by the L-55 and I-45 wells; and the Avalon and Hibernia reservoirs penetrated by the I-45 well.

The Ben Nevis pool in Hebron field is likely to yield 80% of the field's total oil, even though its 20° gravity oil is 10-20 times as viscous as water and reservoir quality is lower than that in Hibernia or Terra Nova fields.

Relative to the Hebron Ben Nevis pool, the Hebron Jeanne d'Arc and Hebron Hibernia pools have higher oil quality, poorer reservoir quality, lower recovery factors, and higher development costs.

Development details

Start-up could occur in 2017 if regulatory approvals were received in 2011 and the partners sanctioned the project in 2012.

The partners visualize a base case development of 35-45 wells, of which 13 could be predrilled. Drilling would continue at least through 2025.

A glory hole would not be used if wells are predrilled because the risk of exposure to potential ice damage for 2-3 years is much lower than for the predicted well life of 20-40 years.

"In addition to the base case development, there is opportunity for the development of additional pools in the Hebron Project Area, depending on the drilling results, production performance (of wells from the initial development), studies, possible delineation wells, new seismic data or some combination of these," the filing said. For example, the Ben Nevis reservoir in Ben Nevis field could be part of an optional later phase of development subject to filing a supplemental development plan. In that case, the total number of wells could grow to 70 or more.

Gas potential

Gas-oil ratio of Hebron field fluids is relatively low, but ExxonMobil expects the gas yield to exceed what is needed to facilitate oil production.

The partners are developing a gas management plan that will take into account a number of considerations including:

- Utilization of gas for artificial lift in the producing wells.
- Injection of excess produced gas into secondary reservoirs such as the Ben Nevis pool at West Ben Nevis field.
- Potential need to produce back injected gas later in field life.
- Gas injection into primary producing intervals to improve oil recovery, such as water alternating gas injection. ✦

Iceland's first licensing round nets two bidders

Iceland's National Energy Authority (NEA), which recently launched the country's first-ever licensing round, said it received bids from two companies for exploration rights to the northern Dreki area.

"This is a big day in the history of Iceland's energy resources utilization," said Industry Minister Katrin Juliusdottir as quoted by the Icelandic daily Morgunbladid.

NEA said it received applications from Aker Exploration as well as a combined bid from Sagex Petroleum and Lindir Exploration for Blocks IS6708/1, IS6708/2, IS6808/11, and IS6909/11.

Blocks IS6808/11 and IS6909/11 are within the area of an Oct. 22, 1981, agreement between Norway and Iceland on the continental shelf between Iceland and Jan Mayen (OGJ Online, Sept. 5, 2008).

As a result of that agreement, according to one official, the Icelandic authority will have to consult with Norwegian authorities before it can grant permission to companies to explore the area of shared sovereignty.

NEA, which announced the licensing round on Jan. 22, said it would evaluate the bids and announce its decision by the end of October this year.

NEA expressed disappointment in the low number of bidders, saying that "the difficult conditions in the world economy as well as the low oil prices have undoubtedly affected other parties that were interested in the licensing round."

Altogether, Iceland plans to offer 100 offshore oil and gas licenses this year. At the time of the January launch, NEA said individual applications for licenses may cover one or more of the blocks or partial blocks, up to a maximum of 800 sq km.

"The number of licenses on offer is up to five as a maximum," NEA said, adding, "Applicants are also encouraged to nominate a secondary area in case of an area of first choice overlapping with other applications." ✦

Australia

Spectrum ASA, Oslo, and Australian Seismic Brokers are reprocessing 15,800 km of regional 2D data from Australia's Northwest Shelf.

The deep-imaging data, which incorporate scores of key well ties, were originally recorded to 16 sec using a 5,000-m streamer by Australian Geological Survey Organisation in the 1980s-90s.

Reprocessing focuses on accurate and detailed velocity analysis and preserving amplitudes for subsequent amplitude variation with offset information, and on providing improved structural and stratigraphic imaging.

To be completed by September 2009, the new dataset will comprise prestack time migration stacks, gathers, angle stacks, velocities, and navigation data. The first reprocessed lines available will be those related to the upcoming acreage release by the Australian government in the Exmouth and southern Browse areas.

Colombia

Ecopetrol's Hocol SA subsidiary has an indicated gas-condensate discovery on the Niscota block in the Andes foothills 186 miles northeast of Bogota.

Talisman Energy Inc., whose Colombian subsidiary holds 30% interest in the Llanos basin block, said the Huron-1 exploration well was spud in June 2008 and has drilled to 18,275 ft.

It has encountered several reservoirs in a heavily faulted area. One reservoir tested at 3,400 b/d of condensate. Gas volume wasn't disclosed.

The well, in the Casanare area of Piedemonte department, is being deepened to complete evaluation of the prospective section.

Hocol is operator with 20% interest. Tepma BV, Bogota, has 50%.

India

Consulting engineers estimated a prospective resource of 10.8 tcf of gas and 143 million bbl of oil for the D3 and D9 exploration licenses in the Krishna Godavari basin off India, said Hardy Oil & Gas PLC.

The technical review incorporated data from the company's Dhirubhai-39 and 41 discoveries and extensive geological and geophysical work undertaken by the respective joint ventures. That work includes more than 2,000 sq km of 3D seismic data on D3 and

prestack time migration 3D seismic data processing and a constrained source electromagnetic survey on D9.

Using a play-based exploration methodology, the potential gross risked best estimate resource for the D3 block is estimated at 9.5 tcf. This includes identified prospects and leads and a number of postulated prospects based on the play area and field size distribution.

Colorado

Etoco LP, private Houston independent, proposes to drill two rank wildcats in east-central Colorado in nonproducing El Paso County.

The company sought state permits to drill the State-1 and Ververs-1 wells about 10 miles east of Colorado Springs to 7,000 ft.

The objectives are the Upper Cretaceous Fort Hays (Niobrara) and Codell formations, IHS Inc. reports. The locations are 45 miles northeast of Florence-Canon City oil and gas field and 50 miles south of nearest oil and gas production in the Denver basin.

Simultaneous operations develop Piceance tight gas

Guntis Moritis
Production Editor

Williams Exploration & Production in recent years has changed the way it is developing the tight gas sands in the Piceance basin of Western Colorado. It has started using skidable rigs that can drill up to 22 wells from a single well pad and fracturing operations that can stimulate wells on multiple pads from a central location.

These along with other changes in operations have made the gas development both more efficient and environmentally friendly, according to Williams.

Piceance operations

Williams acquired its interest in the Piceance basin when it purchased Barrett Resources Inc. in 2001. Barrett had drilled its first well in the basin in 1983.

The producing sands are in the Williams Fork member of the Mesa Verde formation.

William operates out of an office in Parachute, Colo., and employs about 250 people in the basin. Its operations are mainly in Garfield County with some also in Rio Blanco County.

Steve Soychak, district manager for Williams, said the company in early 2009 completed its 3,000th gas producing well in the basin compared with having only 400 producers 9 years ago.

The three main fields it is developing are Grand Valley, Parachute, and Rulison.

He noted the basin currently produces about 1.7-1.8 bcfd with Williams producing about 850 MMcfd gross, making Williams the largest producer in the basin.

He said that for 2009 the company has a $500-600 million capital-spending program and will employ 9-10 drilling rigs. Its plans are to drill about 300 wells in 2009, compared with the 600 drilled in 2008 when it had 25 rigs running, Soychak said.

In April 2009, Williams had 9 rigs working in the basin, with 8 in Garfield County and 1 in Rio Blanco County.

He added that Williams has about 7,000 remaining locations to drill in the Williams Fork, as well as potential deeper targets. Williams has not drilled a dry hole in the basin in several years, he said.

Besides the gas wells, Williams operates the Parachute Creek gas plant that has a capacity 1 bcfd throughput capacity and also has under construction the $350 million, 450-MMscfd Willow Creek cryogenic gas processing plant

The H&P Flex Rig 278 on this well pad in South Rulison field will drill 22 wells (Fig. 1). Photo by Guntis Moritis.

Wells on this pad have a spacing of 7½ ft between wells and 10 ft between rows (Fig. 2). Photo by Guntis Moritis.

This centralized frac site in South Rulison field has six 2,000-hp frac trucks for a total of 12,000 hp, and a 77,000 bbl water pit in back of the site (Fig. 3). Photo by Guntis Moritis.

near Meeker that will start operations in third-quarter 2009.

Drilling

Soychak said that drilling during the 1980s and 1990s in the basin typically involved one well from one drilling location or pad. But to minimize land disturbance and gain efficiency, William has started drilling up to 22 wells from a single well pad using skidable drilling rigs similar to ones used offshore, such as the Nabors Drilling USA LP Super Sundowner and the Helmerich & Payne Inc. Flex Rig (Fig. 1). These rigs also have top drives to improve drilling efficiency.

Williams runs a year-round drilling operation with crews working 2 weeks on and 2 weeks off.

The well locations on the pads are 7½ ft apart and form two rows, with 10 ft between rows (Fig. 2).

Soychak said the bottomhole well locations are on 10-acre spacing and produce from sands at 5,000-8,000 ft. The target sands are in the Williams Fork member of the Mesa Verde formation. These are fluvial

river channels with coal sections in between sands.

The wells have an S-shape with the bottomhole section 700-2,000 ft away from the wellhead. The bottomhole section is vertical; otherwise, the wells would be too close together, Soychak said.

William aims for a 50-ft target for the bottomhole section and uses mud motors and a 1° bent sub to build angle.

Typically the wells have a 2,500-ft gross pay section containing six to seven producing stages, Soychak said.

For handling the fluids and sand flowing back after a frac job, Williams uses a skid-mounted separator (Fig. 4). Photo by Guntis Moritis.

Operations involve simultaneous drilling, completion, fracturing, and producing from the well pad. After drilling of the first four wells, hydraulic rams skid the rig back without laying down the 4½-in. drill pipe so that another rig can complete the wells while the skidable rig drills another four wells.

The location can accommodate a completion rig, such as a stand-alone snubbing unit, alongside of the skidable drilling rig.

The drilling requires weighted water-based mud because of overpressured sands, with 9-11 ppg mud in shallower wells and 14-15 ppg mud in deeper wells.

Soychak said the use of skidable rigs has reduced surface disturbance by 75%, for instance one 2-3 acre pad can accommodate up to 22 wells. Williams's current procedure calls for not bringing the rig back to the location after completing the drilling on a pad and reducing the pad size to less than 1 acre after moving the rig off.

Soychak said average drilling time is 14 days for a 7,000-ft well, but it also can vary depending on the field. For instance, in Parachute it takes 7 days to drill a 6,500-ft well compared with 15 days for an 8,500-ft well in Rulison, he said.

The wells have a standardized tubular size, with a 13⅝-in. conductor, 9⅝-in. surface casing set at about 1,100 ft in a 12¼-in. hole, 4½-in. production casing run in a 7⅞-in. hole, and 2⅜-in. production tubing.

Williams drills the 7⅞-in. hole with polycrystalline diamond compact bits. It disposes of the cutting in an onsite long trench.

Hydraulic fracturing

Soychak said Williams started cluster fracturing about 3 years ago. This involves placing the fracturing equipment in a central location from which the equipment can pump fracturing fluids to wells on multiple well pads (Fig. 3).

The company has fractured wells at distances of more than 3 miles from the centralized frac site and Soychak noted that the centralized sites have reduced truck traffic that can disturb wildlife. The equipment on one location has fraced as many 60 wells, he said.

Soychak says that Williams fracs 50-60 zones/week.

Williams stages the frac jobs with the lowest most zone perforated and hydraulically fractured first.

It typically perforates a zone at 4 shots/ft using a limited entry technique with typically 15-20 shots total and spearheads the frac with 500 gal of 7½% HCl acid.

For hydraulic fracturing, Williams uses a water-based frac fluid with surfactant, biocides, and a friction reducer. The slick water has much less chemical than previously used in frac jobs, Soychak noted.

Solar panels power remote terminal units (RTUs) for sending information from the production site to the company's Parachute office. The Roan plateau appears in the background (Fig. 5). Photo by Guntis Moritis.

Two-stage reciprocating compressors increase the gas pressure to the gas plant inlet pressure of 800 psi from the 250 psi in the gathering line (Fig. 6). Photo by Guntis Moritis.

The surfactant in the frac fluid enhances water recovery, which in turn enchances gas recovery, the biocide controls bacteria growth, and the friction reducers allows for the pumping of fracturing jobs through the 4-in. high-pressure lines at greater distances from the fracturing equipment.

A typical frac job initially pumps the frac fluid with ½ ppg of 20/40 sand before ramping up the sand concentration to 1½ ppg toward the end of the frac. Each frac stage entails pumping 2,000-4,000 bbl of fluid with a maximum pressure of 7,000 psi. Typical pumping rates are 55 bbl/min.

Williams notes that it takes about 3 weeks for the fracturing fluid to flowback. The flowback after fracturing the zone goes through a skid-mounted unit that separates out the gas, condensate, water, and sand (Fig. 4). The use of the separator has eliminated the need to flare gas by 90%, Soychak said.

The separated fluid goes into a closed loop system the recycles the frac fluid for use in subsequent frac job and

puts the gas into the field's gas-gathering system.

Williams obtains water for the frac jobs from evaporation ponds for produced water. It has a 200,000 bbl pond at Parachute and a 500,000 bbl pond at Rulison.

The Parachute Creek gas plants have a 1-bcfd throughput capacity (Fig. 7). Photo by Guntis Moritis.

Production

The basin produces sweet gas with about 3% CO_2.

The company's gas producing wells are all on plunger lift. Soychak said the wells produce with a hyperbolic decline that initially starts at 1-1½ MMcfd and drops sharply before entering a long-lived low production rate.

The wells produce against a gathering line pressure of about 250-psi and have initial bottomhole pressures of 2,500-3,500 psi.

The company uses solar panels to power remote terminal units to communicate production information so that operational personnel need to make fewer visits to wellsites (Fig. 5).

Williams has 13 field compressor sites for increasing the gas pressure to the 800 psi needed for the flow into the Parachute Creek gas plants. For flexibility, the gas-gathering system ties all wells and compressor stations together.

The sites have 75 two-stage reciprocating compressors, each of which can compress about 9 MMscfd of gas. The 1,200-hp compressors have a 1,000-hp rating because of the high altitude of the area (Fig. 6).

Williams recently completed the expansion of Parachute Creek Gas Plant 3, increasing total capacity of its four plants at Parachute Creek to 1 bcfd (Fig. 7).

The Parachute Creek gas plants are refrigeration plants that operate at −20° F. compared with the −155° F. operating temperature of the cryogenic turboexpander under construction at Willow Creek.

The company also has four smaller gas plants in the basin, some of which it may phase out.

Williams previously trucked out liquids from the Parachute Creek gas plants but now the liquids enter a pipeline system that moves them to a fractionator in Mount Belvieu, Tex.

Some produced water, which is saline, goes to evaporation ponds and recently because of the reduced drilling and fracturing, Williams has started trucking some water to Cisco, Utah, for disposal.

The Parachute Creek plants have amine units for removing CO_2 from the gas.

Williams sells part of the CO_2 to a nearby Solvay Chemical Inc. plant that manufactures bicarbonate of soda (baking soda) and reinjects another portion back into the gas to obtain the 2% CO_2 pipeline gas specification. It vents the remaining CO_2.

Environmental footprint

Some activities that Williams cites as lessening its effects on the environment include:

- Partnering with the Colorado Division of Wildlife to study and track mule deer movement.
- Working with the US Department of the Interior to explore new and improved ways to camouflage energy facilities.
- Recycling as muich produced water as possible for use in other operations.
- Reducing its emissions during the completions process by about 90% through the use of equipment to eliminate flaring.
- Installed telemetry for monitoring and controlling wells to reduce truck traffic.
- Using less land to drill and produce.

