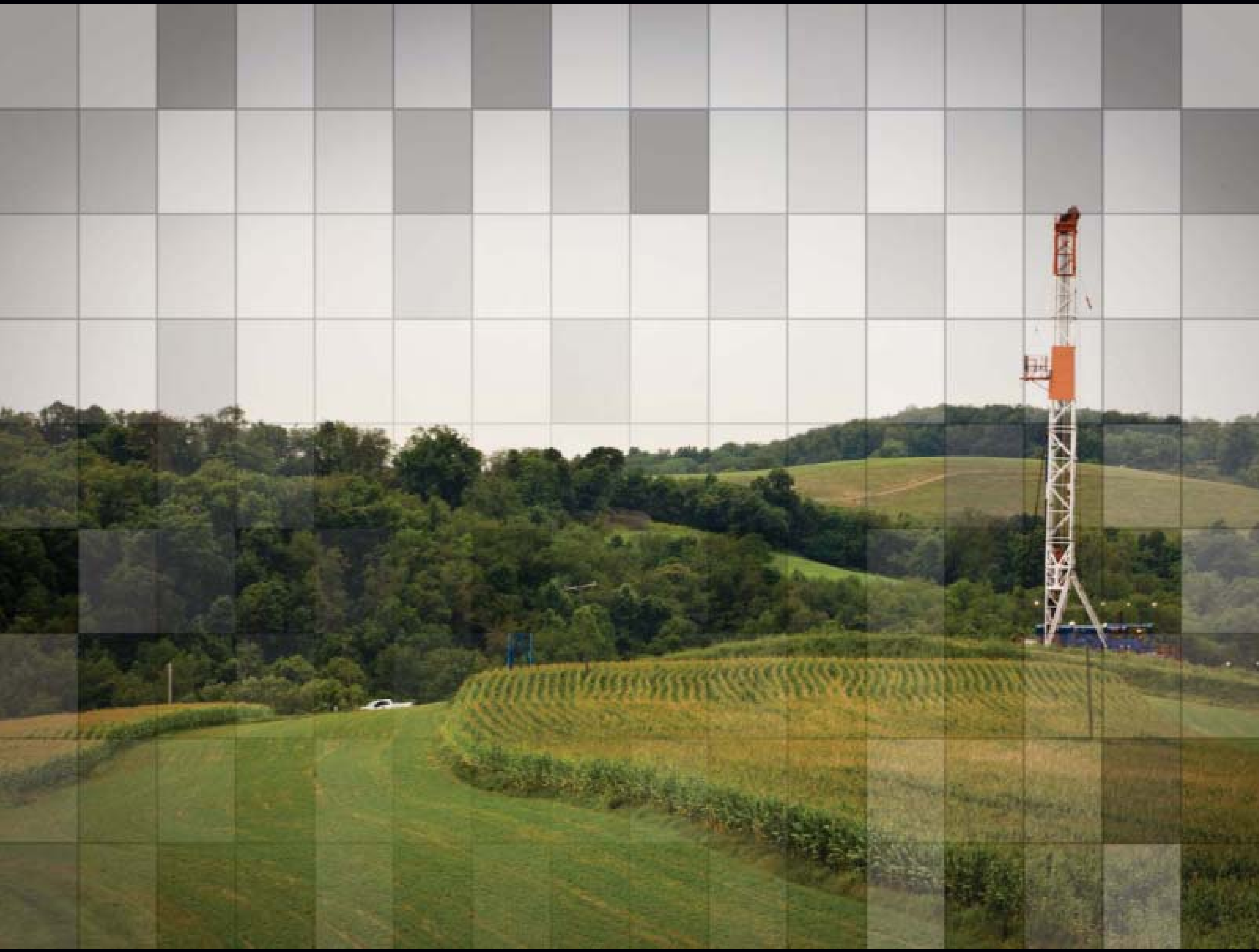
Week of Nov. 10, 2008/US$10.00

PennWell

OIL&GAS JOURNAL

International Petroleum News and Technology / www.ogjonline.com



Independent Operations

Ultradeep shelf well logs four indicated pays in Miocene
Study analyzes nine US, Canada shale gas plays
Monte Carlo analysis assesses expansion project risk
Hybrid riser use provides deepwater crude export solution

OIL&GAS JOURNAL

Nov. 10, 2008
Volume 106.42

Independent Operations

Regular Features

Cover

The first article in the special report on Independent Operations, starting on p. 24, highlights strategies for overcoming obstacles involved in developing the Marcellus shale, one of the largest new onshore gas plays in the US. On the cover is the Patterson No. 163 rig, which is drilling Range Resources Corp.'s 29th horizontal shale well in the rolling hills of Pennsylvania. Range expects at yearend to be producing 30 MMcfd of gas equivalent from its Marcellus shale acreage. A second article, on p. 28, examines stock sale trends by some independents during a time of intense market fluctuations. Cover photo by Brandon Parscale for Range Resources.

Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page


corus

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 48 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $89; Latin America and Canada: 1 yr. $94; Russia and republics of the former USSR, 1 yr. 1,500 rubles; all other countries: 1 yr. $129, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 106, No. 42) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9. Standard Mail A Enclosed in Version P2

PennWell, Houston office
1455 West Loop South, Suite 400, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com

Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Associate Editor Judy R. Clark, judyrc@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor/News Writer Leena Koottungal, lkoottungal@ogjonline.com
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290

Presentation/Equipment Editor Jim Stilwell, jims@ogjonline.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Kermit Mulkins, Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

London
Tel +44 (0)20.8884.4246
International Editor Uchenna Izundu, uchennai@pennwell.com

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

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

OGJ News
Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service
P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Circulation Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

PennWell® MEDIA FOR STRATEGIC MARKETS SINCE 1910

P.C. Lauinger, 1900-1988
Chairman Frank T. Lauinger
President/Chief Executive Officer Robert F. Biolchini

The Audit Bureau

AMERICAN ABM BUSINESS MEDIA

Member Audit Bureau of Circulations & American Business Media

OGJ Newsletter

Nov. 10, 2008

International news for oil and gas professionals
For up-to-the-minute news, visit www.ogjonline.com

General Interest — Quick Takes

API: Industry will work with new president

The US oil and gas industry is looking forward to working with President-elect Barack Obama and a new Congress "to get to work on meaningful energy policy that contributes to economic stability," according to Jack Gerard, American Petroleum Institute president and chief executive officer.

"The American people have spoken loud and clear that they want politicians to put aside partisan bickering," Gerard said in a Nov. 5 news release. "The oil and natural gas industry stands ready to help put America's vast energy resources to good use, strengthening our nation's economy and energy security, and providing good jobs for Americans across the country," he added.

Gerard said the industry stands ready to help the new administration deliver "a comprehensive and realistic energy policy that encourages development of all domestic energy sources, including oil and natural gas, for the benefit of consumers."

Iraqi deputy oil minister escapes attempt on life

Iraq's Deputy Oil Minister Saheb Salman Al-Qutub was wounded in a bomb attack outside his home in the northern Ataifiyah neighborhood of Baghdad.

"The senior deputy oil minister Abdul Saheb Al-Qutub escaped an assassination attempt by improvised explosive device close to his house on Nov. 3," the oil ministry said.

"The deputy minister left the hospital after he received the required treatment," the ministry said, adding that Al-Qutub suffered slight wounds and his driver was severely hurt.

Al-Qutub, a Shiite from the southern province of Basra, also survived an assassination attempt in 2004 along the highway between Baghdad and Hilla, south of Baghdad. He was an adviser to the oil minister at the time.

Al-Qutub was appointed to his position last year when the former deputy oil minister, Abdul Jabar Al-Wagaa, a Sunni, decided to retire after being kidnapped along with four other ministry officials. Al-Wagaa was released a few weeks later.

The latest attempted assassination on Al-Qutub coincided with reports that Iraq's crude oil exports in October rose 3.6% to 1.703 million b/d from 1.644 million b/d.

Iraq exported 1.385 million b/d from the Basra oil terminal, while some 309,000 b/d were exported via pipeline to Turkey's Mediterranean port of Ceyhan. The remaining 9,000 b/d were trucked to neighboring Jordan.

NEB: Economic uncertainty dominates outlook

Canada has sufficient oil and natural gas supplies to meet winter demand, although price volatility is likely, the National Energy Board said.

"Markets here cannot help but be affected by the current volatility of world commodity markets," NEB Chair Gaetan Caron said Oct. 30 in his agency's winter energy outlook.

Fuel prices have declined on a combination of factors, including a deepening global financial crisis, falling demand, and a worsening US and global economic outlook.

NEB forecast that crude oil could average $50-75/bbl this winter on the New York Mercantile Exchange, where natural gas could average $6-9/MMbtu.

Heating oil prices are expected to track crude oil prices, which means average Canadian heating oil prices probably will be lower than last year.

Strong US natural gas production has helped to keep gas prices low while helping to ensure adequate gas supply.

Canadian drilling activity has stabilized but remains down from its 2005-06 winter peak, NEB said.

"Relative to the previous winter, Canadian production is expected to continue trending downward," given slowing gas drilling combined with declines in initial productivity of new wells, NEB said. ✦

Exploration & Development — Quick Takes

Apache's Egyptian discovery tests 4,746 b/d

Apache Corp. said its WKAL-C-1X discovery in Egypt's Western Desert flowed on test at a rate of 4,746 b/d of oil and 4.4 MMcfd of gas.

"The WKAL-C-1X discovery represents the westernmost oil ever discovered in Egypt and confirms our exploration model for this area of the Faghur basin," said G. Steven Farris, Apache president and chief executive officer.

The West Kalabsha concession involves the Jurassic Safa formation in Faghur basin, 50 miles east of the Libyan border (OGJ Online, Aug. 11, 2008).

The well, drilled to 14,600 ft TD, logged 46 ft of Safa oil pay. It also logged 36 ft of pay in the Alem El Bueib 3C formation. Wireline pressure data suggests the water level may be at least 190 ft below the base of the oil sand, Apache said.

Shell, ADNOC sign MOU for gas exploration

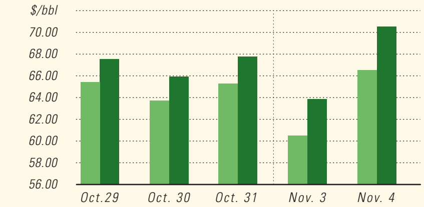
Royal Dutch Shell PLC will partner with Abu Dhabi National Oil Co. to carry out possible deep offshore gas exploration in the country.

The companies have signed a memorandum of understanding, and Shell plans to sign final agreements to quickly begin joint exploration and development activities.

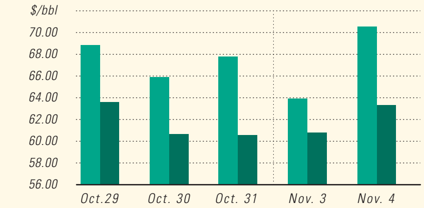
Last year Shell's production in Abu Dhabi averaged 146,000 boe/d.

Industry Scoreboard

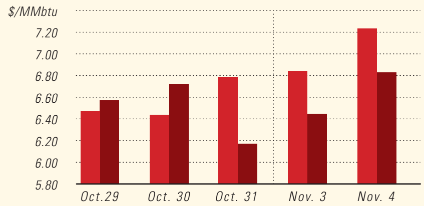
IPE BRENT / NYMEX LIGHT SWEET CRUDE



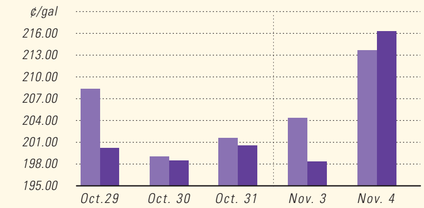
WTI CUSHING / BRENT SPOT



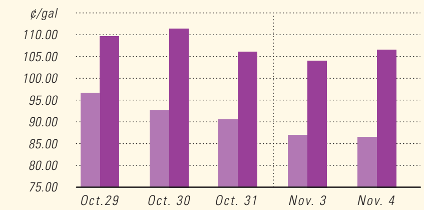
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



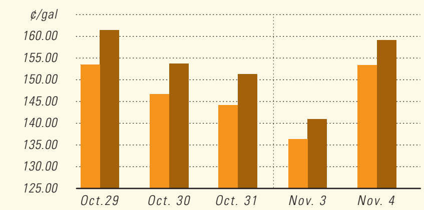
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

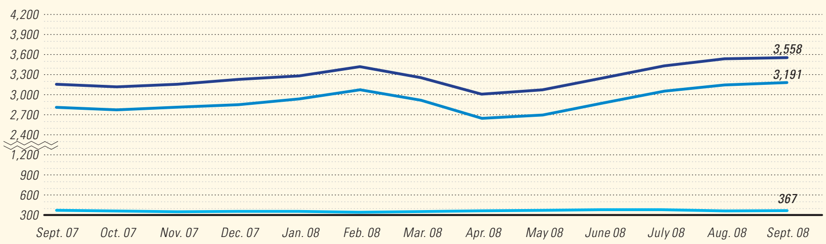
US INDUSTRY SCOREBOARD — 11/10

Latest week 10/24	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	8,927	9,239	–3.4	9,042	9,296	–2.7
Distillate	3,986	4,204	–5.2	4,009	4,208	–4.7
Jet fuel	1,407	1,619	–13.1	1,539	1,626	–5.4
Residual	436	635	–31.3	600	727	–17.5
Other products	4,122	4,768	–13.5	4,645	4,811	–3.4
TOTAL DEMAND	18,878	20,465	–7.8	19,645	20,697	–5.1
Supply, 1,000 b/d						
Crude production	4,575	5,015	–8.8	4,959	5,070	–2.2
NGL production[2]	2,286	2,443	–6.4	2,255	2,380	–5.3
Crude imports	10,311	9,836	4.8	9,759	10,056	–3.0
Product imports	3,432	3,222	6.5	3,177	3,511	–9.5
Other supply[3]	1,393	1,053	32.3	1,375	1,036	32.7
TOTAL SUPPLY	21,997	21,569	2.0	21,525	22,053	–2.4
Refining, 1,000 b/d						
Crude runs to stills	14,660	15,325	–4.3	14,660	15,144	–3.2
Input to crude stills	14,899	15,280	–2.5	14,899	15,434	–3.5
% utilization	84.9	87.6	—	84.9	88.5	—

Latest week 10/24	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	311,873	311,380	493	312,683	–810	–0.3
Motor gasoline	194,990	196,497	–1,507	195,132	–142	–0.1
Distillate	126,629	124,304	2,325	135,279	–8,650	–6.4
Jet fuel-kerosine	35,991	36,579	–588	41,543	–5,552	–13.4
Residual	38,622	37,359	1,263	36,958	1,664	4.5
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	21.7	22.6	–4.0	20.8	4.3	
Motor gasoline	21.8	22.2	–1.8	21.0	3.8	
Distillate	31.8	31.5	1.0	31.7	0.3	
Propane	58.1	67.6	–14.1	55.7	4.3	
Futures prices[5] **10/31**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	65.44	68.78	–3.34	88.45	–23.01	–26.0
Natural gas, $/MMbtu	6.40	6.60	–0.21	7.01	–0.61	–8.7

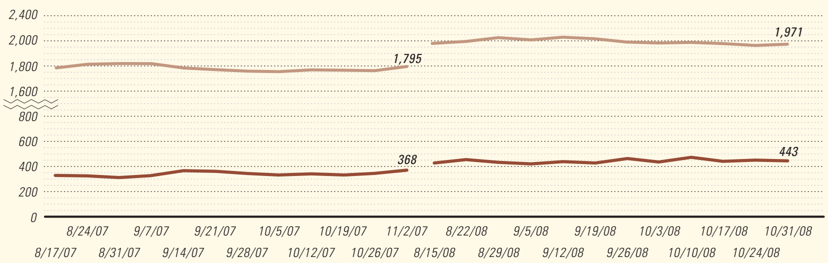
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

Shell holds a 9.5% interest in a joint venture with Abu Dhabi Onshore Co., and it has a 15% stake in Abu Dhabi Gas Industries.

Total acquires interest in Nigerian licenses

Nigeria has approved Total SA's farming into two deepwater licenses off its coast. The French company will acquire a 25.67% interest in OPL 285, operated by OMEL Energy Nigeria Ltd., and a 14.5% interest in OPL 279, operated by OMEL Exploration & Production Nigeria Ltd. (OEPNL).

Nigerian firm EMO Exploration & Production Ltd. also is partner in both assets.

OMEL Energy and OMEL E&P will shoot 500 sq km of 3D seismic and drill one exploration well on the blocks. The exploration period runs until 2012.

OPL 285, covering an area of about 1,170 sq km, lies 80 km offshore near Bonga field in 400-900 m of water.

OPL 279, which is 1,125 sq km in area, is 100 km offshore near Ehra and Bosi fields in 800-1,800 m of water.

"In the second 5-year exploration period, which is optional, the work commitments will cover the acquisition of a further 500 sq km of 3D seismic and the drilling of two exploration or appraisal wells," Total said.

Total's offshore operated production in Nigeria currently comes from the OML 99, 100, and 102 blocks in joint venture with the Nigerian National Petroleum Corp. The main fields are Amenam-Kpono, Ofon, and Odudu area fields.

Total makes gas, condensate find off Brunei

Total SA has struck a new gas-bearing compartment of over 400 m in Brunei's offshore Maharaja Lela-Jamalulalam field.

The company said that on Block B within the ML-4 well the column was equivalent to those already in production in the field. Gas also was found in deeper, high-temperature-high-pressure formations. Total will appraise the gas and condensate discoveries later.

The ML-4 well reached a TD of 5,227 m and was drilled in water 62 m deep, about 50-km offshore.

"Following the successful MLJ2-06T well, the ML-4 well completes the first phase of an exploration drilling program that will resume in 2009," Total added.

Total supplies gas from Maharaja Lela-Jamalulalam field to the Brunei LNG liquefaction plant, which had an average production of gas and liquids of 28,500 boe/d in 2007.

Total operates Block B with a 37.5% interest; partner Shell Deepwater Borneo Ltd. holds 35%, and local partners 27.5%.

MMS to assess mitigation measures off California

The US Minerals Management Service has contracted with Applied Marine Sciences Inc. to help evaluate environmental mitigation measures and conditions required for oil and gas projects off Southern California's coast.

The 5-year study will examine methods used to alleviate concerns associated with oil and gas operations on the US Outer Continental Shelf there, the US Department of the Interior agency said on Oct. 30.

"The objective of these requirements is to preserve and protect the quality of the human, marine, and coastal environments. Our goal will be to look at whether the measures have achieved their intended purpose or if there are better ways to accomplish the desired protection," said MMS Pacific Region Manager Ellen G. Aronson.

The study contract with Applied Marine Sciences, Livermore, Calif., calls for ocean fieldwork, including observing, sampling, or monitoring existing OCS oil and gas operations' mitigation measures and their effects, according to MMS. The Santa Barbara Channel, Santa Maria basin, and San Pedro basin will be the primary study locations, it indicated.

"We expect that information from the study's scientific analysis will be useful to decision-makers in adapting and-or developing future mitigation measures and project conditions for oil and gas and, perhaps, future alternative energy operations off our coast," Aronson said.

Science Applications International Corp. (SAIC), Reese-Chambers Systems Consultants Inc., and Fugro West will work with Applied Marine Science on the study, MMS said.

Petrobras to explore just off northwest Cuba

Brazil's Petroleo Brasileiro (Petrobras), building on agreements signed earlier this year, plans to explore Block 37 in the Florida Straits just off Cuba's north coast.

The exploration period for the block is 7 years in four periods of 18-24 months each. At the end of each period, Petrobras will decide whether to remain in the contract. The rights can be extended 25 years in case of a commercial discovery.

Cuba's state Cubapetroleo (Cupet) retains the option to participate further in the project, paying for past and future investments corresponding to costs related to exploration, development, and production, Petrobras said.

In February, reports said Petrobras signed several cooperation agreements with Cupet, marking the first involvement for Brazil in the Cuban oil and gas sector, which Venezuela had previously dominated (OGJ, Feb. 4, 2008, p. 34).

Block 37 is in 500-1,600 m of water between Havana and Matanzas and 90-95 miles south of Key West, Fla.

North of the west end of Block 37, Repsol-YPF drilled the Yamagua-1 exploration well in 2004 in Block 27 about 20 miles northeast of Havana. That well, drilled to TD 3,410 m in 1,660 m of water, revealed the absence of a seal but showed "the existence of oil generation in the basin as well as an excellent carbonate complex," Repsol said.

Petrobras's Block 37 adjoins Block 7, which is operated by Sherritt International Corp., Toronto. Block 7 contains several offshore heavy oil fields drilled directionally from shore (see map, OGJ, Jan. 10, 2005, p. 31). Block 7 extends 7-10 km off the coast.

Sherritt relinquished deepwater Blocks 16, 23, 24, and 33 in the Catoche basin to the west of Block 37 earlier this month, saying exploration was not worth continuing (OGJ Online, Oct. 17, 2008).

Meanwhile, Cupet signed an agreement recently with Russia's Zarubezhneft to improve recovery of heavy oil from Boca de Jaruco field, IHS Inc. reported. Boca de Jaruco field, discovered in 1968 on the north coast, is within the coverage area of Block 7 but is excluded from it. ✦

Drilling & Production — *Quick Takes*

Jordan freezes oil shale proposals for 18 months

Jordan has stopped all oil shale activities in central Jordan for 18 months to enable the government to explore for uranium.

The Natural Resources Authority (NRA) posted a statement on its web site announcing such a decision of the Council of Ministers. The central Jordan area includes the Attarat Um Ghudran region, which is 34 km east of Qatrana, and the Wadi Maghar region, 40 km southeast of Qatrana.

Royal Dutch Shell PLC is negotiating. Shell is interested in evaluating an area that extends from northern Jordan and West Safawi to Azraq in the middle and Sirhan and al-Jafer in the south.

A Shell spokesman said Shell is working with the government of Jordan under an existing, long-term relationship, and Shell envisions that its activities will be unaffected by this announcement.

Jordan depends on imported oil and refined products to meet all its energy requirements. Oil shale is the only important indigenous source of energy in Jordan, a government document said.

The Jordanian government estimates that Jordan holds more than 50 billion tonnes of oil shale resources.

Galoc sells first oil from field off the Philippines

Galoc Production Co. (GPC), operator for Galoc oil field off the Philippines, has sold its first cargo of 300,000 bbl of crude oil from its new development in the Palawan basin to local refiner Petron Corp.

Offtake is scheduled for Nov. 7 from the Rubicon Intrepid, the field's floating production, storage, and offloading vessel. The oil is bound for Petron's 180,000 b/d refinery at Limay, Batan, just outside Manila. Petron supplies about 40% of the country's total fuel requirements.

Production from Galoc field began in early October and has been flowing at an average 15,000 b/d.

GPC has a 58.29% interest in Galoc field, with Nido Petroleum Ltd., Perth, holding 22.8%. Fellow Perth company, Otto Energy Ltd., has an 18.28% indirect interest through its 31.38% stake in GPC. Other partners in the field include Oriental Petroleum, Alcorn Gold Resources, Forum Energy, PetroEnergy Resources, and Philodrill.

Total plans downhole sulfur removal demonstration

Total SA intends to use the downhole sulfur removal (DSR) technology, which it developed with Austin-based CrystaTech, on sour gas fields in the Middle East and in the Caspian Sea area, Total spokesman Kevin Church told OGJ. A decision has already been taken to move to the pilot unit demonstration phase of the project.

Total signed a technology development and commercialization agreement with CrystaTech, a clean-energy technology development company, to develop a recycling process for the continuous removal and recovery of sulfur deposits in sour gas well bores. CrystaTech is modifying its patented CrystalSulf hydrogen sulfide removal process to develop the new technology for this downhole application.

DSR technology makes the sulfur soluble by continuously injecting a liquid hydrocarbon into the production well bores. It is a nonspecified refinery product that absorbs and carries the sulfur out of the well bore through a state-of-the-art recycling and regeneration process.

Total plans to use the technology in the production of large sour gas reserves in the Middle East and the Caspian Sea. Existing technologies, points out the company, require producers to either shut in gas production while injecting disposable solvents to clear blocked well bores, continuously inject nonrecyclable solvents, or use chemical regeneration processes. ✦

Processing — *Quick Takes*

Sasol arranges China CTL feasibility study

Sasol Synfuels International Ltd. and Shenhua Ningxia Coal Industry Group Ltd. hired subsidiaries of Foster Wheeler Ltd. to conduct a coal-to-liquids (CTL) feasibility study in China.

The study will evaluate the cost of building an 80,000 b/d CTL plant in the Ningxia Hui region of western China.

The Foster Wheeler contract value was not disclosed. Foster Wheeler's Chinese consortium partner on the contract is Wuhuan Engineering Co.

Zorco selects project manager for Libyan refinery

Zwara Oil Refinery Co. Ltd. (Zorco) let a contract to Foster Wheeler Italiana SPA to perform consultancy and project management services for a planned 200,000 b/sd refinery at Mellita, near Zwara, in Libya. The $4 billion refinery is planned to be completed in 2014.