It also completed in 2007 a $20 million road tunnel on private land to help reduce traffic on county roads to its Allen Point development area on the Roan plateau. ✦

CFD techniques determine gas-lift valve behavior

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Gabor Takacs
Petroleum Institute
Abu Dhabi

A novel approach using computational fluid dynamics techniques provides a way for determining the characteristics of gas passing through a gas-lift valve.

In the method, CFD calculations numerically solve the governing equations for a flowing fluid. To facilitate the simultaneous solution of the governing equations, the procedure involves dividing the flow space (the inside of the valve available for gas flow) into sufficiently small finite volumes or cells. The accuracy of flow modeling greatly depends on the proper setup of these cells. This article describes this spatial distribution.

After one properly sets up the cell structure in the gas-lift valve's inside gas passage path, CFD calculations can determine the gas volumes passed by the valve under static conditions for different combinations of valve stem travel, injection, and production pressures.

In dynamic conditions, however, valve stem travel is a function of the net opening force on the valve stem tip. The authors developed an iterative procedure to describe this valve behavior that finds this force by integrating the pressure distribution on the valve stem tip,

The result of the proposed model is the dynamic performance curve of the gas-lift valve from which one can obtain the injected gas rate vs. injection, production, and dome charge pressures.

The procedure developed results in gas injection rates close to those determined from the API RP11V2 model.

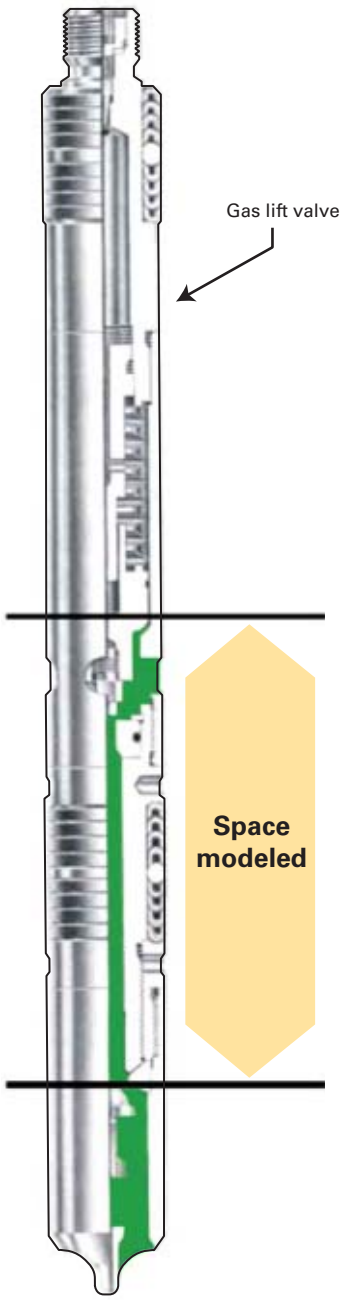
Characterizing valves

Although gas passage characteristics of gas-lift valves are important, the industry did not investigate the problem in depth for many years. In the past, the static force balance equations and the assumption that valves while open behave as square-edged orifices described the performance of gas-lift valves.

This characterization assumed that the valve quickly and fully opened as soon as the injection and production pressures satisfied the opening conditions.

When the valve was fully open, the basis of the gas flow rate calculations was the valve's port size and the equation originally proposed by the Thornhill-Craver Co., which is valid for

MODELED FLOW SPACE Fig. 1



Based on a presentation to the 56th Southwestern Petroleum Short Course, Lubbock, Tex., Apr. 20-23, 2009.

flow of ideal gases through fixed orifices.

Gas-lift valves, however, do not provide a constant flow area because the valve stem rarely lifts completely off the seat. The position of the stem, in relation to the valve seat is a function of the pressure conditions; therefore, the valve acts as a variable orifice.

One of the first papers investigating this problem states that the gas-lift valve tested (a Camco R-20) behaved as a variable-orifice Venturi device and not as a simple orifice.[1] A Venturi device is a converging-diverging nozzle in which the minimum flowing pressure occurs at its throat and there is a considerable pressure recovery downstream of the throat. The cross-sectional area of the throat changes with the position of the valve stem which, in turn, varies with changes in the injection or production pressures.

In conclusion, the pressure acting on the valve stem tip never equals injection pressure, as suggested from the static-force balance equations.

L.A. Decker, who laid the foundation for present-day valve testing procedures, did the first practical investigation on the dynamic performance of gas charged bellows valves.[2] He derived the formulas to describe the behavior of the bellows assembly and introduced the concept of the bellows load rate.

His analytical model allows one to determine the valve stem's position as a function of the mean effective pressure acting on the bellows area.

The spring-loaded valve without bellows charge was the first valve experimentally investigated for its gas passage behavior. In normal operation, this valve never opens fully and the pressure upstream of the port is very close to production pressure both in open and closed positions. The original manufacturer, Merla Tool Corp., realized the need for flow capacity data on such throttling valves and performed hundreds of flow tests, starting in the early 1960s, and made the results available to the industry.[3,4]

Research into the dynamic behavior of gas-lift valves received a new impetus in the late 1980s after the founding of the Tulsa University artificial lift projects (TUALP), an industry-sponsored research consortium. It published several papers covering the main results of many years of experimental work.[5-8]

Gas passage through gas-lift valves can occur under two different flow patterns: orifice and throttling flow. Orifice flow is similar to gas flow through a fixed choke, whereas throttling flow resembles flow through a variable-area Venturi device.

The orifice flow model occurs with the valve stem at its maximum travel when the valve port behaves as a fixed orifice. For a constant injection pressure, decreasing production pressures entail an increase in the gas rate until reaching critical conditions. Upon further decrease in production pressure, the injection rate remains at its critical value.

In throttling flow if production pressure decreases below the injection pressure, the gas rate increases due to the increasing pressure differential across the valve seat. After reaching a maximum value, injection rate linearly decreases with production pressure until gas flow ceases at the closing production pressure.

Mainly based on the systematic work performed at TUALP, API published the first edition of Gas Lift Valve Performance Testing (API RP11V2) in 1995.[9] It covers recommendations on the proper measurement and testing procedures for gas-lift valves and contains a calculation model for determining gas throughput capacities of valves.

The Valve Performance Clearinghouse, a joint industry project founded in 1996, used a closely related procedure to provide experimental performance data on gas-lift valves for the industry.

Basic flow equations

The Navier-Stokes equation representing Newton's second axiom characterizes gas flow inside of a gas-lift valve (Equation 1 in the accompanying equation box).

The continuity equation, Equation 2, describes the conservation of mass, while Equation 3 expresses the con-

Equations

$$\frac{\partial \vec{v}}{\partial t} + \operatorname{div}(\vec{v} \circ \vec{v}) = \vec{g} - \frac{1}{\rho} \operatorname{grad} p + \vec{v}\Delta\vec{v} + \frac{\mu + \zeta}{\rho} \operatorname{grad} \operatorname{div} \vec{v} \quad (1)$$

$$\frac{\partial p}{\partial t} + \operatorname{div}(\rho\vec{v}) = 0 \quad (2)$$

$$\frac{\partial}{\partial t}\left(\frac{v^2}{2} + h\right)\rho + \operatorname{div}\left[\left(\frac{v^2}{2} + h\right)\rho\vec{v} - \lambda \nabla T\right] = \frac{\partial p}{\partial t} \quad (3)$$

$$\rho = \rho(p, T) \quad (4)$$

$$h = h(p, T) \quad (5)$$

$$F_c = \frac{p_{d1} V_{d1}}{V_{d1} - x A_b} A_b + k x \quad (6)$$

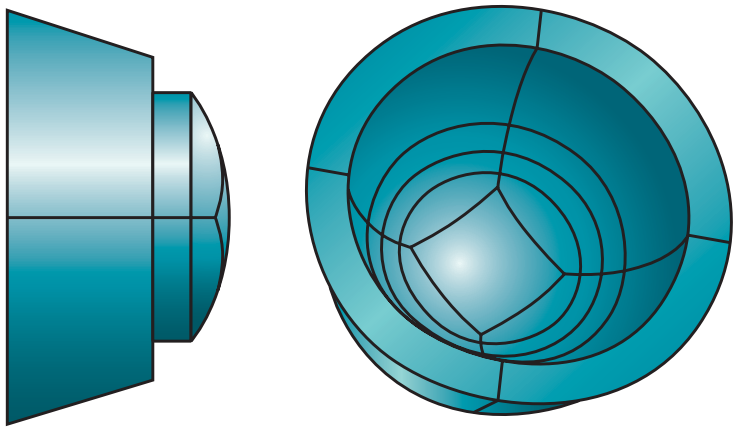
Nomenclature

A_b	=	Effective bellow area
F_c	=	Sum of valve closing forces
Q_g	=	Gas injection rate through the gas-lift valve
V_{d1}	=	Volume of valve chamber at zero valve stem travel
$\vec{g}$	=	Acceleration of gravity
h	=	Enthalpy
k	=	Spring constant of the unloaded bellows assembly
p	=	Pressure
p_{d1}	=	Bellows charge pressure at zero valve stem travel
p_p	=	Production pressure
p_i	=	Injection pressure
t	=	Time
$\vec{v}$	=	Fluid velocity
x	=	Valve stem travel
λ	=	Heat transfer coefficient
μ	=	Dynamic viscosity
ρ	=	Density of flowing fluid
ζ	=	Bulk viscosity

FLOW SPACE AROUND VALVE STEM TIP

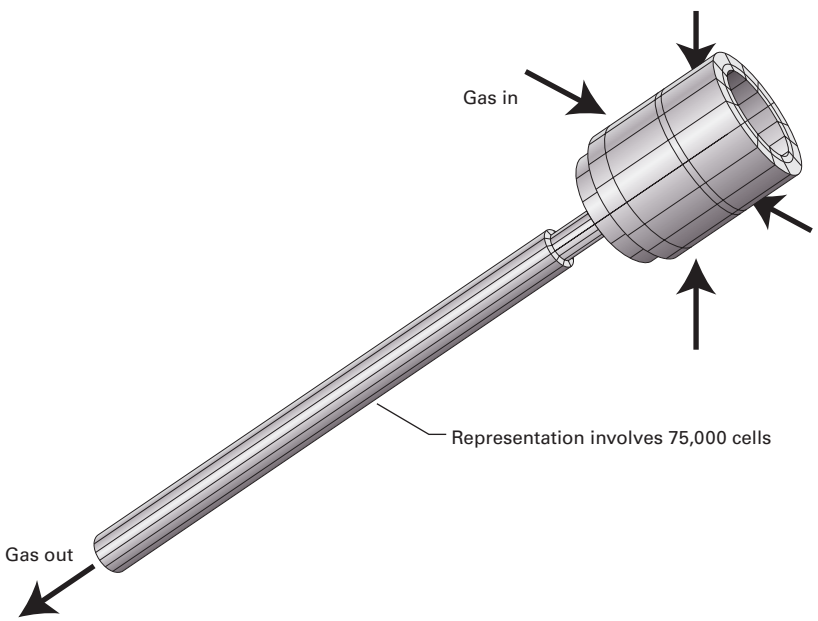
Fig. 2

The cell structure around the stem tip is complex.



FLOW SPACE, ORIGINAL REPRESENTATION

Fig. 3



servation of the energy of the flowing fluid.

Because these three basic differential equations governing the flow conditions have five unknowns, an unambiguous solution requires two more equations. These are the equation of state for the flowing fluid and the equation describing the change of the enthalpy with the state parameters (Equations 4 and 5).

The five equations constitute a system of equations with five unknowns, making the simultaneous solution of them theoretically possible.

Numerical solution

Because an analytical solution of the basic flow equations (Equations 1-5) is possible only for very simple cases, complex cases usually require numerical solutions, so-called finite element models.

The computational fluid dynamics program package used in this article performs a numerical solution of the governing equations using finite volumes. The program constructs these by dividing the flow space into a finite number of cells with finite volumes connected to each other.

It makes calculations at the geometrical centers of the cells (the node points) and first calculates the fluid and flow parameters. Then it solves the algebraic equations resulting from the integration of the basic differential equations at cell boundaries to obtain the five unknowns at the node points.

Geometrical flow space model

Results of CFD calculations depend on the proper setup for the geometrical model of the flow space because improper models can cause convergence difficulties and erroneous results. In our case, the geometrical model means the representation of the internal space of the gas-lift valve where gas flow takes place.

Fig. 1 shows the part of the valve investigated. The space available for gas flow constitutes the flow space for the CFD calculations. The calculations require the filling of this space with interconnected hexahedrons representing the cells.

Ensuring higher accuracies and faster solutions requires selection of the hexahedrons that are nearly cubes.

The most important part of the flow space is around the valve stem tip for two reasons:

1. The geometry in this area is the most complicated, involving the valve ball that is difficult to approximate with hexahedrons.

2. Proper knowledge of pressure distribution on the valve stem tip is essential for calculating the forces acting on the valve stem.

Fig. 2 displays cell structure details at this critical part of the flow space.

The remaining parts of the flow space have a tube shape below the valve port and form an annulus above the valve port. These are easier to represent than the region around the valve stem

tip. Finally, Fig. 3 shows an approximation of the total flow space of the gas-lift valve.

The cell structure in Fig. 3 involves 75,000 cells. Because this large number of cells led to an excessive CFD program run time, the authors investigated the possibility of simplifying the flow geometry. To reduce the cell number while sustaining calculation accuracy, the analysis tried two simplifying modifications as follows:

1. Replacing the four gas inlet ports by one of the same total cross-sectional area.
2. Trimming the two ends of the flow space by decreasing the length of the tube-like shape downstream of the valve port and the annulus upstream of the valve port.

These modifications reduced the required cells to about 10,000. Fig. 4 displays the final cell structure.

Computational time with the new flow space configuration was about one tenth of the original run times.

To ensure that the reduced cell number did not sacrifice calculation accuracy, the analysis included a set of control calculations. Comparisons of the results of pressure distributions along the flow path showed negligible differences, justifying the use of the simplified flow space configuration.

Simulation results

The analysis applied the theoretical and practical considerations detailed so far to determine the gas throughput capacity of a 1 in. OD, Camco BK-1 type gas-lift valve with a 3/16-in. port.

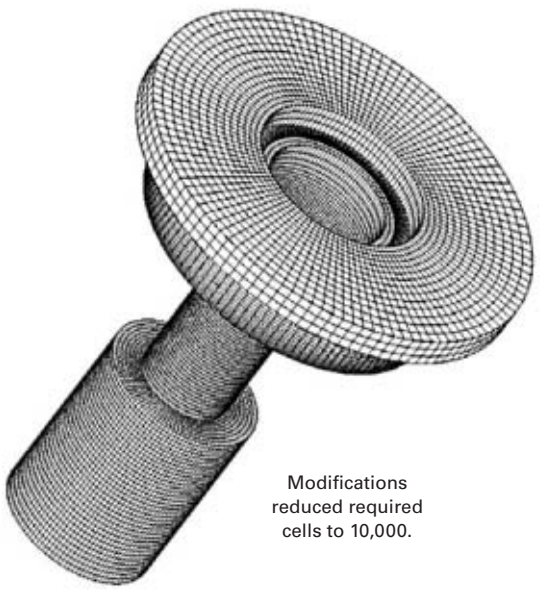
Simulations of gas-lift valve behavior consisted of the following main tasks:

- First, the simulation assumed a valve stem's travel measured from the valve's closed position.
- It then constructed the flow space using carefully measured dimensions of the disassembled valve.
- Next, the simulation assumed values for the prevailing bellows charge, injection, and production pressures.
- The CFD program solved the governing equations (Equations 1-5) and calculated the spatial distributions of pressure, velocity, and temperature.