The contract includes the optimization of the refinery's configuration, selection of the licensors and the front-end engineering and design, including preparation of a cost estimate. Foster Wheeler also will prepare the tender documents for the engineering, procurement, and construction phase, will assist Zorco in selecting the EPC contractor, and will serve as project management consultant during the EPC phase.

Foster Wheeler said the planned refinery will be a state-of-the-art facility aimed at producing premium quality gasoline, jet fuel, and diesel with minimal fuel oil production, and related utilities, offsites, and marine facilities.

Tamoil Africa Holdings Ltd. holds the equity in Zorco.

Tula cat cracker offline until late November

Petroleos Mexicanos (Pemex) reported it has shut down the catalytic cracking unit at its 315,000 b/d Tula Hidalgo refinery for maintenance. The cat cracker, which was shut down Oct. 19, will be offline until late November, the company said.

Tula is Mexico's second-largest refinery after its 330,000 b/d Salina Cruz facility and produces about 100,000 b/d of gasoline.

Pemex usually imports gasoline from US Gulf Coast refineries when it is shut down for maintenance, but because of hurricane-related repairs to US refineries, Mexico had to purchase gasoline from European and Asian refineries in September and October. ✦

Transportation — *Quick Takes*

Baku-Supsa line reopens, BTC ships Kazakh oil

BP PLC said the Chevron-led TengizChevrOil (TCO) consortium has begun transporting crude oil through the Baku-Tbilisi-Ceyhan pipeline and that the Baku-Supsa pipeline has reopened after being closed during recent hostilities between Russia and Georgia.

"As of today the Baku-Supsa pipeline has started working again and we will gradually raise the amount of oil pumped through it to the optimal level," said BP Azerbaijan spokesperson Tamam Bayatly Nov. 5.

The State Oil Co. of the Azerbaijan Republic (SOCAR) said the Baku-Supsa pipeline, which has a benchmark capacity of 145,000 b/d, will carry 90,000 b/d after reopening and likely will remain at that level until yearend.

The line was closed down as a safety measure in August during Georgia's 5-day war with neighboring Russia. At the time, the Baku-Supsa line had been open only a week after returning to service following an 18-month closure for maintenance and repairs.

BP Azerbaijan also said shipments of TCO oil are now under way through the BP-led BTC pipeline. Shipments of TCO crude began in late October, the firm said, without detailing the amounts or dates of shipments.

The oil from Kazakhstan's Tengiz field is shipped by tankers across the Caspian Sea to the Apsherob Peninsula in Azerbaijan and then loaded into the BTC line, the BP Azerbaijan spokesperson said.

According to SOCAR officials, the BTC line could eventually transport as much as 100,000 b/d of Kazakh oil.

Origin, ConocoPhillips finalize CSM-fed LNG venture

Origin Energy Ltd., Sydney, has finalized its deal with ConocoPhillips to form a coalseam methane (CSM)-supplied LNG joint venture to be called Australia Pacific LNG. ConocoPhillips has submitted an upfront payment of $5 billion.

The proposal is to develop Origin's CSM resources in the Surat and Bowen basins in Queensland to supply a proposed 14 million tonnes/year LNG plant at Gladstone on the central east coast of Queensland.

First investment decision for Train 1 is due by the end of 2010, and first LNG production is scheduled for 2014.

Through the JV, Origin will become the largest CSM-LNG producer in Australia.

Origin says Australia Pacific LNG brings together Origin's 10 and ConocoPhillips' 25 years of CSM experience. Through ConocoPhillips, the new JV has access to 40 years of experience in operating and developing LNG facilities.

PNG names LNG project share nominee

After several months deliberation, Papua New Guinea has put forward Independent Public Business Corp. (IPBC) as the state's nominee to manage the government's 19.4% stake in the $11 billion ExxonMobil Corp.-led Papua New Guinea LNG project.

IPBC was competing with fellow state-owned Petromin for the position.

Prime Minister Michael Somare said the government's ministerial economic committee and the National Executive Council had noted IPBC's progress to secure financing for the state's equity in the project without any sell-down of the government's stake.

In other words, he said, the state won't go into debt to finance its equity and won't need to provide state guarantees.

The equity funding arrangements are expected to be announced in the PNG Parliament in mid-November.

Somare added that the government is pleased with the manner in which ExxonMobil and its coventurers are driving the project, particularly in the uncertain global financial market climate.

He said the time is ripe for development of PNG's gas resources in view of the growing role of gas as a fuel of choice in global efforts to reduce carbon dioxide emissions and global warming.

IPBC also manages the government's 17.56% interest in Oil Search Ltd.

Centrica secures LNG cargo from Qatar

Centrica PLC will import its first cargo of LNG from Qatar later this month to commission the second expansion phase of the Isle of Grain LNG terminal in Kent.

The cargo from RasGas Co. Ltd. will be the UK's largest ever LNG delivery, according to Centrica, and is a crucial step in helping the country address its dwindling indigenous supplies from the North Sea.

National Grid PLC owns the terminal, and Centrica has the rights to import 3.4 billion cu m/year of gas for the next 20 years.

"RasGas will use one of the new generation of high capacity Q-Flex super-tankers, the Al Khuwair. It is among the world's largest LNG carriers and the largest gas vessel to call at a British port," Centrica said.

The tanker will deliver up to 50 million therms of gas, which represents about 35% of total UK demand on an average winter day.

The company's chief executive, Sam Laidlaw, is in Qatar on a trade delegation visit with the British Prime Minister Gordon Brown and other British CEOs.

Sam Laidlaw, chief executive of Centrica, said: "Our capacity at Isle of Grain is just one of many strategic investments Centrica is making in new gas and power assets to secure the UK's future energy needs."

LNG, increasingly important for the UK, is expected to make up 28% of the UK's total supply by 2017, according to National Grid's 2008 forecast. This year the UK will import 40% of its gas demand, rising to 75% by 2015.

Under a 19-year contract, Centrica also has the rights to an additional 2.4 billion cu m/year of gas due to be available in 2010-11 in the third phase of the Isle of Grain expansion. This will mean that almost 30% of the terminal's total capacity will be available to supply British Gas customers from that time and, overall, the Isle of Grain will then be capable of supplying 20% of the UK's annual demand. ✦

Letters

Unwarranted hostility

The editorial "An unprecedented rebuke" (O&GJ, 10/13/08) might better have been titled "Unwarranted hostility" (OGJ, Oct. 13, 2008, p. 20). A major dilemma facing the US petroleum industry and especially international oil companies is that of being taken to task by the US government for doing what the industry is supposed to do: that is, to find and produce energy for the nation at the lowest practicable cost. This is a formidable challenge recognizing that new petroleum reserves are becoming increasingly hard to find and expensive to produce.

Add to this the fact that the government-owned national oil companies (NOCs) control over 70% the world's oil reserves and are using their growing wealth to invest in energy-related activities outside of their national borders. The long-term implications of this growing NOC presence in the international oil arena are not clear, but almost certainly it will impact energy security and stability of oil markets. For example, developing competition from NOCs involves governments where traditional economic constraints may be less of a consideration than in the private sector. This poses new, potentially costly challenges for international oil companies.

There is insufficient understanding and appreciation in US government circles of what the petroleum industry does year after year in helping to assure the nation of adequate energy supplies. This governmental insensitivity simply feeds public hostility and makes it more difficult for the industry to get on with its job. Understand, this is by no means an appeal to government to coddle the industry. However, government should avoid selectively imposing harsh new taxes and restrictions on an industry that faces extraordinary challenges in finding new petroleum reserves in increasingly hostile natural environments and in competition with other foreign-based international oil companies and well-financed NOCs.

In short, American oil companies are involved in fierce worldwide competition to secure energy supplies to meet our nation's needs. Government should take care not to hobble our country's team.

Thomas Wyman
Palo Alto, Calif.

Calendar

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

OIL&GAS JOURNAL online

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

NOVEMBER

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

Financial Modelling in the Oil and Gas Industry Conference, London, +44 (0) 20 7827 6000, +44 (0) 20 7827 6001 (fax), website: www.smi-online.co.uk/oilgasmodelling38.asp. 12-13.

✦SEA-ALOGE Algeria Energy Week and Algeria Oil& Gas Exhibition, Algiers, +44 20 7978 0080, +44 20 7978 0099 (fax), e-mail amarhic@thecwcgroup.com, website www.thecwcgroup.com. 15-19.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

ERTC Annual Meeting,Vienna, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 17-19.

Annual Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 18-20.

Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.com, website: www.theeagc.com. 25-26.

✦Offshore Energy, Den Helder, +31(0)10 4360112, e-mail: jl@navingo.com, website: www.offshore-energy2008.nl. 27.

DECEMBER

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 2-3.

Annual Refining & Petrochemicals in Russia and the CIS Countries Roundtable, Prague, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 2-4.

Downstream Asia Refining & Petrochemicals Conference, Singapore, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/dalregister.html. 3-4.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

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

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

USAEE/IAEE North American Conference, New Orleans, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 3-5.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8-9.

PIRA Understanding Global Oil Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10-11.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Petrotech International Oil & Gas Conference & Exhibition, New Delhi, +91 11 2436 4055, +91 11 2436 0872 (fax), e-mail: convenor_petrotech@iocl.co.in, website: www.petrotech2009.org/registration.aspx. 11-15.

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.oilandgas-maintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.pipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), e-mail: sales@turretme.com, website: www.worldfutureenergysummit.com. 19-21.

API Exploration & Production Winter Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 19-23.

API/AGA Oil and Gas Pipeline Welding Practices Conference, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-23.

International Process Analytical Technology Forum (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 25-28.

Global E&P Summit, Madrid, +44 (0)20 7202 7500, +44 (0)20 7202 7600 (fax), e-mail: info@wtgevents.com, website: www.epsummit.com. 26-28.

Calendar

Offshore West Africa Conference, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendOWA@pennwell.com, website: www.offshorewestafrica.com. 27-29.

The European Gas Conference, Vienna, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 27-29.

SIHGAZ International Hydrocarbon & Gas Fair, Hassi Messaoud, + 213 21 21 58 74, + 213 21 21 58 72/76 (fax),e-mail: contact@foirex.com, website: www.sihgaz2009.com. 28-31.

FEBRUARY

SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 2-4.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition (DOT), New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 3-5.

Global Petrochemicals Conference & Annual Meeting, Cologne, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 3-5.

Russia Offshore Annual Meeting, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 4-6.

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 5-6.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 9-12.

SPE Unconventional Fields Conference, Margarita Island, Venezuela, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Pipe Line Contractors Association Annual Conference (PLCA), Carlsbad, Calif., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 11-15.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

International Petrochemicals Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 16-17.

IP Week, London, +44 (0)20 8561 6030, +44 (0)20 8561-0131 (fax), e-mail: events@energyinst.org.uk, website: www.energyinst.org.uk. 16-19.

✦EnerCom's The Oil & Services Conference, San Francisco, (303) 296-8834, e-mail: kgrover@enercominc.com, website: www.theoilandservicesconference.com/index.html. 18-19.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 18-19.

ASEG/PESA International Geophysical Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au, website: www.sapro.com.au/aseg.htm. 22-25.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-2248, (405) 325-7164 (fax), e-mail: bettyk@ou.edu, website: www.engr.outreach.ou.edu. 22-25.

Nitrogen + Syngas International Conference and Exhibition, Rome, +44 20 7903 2167, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: http://crugroup.com. 22-25.

✦CERI Natural Gas Conference, Calgary, (403) 282-1231, (403) 284-4181 (fax), e-mail: conference@ceri.ca, website: www.ceri.ca. 23-24.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 23-26.

MARCH

EAGE North African/Mediterranean Petroleum and Geosciences Conference & Exhibition, Tunis, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 2-4.

SPE Research & Development Conference, Lisbon, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-4.

APPEX Prospect and Property Expo, London, (918) 560-2616, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 3-5.

Subsea Tieback Forum & Exhibition, San Antonio, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Doha Natural Gas Conference & Exhibition, Doha, e-mail: gascon@qp.com.qa, website: www.dohagascon.com.qa. 9-12.

ARTC Annual Meeting, Kuala Lumpur, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 10-12.

European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 10-12.

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 10-12.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 17-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

PIRA Understanding Global Oil Markets Seminar, Dubai, 65 6581 4122, e-mail: jay@pira.com, website: www.pira.com. 23-24.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

Offshore Mediterranean Conference & Exhibition (OMC), Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc2009.it. 25-27

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 29-31.

Petroleum Geology Conference, London, +44 (0)20 7434 9944, +44 (0)20 7494 0579 (fax), e-mail: georgina.worrall@geolsoc.org.uk, website: www.geolsoc.org.uk. Mar. 30-Apr. 2.

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 1.

Offshore Asia/Multiphase Pumping & Technologies Conference & Exhibition, Bangkok, 918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOA@pennwell.com, website: www.offshoreasiaevent.com. Mar. 31-Apr. 2.

APRIL

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-3.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-8.

ATYRAU Regional Oil & Gas Exhibition & OilTech Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 7-9.

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 14-16.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 16.

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

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

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

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

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

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

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

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

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

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

STATEMENT OF OWNERSHIP, MANAGEMENT AND CIRCULATION

1. Publication Title: Oil & Gas Journal. **2. Publication Number:** 405-760. 3. **Filing Date:** October 1, 2008. **4. Issue frequency:** Weekly. **5. Number of Issues Published Annually:** 48. **6. Annual Subscription Price:** $89.00. **7. Complete Mailing Address of Known Office of Publication:** PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, OK 74112, Tulsa County. **7a. Contact Person:** Traci Huntsman. **7b. Telephone:** 918-831-9435. **8. Complete Mailing Address of Headquarters or General Business Office of Publisher:** 1421 South Sheridan Road, Tulsa, OK 74112. **9. Full Names and Complete Mailing Addresses of Publisher, Editor and Managing Editor:** Publisher: Bill Wageneck, 1455 W. Loop S. #400, Houston, TX 77027. Editor: Bob Tippee, 1455 W. Loop S. #400, Houston, TX 77027. Managing Editor: Bob Tippee, 1455 W. Loop S. #400, Houston, TX 77027. **10. Owner:** PennWell Corporation, 1421 South Sheridan Road, Tulsa, OK 74112, Tulsa County; Successors to the estate of Helen B. Lauinger, 1421 South Sheridan Road, Tulsa, OK 74112, Tulsa County. **11. Known Bondholders, Mortgages, and Other Security Holders Owning or Holding 1 Percent or More of Total Amount of Bonds, Mortgages, or Other Securities:** None. **12.** N/A. **13. Publication Title:** Oil & Gas Journal. **14. Issue Date for Circulation Data:** September 22, 2008.

15. Extent and Nature of Circulation:

	Average No. Copies Each Issue During Preceding 12 Months:	No. Copies of Single Issue Published Nearest to Filing Date:
a. Total Number of Copies	24782	23894
b. Paid Circulation (By Mail and Outside the Mail)		
1. Mailed Outside-County Paid Subscriptions Stated on PS Form 3541	16226	15846
2. Mailed In-County Paid Subscriptions Stated on PS Form 3541	0	0
3. Paid Distribution Outside the Mails Including Sales Through Dealers and Carriers, Street Vendors, Counter Sales, and Other Paid Distribution Outside USPS	4925	5134
4. Paid Distribution by Other Classes of Mail Through the USPS	0	0
c. Total Paid Distribution	21151	20980
d. Free or Nominal Rate Distribution		
1. Free or Nominal Rate Outside-County Copies included on PS Form 3541	1245	997
2. Free or Nominal Rate In-County Copies Included on PS Form 3541	0	0
3. Free or Nominal Rate Copies Mailed at Other Classes Through the USPS	0	0
4. Free or Nominal Rate Distribution Outside the Mail	654	455
e. Total Free or Nominal Rate Distribution	1899	1452
f. Total Distribution	23050	22432
g. Copies not Distributed	1732	1462
h. Total	24782	23894
i. Percent Paid	91.76%	93.53%

16. Publication of Statement of Ownership: Will be printed in the November 10, 2008 issue of this publication. **17. Signature and Title of Editor, Publisher, Business Manager, or Owner:** Paul Bernius, Vice President, Human Resources & Corporate Assets. **Date:** 10/01/08

I certify that all information furnished on this form is true and complete. I understand that anyone who furnishes false or misleading information on this form or who omits material or information requested on the form may be subject to criminal sanctions (including fines and imprisonment) and/or civil sanctions (including civil penalties).

Calendar

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

MAY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

JUNE

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

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

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

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. 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.

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

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.

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.

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: http://oshot09.events.pennnet.com/fl/index.cfm. 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.

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

EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

Polar Petroleum Potential 3P Conference, Moscow, (918) 584-2555, (918) 560-2665 (fax), website: www.aapg.org. 16-18.

ADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

SPE Eastern Regional Meeting, Charleston, W.Va., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

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

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

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

OCTOBER

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

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

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

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

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

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

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

Producing energy from smoke

Sam Fletcher
Senior Editor

Congratulations to President-elect Barack Obama for his unsurprising victory after an unusually long and unusually bitter campaign. Many campaigners and analysts kept promising energy would be a major election issue, but the closest the candidates came to a real energy debate were the clouds of smoke each generated.

Both pledged to work for energy independence, an objective that those in the energy business know is not possible in 10-20 years and is perhaps not even desirable. Would US voters pay more for homegrown energy if cheaper foreign supplies were available? Not likely.

Back in the 1950s when independent producers and governors of oil-producing states testified that increased imports of Middle East oil eventually would result in energy dependence, Congress' response was: "You just don't want the public to have access to all this cheap oil."

Irwin Stelzer, director of Hudson Institute's Economic Policy Studies, said the US will remain dependent for transportation purposes on imported oil from unfriendly nations for the foreseeable future—"whether or not we decide to drill at home." He said, "For both transportation and other energy needs, neither nuclear nor alternative fuels can be developed quickly enough—even if politics and environmental concerns were not an issue."

From its initial discovery, this continent has prospered primarily because of its vast resources. We had so much crude we once were a major exporter, supplying the "sea of oil" that carried us and our allies to victories in World War I and World War II. Problem is, US citizens long ago became so used to cheap fuel that most now consider it their birthright. If that fuel is now more expensive, it can't be the result of diminished resources, or rising production and processing costs, or a faltering economy, or poor government policies. No, it must be a conspiracy of some sort.

Conspiracy theory

David Blume, executive director of the International Institute for Ecological Agriculture, predicted US gasoline prices would swiftly escalate immediately after the presidential election. Blume, an ethanol expert, claims to have price index data over the last 20 years proving the "world price of oil is totally dependent every 2 years on the federal elections in the US." He claims it clearly shows "prior to each national election in the US the price of oil plummets for a several-month cycle prior to November voting, and then immediately climbs back up to record-setting highs by about Mar. 1."

He concludes that movement may result from "incumbents who want to avoid blame for high prices on their watch and are willing to grant concessions and deals to Big Oil interests in return for temporary price drops." Apparently Democrats and Republicans both are willing to encourage illegal price-fixing to keep pump prices low and voters dumb and happy until they cast their ballots. Blume says the problem would be resolved when ethanol competes.

According to Frank Maisano, a pro-energy Washington, DC-based public relations specialist, the only energy issue being pushed by the John McCain camp just days before the election was a charge that Obama's climate plan would put into place an economic cap so tough that it would "bankrupt" any coal-plant builder. That was picked up by the Congress of Racial Equality, who called vainly on the Congressional Black Caucus to disavow support for such policies.

Still, EPCglobal, an "engineering staffing specialist," acquired in October by Modern Professional Services recruitment group in Troy, Mich., said energy was a salient election issue to 1,013 respondents to an Oct. 22-27 online survey that is "broadly demographically representative" of 1.5 million US engineers. For 99% of those respondents, energy policy was "very" or "quite" important, just ahead of the economy and jobs at 98%.

According to 85% of respondents, the principal energy issue requiring a presidential policy response is satisfying the country's future needs for more power. Less important are opportunities from "green collar" jobs (33%).

Of the respondents, 45% said McCain had the most effective policy package to address short and long-term energy problems. But that fell to 31% among female engineers. Only 27% of the responding engineers favored Obama's policies. Yet among engineers under 45 years of age McCain's support dropped to 33% while Obama's rose to 37%. "Significantly, almost one fifth of engineers think neither candidate has the solution," said EPCglobal officials. ✦


Some say you can't do anything about higher energy costs.
Guess what? They're wrong.

Editorial

Dollars and politics

The US oil and gas industry, politically unpopular and publicly misunderstood, spent its political money on a losing cause in this year's general election. Campaign contributions associated with the industry favored Republicans. At the national level, the other party won.

For the oil and gas business, political weather is never calm. Since the gasoline price leaps that followed Hurricanes Katrina and Rita in 2005, it has been persistently stormy. Once Democrats, always cranky toward oil and gas, settle into new and newly fortified seats of power and notice where the industry spent its political money in the elections of 2008, things can only get worse.

Industry giving

According to the Center for Responsive Politics (CRP), which uses data from the Federal Election Commission, oil and gas giving in the 2007-08 election cycle as of Oct. 19 totaled slightly more than $26 million. That total ranked 16th on the CRP's list of "top industries." The number represents contributions by political action committees (PACs) and individuals giving at least $200. Of the total, $18.3 million came from individuals and $7.8 million from PACs.

The oil and gas industry's giving fell well below levels by the CRP's top five "industry" donor categories: retired, $204 million; lawyers and law firms, $181 million; securities and investments, $123 million; real estate, $105 million; and health professionals, $70 million. Other "industries" contributing more than oil and gas, in descending order, were candidate committees, business services, insurance, education, TV-movies-music, Democratic-liberal, leadership PACs (set up by politicians to contribute to other candidates' campaigns), commercial banks, computers-internet, and lobbyists.

The oil and gas category was the only industry among the top 20 with a giving pattern characterized by the CRP as "strongly Republican." Republicans received 76% of the donations associated with oil and gas. In fact, the industry was one of only three in the top 20 giving more heavily to Republican than to Democratic election efforts. Seventeenth-ranked general contractors and 19th-ranked "miscellaneous manufacturing and distributing" both earned "leans Republican" descriptions from CRP. All other industries in the top 20 were "on the fence" or tilted to varying degrees toward Democrats.

Oil and gas industry donations strongly favored the losing presidential candidate. The campaign of Sen. John McCain (R-Ariz.) received slightly more than $2 million from industry PACs and individuals. The campaign of president-elect, Sen. Barack Obama (D-Ill.), received $523,000. The oil and gas business ranked 12th on the CRP's list of industries supporting McCain. It wasn't among the top 20 industries supporting Obama.

The heaviest spending by oil and gas industry donors in congressional races produced mixed results. Twelve of the top 20 senators or senatorial candidates in receipts of oil and gas donations won their elections or were leading in close races at this writing. The top-20 list includes three senators who weren't seeking reelection: Democrat Hillary Clinton of New York, who unsuccessfully sought her party's presidential nomination, as well as Republicans Pete Domenici of New Mexico and Kay Bailey Hutchison of Texas. The top 20 list also includes both of the candidates in a single race: incumbent Louisiana Democrat Mary L. Landrieu, who ranked sixth and won, and Republican John Neely Kennedy, No. 11, who lost. The leading senatorial recipient of oil and gas contributions was Republican incumbent John Cornyn of Texas, who in a ranking of all leading recipients of oil and gas industry donations was No. 3 behind McCain and former presidential hopeful and New York Mayor Rudolph W. Giuliani. He won.

Scattered victories

All the top 20 House candidates in receipts from oil and gas donors, 14 Republicans and 6 Democrats, won or were the apparent winners of their elections. All but incumbent Roy Blunt (R-Mo.) are from producing states, mainly Texas and Oklahoma.

Scattered victories in Congress will provide little comfort amid the Democratic political tempest soon to batter the "strongly" Republican-leaning oil and gas industry. The experience will raise useful questions about campaign contributions. In the election cycle just ended, oil and gas political donors probably have bought a $26-million bull's-eye. ✦


Insurance
Risk Management
Zurich HelpPoint

Producers, regulators address Marcellus shale gas challenges

Nick Snow
Washington Editor

The Marcellus shale, which extends 575 miles across parts of three eastern US states, is thought to hold as much as 500 tcf of natural gas, about 50 tcf of which is considered recoverable. The area is bringing producers, landowners, and state and local officials to address water use and other questions.

The Marcellus shale deep-gas formation also is bringing the oil and gas industry into parts of Pennsylvania, New York, and West Virginia for the first time. Producers have responded with aggressive outreach efforts.

"We have been meeting with individual groups about the Marcellus play for some time," said Charlie Burd, executive director of the Independent Oil & Gas Association of West Virginia (IOGA of WV) in Charleston. "We have been to several places in eastern West Virginia where this development will take place because it lies in a formation that hasn't been produced and a part of the state that hasn't had a lot of oil and gas exploration, Burd said, adding, "So there's more concern, both positive and negative, from those constituents. Residents and royalty owners where there has been shallow drilling are more familiar with the process of exploring and producing natural gas and oil."

State regulators also have responded. "We have experienced here in Pennsylvania what may be a relatively unprecedented land rush," said J. Scott Roberts, deputy for mineral resources management in Pennsylvania's Department of Environmental Protection. "There are now several million acres of private land which have been leased for Marcellus shale development, including 78,000 acres of state forest land where bids were put out in September," Roberts said.