CFD calculation results determined the following two important operational parameters of the gas-lift valve under the assumed conditions:

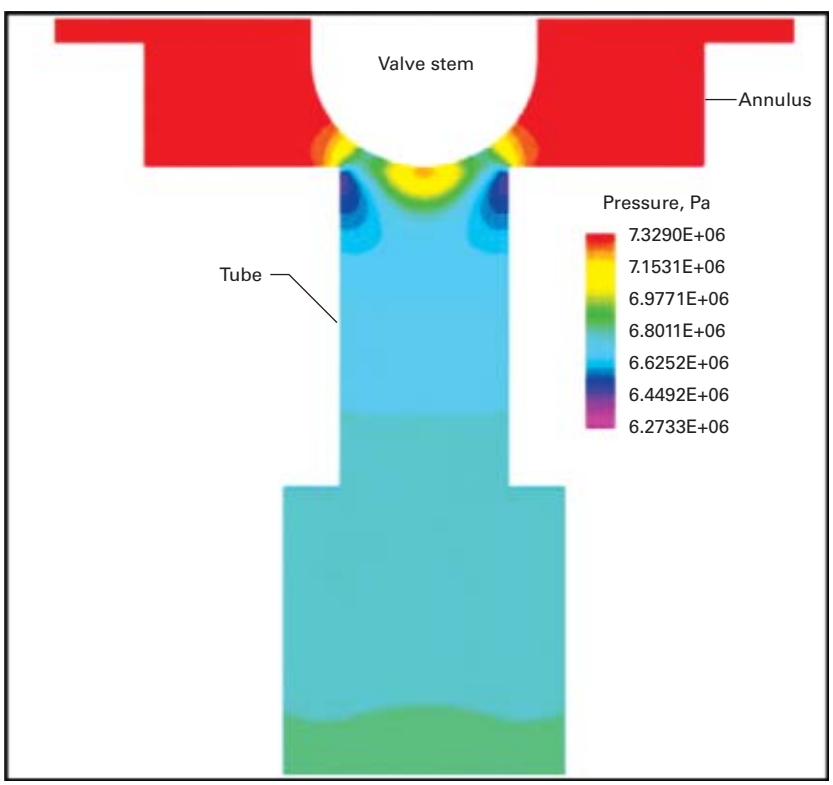
Flow space, final cell structure

Fig. 4



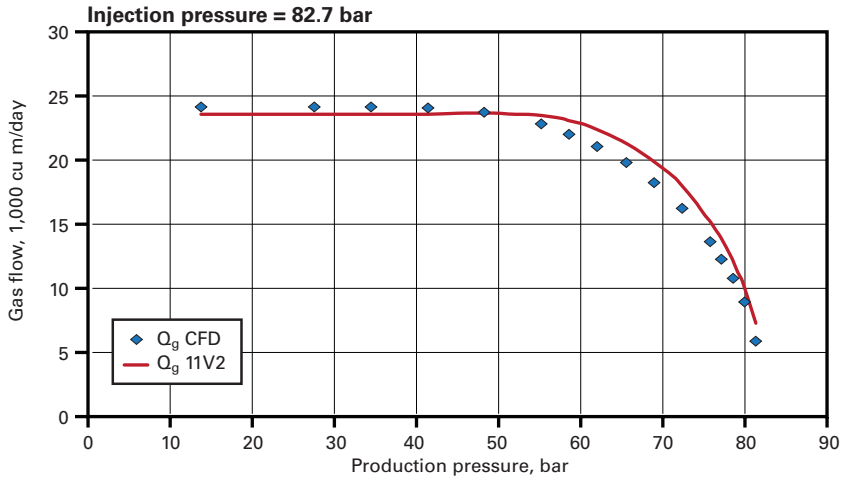
Pressure distribution inside gas lift valve

Fig. 5



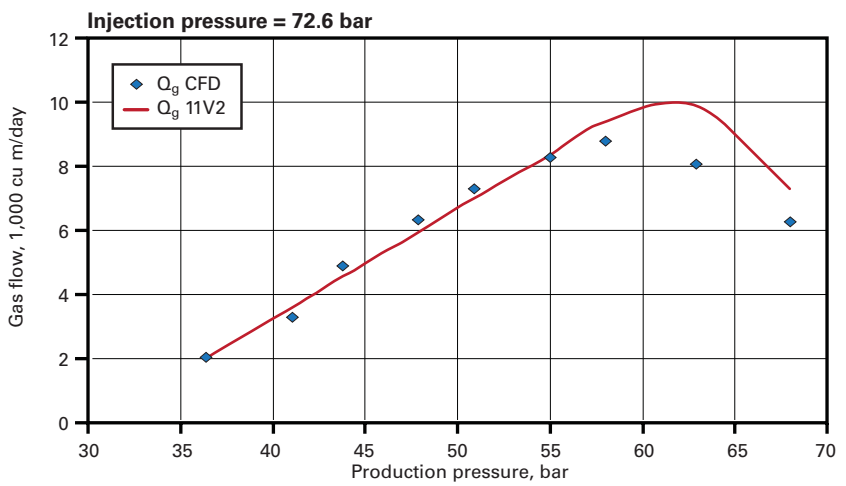
VALVE PERFORMANCE CURVE, ORIFICE FLOW

Fig. 6



VALVE PERFORMANCE CURVE, THROTTLING FLOW

Fig. 7



1. The net vertical force acting on the valve stem.
2. The gas flow rate across the gas-lift valve.

Fig. 5 shows the pressure distribution inside the valve for an example case.

Valve performance curves

The valve performance curve describes the dynamic performance of the gas-lift valve and presents the valve's gas throughput capacity for different injection and production pressures at a given bellows charge pressure.

As previously mentioned, gas-lift valves can have two main kinds of behavior: orifice flow or throttling flow. Orifice flow occurs when valve stem travel is at its maximum and the valve behaves like a simple orifice. Throttling flow, on the other hand, occurs at smaller stem travels when the valve behaves as a variable-orifice Venturi device with a restricted gas-injection capacity.

It follows from the nature of the two possible flow conditions that CFD calculations easily simulate orifice flow. This is due to the fact that the valve stem is always at its maximum upward position so that the simulation run easily finds the gas rates. One simulation, therefore, can provide the valve performance curve for orifice flow.

Throttling flow, however, is more complicated to describe because the valve stem assumes its equilibrium position as the result of the different forces acting on the stem. These forces come from the dome charge and the injection pressures acting on their respective surfaces in addition to the net force acting on the valve stem's tip.

Because CFD calculations require the knowledge of the actual valve stem travel to calculate the pressure distribution and consequently the net force arising on the stem's tip, deriving the valve's performance curve requires an iterative procedure.

The analysis bases the iterative solution on the fact that at equilibrium conditions the sum of the forces acting on the valve stem is zero. The four forces involved are:

1. Dome charge pressure acting on the full bellows area.
2. Spring force arising in the metal bellows.
3. Net force acting on the valve stem's tip.
4. Injection pressure acting on the difference of the bellows and port areas.

The sum of the two first forces, as calculated in Equation 6, tries to close the valve. The equation properly considers both the increase in dome charge pressure due to compression of the bellows and the increase of spring force due to the increase of valve travel.

The two latter forces try to open the valve. CFD calculations using the injection pressure easily determine these forces. By setting the opening and closing forces equal, the calculation finds the valve's actual stem travel. This is the principle of the iterative procedure.

Using the procedure detailed, one can easily develop valve performance curves for any gas-lift valve under conditions.

Figs. 6 and 7 are two sample curves for a Camco BK-1 valve with a 3/16-in. port and a dome charge pressure of 67 bar. Both figures present gas injection rates calculated from CFD simulations

as well as those found from the API RP11V2 model.[9]

Fig. 6 involves orifice flow with an injection pressure of 82.7 bar, while Fig. 7 shows the valve performing in the throttling region at an injection pressure of 72.6 bar. ✦

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LIQUIDS ENTRAINMENT—Conclusion

This is the final of three articles that describe BP's experience with reciprocating compressor damage from liquids intrusion at two facilities, in Oklahoma and Alaska.

Part 1 of the series (OGJ, May 18, 2009, p. 46) discussed the role of changing operating conditions in leading to compressor damage and reviewed details of the Oklahoma incident.

The second article reviewed the validation of CFD modeling by on line laser isokinetic probe sampling for liquid entrainment and the impact of NGL solubility in compressor lube oil.

This concluding article examines the use of state-of-the-art inline cyclonic separation technology to mitigate liquid entrainment.

In-line cyclonic technology remedies compressor liquid ingestion problem

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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 increased. Intense examination identified both mechanical and process-related causes for the failures, including entrainment of water and NGLs in the compressor suction.

Options rejected

Various options were evaluated to prevent liquids from entering Big A/B compressors. Of those rejected, reasons for elimination included technical infeasibility, technical risk, and economic uncertainty.

New scrubbers

Installation of new suction scrubbers is technically feasible to eliminate the liquid entrainment found with the existing suction scrubbers. Space limitations, however, precluded new scrubbers being much taller than existing scrubbers. Although this may have been a problem for a conventional scrubber with a horizontal mesh pad to reduce liquid entrainment, newer scrubber technology works within available space constraints.

To eliminate condensation of additional liquids downstream of the scrubbers, this option would also have required removal and replacement of all existing insulation and abandoned heat tracing between the suction scrubbers and compressors. Total installed cost of this option differed little from the selected demister option.

The economic risk of excessive downtime ruled out this option. Because scrubber replacement would require a complete field shutdown, economic evaluation of this option had to include any lost or deferred production that could not be sheltered by a normal, planned turnaround. Even relatively short added downtime would be costly.

In this instance, dual factors made the risk unacceptable. First, scrubber replacement within a crowded module is not routine, which limits the quality of any estimate of time required to complete the task. Second, BP Alaska has adopted strict control-of-work procedures that limit the amount and types of work that can be performed concurrently inside a process module.

Recent experience has shown that even with more rigorous planning, plant turnarounds take more time than they would without the new procedures.

New internals

Replacement of scrubber internals was an alternative to new scrubbers. As with new scrubbers, this option required complete removal and replacement of all downstream insulation and heat tracing. It was rejected both for

Shown (left) is the ProSep axial flow cyclone bundle and (right) the fully assembled demister (Fig. 1).

economic and technical uncertainty.

Economic risk is similar to that for the new scrubber option. Estimation of time to replace internals would probably be somewhat more accurate than for scrubber replacement, but all such estimation would have to be in the absence of physical inspection of each vessel's interior.

As with scrubber replacement, this option would also require a complete field shutdown with total loss of production. Also, the same concerns with the non-routine nature of the task and control-of-work procedures apply here as well.

Technical risk is always present in a separator retrofit. The Big A/B suction scrubbers were already retrofitted once in 1995. Current scrubber performance does not meet the process specification for liquid entrainment guaranteed for that retrofit. Advancements in separator design technology over the last 10-20 years, however, afford a greater chance that a new retrofit would be more successful than the 1995 upgrade.

If no other technically viable option were available that could be installed with less economic risk, then a more detailed evaluation would have been performed to choose between scrubber replacement or retrofit.

A third option was chosen, however, which does not require a full field shutdown for installation and removes the technical risk associated with replacement of scrubber internals. The chosen option also significantly reduces insulation and heat trace requirements, as described presently.

Suction gas superheating

Gas turbines are extremely sensitive to liquid entrainment. Vendors normally require gaseous fuel to be superheated to at least 50° F. above the hydrocarbon and water dewpoints to prevent any possibility of liquids entrainment. Such a stringent specification is not applicable to compressors, which are normally only required to be supplied with clean, dry gas.

On the other hand, superheating of compressor suction gas would most certainly eliminate problems associated with liquid entrainment. Milne Point has an adequate supply of heating glycol that could be used as a heat source for superheating the Big A/B suction streams. This option was briefly considered but rejected for technical and logistical reasons.

Technically, the option is infeasible because the compressor discharge temperature is normally 260-265° F., with an upper limit of 275° F. Current discharge temperatures cannot be increased and still retain a reasonable margin of safety. Alternatively, gas cooler limitations and potential for hydrate formation do not allow the suction scrubbers to be operated at lower temperatures as a means of lowering normal discharge temperatures.

Logistically, there is no available space in the module to install superheaters. Two heaters would be required, one for each of the two suction scrubber's overhead vapor streams. Each heater would have to be sized to handle 36 MMscfd. In addition, to ensure proper heater operation, liquid knockout vessels would be required to prevent liquids from entering the heaters.

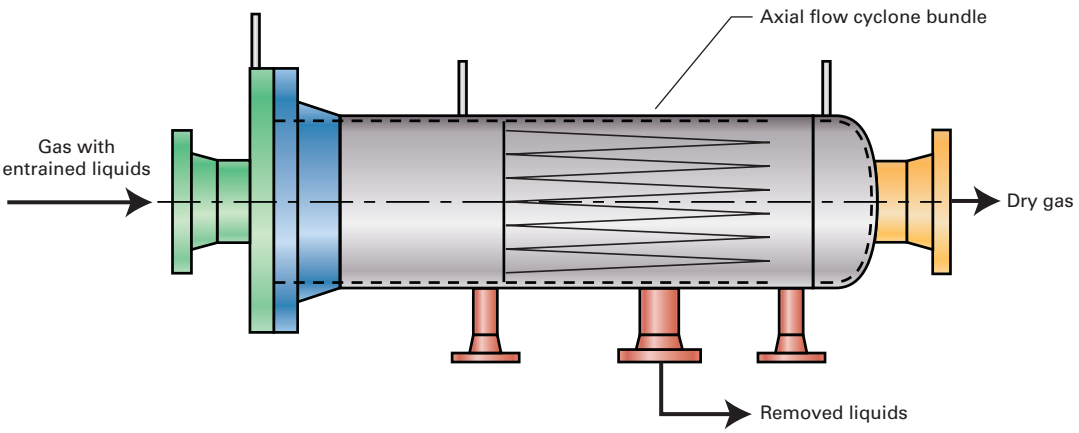
Automating bottle drains

Manually operated drain valves were installed on all Big A/B suction bottles and on the discharge bottles of cylinder Nos. 1 and 2 during the April 2007 rebuild of Big A. Liquids are currently drained from these vessels daily. This practice will continue until inline demisters are installed immediately upstream of the suction bottles.

An early idea was to automate these drain valves as a potential solution to the problem of liquids getting into the

IN-LINE AXIAL FLOW CYCLONE DEMISTER

Fig. 2



compressor cylinders. This option was rejected for technical reasons.

First, these vessels were designed to dampen pulsations, not to separate liquids and vapor. As such, these bottles are not amenable to liquid-level detection and control. Second, even though each of these bottles has an internal weir that captures some liquids, the weirs are designed with weep holes that allow any captured liquids to drain slowly through to the other side and enter the compressor cylinder.

Routine operation of pulsation bottle drains has been and still is an important step in minimizing the ongoing infiltration of liquids into Big A/B cylinders. But it is only a temporary measure that is insufficient to prevent all liquids from entering the compressors and causing mechanical damage.

Solution

The solution to Milne Point's entrained liquids problem consists of several interrelated actions. Many of these have already been implemented, which has considerably reduced the frequency and severity of liquids-related events.

All remaining actions will be completed by the end of summer 2009.

Operational procedure

During periods of high cylinder knocking, plant operators tried various ways to reduce knocking by optimizing compressor scrubber operation. These efforts generally included changing the upstream gas cooler's discharge temperature set point and lowering the scrubber's liquid level. Such operational changes yielded mixed results, but more importantly, provided valuable feedback to allow proper operating guidelines to be established.

One important lesson of these operator interventions was undesirable effects of setting the gas cooler's discharge temperatures too high or too low.

If the temperature were too low, liquids formed more rapidly than the scrubbers could dump them. Operators had to open manual bypass valves to reduce liquids to a safe level. If the temperature were raised too high, the gas exiting the scrubbers, being much richer and warmer, condensed rapidly in the cooler downstream piping. This was accompanied by an increase in knocking that did not stabilize until the downstream piping warmed enough to reduce the rate of condensation.

Operating data and process simulation results helped establish a safe operating temperature range of 75-95° F. for the scrubbers. Except during severe ambient conditions that affect gas cooler operations, temperatures are now normally maintained between 80-85° F. Also, if and when the gas cooler's temperature set point changes are required, operators now make them gradually if possible. This practice minimizes the condensation of liquids in downstream piping.