"Pennsylvania's traditional oil and gas production has been in the western quarter of the state," Roberts told OGJ during an Oct. 28 telephone interview. "The Marcellus exists in sort of an arc, starting in the same portions to the south but extending north and east, including all of our northern tier counties to the Delaware River. Those counties haven't seen any oil and gas production because the opportunities haven't existed," he said.

Marcellus shale committee

The state's two main industry associations—the Pennsylvania Oil & Gas Association (POGAM) and the Independent Oil & Gas Association of Pennsylvania (IOGA of PA)—announced the formation of a joint Marcellus shale committee on Oct. 15. The associations said the committee will represent Pennsylvania producers on matters connected with acquisition, exploration, drilling, and development of the Marcellus shale gas resource. It also will help present a unified voice before state, county, and local governments and regulators, they said.

"We're focused on Pennsylvania, which has had an active oil and gas industry for 150 years. But the industry has been relatively small, focusing on smaller producing wells, and has flown under the radar," said Richard D. Weber, one of the committee's cochairman and president of Atlas Energy Resources LLC in Moon Township near Pittsburgh. "The Marcellus shale has brought a lot more attention to it," Weber noted, adding, "It potentially could be one of the larger US natural gas fields, and it has caught the attention of our legislators, regulators, and governor."

Weber told OGJ in an Oct. 30 telephone interview that POGAM and IOGA of PA recognized that several changes had been proposed for regulating oil and gas industry activities in Pennsylvania "and we felt we needed to come together on issues related to the Marcellus shale," he said, adding, "We invited some newer companies to Pennsylvania to join us. There are about 26 companies participating. The committee tries to provide a unified voice on regulatory issues and best practices."

A separate, Appalachian shale water conservation and management committee has existed for about 6 months to address technical issues. It was formed last spring by about half a dozen Marcellus shale producers, which have been active in the Barnett shale formation near Fort Worth, Tex., according to Tom Hayes, its managing director and a senior engineer at the Gas Technology Institute in Des Plaines, Ill. There are about 20 members now who are working to develop best management practices and technical solutions for Appalachian shale gas development, Hayes said in an Oct. 23 telephone interview.

Some major differences

"There are tools that have been examined and evaluated in the Barnett that have been helpful with the Appalachian," Hayes said. "But the two regions are different in terms of regulatory environment and the challenges the industry faces there. Climate is a big difference. The availability of water is another. Having to deal with three states instead of one is a third. The Appalachian shale also traverses states that are in three [Environmental Protection Agency] regions," Hayes said.

Water use is the single biggest issue that has emerged as producers look more closely at hydrological fracturing to develop Marcellus shale gas. Hayes said producers will need to begin the actual process before they can say whether there's a major difference from the Barnett shale experience. "For now, they're estimating the same water use per well," he said.

"If you look at the economic opportunities that were created in the Dallas-Fort Worth area by the Barnett shale and then apply it across Pennsylvania, the potential is immense."—
J. Scott Roberts, deputy for mineral resources management, Pennsylvania Department of Environmental Protection

"The companies have worked together to bring a lineup of service companies, key equipment vendors, engineers, and regulatory organizations to help understand the challenges and possible solutions to what lies before us," Hayes told OGJ. "They have made a lot of progress in bringing a lot of information into the arena. Now that we have it, we're continuing to gather more while starting to understand how to use it to make integrated solutions come to the forefront. We've even had a lot of very good meetings with regulators on a technical, rather than legal, basis. They have been good conversations," he said.

State regulators' approaches to potential Marcellus shale gas development have varied. In New York, where 54.9 bcf of gas was produced in 2007 from existing shallower wells that were drilled vertically, the horizontal drilling necessary to produce from the deeper Marcellus and Utica formations has raised questions. "Land agents and companies have been scouring the Catskill foothills and southern mountains signing up leases," said a spokesman for the state's Department of Environmental Conservation.

The state has updated its well spacing law to address horizontal drilling issues, the DEC spokesman said. The department also launched a Marcellus shale information page on its web site. Gov. David A. Paterson also directed DEC on July 25 to draft a supplement to a 1992 Generic Environmental Impact Statement (GEIS) to address issues related to the larger water volumes needed for hydrologic fracturing. DEC scheduled six public meetings from Nov. 6 to Dec. 4 on its proposal. "This is just the first step in what will be a careful process designed to look at environmental issues unique to the high-volume hydraulic fracturing of horizontal wells in these deep rock layers," DEC Commissioner Pete Grannis said on Oct. 6.

Combination of elements

"Horizontal drilling is not new. Hydraulic fracturing is not new. And drilling into the Marcellus shale is not new. But the drilling operations proposed involve all three of these elements, along with greatly increased water use," Grannis said. "This review is designed to ensure that if the drilling goes forward, it takes place in the most environmentally responsible way possible," he said.

Following the public hearings and comment period, DEC will release a final scoping document and then prepare the supplemental GEIS. It hopes to have a draft ready for public review by early spring 2009.

The DEC spokesman said during the supplemental GEIS's scoping and preparation, producers applying for

Marcellus shale drilling permits will be required to undertake an individual, site-specific environmental review. That review must take into account the same issues being considered in the supplemental GEIS process and must be consistent with the requirements of State Environmental Quality Review Act and the state Environmental Conservation Law. Three companies applied to drill eight horizontal wells before the announcement, the spokesman said. No new applications have come in since, he added.

Producers also have tried to respond to concerns expressed about possible impacts on drinking water supplies. Testifying before the New York State Assembly's Standing Committee on Environmental Conservation on Oct. 15 on behalf of the Independent Oil & Gas Association of New York, Roger Willis, president of Universal Well Services Inc. in Meadsville, Pa., said the US EPA has reviewed hydraulic fracturing extensively and found no cause for alarm.

"With all of the hydraulic fracturing treatments that have been pumped in New York state, DEC has not found one case of documented damage to aquifers," Willis said. "The waters of the Marcellus have no potential to be used for potable water and have been in place without migrating for over 50 million years. We are utilizing fluids that comply with EPA regulations and all of them have been divulged to DEC for [its] review," he added.

The industry also continues to work to advance the technology from "greener" additives and continues research with the Groundwater Protection Council and the US Department of Energy, Willis said. "Industry partners are working with DOE on a project named 'Modern Shale Gas Development,' which is a nationwide shale program with emphasis on the Barnett, Marcellus, Fayette and Woodford shales," Willis said.

*"I think we have made progress, but I don't want to give anyone the impression that we're done. We have work to do."***—Richard D. Weber, president, Atlas Energy Resources LLC**

West Virginia responses

Water use also has raised questions in West Virginia. "The big difference is the volume [of water] used in the completions compared with more conventional activities," said James Martin, chief of the Office of Oil and Gas in the state's Department of Environmental Protection, in an Oct. 28 telephone interview. "That's not the case with all of the Marcellus, but most if it is that way. If the water has been intended to be land applied, that raises questions, particularly since some of the terrain is not suitable for that application," he said.

"There's no question that more water will be needed," confirmed IOGA of WV's Burd. "Clearly, the play requires a good deal more than has historically been needed to develop shallow wells. It's the difference between a 1,000 bbl frac and a 10,000 bbl frac," he said, adding, "That has been, without question, the leading area of discussion in all the meetings we've been invited to or held around West Virginia. The concern most likely expressed at these meetings has to do with water withdrawal, usage, treatment, and disposal."

Burd said the state also adopted water claiming legislation that established a reporting process that has been tweaked several times. Essentially, it states that a withdrawal of more than 750,000 gal of water from one or more streams to be used at a single facility triggers a 3-year reporting process, Burd said.

"Currently, our West Virginia [Department of Environmental Protection] water resources division understands that oil and gas is significantly different from a traditional industrial facility withdrawing water," Burd said, adding, "[Both] DEP and the industry are working through that issue to determine how to best apply this statute so it doesn't trigger the reporting process while the well is developed and produced and the land is reclaimed. They have recognized that this needs to be addressed, and there is a working group."

Recycling as an option

"We have looked at recycling as a good way to approach some of these challenges, said DEP of WV's Martin. "The more that can be used, the less impact on resources upfront. We know the industry is aware of this as an option and is looking into it. There are companies that are looking at treating the water to get it to levels where this can be done," he told OGJ.

In Pennsylvania, said Roberts, staff members of the state's DEP department held several conferences with landowners who had no previous oil and gas experience about provisions under the state's oil and gas law and what the department regulates. Pennsylvania State University county extension provided landowners other information about leases, Roberts said. DEP also has launched a web page with Marcellus shale information for landowners and the general public at its own web site.

Considered the US oil industry's

birthplace because of Col. Edwin L. Drake's discovery at Titusville in 1859, the state of Pennsylvania more recently has had a robust gas producing industry and has seen significant coal-bed methane production over the last couple of years, according to the DEP official. Roberts said the Marcellus is an unconventional formation that requires more water for fracturing and that led to the development of a water permit addendum, which asks not so much how much water will be used but how much will be left in the stream after it's withdrawn.

"The producers may think this is a bit clumsy. We continue to meet with them to understand their concerns and try to streamline things," Roberts said. "We felt it was important to get something out and put people to work. Now, we're going back and engaging in training for the oil and gas industry and our own staff in regard to how we do these things," he said.

'Constructive attitude'

"We think it still needs work," said Weber, adding, "The DEP is working very hard to try and streamline the process to provide adequate environmental protections, but the addendum needs work and we've communicated that to the DEP. I think it has a constructive attitude and is looking for a proper balance."

Roberts agrees, saying: "Withdrawal of waters is one of two problems, and in some respects is the easier one to tackle. What is done with the water after it's used is a thornier question. In Pennsylvania, we have not seen much deep well injection of waste water. We will need to see if the rock here is suitable for it. Without that, we need to have industrial facilities for the industry to use. Up until now, it has been using sewage treatment plants with wastewater facilities. That's not going to suffice in the long term for the Marcellus formation."

Producers recognize that water will be needed to be treated to remove contaminants and solids once it has been used to recover Marcellus shale gas, Weber said. "We as an industry intend to responsibly dispose of this water through specially permitted facilities. We're also evaluating other methods such as disposal wells, evaporation ponds and ways to recycle our frac water on site so we can reuse it. This last approach poses some technical challenges," he told OGJ.

Against this backdrop, Roberts said the state recognizes that Marcellus shale gas development could have a major positive economic impact. "If you look at the economic opportunities that were created in the Dallas-Fort Worth area by the Barnett shale and then apply it across Pennsylvania, the potential is immense," he said, adding, "Our original oil and gas act specified to make certain Pennsylvanians get the most out of our resources. Gov. [Edward G.] Rendell wants to make sure that Pennsylvania companies can compete for that work and that Pennsylvania citizens can be trained for careers in the oil and gas industry, yet in a way that respects our state, our environment, and our natural resources. That's a challenge that the industry is embracing."

Weber noted, "I think we have made progress. But I don't want to give anyone the impression that we're done. We have work to do." ✦

Analysts see no trend of insider stock sales

Sam Fletcher
Senior Writer

In early October, top executives of two large independent production companies, Chesapeake Energy Corp. in Oklahoma City and XTO Energy Inc. in Fort Worth, separately sold large blocks of personally owned stock in their companies.

Because of intense market fluctuations in recent weeks, some investors have been forced to liquidate holdings in the commodity markets to cover margin calls in equity markets. But these sales of company stock by three corporate executives appear to be isolated incidents, analysts said. "If there were any more CEOs with investments at risk, more stock sales would have happened by now," said Ray Deacon, senior analyst at Pritchard Capital Partners LLC in New Orleans.

Aubrey McClendon, chief executive of Chesapeake Energy Corp., sold "substantially all" of his Chesapeake common shares to meet margin loan calls. McClendon blamed "the extraordinary circumstances of the worldwide financial crisis" for forcing the sale.

Analysts peg Chesapeake as the worst-performing producer this year in the Standard & Poor's 500. However, McClendon said, "In no way do these sales reflect my view of the company's financial position or my view of Chesapeake's future performance potential."

According to a Sept. 30 filing with the US Securities and Exchange Commission, McClendon was the company's third-largest shareholder, with 33.5 million shares, or 5.8% of the company's common stock. Stock awards accounted for more than three quarters of his $18.7 million

compensation in 2007 and helped put him at 134 on the Forbes 400 list of wealthiest Americans.

XTO Energy Chairman and Chief Executive Bob R. Simpson sold 2.8 million shares of his XTO stock for $101.3 million, or an average $37.43/share during the week ended Oct. 10. A company statement said the sale "satisfied all considerations for debt, personal interests, and family liquidity." Simpson was XTO's 10th largest shareholder, and the sale involved more than 28% of his stock in the company. But he still holds 6.8 million shares, with options to buy another 4 million.