Concerns with the existing level-control system capability prevented permanent changes to normal scrubber liquid level. This will be done, however, during the scrubber instrumentation upgrade to be installed during the summer 2009 plant turnaround.

Control logic reconfig

Early process analysis of compressor scrubber operation revealed that the temperature of the process gas exiting the upstream aerial gas coolers fluctuated considerably and was often off its set point. This was due to the temperature control scheme employed for the gas coolers, which set the cooler plenum temperature as the primary control variable and the process gas temperature as secondary. This resulted in a fairly steady plenum temperature with an often unstable process gas temperature.

Operating experience had already established the importance of maintaining a stable scrubber temperature, which was not possible with such a temperature control scheme. Discussions with plant automation technicians confirmed that the plenum temperature did not need to be maintained at a constant temperature but only that it could not be allowed to drop below a specified minimum temperature to prevent hydrate formation in the gas cooler tubes.

The gas cooler's temperature control scheme was modified to make the process gas temperature the primary control variable. The plenum temperature was allowed to fluctuate as necessary to maintain the process gas temperature, subject only to remaining above its specified minimum temperature. This

control change resulted in a more stable operation of the compressor suction scrubbers.

Level system upgrade

Suction scrubbers V-5501 and V-5511 are currently equipped with local, pneumatic level-control instruments and level switches for alarm and shutdown. Because the level-control systems for these scrubbers are not tied into the plant's basic process control system, control room operators are unable to monitor vessel levels.

Under certain process conditions, liquid levels can rise and fall quite rapidly, with no indication to the control room until a high or low level alarm is triggered. Liquid levels occasionally rise so fast that the current level control valves cannot reduce the level, requiring an operator to open a manual bypass.

In late 2007, the Milne Point facility was shut down when a high-level shutdown switch on one of the scrubbers tripped. Normally, this event would have been preceded by a high-level alarm that would have allowed a local operator time to respond before the plant shut down.

In this instance, the high-level alarm switch failed. Had the high-level shutdown switch also failed, a large slug of liquid would have entered the Big A/B compressors, most likely causing major damage.

To correct these deficiencies, a new level-control alarm and shutdown system will be installed during this summer's turnaround. All existing instrumentation, level bridles, control valves, and level switches will be removed from V-5501 and V-5511.

New process control system level-control loops that use guided-wave radar level transmitters will be installed. The existing low-low level switches are being replaced by differential-pressure level transmitters to provide control of the emergency shutdown valves on the liquid drains and to provide redundant continuous level measurement.

Also, new level-control valves with larger ports are being installed to provide adequate liquid removal capability. Once the new system is installed, control room operators will be able to view scrubber operation in real time, monitor the impact of operational changes on liquid level, and trend operating data for engineering analysis.

Demisting cyclone bundles

To eliminate the risk of excessive field downtime associated with replacing the existing two suction scrubbers, four inline demisters will be installed instead, one immediately upstream of each Big A/B suction bottle on the Nos. 1 and 2 cylinders. Because the flow rate to each demister will be constant, there are no concerns with turndown.

Demister units for Milne Point were engineered and fabricated by ProSep Technologies. Each demister consists of an 18-in. external pipe shell that houses a bundle of 19 axial flow cyclones (2-in. diameter) designed and manufactured by ConSepT. Fig. 1 shows a typical cyclone bundle, alongside one of the fully assembled demisters purchased for the Milne Point facility.

These demisters, fabricated entirely of piping components, are not subject to pressure vessel codes. The cyclone bundles are made of stainless steel to prevent corrosion and are permanently secured to the interior of the demister shell. Fig. 2 shows a view of demister operation.

Gas enters the shell and is evenly distributed over the flow area of the cyclone bundle. Each of the 19 cyclones consists of a tube with a stationary swirl element at the entrance to induce cyclonic motion.

Upon entering each cyclone, gas and entrained liquids begin rotating. Centrifugal motion slings the heavier liquids to the cyclone walls. At the end of each cyclone, a slit in the cyclone wall allows liquids to escape and flow into a nozzle in the bottom center of the shell.

Dry gas from each cyclone combines and exits the shell. Liquids from each cyclone flow downward into a separate level-controlled liquid collection boot (not shown) located a few feet away from the demister. Liquids from each of the four collection boots are tied into the same drain lines that remove liquids from their respective upstream suction scrubbers.

ConSepT performed engineering calculations and computational fluid dynamic simulations of these demisters under Big A/B operating conditions. Results indicated more than 99% liquid removal efficiency over a wide range of inlet liquid loading. The impact of pressure pulsations from the suction bottles was also analyzed and found not to be a factor in demister performance.

Heat tracing, insulation

After installation of the inline demisters, heat tracing will be installed on the four Big A/B suction bottles on the Nos. 1 and 2 cylinders and on the short pipe segments between the bottles and demisters.

The pipe segments will then be insulated, and insulating blankets will be wrapped around the suction bottles. This heat tracing and insulation will prevent any condensation of liquids downstream of the demisters to provide clean, dry gas to the compressor cylinders.

On line monitoring

One of the recommendations made for continuous assurance of Big A/B mechanical integrity was to install on line compressor monitoring and data collection systems. Lack of sufficient, relevant historical data often prevents exact determination of the root cause of a machine failure.

A separate project was initiated to install Prognost and Kongsberg systems, which now provide continuous, real-time data to monitor compressor process temperatures, bearing and cylinder liner temperatures, process pressures, vibration, rotational speed, rod position, and lube-oil system performance.

These robust systems provide numerous alarms of impending or actual machine damage. Potential problems related to liquids ingestion are readily detected, but this is only a small part of the capability of these systems.

Project lessons

Following are major conclusions from this series of three articles:

1. Changing process conditions can significantly increase the potential for damage to a reciprocating compressor related to liquids ingestion.

This can occur as a result of changing liquid and gas production profiles, expansion to an existing facility, or modifications to an existing compressor or related process equipment.

2. The most current tools available should be used to evaluate existing or new compression systems when a potential for liquids ingestion exists. Computational fluid dynamic modeling can identify limitations within existing separation equipment and predict performance of new or retrofitted separators.

On line laser isokinetic sampling probe testing can quantify liquid carryover from existing separators and monitor changes in performance over time. Branch connections for LISP testing should be considered for all new separator vapor lines that feed downstream compressors.

The process systems standard adopted by the Norwegian oil industry requires such connections for offshore production facilities.

3. The impact of NGL solubility in lube oil should be considered when selecting a cylinder lubricant or considering a change to an existing lubricant. Synthetic lubricants should not be viewed as the solution to an ongoing liquid ingestion problem, but may be beneficial in minimizing negative impacts from low levels of liquid entrainment in compressor suction streams.

4. The state of the art in separator technology has improved over the last couple of decades. Before a decision is made on a course of action to address a specific separation problem, a little research into the capabilities of various separation vendors will go a long way to ensuring that a workable solution will be found.

Different companies have different areas of expertise, and a solution from one vendor may work superbly in one situation but not quite so well in another.

5. An on line compressor monitoring system can pay for itself many times over during the life of a reciprocating compressor installation. With immediate access to current and historical compressor data, impending failures can be avoided, downtime can be minimized, and routine maintenance can be optimized.

Various high quality systems are available and in use at reciprocating compressor installations all over the world. ✦

CORROSION CONTROL—Conclusion

Integrity management must include practiced failure plans

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Reliance on integrity management policies, processes, and practices can lead to a false feeling of security. An operator must have a systemic and rehearsed approach to urgent operational failures if it is to ensure a response that limits potential damage to the environment, as well as to its reputation and business.

Intelligent pigging has proven useful in assessing pipeline condition for both multiphase and oil transport lines. It sets a new baseline for future life predictions by corrosion modeling or growth extrapolations. Intelligent pigging, however, can miss defects, resulting in unanticipated pipeline leaks.

The first article of this series (OGJ, June 1, 2009, p. 54) concentrated on microbial-influenced corrosion (MIC) modeling and subsequent intelligent in-line inspection of Forties pipelines. This concluding article details a leak that occurred despite these efforts and the response to it.

Forties leak

An oily sheen on the sea surface on Apr. 4, 2008, disclosed a pipeline leak. Pipeline shut-in occurred immediately and a remotely operated vehicle inspection vessel mobilized to investigate the leak. The leak lay about 258 m downstream of the pipeline tie-in spool piece flanged connection at Forties Bravo. It displaced the sandy seabed near the leak hole, creating a 2-m deep hole.

A diving support vessel and Plidco pipeline repair clamp mobilized to the leak site a few days later. Divers inspected the leak site and confirmed it as being at the intersection of the line pipe spiral weld and the circumferential butt weld between two pipe lengths, near the bottom of the pipe. Fig. 1 shows the leak hole.

Pipeline hydrotesting at 52.5 barg (1.5 x 35 barg) to confirm integrity of the pipeline at a further-reduced maximum allowable operating pressure of 35 barg followed installation of a repair clamp. The pipeline returned to operation for a short period Apr. 13, 2008, before the planned platform maintenance program and tie-in of the replacement pipeline a few days later.

Although the June 2007 in-line inspection identified metal loss at the leak site, the reported 24% of peak depth (3.05 mm of 12.7 mm nominal WT) was not seen as suggesting a risk of failure. Of the 8,181 internal metal loss features reported between 2% and 85% of peak depth, a total of 748 had peak depths of 24% or more. Identified corrosion mechanisms could not account for the loss of the remaining WT from 76% (9.65 mm) to zero between June 2007 and April 2008.

The inspection tool's stated minimum pitting detection capability was 7 mm diameter, although it might also detect slightly narrower pits. Reduced detection capability occurs at welds, though this is not specifically stated in datasheets. Automatic feature recognition and sizing software size the vast majority of features. The larger features are subject to additional manual sizing, increasing the confidence they were accurately sized.

The metal loss reported at the leak site was not initially subject to manual sizing, but manual sizing following the leak yielded no change in assessed metal loss dimensions at the weld. PII confirmed the absence of discernible, deep metal loss at the leak site during its reexamina-

This leak hole lies at the weld junction of the Forties Bravo to Forties Charlie 20-in. OD pipeline (Fig. 1).

tion of the in-line inspection trace.

The precise nature of the eventually failed defect at the time of the in-line inspection can no longer be determined for the Forties Bravo to Charlie pipeline. But in the absence of another credible cause, the leak was ascribed to an original weld defect combined with progressive deterioration due to internal corrosion, eventually removing remaining WT at the weld. The original weld defect likely consisted of a lack of side-wall fusion not large enough to have been detected by the original weld radiographs or to have failed the pipeline commissioning hydrotest at 193 barg.

At the time of the in-line inspection, the weld defect likely had the form of a near through-wall feature outside the detection capability of the in-line inspection system. A probable loss of containment lay outside the detection capability of the in-line inspection tool.

In-line inspections will generally provide reliable condition information for line pipe, in line with their stated capabilities. But their capabilities may not apply to certain pipeline features, including welds. Though in-line inspection can be part of a pipeline condition monitoring plan, it does not fully confirm integrity of a pipeline. A residual risk remains of failure due to defects, including metal loss features, outside the detection capabilities of the in-line inspection tool.

Rapid response

Complacency or over confidence in modeling, analysis, risk-based inspection, and intelligent pig programs can hinder swift operational response to failures. Fostering an operational ability to launch an intensive engineering effort is paramount to achieving a positive outcome when a pipeline fails. Apache faced two scenarios for response and in both cases showed what can be achieved when decisive leadership focuses on operational problems.

The first scenario was responding to the original findings of the intelligent pig run of June 2007 on the PL55

Installation of this clamp as repair to the weld junction of the Forties Bravo to Forties Charlie pipeline took a total of 6 days following detection of the leak (Fig. 2).

Forties Bravo to Forties Charlie multiphase pipeline. The quantity, nature, and severity of the defects, the future life-extension requirements of the pipeline, and a risked cost-benefit analysis undertaken by a small team within 3 days of receiving the intelligent pig data guided the decision to replace the pipeline. The replacement project started with no personnel, materials, or contracts in place. It required signing 12 new contracts and agreements, production of 108 specifications and procedures by Apache and its contractors, and 31 vessel-days of installation work.

Successful completion of the project took 95 days, starting on receipt of an email from the intelligent pigging company, stating "we have identified some deep features" and ending with the final survey of the trenched, buried, and hydrotested pipeline ready for tie-in. Despite the fast-track nature of the project, pipeline installation took place within 1 day of the original base line schedule produced 6 days into the project.

Beside being executed swiftly, the project complied with the full legal requirements of and support from the Department of Business, Enterprise, and Regulatory Reform and the UK Health and Safety Executive. Execution delivered all normal safety requirements, exceeded required specifications, and occurred on budget and without accidents. This speed of delivery is an achievement when compared with the last pipeline replaced in the Forties field in 1994, which cost more to install and took more than 2 years to complete.

The new Forties Bravo to Forties Charlie multiphase pipeline is designated PL2496.

The second scenario for an operational response came 2 weeks before decommissioning the original Forties Bravo to Forties Charlie pipeline when the platform reported a small slick. Repair entailed the installation of a clamp by divers in 6 days: 1 day for ROV vessel mobilization, 2 days waiting on weather, 1 day of ROV inspection, 1 day for diving-support vessel mobilization, and 1 day to install and test the clamp (Fig. 2).

Timely installation of this clamp prevented any additional environmental damage, allowed production of an additional 34,000 bbl of oil before decommissioning the line and enabled full decommissioning of the pipeline and suitable protection of the line following decommission and before recovery.

The employment of mission analysis and the requirement for a sense of urgency led to the fundamentally successful response operations. Mission analysis or maneuver theory is the military strategic and tactical philosophy of planning; utilizing surprise, speed, and economy of effort. This military battlefield proven method transfers well to the business environment.[1,2] Maneuver theory requires aggressive, decisive, timely and well informed decision making supported by:

- Porous, flexible, and rapid planning.
- Devolved decision making.
- Organization capability.
- Initiative.
- Trust, training, and competence.

Applying a sense of urgency evolves from recognizing time as a constraint on a project along with cost, quality, risk, and benefits. A sense of urgency, however, does not allow discarding or ignoring the process or discipline of project management. Time as a major constraint actually requires applying more discipline, structure, leadership,

and clear risk-based decision making.

Apache's key focus areas included:

- Senior management commitment. Full commitment and support by senior management allows the operational staff to move forward with clear objectives and boundaries, enabling speedy decision making.
- Leadership drive. Applying all the qualities and functions of leadership into the project management process from concept to closeout ensures implementation of command, control, and communication throughout the project.
- Contractor-management interface. Understanding the contractors' business at both technical and commercial levels but specifying only functional delivery criteria ensures performance, efficiency, and effective support of contractors in the delivery of their services. All key stakeholders should be involved and informed at project initiation and through its lifecycle to final commissioning and beyond.
- Small, flat, focused internal teams. Keeping the project team tight reduces interfaces and accelerates communication. It also creates individual responsibility and commitment to delivery of the project, rather than relying on a process or committees to drive outputs.
- Risk appreciation though knowledge and competence. Employing competent experienced staff and contractors ensures understanding the technical risks brought by the project and inherent risks at the worksite.
- Configuration management. This process ensures all parties have the latest knowledge and understanding of project design.

Apache previously used this mission-oriented approach in a 2004 Forties repair: replacing the 12-in. OD Forties Echo export riser with a new steel riser in 84 days from a standing start and with an installation contractor other than that which had performed the initial installation.

Riser replacement entailed installing a J-tube on the end of a redundant mud outfall caisson, floating out a steel riser from Leith, UK, pulling and plastically deforming the steel riser up through the new J-tube and existing caisson, installing new spools subsea, and welding the riser into new topside piping. ✦

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Mark Richardson is subsea projects manager with Apache North Sea Ltd. He has worked for Apache since their takeover of Forties field in 2004 and has project managed their largest topsides and subsea projects. He has an MS in offshore engineering, an MBA from Aberdeen Business School, and is a member of the Association of Project Managers.

Equipment/Software/Literature

Casing patch designed for high pressures

This new 15,000 psi casing patch is designed to simply, quickly, and economically repair damaged casing in high-pressure environments.