A few days later Louis G. Baldwin, executive vice-president and chief financial officer of XTO, sold 535,700 shares of XTO common stock to eliminate "all of his margin debt." Baldwin still owns 1.1 million shares of XTO, with options to buy an additional 900,000.

XTO Energy

XTO Energy is an independent US producer engaged in the acquisition and exploitation of long-life producing natural gas and oil properties. Its reserves have grown to 11.29 tcfe at the end of 2007 from 296 bcf of gas equivalent in 1993, making it one of the largest owners of domestic natural gas reserves among the independents.

Its properties are concentrated in Texas, New Mexico, Arkansas, Oklahoma, Kansas, Wyoming, Colorado, Alaska, Utah, Louisiana, Mississippi, Montana, North Dakota, Pennsylvania, and West Virginia. XTO is active in the Marcellus shale, Bakken shale, and Haynesville shale, and has substantial acreage in the Fayetteville shale play in north-central Arkansas.

Pritchard Capital analysts rank XTO among their "best of breed" E&P companies along with Range Resources Corp. and Ultra Petroleum Corp., capable of replacing 350% of production in 2009 while financing projects out of existing cash flows based on a $7/MMbtu benchmark gas price.

"Many resource play stocks are back to 2006 levels despite gas prices very similar to year-ago levels and a storage deficit vs. a year ago," the analysts said. "Each of the large-cap companies we mentioned would stand out from the peers in two additional regards: the robust economics of their projects and their shallow first-year production declines, particularly for XTO."

XTO said Oct. 24 it has hedged 70% of its expected 2009 production at an equivalent price of $11/Mcf of natural gas equivalent. "Given these hedges and the current commodity strip pricing, XTO anticipates record cash flow and production volumes with the financial strength to reduce debt by at least $1 billion next year," Simpson said. "With our focus on delivering performance, particularly in these challenging times, we will continue to look for opportunities to increase our hedge position."

Many producers have used hedging contracts to lock in returns on future oil and gas output. But some analysts have recently speculated that the global credit crisis and recession may not permit payment for hedged production at the agreed prices.

Chesapeake Energy

Chesapeake Energy is the second-largest independent and third-largest overall producer of natural gas in the US, with operations focused in the Mid-Continent, Fort Worth Barnett shale, Fayetteville shale, Haynesville shale, Permian basin, Delaware basin, South Texas, Texas Gulf Coast, Ark-La-Tex, and Appalachian basin regions.

Chesapeake had hedging arrangements with 19 different parties, including knockout swap contracts for a third of its 2009 production. Under those contracts, buyers are not obligated to take the gas if market prices drop to $6.28/Mcf. It also has used kick-out swaps for some production, but only 4 of the past 57 months has resulted in any of its hedges being kicked out. However, it has since eliminated all knockout swap provisions with its hedges for November and December, transforming them into traditional collars. It also eliminated its April-October knockout swaps, leaving only 15% of its 2009 volumes hedged in this manner.

In September, Chesapeake slashed its drilling capital expenditure budget by $3.2 billion, or 17%, for the second half of 2008 through 2010. Company officials blamed a 50% drop in gas prices since June and the possibility of an emerging gas surplus (OGJ Online, Sept. 25, 2008)

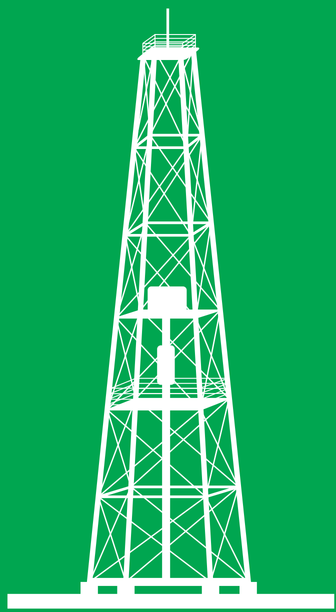
At that time, analysts in the Houston office of Raymond James & Associates Inc. warned, "Expect other firms to follow Chesapeake's lead and lay down rigs as well." They said, "We continue to see reduced drilling activity (lower rig count) as necessary to balance the natural gas market. Still, this may lead to the decline in activity about a quarter earlier than we anticipated."

Other capex cutbacks

Others who have announced capex cutbacks include Newfield Exploration Co., Petrohawk Energy Corp., Penn Virginia Corp., SandRidge Energy Inc., Quicksilver Resources Inc., Equitable Resources Inc., Denbury Resources Inc., ATP Oil & Gas Corp., and Energy XXI (Bermuda) Ltd.

"We expect the list to accelerate as we move toward the end of 2008," said Pritchard Capital analysts. In Canada, Suncor Energy Inc., the world's second-largest oil-sands producer, slashed its 2009 capital budget by 33% to $6 billion (Can.) and slowed construction at its Voyageur expansion project.

At the end of the third quarter, Chesapeake borrowed the remaining capacity of its revolving credit and invested the proceeds in short-term US Treasury and other liquid securities. However, financially troubled Lehman Brothers Holdings Inc. failed to fund its $11 million share of the advance. Chesapeake's financial exposure to Lehman Brothers included unpaid gas sales and derivates contracts. The company received cash payment for all gas marketed through a former affiliate of Lehman Brothers, but it estimated a maximum loss of $50 million on terminated derivate con-



tracts and the net value of hedges with Lehman.

Analysts at Friedman, Billings, Ramsey & Co. Inc. (FBR) in Arlington, Va., said some independent producers are planning their 2009 budgets based on average prices of $80/bbl for oil and $7.50/Mcf for natural gas. "Hedging costs are expected to increase, and liquidity on the long end of the curve is expected to decrease. Management teams expect bank debts, whenever possible, to be repriced to match funding cost increases. Also, bank debt capital available to the industry in general and smaller players specifically is expected to go down reasonably," they said.

"E&P spending cuts make it clear to us that operators will not simply 'drill through' this period of natural gas price uncertainty," said analysts at Pritchard Capital (OGJ Online, Oct. 15, 2008). "We have begun to see spending reductions or deferrals that will negatively affect oil service demand. Key markets are oversupplied with natural gas, with prices below $4/MMbtu in the Midcontinent, West Texas, and the Rockies."

Transparency impresses

Despite Chesapeake's disappointing performance earlier this year, analysts were impressed with the company's plans at its inaugural analyst meeting in mid-October. "The impressive level of transparency shown by the management team should calm any lingering fears about the company's financial position," said Raymond James analysts.

Company officials told analysts its operations in the Haynesville and Fayetteville shale areas alone could replace 95% of Chesapeake's 2009 production. "Due to the innovative joint venture structures in these plays, Chesapeake's partners are expected to cover 64% of the costs, meaning Chesapeake needs to only spend about $545 million to replace 95% of its 2009 production, less than one tenth of our 2009 operating cash flow forecast of $5.8 billion," Raymond James said.

Company officials are certain they can drive down acreage costs 50% in the Barnett and Haynesville plays.

Pritchard Capital analysts previously reported "significant skepticism regarding the Marcellus value proposition, given that Chesapeake has not discussed its plans in the past to any degree." They said, "Management believes Marcellus wells from pads can be drilled for $3.5 million. They see returns in excess of 200% at $7/MMbtu pricing on the New York Mercantile Exchange."

Chesapeake is operating 3 rigs on its 1.8 million net acres in the Marcellus play and plans to go to 20 rigs by yearend 2010, with net production expected to reach 130 MMcfd of gas equivalent from current levels of 15 MMcfd. That development could be accelerated with completion of a planned joint venture. ✦

Capital spending cuts will delay oil sands projects

Sam Fletcher
Senior Writer

Suncor Energy Inc. and Petro-Canada are trimming their capital expenditure budgets and delaying some of the plans for their oil sands production projects next year.

After "a thorough review" of financial market conditions, Suncor directors reduced their 2009 capex budget to $6 billion (Can.) from an earlier proposed $10 billion. Of that budget, $3.6 billion, or 60%, is earmarked for the company's development of its $20.6 billion Voyageur oil sands project.

Suncor will scale down investment and construction of its Voyageur upgrader, delaying its completion until 2013 rather than 2012 as earlier planned. The delay means Suncor can finance more of the upgrade project out of cash flow rather than rely on increasingly skittish debt markets.

The Fort Hills consortium headed by Petro-Canada said it also will delay building a planned upgrader and instead will construct only its planned oil sands mine at its $23.8-billion Fort Hills project. The Suncor and Petro-Canada projects are among the most expensive projects ever undertaken in Canada.

Upgraders are processing facilities that turn oil sands bitumen into a lighter, synthetic product that can be processed by more refineries. Alberta is anxious to ensure that the costly upgraders are built within the province, rather than in the US, to generate more local jobs.

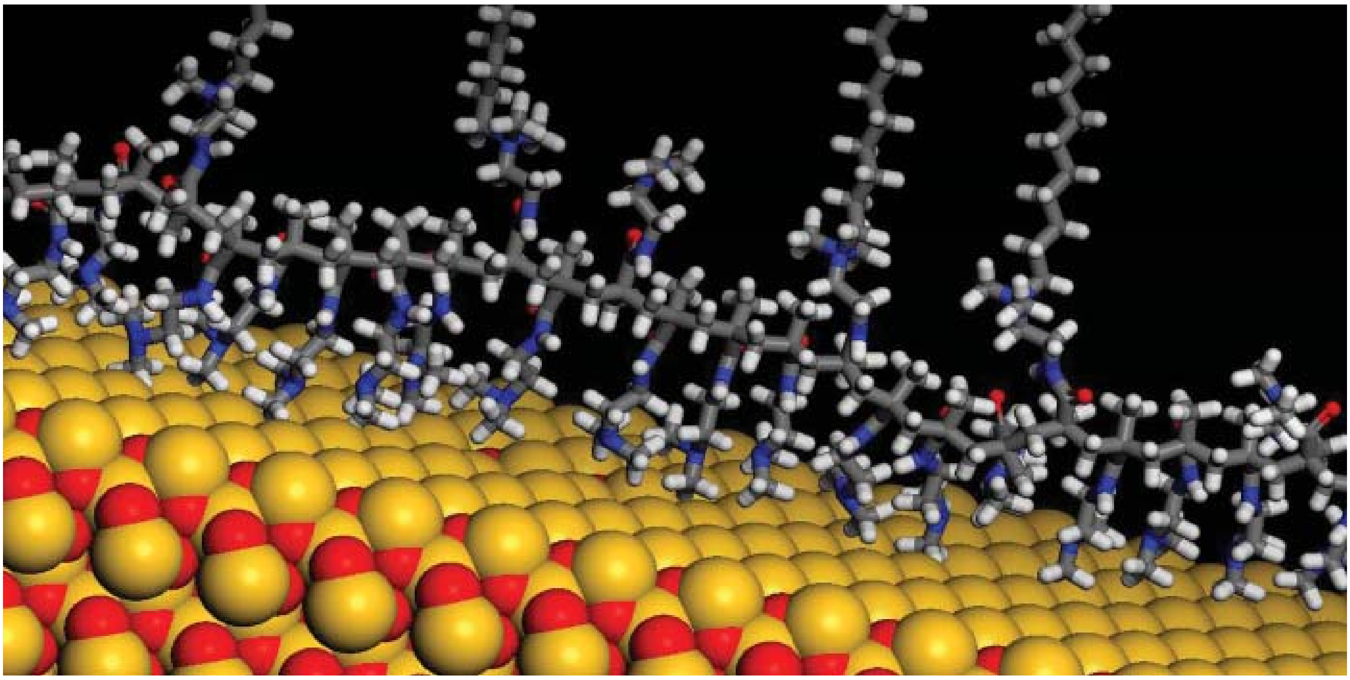
"Our aim is to ensure we are living within our means during a time of market uncertainty, while also making the strategic spending decisions that will allow us to continue on our growth path," said Rick George, president and chief executive officer.

Suncor 2009-10 projects

Suncor's 2009 plan maintains spending and construction timelines for the third and fourth stages of its Firebag in-situ operations, part of the $20.6 billion Voyageur strategy. Completion of the two stages (in 2009 and 2010, respectively) is expected to increase bitumen production and future cash flow.