The patch (patent application pending) can seal internal and external pressure without restricting the bore's internal diameter. Once installed, the patch restores integrity to the damaged casing and becomes a permanent part of the string.

Major load bearing components are manufactured of alloy steel. A top sub, bowl, and cut-lipped guide, plus optional extensions make up the outer components of the assembly. Internal components include a basket grapple control, basket grapple, four Type L high-pressure packer sets, and a packer protector with shear pins. A longer-than-standard basket grapple engages more of the casing to provide additional pull load. High-pressure packers are made of a blend of synthetic rubber and Kevlar material that is compatible for service with most drilling and completion fluids, and is resistant to gas invasion and abrasion. For maximum top-to-bottom patch integrity, two inverted packers provide sealing in both directions. The packers are fully covered by a packer protector to guard them against damage when engaging the casing into the patch. The packer protector is secured by shear pins that break when subjected to the excess stress caused when the casing comes into contact with the packer protector.

Source: **Logan Oil Tools Inc.,** 11027 Lucerne St., Houston, TX 77016.

New oil field water-cooled clutches, brakes

New AquaMaKKs water-cooled clutches and brakes from Wichita Clutch USA, Wichita Falls, Tex., are air, hydraulic, or spring-set actuated and feature heat-dissipating copper wear plates and nonmetallic composite water jackets that are optimized for heavy-duty continuous slip tension applications.

Available in sizes of 19-36 in. (friction lining OD), the units provide as much as 3,400 hp heat absorption.

The family of clutches and brakes is suited for tension control in traditional style drawworks control systems, for integration into electronic drilling systems, and for accurate tension control of positioning and mooring winches that require high heat dissipation.

Designed with a series of alternating friction disks and water jackets, AquaMaKKs transmits torque by applying axial force from the pneumatic, hydraulic, or spring-set actuator, which provides accurate torque control for constant tensioning, the supplier points out.

Source: **Altra Industrial Motion,** 300 Granite St., Suite 201, Braintree, MA 02184.

Services/Suppliers

Noble Denton,

London, has named Graeme Reid regional managing director, UK and Kazakhstan. He will be responsible for focusing on growth in the UK and Kazakhstan region. Reid started his career with Arjo Wiggins in Aberdeen before joining ABB Ltd. in 1995 as a field engineer in the city, where he rose to the position of account manager for the UK marine business. More recently, he was operations director with Poseidon Maritime (UK) Ltd. (PML), in charge of strengthening the company's marine, engineering, and security areas worldwide. PML was acquired by Noble Denton in 2007.

Reid

Noble Denton is a provider of life cycle marine and offshore engineering services to the oil and gas, marine, and renewables industries. The company is wholly owned by Germanischer Lloyd.

SBM Offshore NV,

Schiedam, the Netherlands, has announced that Malaysian state oil company Petronas Caligari intends to exercise its purchase option over the Oguzhan mobile offshore production unit/floating storage and offloading facility currently operating off Turkmenistan. The expected transaction date is June 18, 2009. The purchase option is expected to generate nonrecurring turnover of $51.5 million and a post-tax profit of $30 million. A short contract extension from the May 23 expiration of the existing lease contract to the purchase date will also be executed.

SBM Offshore provides engineering, supply, and offshore installation of single-point mooring systems for offshore loading and unloading of vessels or the permanent mooring of offshore oil production and/or storage vessels, as well as the turnkey supply of complete floating facilities for the production, storage, and export of crude oil and gas.

CygNet Software,

San Luis Obispo, Calif., has appointed Tom Ordes director, pipeline market. He has 28 years of experience in the oil and gas enterprise automation market. He will lead CygNet's initiative with the pipeline industry task force. Previously, Ordes worked for Telvent, where he was a director on the sales team with major client responsibility for sales and business development activity. Prior to that, Ordes served as general manager at Teledyne Brown Engineering Control Applications, senior vice-president of GSE Systems, and in a variety of management positions at Teledyne Control Applications, EMC/Rexnord/Texas Instruments, and Tano Corp. He has a bachelor's degree in science/electrical engineering from the University of New Orleans.

CygNet Software offers a new generation of enterprise operations software and solutions to the oil and gas production and gas transportation industries.

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Imports of crude and products

	Districts 1–4		District 5		Total US		
	5-22 2009	5-15 2009	5-22 2009	5-15 2009	5-22 2009	5-15 2009	*5-23 2008
	1,000 b/d						
Total motor gasoline	960	880	45	58	1,005	938	1,023
Mo. gas. blending comp.	695	573	45	55	740	628	615
Distillate	203	173	0	0	203	173	250
Residual	454	252	34	59	488	311	301
Jet fuel-kerosine	60	128	13	42	73	170	116
Propane-propylene	128	94	4	5	132	99	283
Other	515	498	11	(58)	526	440	328
Total products	**3,015**	**2,598**	**152**	**161**	**3,167**	**2,759**	**2,916**
Total crude	**7,873**	**7,782**	**905**	**1,009**	**8,778**	**8,791**	**8,959**
Total imports	**10,888**	**10,380**	**1,057**	**1,170**	**11,945**	**11,550**	**11,875**

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

Purvin & Gertz LNG netbacks—May 29, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.31	4.79	6.54	4.69	5.88	6.47
Everett	2.78	1.16	2.50	1.27	1.64	3.03
Isle of Grain	3.00	1.22	2.50	1.13	1.70	2.51
Lake Charles	1.26	-0.40	1.05	-0.25	-0.09	1.77
Sodegaura	3.51	5.52	3.77	5.25	4.62	2.96
Zeebrugge	4.52	2.73	4.03	2.63	3.26	4.07

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,141	52,684	35,915	10,758	58,582	16,247	3,701
PADD 2	85,250	46,623	20,757	7,848	31,958	1,237	18,394
PADD 3	186,093	70,092	39,117	12,680	42,905	16,024	25,808
PADD 4	16,987	5,612	1,964	507	3,019	248	[1]1,030
PADD 5	60,640	28,406	22,375	8,656	11,911	4,712	—
May 22, 2009	**363,111**	**203,417**	**120,128**	**40,449**	**148,375**	**38,468**	**48,933**
May 15, 2009	**368,524**	**203,954**	**120,361**	**39,665**	**148,127**	**36,961**	**48,002**
May 23, 2008[2]	**311,559**	**206,155**	**102,316**	**39,581**	**109,431**	**39,185**	**35,655**

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

Refinery report—May 22, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,208	1,202	2,487	58	409	93	52
PADD 2	3,278	3,266	2,132	237	858	44	263
PADD 3	7,255	7,138	2,981	685	2,098	275	691
PADD 4	550	542	309	23	165	10	[1]66
PADD 5	2,749	2,585	1,469	436	506	130	—
May 22, 2009	**15,040**	**14,733**	**9,378**	**1,439**	**4,036**	**552**	**1,072**
May 15, 2009	**14,457**	**14,109**	**8,735**	**1,310**	**4,132**	**567**	**1,022**
May 23, 2008[2]	**15,460**	**15,297**	**9,098**	**1,470**	**4,315**	**660**	**1,073**
	17,672 Operable capacity		**85.1% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*5-29-09	*5-30-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	73.07	145.08	–72.01	–49.6
Brent crude	62.11	129.76	–67.65	–52.1
Crack spread	10.96	15.32	–4.36	–28.5
FUTURES MARKET PRICES				
One month				
Product value	74.46	148.84	–74.38	–50.0
Light sweet crude	64.32	128.46	–64.14	–49.9
Crack spread	10.14	20.37	–10.24	–50.2
Six month				
Product value	72.37	142.95	–70.58	–49.4
Light sweet crude	67.20	127.97	–60.78	–47.5
Crack spread	5.17	14.98	–9.80	–65.5

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

OGJ GASOLINE PRICES

	Price ex tax 5-27-09	Pump price* 5-27-09	Pump price 5-28-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	197.4	243.9	396.3
Baltimore	199.3	241.2	382.6
Boston	201.3	243.2	379.4
Buffalo	192.0	252.9	400.6
Miami	203.5	255.1	407.2
Newark	202.2	234.8	390.1
New York	183.7	244.6	389.4
Norfolk	194.4	232.8	381.9
Philadelphia	199.8	250.5	289.2
Pittsburgh	199.5	250.2	387.4
Wash., DC	215.2	253.6	396.2
PAD I avg	198.9	245.7	390.9
Chicago	218.0	282.4	419.4
Cleveland	209.5	255.9	376.7
Des Moines	208.1	248.5	372.7
Detroit	207.8	267.2	386.7
Indianapolis	196.8	256.2	384.0
Kansas City	199.9	235.9	369.4
Louisville	212.3	253.2	395.3
Memphis	196.4	236.2	374.3
Milwaukee	210.6	261.9	400.3
Minn.-St. Paul	207.5	251.5	379.3
Oklahoma City	200.5	235.9	371.0
Omaha	198.6	243.9	379.7
St. Louis	197.9	233.9	383.3
Tulsa	196.1	231.5	366.7
Wichita	195.5	238.9	369.3
PAD II avg	203.7	248.9	381.9
Albuquerque	201.9	238.3	375.0
Birmingham	195.0	234.3	378.7
Dallas-Fort Worth	197.5	235.9	380.7
Houston	195.0	233.4	375.7
Little Rock	192.7	232.9	377.7
New Orleans	197.5	235.9	378.0
San Antonio	192.5	230.9	375.0
PAD III avg	196.0	234.5	377.3
Cheyenne	198.8	231.2	367.1
Denver	196.5	236.9	396.0
Salt Lake City	189.7	232.6	377.0
PAD IV avg	195.0	233.6	380.0
Los Angeles	199.6	266.7	416.2
Phoenix	197.7	235.1	377.2
Portland	215.3	258.7	391.1
San Diego	207.3	274.4	424.6
San Francisco	214.4	281.5	429.8
Seattle	210.8	266.7	399.5
PAD V avg	207.5	263.9	406.4
Week's avg.	**201.1**	**246.7**	**386.8**
May avg.	**179.0**	**224.6**	**372.9**
Apr. avg.	**156.7**	**202.3**	**339.3**
2009 to date	**152.0**	**197.6**	—
2008 to date	**283.9**	**327.5**	—

*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

	5-22-09 ¢/gal		5-22-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	176.75	New York Harbor	152.90
Gulf Coast	174.53	Gulf Coast	149.76
Los Angeles	184.28	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	172.23	ARA	148.33
Singapore	167.33	Singapore	155.71
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	184.25	New York Harbor	125.52
Gulf Coast	183.50	Gulf Coast	136.83
Los Angeles	194.78	Los Angeles	160.19
		ARA	122.98
		Singapore	130.50

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

BAKER HUGHES RIG COUNT

	5-29-09	5-30-08
Alabama	4	5
Alaska	6	6
Arkansas	43	48
California	20	43
Land	19	42
Offshore	1	1
Colorado	45	110
Florida	1	0
Illinois	1	1
Indiana	2	2
Kansas	17	9
Kentucky	10	10
Louisiana	143	152
N. Land	78	53
S. Inland waters	4	20
S. Land	12	25
Offshore	49	54
Maryland	0	1
Michigan	0	1
Mississippi	9	14
Montana	0	13
Nebraska	1	0
New Mexico	36	74
New York	1	7
North Dakota	36	68
Ohio	8	11
Oklahoma	76	208
Pennsylvania	33	19
South Dakota	0	2
Texas	330	921
Offshore	2	11
Inland waters	0	2
Dist. 1	9	28
Dist. 2	11	33
Dist. 3	25	70
Dist. 4	39	97
Dist. 5	81	179
Dist. 6	52	120
Dist. 7B	11	28
Dist. 7C	9	72
Dist. 8	34	135
Dist. 8A	12	26
Dist. 9	22	40
Dist. 10	23	80
Utah	13	41
West Virginia	22	26
Wyoming	32	70
Others—NV-5; VA-5;	10	15
Total US	**899**	**1,877**
Total Canada	**90**	**176**
Grand total	**989**	**2,053**
US Oil rigs	187	390
US Gas rigs	703	1,479
Total US offshore	55	67
Total US cum. avg. YTD	**1,183**	**1,802**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	5-29-09 Percent footage*	Rig count	5-30-08 Percent footage*
0-2,500	50	10.0	71	5.6
2,501-5,000	64	62.5	119	56.3
5,001-7,500	108	16.6	219	12.3
7,501-10,000	185	3.2	431	4.4
10,001-12,500	169	5.9	476	2.5
12,501-15,000	153	0.6	293	0.3
15,001-17,500	121	--	123	--
17,501-20,000	46	--	76	--
20,001-over	36	--	35	--
Total	**932**	**8.5**	**1,843**	**7.0**
INLAND	12		24	
LAND	873		1,764	
OFFSHORE	47		55	

*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]5-29-09	[2]5-30-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	708	685
California	655	652
Colorado	63	65
Florida	6	3
Illinois	28	25
Kansas	103	104
Louisiana	1,444	1,308
Michigan	16	17
Mississippi	61	59
Montana	95	86
New Mexico	165	161
North Dakota	197	156
Oklahoma	177	170
Texas	1,352	1,340
Utah	58	55
Wyoming	151	144
All others	67	82
Total	**5,367**	**5,133**

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

US CRUDE PRICES

	5-29-09 $/bbl*
Alaska-North Slope 27°	42.37
South Louisiana Sweet	65.75
California-Kern River 13°	58.85
Lost Hills 30°	67.35
Wyoming Sweet	55.81
East Texas Sweet	62.25
West Texas Sour 34°	56.75
West Texas Intermediate	62.75
Oklahoma Sweet	62.75
Texas Upper Gulf Coast	55.75
Michigan Sour	54.75
Kansas Common	61.75
North Dakota Sweet	53.50

*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]	5-22-09
United Kingdom-Brent 38°	57.63
Russia-Urals 32°	57.02
Saudi Light 34°	54.55
Dubai Fateh 32°	58.09
Algeria Saharan 44°	58.26
Nigeria-Bonny Light 37°	59.13
Indonesia-Minas 34°	62.32
Venezuela-Tia Juana Light 31°	58.61
Mexico-Isthmus 33°	58.50
OPEC basket	57.73
Total OPEC[2]	56.68
Total non-OPEC[2]	57.25
Total world[2]	56.93
US imports[3]	56.12

[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]

	5-22-09	5-15-09	5-22-08	Change, %
	bcf			
Producing region	900	870	618	**45.6**
Consuming region east	953	892	838	**13.7**
Consuming region west	360	345	232	**55.2**
Total US	**2,213**	**2,107**	**1,688**	**31.1**
	Mar. 09	**Mar. 08**	**Change, %**	
Total US[2]	**1,656**	**1,247**	**32.8**	