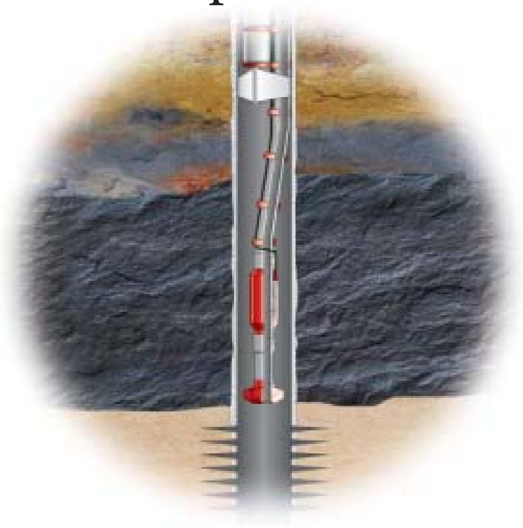
Stages 5 and 6 are at "relatively early phases" of development, so spending and scheduling plans can respond to market conditions. "We remain committed to an integrated expansion strategy and targeted oil sands production of 550,000 b/d, said George.

In addition, Suncor plans to spend $2.4 billion in support of its base business. Some 1.7 billion is targeted for the company's oil sands operations, including new extraction facilities and various projects to improve the reliability and productivity of oil sand properties. Investments in emission-control equip-



What is **reliability** worth?

For operators,
it's not damaging the
formation during
well operations.



Industry Challenge

Control fluid loss to the formation during electric submersible pump (ESP) installation, TCP operations, gravel-pack operations or while performing clean outs, tubing changes, etc.

Halliburton Solution

Used to prevent damage to the reservoir during well completion and workover operations, **LO-Gard**® service is a solids-free, low-viscosity, fluid-loss control system that's applicable over a broad range of temperatures and permeabilities.

Operator Benefit

- Avoiding formation damage during completion and workover ops
- Maintaining a hydrostatic fluid column for well control
- No breaker agent required

Because LO-Gard service's chemical composition impedes water flow not hydrocarbon flow, it can be left in the well.

Operator Results

In a recent West Africa job, fluid loss was cut by 90 percentage while changing out the ESP. Plus, there was no change in hydrocarbon production after the LO-Gard treatment.

To learn more about how Halliburton drives reliability through innovation, visit www.halliburton.com/reliability or e-mail us at sandcontrol@halliburton.com.

HALLIBURTON

ment also will continue in 2009.

Suncor will spend $300 million on exploration and production and $400 in maintenance and environmental improvements in its refining and marketing operations. It expects similar levels of capital spending through 2012. Suncor will finance its capital spending through undrawn credit facilities and cash flow from operations.

Fort Hills project

The Fort Hills consortium—Teck Cominco, UTS Energy, and project operator Petro-Canada—said last month the cost of its oil sands project had escalated more than 50% to $21 billion—$19.6 billion (US)—in just over a year to more than the combined $19 billion market value of the consortium partners, forcing them to find ways to reduce capital expenditures.

Oil prices have fallen by more than half from a July high of $147/bbl (US). Some say the economics of integrated oil sands projects require long-term prices of $85/bbl for a solid rate of return. Meanwhile, the difference between bitumen and synthetic crude has narrowed, leaving less value for the facilities to capture.

Oil sands outlook

According to the Canadian Association of Petroleum Producers, current oil sands production is 1 million b/d and was expected to increase to 4 million b/d by 2020. Current oil sands production is about 1 million b/d of oil. The largest of three oil sands deposits in Alberta is at Fort McMurray; the other two are at Peace River and Cold Lake. There are more than 20 active mining and in-situ oil sands projects in those areas.

Some analysts are anticipating a 10-15% drop in capital spending in western Canada next year as producers try to remain within their cash-flow expectations. To many observers, this is a sign that low oil prices are starting to discourage new investment. Projects that were feasible a year ago no longer seem economic in the current environment. Other companies, including the Nexen Inc.-OPTI Canada partnership and privately held BA Energy Inc., announced delays at smaller projects in recent weeks.

Olivier Jakob, Petromatrix, Zug, Switzerland, earlier reported, "Medium to small size E&P companies have started to be hurt by the credit crunch and are now starting to be hurt by limited cash flows linked to the lower oil prices."

On the other hand, the project postponements may mean the end to Alberta's spiraling costs due to the scarcity of workers and material in Alberta. Some say such shortages have escalated the price of new projects and crippled regional productivity. Some now predict workers will be available at lower salaries in 6 months. ✦

GAO: More verification of MMS RIK production needed

Nick Snow
Washington Editor

The US Minerals Management Service could improve oversight of its oil and gas royalty-in-kind (RIK) program by verifying more production data through third parties and improving reports of benefits and costs, the Government Accountability Office said on Oct. 29.

"Under the royalty-in-kind program, MMS's oversight of its natural gas production volumes is less robust than its oversight of oil production volumes. As a result, MMS does not have the same level of assurance that it is collecting the gas royalties it is owed," the congressional government watchdog service added in its report.

With oil tendered as an RIK, MMS compares producers' self-reported production data with third-party pipeline meter data from the agency's Offshore Energy and Minerals Management (OEMM) Program, which records volumes flowing through pipeline metering points, it said.

"Using these third-party pipeline statements to verify production volumes reported by companies provides a check against companies' self-reported statements of royalty payments owed to the federal government," GAO observed.

"While analogous data are available from OEMM's gas verification system, MMS does not use these third-party data to verify the company-reported production numbers. In December 2007, the Subcommittee on Royalty Management, a panel appointed by the Secretary of the Interior to examine MMS's royalty program, reported that OEMM was not adequately staffed to conduct [a] sufficient review of data from the gas verification system," the report continued.

A growing share

RIK payments make up a growing share of the oil and gas royalties MMS and the US Bureau of Land Management generate, according to GAO. About 58% of the $9.74 billion in royalty payments received in fiscal 2006 were in-value (cash) while 42% were in-kind, it said. MMS takes the oil or gas it receives as an in-kind royalty and sells it on the open market. The agency has said the program increases revenue, improves efficiency, and shortens the compliance cycle.

Before the mid-1990s, MMS's in-kind efforts were generally limited to its small refiners program under which it took in-kind oil and sold it to small refiners that did not have adequate supplies of their own, according to GAO. The agency in 1995 began to study whether taking oil and gas in kind was in the federal government's best interests and in 1998 began a series of pilot sales. Based on the pilot sales' results, MMS has expanded the program, the report said.

In 2003 GAO recommended that MMS develop a more systematic approach to assessing its RIK program, and said the agency has made progress in developing metrics for assessing the program's performance. The agency said on Sept. 8 in an annual report to Congress on the RIK program that it generated more than $63 million in additional benefits during fiscal 2007.

GAO's new report questioned whether MMS's annual reports to Congress are fully describing the program's performance, and in some cases may be overstating its benefits, however.

Based on assumptions

"For example, MMS's calculation that from fiscal 2004 to 2006 [it] sold royalty oil and gas for $74 million more than it would have received in cash was based on assumptions, not actual sales data, about the prices at which royalty payers would have sold their oil and gas had they sold it on the open market. MMS did not report to Congress that even small changes in these assumptions could result in very different estimates," it said.

The report also said that MMS's calculation that the RIK program cost about $8 million more to administer than the royalty-in-value program over the same period did not include costs such as information technology expenses that the two programs shared, which likely would have changed the results of the agency's administrative cost analysis.

"In addition, these annual reports lack important information on the financial results of individual oil sales that Congress could use to more broadly assess the financial performance of the royalty-in-kind program," GAO said.

It noted that DOI's royalty management programs "have faced increased scrutiny in the last few years, and the [department] is in the process of implementing many recommendations made by GAO, its own inspector general, and its subcommittee on royalty management. While the outcome of Interior's implementation of these recommendations will not be known for some time, we believe additional opportunities exist to enhance the oversight of MMS's royalty-in-kind program."

DOI responds

In a Sept. 18 response attached to the report, C. Stephen Allred, assistant Interior secretary for land and minerals management, said the department agreed with GAO's recommendation to extend the verification system it uses for offshore oil volumes to gas.

He also said that MMS will disclose IT system expenses specifically associ-

BLM's Utah plans

New resource management plans (RMPs) for five of the US Bureau of Land Management's six Utah field offices received final approval Oct. 31. The sixth is being reviewed at the US Department of the Interior.

State BLM officials said the agency wants to change the way it manages its Utah acreage. Area oil and gas associations are welcoming the new plans.

Environmental organizations, meanwhile, were more concerned about a lease sale they expected BLM to announce Nov. 4. They believed it would include areas that they said BLM previously had declared "wilderness caliber landscapes."

"This has been a truly collaborative effort in balanced stewardship for the future," said Selma Sierra, Utah State BLM director. "We are pleased to have the plans completed and look forward to moving into the implementation phase of the planning process."

Sierra said the new plans will help the agency meet challenges that have emerged since the previous RMPs were written about 25 years ago. Each new plan took about 6 years to complete, she indicated.

Some stricter controls

The agency tried to balance environmental protection with energy resource development, state BLM officials said. In the new plans, 53% of the acres open to leasing are subject to stricter environmental controls, and 18% of the lands within the planning areas aren't available at all.

BLM also wants to minimize the oil and gas production footprint on public land by using innovative methods such as directional drilling, well placement, sound muffling, and other best management practices.

Kathleen Sgamma, government affairs director for the Independent Petroleum Association of Mountain States, said Utah's BLM staff found it difficult to balance often competing interests and respond to nearly 220,000 public comments and 87 formal protests.

Oil and gas production in Utah occupies less than 1% of public land there, she noted. With current technology and industry practices, producers can develop energy resources now, and reclaim the land to its original condition afterward, she said.

Small, temporary impacts

"We hope BLM took into account the small and temporary impacts of natural gas development and recognized that energy production and other uses of public lands in Utah can and do coexist," Sgamma said.

Area environmental groups are more concerned with what they say will be a move by BLM to offer oil and gas leases in the Nine-Mile Canyon region of eastern Utah on Dec. 19.

"What makes this action so deplorable is that BLM itself determined these areas to be wilderness-quality lands," said Stephen Bloch, conservation director for the Southern Utah Wilderness Alliance.

SUWA said the tracts that BLM plans to offer are dominated by acreage that the agency determined had wilderness character after conducting inventories during 1996-99 and 2001-07. They largely are part of land proposed for wilderness designation in legislation introduced during the 110th Congress, the organization said. ✦

ated with the RIK program beginning with the fiscal 2008 report to Congress. The agency also is re-evaluating the process by which it calculates the time value of money benefit or early payment savings, including interest rates used and the comparison methodology to in-value payments, he said.

"While MMS calculates revenue performance metrics by individual property for oil and by pipeline for gas, the results are rolled up into reporting categories in order to protect proprietary information regarding royalty-in-kind sales, particularly contractual arrangements with service providers. The MMS believes reporting revenue performance by individual oil property or gas pipeline has the potential to compromise the actual bid prices that MMS receives for the sale of oil or gas and could affect the competitive nature of the sales," Allred continued.

"Proprietary information includes pricing and sales data. The royalty-in-kind sales contracts include confidentiality clauses that neither party will disclose prices received under the contract. Many RIK service agreements for transportation and/or processing also have confidentiality clauses that neither party will disclose the rates charged or the terms of the agreement. Maintaining the confidentiality of proprietary data is essential to continue to contract for royalty-in-kind," he said. ✦

Brazil's oil development bonanza shapes up

Eric Watkins
Oil Diplomacy Editor

Brazil's Petroleo Brasilerio SA (Petrobras), even as it eyes greater output for the future, exported a record 574,000 b/d of oil in October, breaking the previous monthly high of 532,000 b/d in April.

Altogether, Petrobras exported more than 17.8 million bbl in October, with exports bound mainly for the US (65.2%), China (24.1%), Europe (5.5%), and other South American nations (5.2%).

Analyst Global Insight said this "trend is expected to continue in the coming years as new fields come online, particularly those in the presalt layer, with the company planning to invest in new refineries in order to add value to its future oil exports."

BG sees 300,000 boe/d

Underlining future developments in the country, BG Group PLC said output from the Tupi, Iara, and Guara deepwater fields in the Santos basin should hit 300,000 boe/d by 2012.

"First commercial production is now expected from the 100,000 b/d Tupi pilot by fourth quarter 2010," said BG, whose other partners in the fields are Petrobras and Galp Energia.

BG further said the exploration success with Guara and Iara has led the partnership to hasten planning on two additional 100,000 b/d pilot schemes, with the objective of achieving first production in 2012.

BG estimated its net share of reserves and resources in the Santos basin at 3 billion boe, of which 2 billion boe can be classified as proved or probable.

Low prices no deterrent

The recent fall in crude oil prices is not expected to adversely affect the developments, according to BG Group Chief Executive Frank Chapman, who said, "We are comfortable that these developments are economic at prices significantly below where we are today."

That view was shared by mines and energy minister Edison Lobao who said oil and gas production is viable at Brazil's subsalt reserves even with oil at $60/bbl.