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Mar. 2009	Feb. 2009	3 month average — production — 2009	2008	Change vs. previous year — Volume	%	Mar. 2009	Feb. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	620	630	622	620	2	0.2	118.0	107.6	341.94
Bolivia	40	40	40	41	–1	–2.7	42.0	38.0	122.00
Brazil	1,943	1,908	1,913	1,766	147	8.3	31.0	27.0	88.00
Canada	2,607	2,698	2,638	2,584	54	2.1	470.7	451.9	1,438.90
Colombia	646	646	636	560	76	13.6	22.0	21.0	65.00
Ecuador[1]	460	480	480	500	–20	–4.0	1.0	1.0	3.00
Mexico	2,652	2,663	2,667	2,911	–244	–8.4	215.5	196.3	631.59
Peru	107	103	107	67	39	58.4	9.6	7.8	26.60
Trinidad	110	110	110	117	–7	–5.6	115.0	104.0	334.00
United States	5,440	5,191	5,292	5,115	177	3.5	1,868.0	1,696.0	5,420.00
Venezuela[1]	2,100	2,100	2,127	2,400	–273	–11.4	70.0	60.0	200.00
Other Latin America	83	83	83	83	—	–0.5	5.5	5.1	16.22
Western Hemisphere	**16,808**	**16,652**	**16,715**	**16,765**	**–50**	**–0.3**	**2,968.4**	**2,715.7**	**8,687.25**
Austria	18	18	18	17	1	3.3	5.2	4.7	15.30
Denmark	275	283	278	290	–12	–4.2	16.1	24.1	70.40
France	18	20	19	21	–2	–10.5	2.8	2.8	8.40
Germany	58	59	59	63	–4	–6.4	46.4	44.0	138.40
Italy	90	80	86	108	–22	–20.4	24.0	22.0	71.00
Netherlands	26	29	28	40	–12	–30.0	340.0	330.0	1,070.00
Norway	2,238	2,260	2,231	2,205	26	1.2	342.6	345.6	1,051.69
Turkey	46	39	41	39	2	5.4	—	—	—
United Kingdom	1,452	1,468	1,451	1,484	–32	–2.2	201.1	198.2	640.82
Other Western Europe	3	3	3	4	–1	–27.3	3.0	2.7	8.81
Western Europe	**4,224**	**4,260**	**4,213**	**4,270**	**–57**	**–1.3**	**981.2**	**974.1**	**3,074.81**
Azerbaijan	920	920	913	945	–32	–3.4	35.0	30.0	100.00
Croatia	14	14	14	15	–1	–6.5	5.3	4.8	15.72
Hungary	13	15	14	14	—	–0.8	7.2	8.5	24.13
Kazakhstan	1,300	1,250	1,267	1,183	83	7.0	100.0	90.0	300.00
Romania	90	90	90	95	–5	–5.3	19.0	17.0	55.00
Russia	9,770	9,730	9,747	9,763	–17	–0.2	1,700.0	1,700.0	5,300.00
Other FSU	400	450	433	400	33	8.3	350.0	350.0	1,100.00
Other Eastern Europe	44	45	44	49	–5	–10.0	22.2	19.8	64.09
Eastern Europe and FSU	**12,551**	**12,514**	**12,523**	**12,465**	**57**	**0.5**	**2,238.7**	**2,220.1**	**6,958.95**
Algeria[1]	1,220	1,250	1,247	1,390	–143	–10.3	250.0	230.0	740.00
Angola[1]	1,680	1,680	1,717	1,891	–175	–9.2	5.0	4.0	14.00
Cameroon	78	78	78	88	–10	–11.2	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	650	657	650	7	1.0	125.0	115.0	370.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.18
Gabon	240	240	240	227	13	5.9	0.3	0.3	0.90
Libya[1]	1,520	1,580	1,583	1,763	–180	–10.2	32.0	30.0	97.00
Nigeria[1]	1,780	1,800	1,813	2,057	–243	–11.8	78.0	70.0	228.00
Sudan	500	500	500	480	20	4.2	—	—	—
Tunisia	84	88	87	81	6	7.8	8.5	7.8	24.88
Other Africa	221	221	221	221	—	—	9.1	8.3	26.50
Africa	**8,548**	**8,672**	**8,728**	**9,433**	**–705**	**–7.5**	**508.0**	**465.4**	**1,501.46**
Bahrain	169	171	170	169	—	0.2	23.4	22.3	70.59
Iran[1]	3,650	3,700	3,713	4,023	–310	–7.7	280.0	255.0	825.00
Iraq[1]	2,380	2,260	2,337	2,373	–37	–1.5	20.0	17.0	57.00
Kuwait[1,2]	2,250	2,300	2,337	2,583	–247	–9.5	38.0	34.0	112.00
Oman	720	720	723	727	–3	–0.5	60.0	54.0	174.00
Qatar[1]	740	750	757	847	–90	–10.6	180.0	160.0	520.00
Saudi Arabia[1,2]	7,810	7,810	7,860	8,993	–1,133	–12.6	200.0	180.0	580.00
Syria	380	380	383	390	–7	–1.7	18.0	16.0	52.00
United Arab Emirates[1]	2,250	2,250	2,287	2,623	–337	–12.8	122.0	110.0	357.00
Yemen	280	280	283	317	–33	–10.5	—	—	—
Other Middle East	—	—	—	—	—	131.5	7.5	8.3	26.23
Middle East	**20,629**	**20,621**	**20,850**	**23,046**	**–2,196**	**–9.5**	**948.9**	**856.7**	**2,773.81**
Australia	472	484	479	409	69	16.9	112.4	108.7	341.07
Brunei	155	152	156	177	–21	–12.0	37.0	33.1	107.36
China	3,381	3,743	3,611	3,771	–160	–4.2	241.1	241.0	742.07
India	686	614	646	678	–32	–4.8	87.9	75.9	244.20
Indonesia	850	870	860	859	1	0.1	200.0	190.0	600.00
Japan	15	20	18	20	–2	–8.6	11.4	11.5	35.38
Malaysia	740	740	740	773	–33	–4.3	140.0	130.0	410.00
New Zealand	50	40	43	61	–17	–28.6	13.0	11.4	35.40
Pakistan	65	64	65	68	–3	–3.7	127.8	114.1	368.18
Papua New Guinea	40	40	40	44	–4	–8.4	1.0	0.9	2.90
Thailand	253	233	248	215	33	15.5	40.3	30.0	102.82
Vietnam	300	250	267	303	–37	–12.1	15.0	13.5	43.50
Other Asia–Pacific	35	35	35	39	–4	–10.7	96.5	91.5	284.50
Asia–Pacific	**7,042**	**7,285**	**7,208**	**7,418**	**–210**	**–2.8**	**1,123.3**	**1,051.6**	**3,317.38**
TOTAL WORLD	**69,803**	**70,003**	**70,237**	**73,397**	**–3,161**	**–4.3**	**8,768.5**	**8,283.6**	**26,313.66**
OPEC	27,840	27,960	28,257	32,304	–4,047	–12.5	1,276.0	3,251.0	5,833.00
North Sea	3,986	4,031	3,981	3,996	–15	–0.4	661.6	666.8	2,083.53

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.
Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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From the Subscribers Only area of OIL&GAS JOURNAL online www.ogjonline.com

Lands bill a new package of horrors for US oil and gas

As horror follows horror in Washington, DC, the US oil and gas industry needs a scorecard to keep track of threats building against it.

Oil & Gas Journal reports continuously on political and regulatory developments. The stories appear on the OGJ Online and Washington Pulse web sites, in associated electronic newsletters and, of course, in the magazine itself.

The Editor's Perspective

by Bob Tippee, Editor

In the May 25 edition, the print editorial assembled a catalog of the most-pressing industry headaches, enacted and proposed (p. 18). It was an impressively full list. And it already has grown.

Large among the latest reasons to worry is a bill under discussion by the House Committee on Natural Resources called the Federal Lands and Resources Energy Development Act.

According to a draft now making the rounds, the bill would expand the federal-lands bureaucracy and raise payments by leaseholders.

It would create one bureau to handle leasing, inspections, and auditing of all energy activity on all federal land. It also would add planning steps, including a system of regional councils for energy development on the Outer Continental Shelf.

In other words, the bill would multiply opportunities for drilling opponents to block activity.

Among onshore reforms, the bill would eliminate noncompetitive leasing, cut initial lease terms by half to 5 years, and require regulations to ensure "diligent development." It would raise the minimum royalty to 18.75% from 12.5%, the minimum bonus bid to at least $2.50/acre from $2/acre, and rental rates to at least $3/acre from $2.50/acre. It also would call for "best management practices" rules to "ensure sound, efficient, and environmentally responsible energy development."

Offshore reforms include a no-discharge requirement for new leases and repeal of deepwater royalty relief. For all leases, the bill would impose a $4/acre fee for nonproducing leases in their 4th and 5th years, rising to $10/acre in 6th years and beyond.

This combination represents the second-most effective way imaginable to foreclose oil and gas production from federal land.

The best way to choke energy supply, of course, is to issue no oil and gas leases at all.

At that, the US already has become painfully adept.

(Online May 29, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Hope floats oil prices

The brief May 28 meeting of members of the Organization of Petroleum Exporting Countries essentially "was over before it started" after Saudi Arabia Oil Minister Ali I. al-Naimi said in advance that the world economy is showing enough signs of recovery to cope with $75-80/bbl oil, said analysts at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK.

The July contract for benchmark US crudes escalated to $65.08/bbl on the New York Mercantile Exchange after OPEC voted to maintain its 24.85 million bbl production ceiling for the 11 members other than Iraq. It continued climbing to $66.31/bbl May 29, capping a five-session rally with the highest closing since Nov. 4.

Most independent analysts disagree with Al-Naimi's "level of confidence," however. KBC analysts expect world oil demand to decline 1.9 million b/d this year and drop another 300,000 b/d in 2010—"back to the level seen in 2005."

Still, just because $75/bbl oil is a minority view "does not mean that it is not going to happen," said Paul Horsnell, a managing director and head of commodities research at Barclays Capital in London. "We expect prices to move above $75, and potentially fairly rapidly, as the market's fear of economic discontinuities abates further," he said.

Still, KBC analysts claimed, "We have an oil market where recent price increases are governed not by what is going on now in the real world but by what could be a rosier outlook in 6 months' time. Investment funds looking for promising returns are buying into oil and other commodities in the belief that a return to growth will happen, and they want to be in on the ground floor ahead of this recovery. By climbing on board now they are of course helping to kick-start the price recovery."

Meanwhile, they said, demand is weak and shows little sign of improving, while oil stocks—based on data for primary consumer markets—are not yet falling. Moreover, official inventory figures "exclude oil held offshore in a growing armada of rented tankers," KBC said.

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, also noted the rapid rise in crude prices over the last 3 months was "based more on hope than fact." He said, "One of the few explanations for the bullish move that we find compelling is that the replacement cost of crude oil is at least $60/bbl and perhaps as high as $80/bbl."

Does compliance matter?

In a press conference, OPEC officials "skillfully dodged" the question whether stricter quota compliance would be sought now crude has increased above $60/bbl. "So we can assume that in the current climate quota compliance is no longer a serious issue, as long of course as it does not seriously deteriorate," said KBC analysts.

Latest US crude imports show Saudi Arabia embracing its role as a swing supplier. "US imports of Saudi crude oil in March went below the 1 million b/d mark for the first time since 1990 and were at the lowest level since November 1988, said Olivier Jakob, Petromatrix, Zug, Switzerland. "In February and March, US imports of Saudi crude oil were 525,000 b/d lower than a year ago, but that was not lost to all as fellow OPEC member Angola shipped 300,000 b/d more crude to the US than a year ago," he said.

US oil inventories

Benchmark US crude inventories fell 5.4 million bbl to 363.1 million bbl the week ended May 22. It was the third consecutive weekly decline. However, part of that loss may be because bad weather closed the Louisiana Offshore Oil Port on May 22-23. That same week implied demand for gasoline jumped 300,000 bbl to 9.5 million bbl, a level last seen in August 2007, "despite a 1 million bbl increase in gasoline imports and a much higher refinery utilization rate," Pritchard Capital analysts said.

Although demand increased just prior to the May 24 Memorial Day holiday, Jacques H. Rousseau at Soleil-Back Bay Research said, "We suspect gasoline consumption will not be sustained at these levels" with unemployment still on the rise. Meanwhile, gasoline production escalated to 9.38 million b/d—the largest weekly total since August 2008. "Gasoline inventories could be on the rise in the coming weeks," he said. Despite continuous draws on crude and gasoline stocks in May, overall US petroleum stocks remained "absolutely unchanged for the third week in a row," Jakob said. The Department of Energy's undefined "Other Oils" category "has been continuously building stocks as gasoline has been drawing stocks and is now at an historic high" up 15.8 million bbl in 4 weeks, he said.

(Online June 1, 2009; author's e-mail: samf@ogjonline.com)

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

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

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

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

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

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

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

See website for prices

www.ogjresearch.com

Deepwater: Horizontal Openhole Gravel-Pack Completions

First Successful Horizontal Openhole Gravel Pack in Deepwater Stybarrow Field

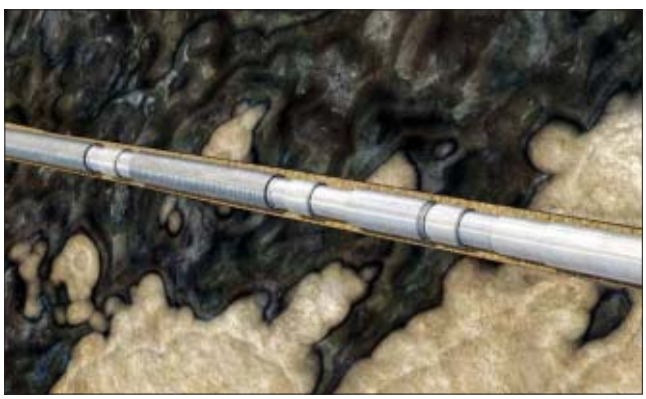
The Stybarrow Field consists of slope turbidite sandstones of the Macedon Formation in the Exmouth Sub-Basin offshore Western Australia. It is one of two fields in Australia's deepest water development, in more than 800 m of water, and was developed entirely by subsea wells connected to an FPSO.

Lateral Reservoir Quality, Sand/Shale Heterogeneities

Lateral reservoir quality variations, difficult sand/shale heterogeneities, and limited in-country technical experience and infrastructure were only some of the obstacles to completing four, near-horizontal production wells in this field. Others included gravel packing across much longer non-reservoir sections, gravel packing out of a milled casing window, narrow pressure margin between circulating pressures and formation fracture pressure, large wellbore washouts, and gravel packing at wellbore inclinations of up to 94°.

Gravel-Pack Design With Ceramic Proppant

To solve these problems, Baker Hughes helped develop an optimized reservoir drilling fluid and gravel carrier fluid design. We also created a gravel pack pumping design that used a 16/20 US Mesh ceramic proppant. This combined with our EXCLUDER2000™ medium-weave premium screen to produce the optimal sandface completion. Baker Hughes engineers sized the screens to retain formation sand. This would ensure sand retention in case of incomplete gravel packs. Slurry and conformance tests with various screen types and a range of sand facies, along with various proppant sizes and types, concluded that inclusion of proppant drastically reduced pressure buildup across the screens as well as the mass of sand particles produced through the screens. The



EXCLUDER2000™ screens like those used in the Stybarrow wells have compiled an outstanding performance record in the world's most extreme conditions.

Baker Oil Tools gravel-pack design also contained contingencies specific to this design in case of poor installation outcomes. Another success factor in the project was continuity of key Baker Hughes personnel and essential equipment from concept through execution.

Near-Record Australian Production Rates

Gravel-pack efficiency factors between 108% and 118% were achieved despite several unforeseen geological and technical challenges. All four Stybarrow production wells achieved maximum sand-free rates per FPSO design capacity. Maximum production rates from all four wells have exceeded 80,000 BOPD, with one well producing at near-record Australian rates of 32,000 BOPD seven months after first oil.

www.bakerhughes.com/gravelpacksystems

BAKER HUGHES

Unconventional Gas:

New Methods. New Supply.

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION

September 29 - October 1, 2009
Fort Worth Convention Center
Fort Worth, Texas USA
www.unconventionalgas.net

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Preliminary Event Guide.

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Unconventional Gas 2009 Advisory Board

Guntis Moritis *Oil & Gas Journal*	Alan Petzet *Oil & Gas Journal*	George Pollock *Baker Energy*	John Wessels *Quintana Energy Partners, L.P*
Thomas Muchard *El Paso Corporation*	Bill Powell *Schlumberger* - Retired	Catalin Teodoriu *Texas A&M University*	Glenda Wylie *Halliburton*
Kent Perry *RPSEA*	Scott Reeves *BG Group*	Bob Tippee *Oil & Gas Journal*	

For more information, please visit our website at **www.unconventionalgas.net**

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

New Methods. New Supply.

Gas production is increasing rapidly from reservoirs once considered economically and technically impossible to develop. Tight sands, shales, and coalbeds now represent large and growing sources of an essential form of clean energy.

But they're still unconventional. The reservoirs are complex. The costs of drilling into and completing wells in them are high and rising. They present unique environmental problems.

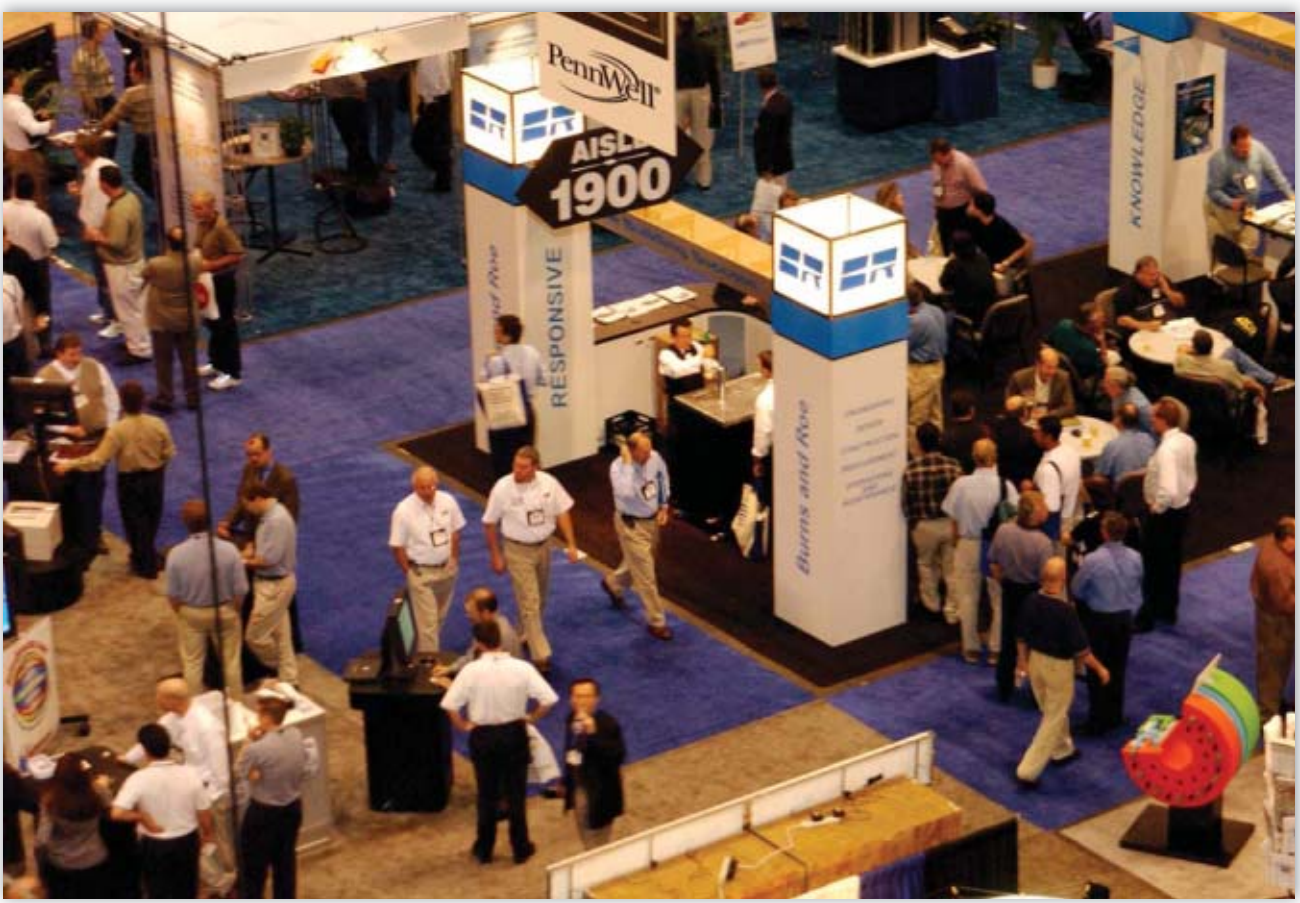
The Unconventional Gas International Conference & Exhibition provides a high-level forum for discussions about solutions to these problems.

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

The Conference Provides:

- Delegates the chance to learn from and meet experts from around the world and to visit exhibitions highlighting front-edge technologies.
- Exhibitors and sponsors exposure to industry decision-makers looking for ways to improve their operations.
- Present to an audience of professionals eager to learn new methods and effective strategies for bringing gas from unconventional reservoirs to market.

The conference, created by an Advisory Board of industry specialists, covers the technologies essential to unconventional gas operations and the business strategies that make them work profitably. It presents information of at-work value to engineers, geoscientists, managers, executives, business developers, planners, service and equipment suppliers, consultants, and other professionals in the business of unconventional gas. Plan now to participate in a high-energy, high-value event.



For more information, please visit our website at **www.unconventionalgas.net**

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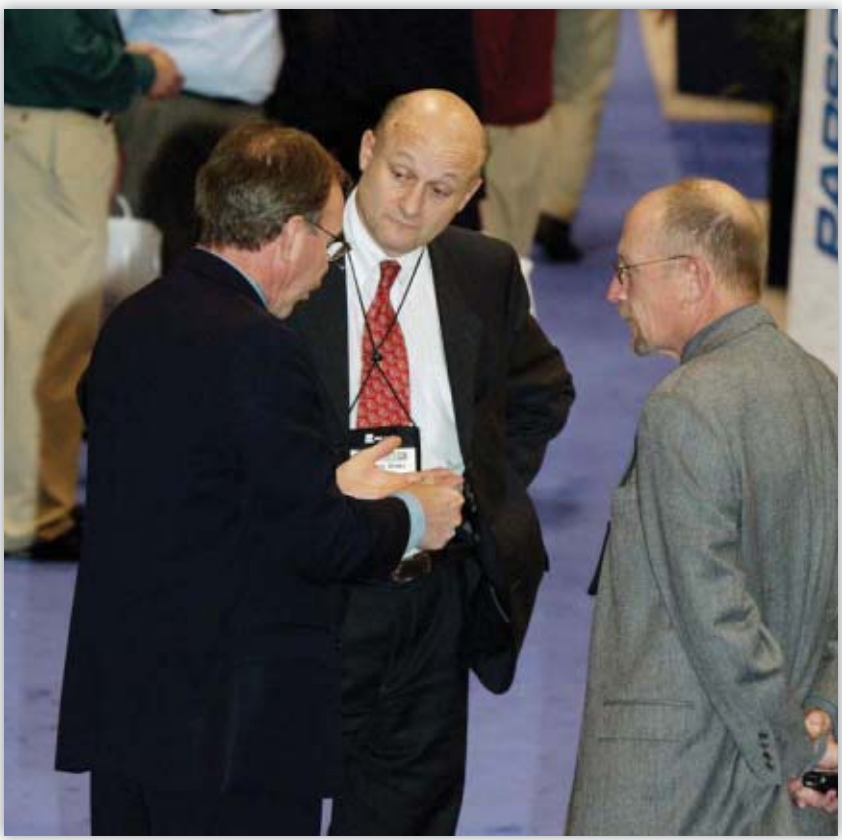
Forth Worth, Texas US

Attendance By Industry Leaders

The Unconventional Gas International Conference & Exhibition attracts a senior level audience.
Those attending include:

- Senior decision makers who seek information about optimizing methods of retrieving gas
- Industry leaders from Independent Operating Companies who must understand the complexities and parameters of redeveloping existing fields and the complexities of processing, and transportation
- Operations personnel involved in planning and scheduling unconventional gas development projects worldwide
- Engineering staff and management involved in unconventional gas development decision-making
- Suppliers who provide equipment or services for unconventional gas development, processing, or transportation
- Consulting companies that advise clients on current industry standards on unconventional gas development
- Business development managers pursuing unconventional gas business opportunities



UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

The Conference Setting

PennWell's Unconventional Gas International Conference & Exhibition is a focused event developed to provide maximum relevance and benefit for both exhibitors and attendees. This pivotal event provides a sophisticated new venue where buyers and sellers meet, learn and build business relationships. A rich learning and marketing environment is ensured by providing:

- Networking opportunities
- High-visibility sponsorships
- Topic-specific technical papers
- Expert-led, expert-attended technical sessions

Technical Focus Areas

- Regulatory Concerns
- Recovery Methods
- Coal Bed Methane
- Tight Sands
- Field Development
- Frontier Areas
- Sustainability Issues
- Completion Technologies
- Reservoir Management
- Well Control
- Drilling Methods
- Field Geology
- Workforce and Demographics
- Shales
- Market Dynamics
- Field Economics
- Transportation and Logistics
- Risk and Reliability
- Technology Qualification and Implementation
- Intervention
- Project Execution and Management

Register Now and Save!

Register and pay by August 28, 2009 and save US$100 on your full conference registration.*

Pre-Conference registration paid by August 28, 2009 US$ 840
Registration paid after August 28, 2009 US$ 940

To register, please go to www.unconventionalgas.net

**Includes admittance to all technical sessions, entrance to exhibit hall, daily luncheons and coffee breaks, receptions.*

For more information, please visit our website at **www.unconventionalgas.net**

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

Event Schedule

Monday, September 28, 2009	
1:00 p.m. – 6:00 p.m.	Exhibitor Move-In

Tuesday, September 29, 2009	
8:00 a.m. – 6:30 p.m.	Registration Open
8:00 a.m. – 12:00 p.m.	Exhibitor Move-In
3:00 p.m. – 5:00 p.m.	Keynote/Opening Session
5:00 p.m. – 6:30 p.m.	Networking Reception on Exhibit Floor
5:00 p.m. – 6:30 p.m.	Exhibit Hall Open

Wednesday, September 30, 2009	
7:30 a.m. – 6:00 p.m.	Registration Open
8:00 a.m. – 9:30 a.m.	Conference Session 1
9:30 a.m. – 10:15 a.m.	Coffee Break on the Exhibit Floor
9:30 a.m. – 6:00 p.m.	Exhibit Hall Open
10:15 a.m. – 11:45 a.m.	Conference Session 2
11:45 a.m. – 1:15 p.m.	Lunch on the Exhibit Floor
1:15 p.m. – 2:45 p.m.	Conference Session 3
2:45 p.m. – 3:30 p.m.	Coffee Break on the Exhibit Floor
3:30 p.m. – 5:00 p.m.	Conference Session 4
5:00 p.m. – 6:00 p.m.	Networking Reception on Exhibit Floor

Thursday, October 1, 2009	
7:30 a.m. – 1:30 p.m.	Registration Open
8:00 a.m. – 9:30 a.m.	Conference Session 5
9:30 a.m. – 10:15 a.m.	Coffee Break on the Exhibit Floor
9:30 a.m. – 1:30 p.m.	Exhibit Hall Open
10:15 a.m. – 11:45 a.m.	Conference Session 6
11:45 a.m. – 1:15 p.m.	Lunch on the Exhibit Floor
1:15 p.m. – 3:00 p.m.	Closing Panel Discussion
1:30 p.m. – 9:00 p.m.	Exhibitor Move-Out

***Times are tentative and subject to change*

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Most Influential Decision Makers

As the industry has developed new technologies to develop gas reserves the need to exchange information has reached new levels. At the Unconventional Gas International Conference & Exhibition the industry engineers and technical experts will address technical issues, introduce pioneering technology, and discuss lessons learned. Exhibit and showcase your company's technical solutions to the most influential decision-makers.

Tradeshows in the Marketing Mix

In our current economic slowdown, we recognize that many people are examining the value of all marketing channels. So how do you make informed decisions about continuing to invest in face-to-face marketing efforts like trade shows?

Exhibitions Work

Exhibitions, such as the Unconventional Gas International, work because they are face-to-face. They provide an opportunity to accelerate the selling cycle by matching needs with a company's ability to fill those needs. They work because adults are visual learners. Exhibiting is a visual medium – the exhibit, products, the graphics, collateral materials and promotional products are visual elements. Buyers are also experimental Trade shows provide an experience through the dynamics of the display process through equipment and scale models.

Exhibiting Investment

Exhibit rates are an economical US $39.00 per square foot (min. 10 ft. x 10 ft. of exhibit space). Space includes one full conference registration and two booth staff personnel passes.

Take advantage of our enhanced exhibitor listings that provide your products with additional exposure on the Unconventional Gas International website. These listings provide a direct link to your home page and/or specific product pages.

For more information, contact your sales representative. Your participation as an exhibitor entitles you to powerful benefits to boost marketing efforts, including:

- Official exhibition invitation passes to send to your clients and potential clients
- Free exhibitor listing on the Unconventional Gas website
- Free listing in the official Unconventional Gas Show Guide – Including company contact information and a 30-word description of your company
- Discounted conference delegate registration for your stand personnel

For more information, please visit our website at **www.unconventionalgas.net**

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

Sponsorship Opportunities

Maximize your attendance dollars at the Unconventional Gas International. Sponsorship opportunities provide a powerful way to leverage your marketing efforts and help to build company awareness.

Sponsorship opportunities include:

- Silver and Bronze Sponsorships
- Opening and Day 1 Receptions
- Online Conference Proceedings
- Badge Holders
- Continental Breakfast and Luncheons
- Webcast Theater
- Cyber Café
- Tea and Coffee Breaks
- Registration Sponsorship

For more detailed information, concerning sponsorships visit us online at www.unconventionalgas.net or contact:

Peter D. Cantu (Companies M - Z)
Phone: +1 713 963 6213
Fax: +1 713 963 6212
Email: peterc@pennwell.com

Kristin Stavinoha (Companies A - L)
Phone: +1 713 963 6283
Fax: +1 713 963 6212
Email: kristins@pennwell.com

Marketing Opportunities

Share your ideas, experiences, technology, and expertise with operators and project managers who are eager to improve their operations. Innovative, responsive, and professionally managed PennWell events maximize your return on investment – whether you are an exhibitor or an attendee.

The Unconventional Gas International Conference & Exhibition offers an integrated program and marketing opportunities to help you achieve your objectives.

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Conference Program Detail

Tuesday, September 29, 2009	
3:00 p.m. – 5:00 p.m.	**KEYNOTE/OPENING SESSION** Dr. Stephen Holditch – *Texas A&M University* TBD – *RyderScott* Vello Kuuskraa – *Advanced Resources International*
5:00 p.m. – 6:30 p.m.	Networking Reception
Wednesday, September 30, 2009	
8:00 a.m. – 9:30 a.m.	**SESSION 1 – THE TURNAROUND: WHEN? WHAT FOLLOWS?** **Outlook: Crude Oil and Natural Gas Markets** David Pursell – *Tudor Pickering Holt & Company* **Current Trend for Unconventional Gas Development in Late 2009 and for 2010** Don Warlick – *Warlick International* **Understanding and Interpreting Governmental Noise Regulations for CBM Industry** Patrick Saussus – *ATCO Noise Management*
9:30 a.m. – 10:15 a.m.	Coffee Break
10:15 a.m. – 11:45 a.m.	**SESSION 2 – PLAYS AND TECHNOLOGIES: WHAT'S VIABLE (PART I)** **Fracturing the Haynesville Shales: It's All the Same, Right?** Jason Baihly – *Schlumberger* **New State-of-the-Art Multistage Fracturing Process Can Help Achieve Branch Fracturing** Milorad Stanojcic – *Halliburton* **The Use of Seismic Emission Tomography (SET) For Direct Mapping** Dr. Peter Geiser – *STRM LLC*
11:45 a.m. – 1:15 p.m.	Lunch
1:15 p.m. – 2:45 p.m.	**SESSION 3 – PLAYS AND TECHNOLOGIES: WHAT'S VIABLE (PART II)** **Production Optimization and Best Practices for Complex Completions in Unconventional Resources** Colin Jordan – *BOE Solutions Inc.* **Using Microseismic Monitoring to Better Understand Completion of the Medina-Whirlpool Formations: A NYSERDA – Sponsored Project** Kirby Walker – *Schlumberger* **Permeability and Stimulation Effectiveness in Shale and Tight Gas Fractured Reservoirs – A Geomechanical Approach** Daniel Moos – *GeoMechanics International*
2:45 p.m. – 3:30 p.m.	Coffee Break
3:30 p.m. – 5:00 p.m.	**SESSION 4 – PANEL DISCUSSION WHAT WILL RECOVERY LOOK LIKE?** Don Warlick – *Warlick International* David Pursell – *Tudor Pickering Holt & Company* (Additional invitations extended)
5:00 pm – 6:00 pm	Networking Reception

For more information, please visit our website at **www.unconventionalgas.net**

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Thursday, October 1, 2009	
8:00 a.m. – 9:30 a.m.	**SESSION 5 – PLAYS AND TECHNOLOGIES: WHAT'S VIABLE (PART III)** **Utilization of Real Time Microseismic Monitoring and Hydraulic Fracture Diversion Technology in the Completion of Barnett Shale Horizontal Wells** Hariharan Ramakrishnan – *Schlumberger* **Porosity and Permeability on Shale Using Nano-CT Imaging** Elizabeth Diaz – *Ingrain, Inc.* **Numerical Study of Well Performance Mechanisms in Tight Gas Reservoirs under Gas-Water Two Phase Flow** Ehsan Heidaryan – *Kermanshah University of Technology*
9:30 a.m. – 10:15 a.m.	Coffee Break
10:15 a.m. – 11:45 a.m.	**SESSION 6 – PLAYS AND TECHNOLOGIES: WHAT'S VIABLE (PART IV)** **Enhancement of Unconventional Gas Reservoir Evaluation with Fiber Optic Technologies** Mikko Jaaskelainen – *Sensortran, inc.* **The Horn River Basin – An Introduction to Canada's Emerging Shale Gas Giant** Harvey Klingensmith – *Stone Mountain Resources* **Using Seismic Data to Guide Lithology and Fracture Distribution in the Barnett Shale Reservoir** Bradley Melton – *Schlumberger*
11:45 a.m. – 1:15 p.m.	Lunch
1:15 p.m. – 3:00 p.m.	**CLOSING DISCUSSION (PANEL DISCUSSION)** **What technologies will improve economics?** Kent Perry - *RSPEA* Harvey Klingensmith, *Stone Mountain Resources* Daniel Moos, *GeoMechanics International* (Additional invitations extended)

***Note: Speakers and Presentation Titles are subject to change*

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Exhibitor Profile

Companies who elect to exhibit at the Unconventional Gas International Conference & Exhibition are those who:

- desire to meet decision makers who share information about the new methods of retrieving gas
- want to share with operating companies best practices and lessons learned
- want to meet the operations planning personnel involved in planning and scheduling unconventional gas development projects worldwide
- want to reinforce their relationships with engineering staff and management involved in the unconventional gas development decision-making process
- want to meet with consulting companies that advise clients on current industry standards and trends

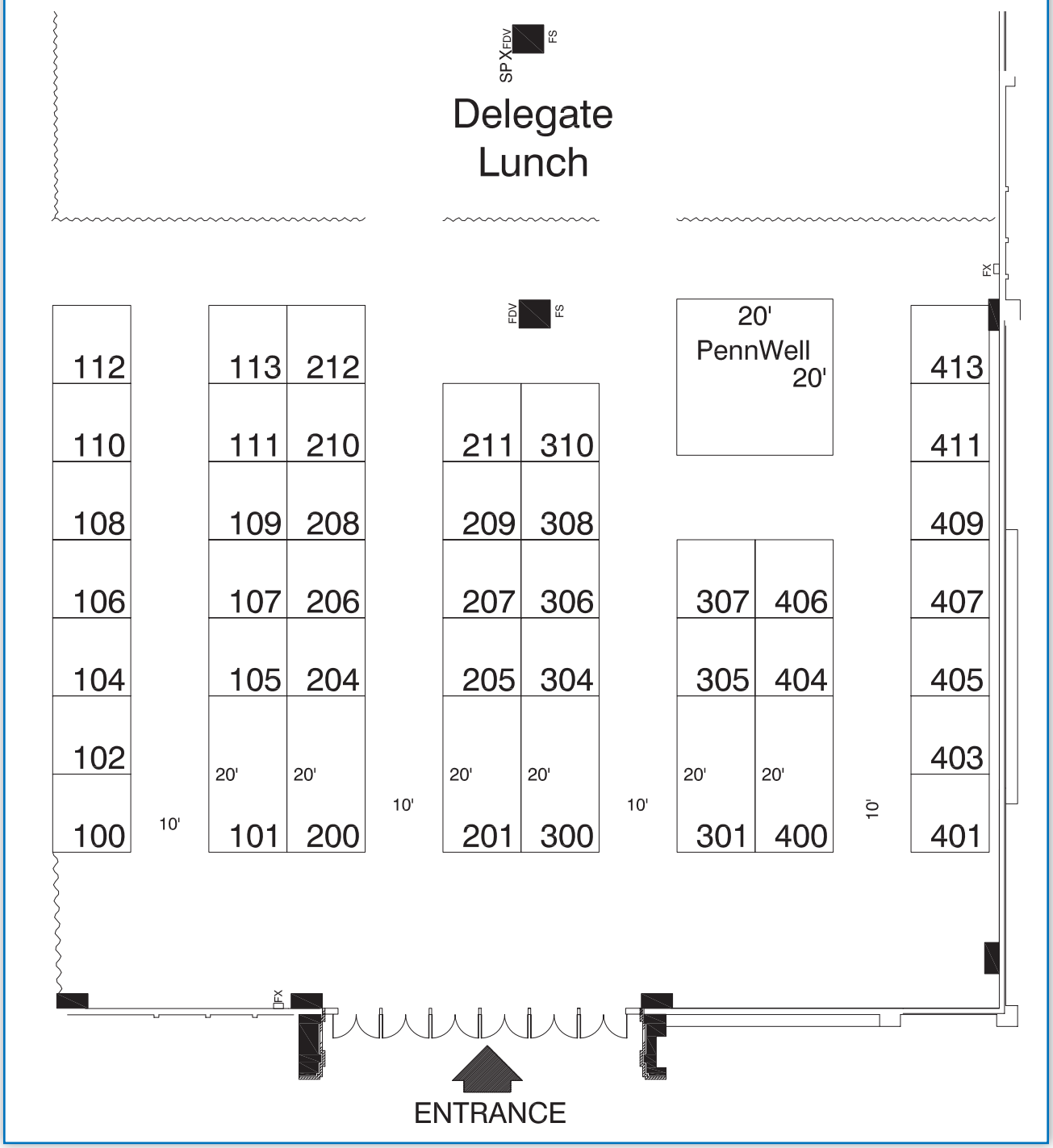
2008 Exhibitor List

212 Resources
Advance Fabrication Services, LLC
Air Products and Chemicals
Baker Energy
Baker Hughes
BJ Services Company
BST Technologies
Cameron
Caterpillar Global Petroleum
CETCO Oilfield Services Company
Compressco Field Services, Inc.
Dexter Magnetic Technologies, Inc.
Dunaway Associates, L.P.
Ecosystem Renewal, LLC
FMC Technologies
Frac Tech Services, Ltd.
The Gearhart Companies
Gel Technologies Corporation
Ingrain, Inc.
Leistritz Corporation
MESA Products, Inc.
Mustang Engineering
Natural Resource Group, LLC
Newpoint Gas
Object Reservoir, Inc.
Pinnacle Technologies, Inc.
Production Control Services
RigData
Schlumberger
Schramm Inc.
Superior Well Services
Universal Well Site Solutions
Veolia Water Solutions & Technologies
VetcoGray
Weatherford Engineered Chemistry
Welltec
Wood Group Pressure Control

For more information, please visit our website at **www.unconventionalgas.net**

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

2009 Floor Plan



UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Unconventional Gas International Conference & Exhibition 2009 Registration Form

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

First Name: _____

Last Name: _____

Title/Position: _____

Company: _____

Address: _____

City/State _____

Country: _____

Postal Code: _____

Telephone: _____

Fax: _____

Email: _____

Confirmations will be sent by e-mail if a unique e-mail address is given.

1. Type of Company or Organization:

- ☐ 10 Oil/Gas company
- ☐ 20 Consulting Company
- ☐ 30 Contractor
- ☐ 40 Engineering/Construction
- ☐ 50 Financial
- ☐ 60 Service/Supply
- ☐ 65 Government/Library/Education
- ☐ 70 Other _____

2. Job Function:

- ☐ 02 Management (CEO, Pres. VP)
- ☐ 05 Engineering/Technical/Geoscience
- ☐ 06 Superintendent/Field Professional/Foreman
- ☐ 10 Purchasing/Consulting
- ☐ 12 Other _____

3. Areas of Interest/Involvement:

- ☐ 10 Exploration
- ☐ 05 Drilling
- ☐ 01 Production
- ☐ 29 Gas Processing
- ☐ 23 Pipeline/Transportation
- ☐ 19 Petrochemical
- ☐ 15 Refining
- ☐ 39 Financial
- ☐ 46 Other _____

4. Purchasing Role:

☐ Specify ☐ Recommend ☐ Approve ☐ None

For information on corporate packages for 21 or more attendees contact:
Carolyn Hall / Phone: +1 918 831 9513 / Email: chall@pennwell.com

3 ways to register:

Pre-register on line before September 11, 2009.

Register on site after September 24, 2009.

1 **Fax:**
Direct: +1 918 831 9161
Toll-Free (US only):
+1 888 299 8057

2 **Website:**
www.unconventionalgas.net

3 **Mail:**
PennWell C&E
Registration (UG)
P.O. Box 973059
Dallas, TX 75397-3059 USA

Method of Payment:

☐ Check enclosed (in U.S. funds only) ☐ Wire (Wire information will be provided on invoice)

Credit Card: ☐ Visa ☐ Mastercard ☐ AMEX ☐ Discover

Credit Card Number: _____ **Expiration Date:** _____

Full Name (as it appears on card): _____

Card Holder Signature: _____ Date: _____

(Required for credit card payment)

Conference Fees: *(All Delegate Registrations Include)*

Includes:
- Access to all Conference Sessions
- Access to the Exhibition Hall, including both the Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Wednesday and Thursday (Ticketed)
- Conference Proceedings

1. Individual Delegate (3-Day Registration)*

☐ Paid By Aug. 28, 2009 ..... US$ 840 ☐ Paid After Aug. 28, 2009 ..... US$ 940

2. Corporate Plan (5 delegates)

☐ Paid By Aug. 28, 2009 ..... US$ 3,340 ☐ Paid After Aug. 28, 2009 ..... US$ 3,760

Corporate Plan (6-10 delegates)

☐ Paid By Aug. 28, 2009 ..... US$ 5,845 ☐ Paid After Aug. 28, 2009 ..... US$ 6,580

3. Exhibitor Delegate

☐ Paid By Aug. 28, 2009 ..... US$ 330 ☐ Paid After Aug. 28, 2009 ..... US$ 475

4. Student Delegate *(Student ID Must Be Provided)*

☐ Paid By Aug. 28, 2009 ..... US$ 130 ☐ Paid After Aug. 28, 2009 ..... US$ 130

5. Exhibition Only ..... US$ 25

☐ Does not include conference sessions, proceedings or delegate luncheons

6. Single Day Delegate

Includes conference sessions and delegate lunch on corresponding day.
Does not include Proceedings.

Paid By Aug. 28, 2009
☐ Wednesday ..... US$ 560 ☐ Thursday ..... US$ 560

Paid After Aug. 28, 2009
☐ Wednesday ..... US$ 670 ☐ Thursday ..... US$ 670

7. Additional Lunch Tickets (for non-delegates)

☐ Wednesday ( ) @ US$ 35.00/day
☐ Thursday ( ) @ US$ 35.00/day

TOTAL PAYMENT AMOUNT (In U.S. funds only) = US$ _____

*Your full-price registration fee includes a one-year paid subscription to Oil & Gas Journal (US$ 89.00 value).

Payment must be received prior to conference. If payment in not received by the conference date, the registration fee must be guaranteed on charge card until proof of payment is provided. Make check payable to PennWell/Unconventional Gas International Conference & Exhibition.

Cancellation: Cancellation of registration must be received in writing. Any individual, exhibitor or corporate registrations cancelled before August 28, 2009 will receive a 50% refund of registration fee. After August 28, 2009 no refunds will be permitted. Substitutions may be made at any time by written notification to the registration office.

For questions please call:
Phone: +1 918 831 9160
Toll Free (US only):
+1 888 299 8016

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

Unconventional Gas International Conference & Exhibition
2009 Hotel Reservation Form

September 29 - October 1, 2009
Forth Worth Convention Center
Forth Worth, Texas US

Hotel Reservation Form

Special rates have been negotiated to accommodate the needs for all of our attendees. By booking your rooms through Preferred Convention Services, the official Unconventional Gas 2009 housing company, you are supporting the Event and gaining access to many benefits. Availability of discounted conference rates cannot be guaranteed after **August 31, 2009.**

A few benefits include...

- Discounted hotel rates
- Assistance in setting up hospitality functions and discounted suite rates
- Networking opportunities with conference attendees and exhibitors
- Experienced reservation agents available for all of your housing needs from the time you make your reservation until the completion of the event.
- Protection of your reservation in the event of an oversold situation at the conference hotel.

To make your hotel reservation, contact **Preferred Convention Services**. DO NOT contact the hotel directly. Discounted rates are available only through our office. You may book your reservation any of the following ways:

On-line: www.preferred1.com
Phone: 888.472.7462 (toll-free) or 310.235.2647
email: reservations@preferred1.com
Fax: 310.235.2648

Mail: **Unconventional Gas 2009**
c/o Preferred Convention Services
1990 E. Grand Ave., Suite 150
El Segundo, CA 90245

Omni Fort Worth Hotel

Deluxe King: $209.00 Single or Double **Deluxe Queen/Queen**: $209.00 Single or Double **Tax**: 15%

Conference Center: Adjacent to Hotel
Airport: Dallas-Fort Worth International (DFW) 15 miles (Shuttle approximately $32 per person one-way)
Restaurant/Lounge: Steak Restaurant, Coffee Shop, Wine Bar, Sports Bar, Pool Bar, 24-hour Room Service

Hotel Services: Fitness Center, Full-Service Spa, Pool
Parking: Valet $18.00
Early Departure Fee: After you have checked in, hotel will charge one night's room & tax to change departure to an earlier date.

DON'T SEE WHAT YOU'RE LOOKING FOR?
PCS can book a room for you at ANY hotel in the Fort Worth area.
We are here to book what you need. Any hotel, anywhere! Call us for more details.....

CHECK ONE:
Exhibitor ☐ Attendee ☐ Other ☐ _____

ROOM TYPE DESCRIPTIONS
S= Single (1 person/1 bed)
D = Double (2 people/1 bed)
D/D = Double/Double (2 people/2 beds)
H = Hospitality Suite
S1 = 1 Bedroom suite
S2 = 2 Bedroom suite

CONTACT _____ **EMAIL** _____

PHONE _____ **FAX** _____

ORGANIZATION _____

ADDRESS _____ **CITY** _____ **STATE** _____ **ZIP** _____

Rm Type	Guest Name	Arr/Dpt	Sharing room with	Arr/Dpt
		/		/
		/		/
		/		/
		/		/

SPECIAL REQUESTS:
Non-Smoking ☐ Low Floor ☐ High Floor ☐ Early Arrival ☐ Late Departure ☐ Other: _____

Credit Card Type (Amex, Visa, MasterCard, etc) _____

Credit Card # _____ **Expiration Date** _____

Cardholder _____ **Signature** _____

Cancellation Policy: Hotel will charge one night's room & tax for cancellations made 7 days or less prior to arrival. All reservations cancelled within 30 days of arrival are subject to a $40.00 processing fee.

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

September 29 - October 1, 2009
Fort Worth Convention Center
Fort Worth, Texas USA
www.unconventionalgas.net

Conference Management

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Conferences Director
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Email: bobt@ogjonline.com

Conference Manager
Kris Loethen
Phone: +1 713 963 6202
Email: krisl@pennwell.com

Event Operations Manager
Emily Gotwals
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