"It's perfectly possible to exploit subsalt oil at this price. Of course, for the good of the country we'd want a bigger gain," he said.

Lobao said the much larger size of the subsalt reserves offsets the higher cost of subsalt exploration. "Drilling that lifts 5,000 or 10,000 b/d in a regular field could lift 50,000 or 100,000 b/d in the subsalt," he said.

ExxonMobil drilling

Meanwhile, ExxonMobil Corp. has started drilling in the presalt layer of Brazil's Santos basin, according to the firm's vice-president of investor relations David Rosenthal.

Rosenthal, in a conference call, said the West Polaris deepwater drilling rig arrived in Brazilian waters in late September, and after concluding the required inspections and clearances, the company has begun drilling the Azulao well on Block BM-S-22.

He said ExxonMobil chartered the rig for 3 years and expects to have its first results on BM-S-22 by yearend, although they could be delayed to early 2009.

"I wouldn't want to speculate on exactly when we'll make an announcement, but that will happen as soon as we are ready and have information to provide," said Rosenthal.

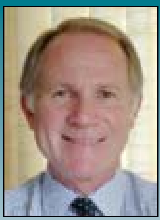
He added that plans to drill a second well on the block are under way and will follow immediately upon completion of the first well.

ExxonMobil is operator of the block,

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



Credit crunch impacts E&P

How the oil and gas industry will be affected by the election of Barack Obama as president of the US remains to be seen. But it will be necessary for Obama to take control of the current financial crisis to ensure the pursuit of energy supplies.

Price inflation for the goods and services used in extracting oil and gas—along with the recent collapse in crude oil prices from a record above $147/bbl in July to around $63/bbl now—is forcing oil companies to rethink many projects around the world.

A sign of that emerged last week when BG Group CEO Frank Chapman said his firm is delaying a final investment decision on whether to proceed with Phase III development of the Karachaganak gas and condensate project in Kazakhstan.

Peak costs

"We don't want to commit to Phase III costs in their entirety at the peak of the cycle," said Chapman, who explained that BG wants to extend the Karachaganak III development timetable due to an anticipated decline in project costs.

With the cost of raw materials and oil services becoming cheaper with the fall in oil prices and the slowdown in the global economy, that does make sense. After all, who wants to pay more for a project when lower costs may be just down the road?

But what does that mean also, other than a delay in the start-up of expected supplies? Under the current program, originally slated to begin in 2012, the Phase III development of Karachaganak is aimed at increasing oil production to 330,000 b/d of oil and 16 billion cu m/year of gas.

That delay, in turn, could give Kazakhstan reason to rethink its relationship with the development partners. Along with BG, which has a 32.5% stake in Karachaganak Petroleum Operating BV (KPO), Eni holds 32.5%, Chevron has 20%, and LUKoil has 15%.

Kashagan revisited?

After all, it was a similar delay in the Eni-led Kashagan project that prompted the Kazakhstan government to seek greater participation for the state-run KazMunaiGaz (KMG). That was settled just a week or 2 ago, when KMG saw its share doubled and a new operating model instituted.

Something similar may be in the offing for the Karachaganak project, especially since BG is already in talks with KMG over an alternative timetable for Phase III.

One can see Kazakh officials readying their knives and forks.

BG is hardly alone in making such decisions, and many companies are taking a long, hard look at their previous investment plans. No doubt moves are already afoot to scale back investments, with potential for outright project cancellations in the medium term.

"This is about spreading the exposure over a longer period," said Chapman in explaining BG's decision over Karachaganak. The question that international oil executives have for President-elect Obama is simple: just how long will that longer period be? ✦

with a 40% stake, while Hess holds 40% interest, and Petrobras has the remaining 20%.

Chevron to start also

Chevron Corp. expects to begin production at its Frade field in Brazil's Campos basin next year. "First oil is expected during the second quarter of 2009," said Chevron Executive Vice-Pres. George Kirkland in a conference call.

Kirkland said construction of the FPSO scheduled to operate in the offshore field is 85% complete, and the vessel is due to set sail from Dubai in late December. Earlier, Chevron said production could reach 85,000 b/d in 2011.

Chevron is operator of Frade and holds a 51.7% stake, while Petrobras holds a 30% share, and Frade Japao owns the remaining 18.3%.

In another development, Inpex Corp. said it has received the Brazilian authorities' approval to acquire a 20% interest in offshore Block BM-C-31 in Brazil from Royal Dutch Shell. In addition to Inpex, Petrobras holds 60% and Shell 20% interest in the field.

In the coming year, an exploration well is scheduled to be drilled on BM-C-31, which covers an area of 710 sq km, some 150 km off the state of Rio de Janeiro.

Matto Grosso

Looking farther ahead, oil and natural gas exploration in Brazil's central-western Mato Grosso state may begin in 2010, according to the state's governor, Blairo Maggi.

Brazil's oil, gas, and biofuels regulatory agency ANP will hold its 10th oil and gas exploration and production rights auction on Dec. 18-19, offering some 130 onshore blocks, located in eight sectors, in seven sedimentary basins.

According to Maggi, the auction will include rights for six blocks in his state, including an area of 14,381 sq km in the onshore Parecis basin, near the Teles Pires River. ✦

Uncertainty afflicts International Gas Summit participants

Doris Leblond
OGJ Correspondent

Uncertainty was the hallmark of the 13th International Gas Summit in Paris Oct. 22-23, reflecting the current world financial turmoil and looming economic slowdown. Speakers felt unable to predict short or medium-term natural gas developments and were more at ease with long-term projections.

Summit Pres. Nordine Ait-Laoussine, president of Geneva-based consulting group Nalcosa, set the tone in his introductory remarks: "We are all apprehensive of the potential consequences of the ongoing global turmoil for the natural gas industry… we do not know the answers to some critical questions:

- 'How deep will the recession be?'
- 'How long will it last?'
- 'Will this turn out to be the most severe crisis the world has ever faced… or will it be short-lived if proper remedies are agreed upon and implemented quickly?'
- 'Will some regions or industries escape relatively unscathed?'"

He added, "It would appear inevitable that the gas industry will be affected, perhaps in a profound way."

Supply security

The "security of supply" issue came in for a new analysis. Moderator Claude Mandil, former International Energy Agency executive director and author of a report on supply security released in May to the French government, quickly noted that "recession reduces tensions on capacities and will create obstacles to investments, with possibly lasting consequences."

GDF Suez global gas and LNG Vice-Pres. Jean-Marie Dauger said, "Certainties have been jostled. The short-term was comfortable; we are not comfortable now in any horizon, so it is easier to talk of the long-term." Although fundamentals such as demography, emerging economies, and Europe's long-term gas market growth remain, he said, "Uncertainty is on the demand level and the short-term availability."

In the current changing environment and volatile market, Daugier said, market risks could be reduced and demand-supply security bolstered through "downstream interpenetration" of producers in consumer countries.

Eni Senior Vice-Pres. for gas and power Camillo Michele Gloria agreed, also suggesting that producing countries become involved in their clients' downstream businesses. The problem, he pointed out, was "government mistrust," but he said the crisis could "bring good news with it."

He added: "We have before us an environment opportunity to think of cooperation as a good way to long-term access to resources. Security will need strong cooperation between producers and buyers," he said. "Gas importers must be engaged in wide-ranging win-win deals well beyond the buyer-seller paradigm."

Phlippe Boisseau, Total's president of gas and power, agreed that the crisis would have an impact on demand but remained bullish about long-term prospects. He was optimistic that "LNG projects decided today will come on stream in 2020" and that they must be started now.

Total intends to pursue a strong investment policy. If investments proceed, he said, there will be no supply problems after the 2013 bubble everyone is expecting. LNG's flexibility as well as the diversity of supply sources are strong reasons to pursue investments.

Future LNG challenges

For Sonatrach, the constraint is not access to markets but securing development of "adequate liquefaction capacities," explained Nabila Metref, pipe gas and LNG exports director. There are many projects planned, she said, but few under construction.

"Suppliers are implementing new development schemes that take into account the reality of each market and [that] preserve security of demand," she said. "This includes downstream positions through dedicated [long-term] affiliates."

Viewing LNG growth with its "long-term promising future," Royal Dutch Shell's general manager for global energy strategy and portfolio development, Jacqueline Redmond, also saw as one of the future challenges "the below-average final investment decisions" in 2006-07 "and none taken in 2008," due, in part, to escalating costs and engineering, procurement, and construction (EPC) constraints.

Utility Electricite de France says the problem is the volatility of gas prices in Europe, making it hard for electricity producers to choose a technology and increasing the risks taken by producers. It strongly favors a "robust gas price index," which, it suggested, could be in euros.

For the index to emerge, efficient access to transit capacities and to efficient flexibility tools would be required together with utility-producer partnerships where project opportunities and risks are shared. A gas price index in Europe, where both piped gas and strongly growing LNG markets coexist, would contribute to stabilizing both spot and long-term gas contracts it said.

Financing gas projects

The crucial question about financing projects in the current financial turmoil received no comforting answer.

Jerome Halbout, a partner in Paris-based 4D Global Energy Advisers, said funding sources were particularly sensitive to the financial markets crisis in a softening economy "where oil was a refuge for liquidity and with no improvement in sight in the price deck."

Pinpointing the impact on upstream companies Halbout said, "Frontier E&P will suffer the most.

Majors, national oil companies (NOCs), successful independents, and recently financed projects—all with sufficient operational cash flow needed to fund their capital expenditure commitments—would be the survivors as funding commitments from banks evaporate until 2009, with the capital markets essentially closed."

Projects not properly financed before the funding crunch will be abandoned—or postponed if the promoter is sufficiently financed to resist the credit squeeze, he said. If not, nonconventional, frontier, or stranded reserves will be canceled.

The pressure on EPC contractors will slacken, but they will have more work in Asia and producing countries, Halbout said.

Concerning the financing of LNG projects, banking group Societe Generale's director of energy project finance Katan Hirachand was more bullish as he expected the market situation to be restored in the short-to-medium term.

"LNG is very favored by banks," he added. Nonetheless, "multi-sourced financings will be the key to maximizing leverage and will need reconciliation of different lenders and their objectives," he said. Strong sponsors with support from governments and with a good history will also be needed, he said, and the intervention of NOCs would provide "more comfort."

Within the LNG sectors, he was specially encouraging about "floating LNG," for it is "redeployable, faster to market, had a reduced environmental and social impact, and enjoyed a lower potential unit cost. "However," he cautioned, "some innovation will be needed to make floating LNG bankable."

Some good news

One area where the current crisis has yielded good news for the gas industry is the change in the European Commission's strong bias for short-term gas purchasing contracts versus long time ones.

"The long term view is being rehabilitated," noted Michel Guenaire, partner at the law firm Gide Loyrette Nouel, who was involved in a number of disputes caused by the commission's short-term bias.

The need by buyers for supply security "is likely to mark a return to long-term contracts," Guenaire said. "The commission focused on short-term contracts as a way to open up the [European Union] gas market and make it more fluid," he explained. While the commission did not forbid such contracts, a supplier could be sanctioned if advantage was taken of a dominant position.

The gas market, Guenaire pointed out, is still 90% involved in long-term, take-or-pay supply contracts. Many were signed when the buyers were still monopolies and the contracts often are renewed before falling due. Their acceptance in markets now open to competition will combine both supply safety and the guarantee of price competitivity.

The fact that gas prices can be hitched to the spot market or forward price of gas or on electricity prices justifies the maintenance of long-term gas contracts in an open competitive market, Guenaire said, along with the growing recourse to the gas release system where an operator enjoying a dominant position can sell gas by auction to a competing operator.

The annual summit was organized by Institut Francais du Petrole and consultant-publisher Petrostrategies. ✦

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

Ultradeep shelf well logs four indicated pays in Miocene

Alan Petzet
Chief Editor-Exploration

The ultradeep Gulf of Mexico shelf well known as Blackbeard has logged four "potential hydrocarbon-bearing zones below 30,067 ft," said operator McMoRan Exploration Co., New Orleans.

Having reached 32,997 ft in October, McMoRan and partners had to decide whether to halt drilling and attempt to test the zones encountered thus far or continue drilling to basement, expected below the permit depth of 35,000 ft, in an effort to penetrate at least another 2,000 ft of sediments.

It is too soon to tell whether the four zones, in the Miocene Rob-L formation, contain crude oil or gas-condensate, James R. Moffett, cochairman of McMoRan said on an Oct. 20 webcast. On Oct. 23, McMoRan said, "The well will be temporarily abandoned while the necessary long lead time completion equipment is procured for this anticipated high pressure test."

How soon formation tests might take place wasn't predicted.

Bottomhole pressure exceeds 25,000 psi, and the four zones exhibit the high resistivity seen in Rob-L elsewhere.

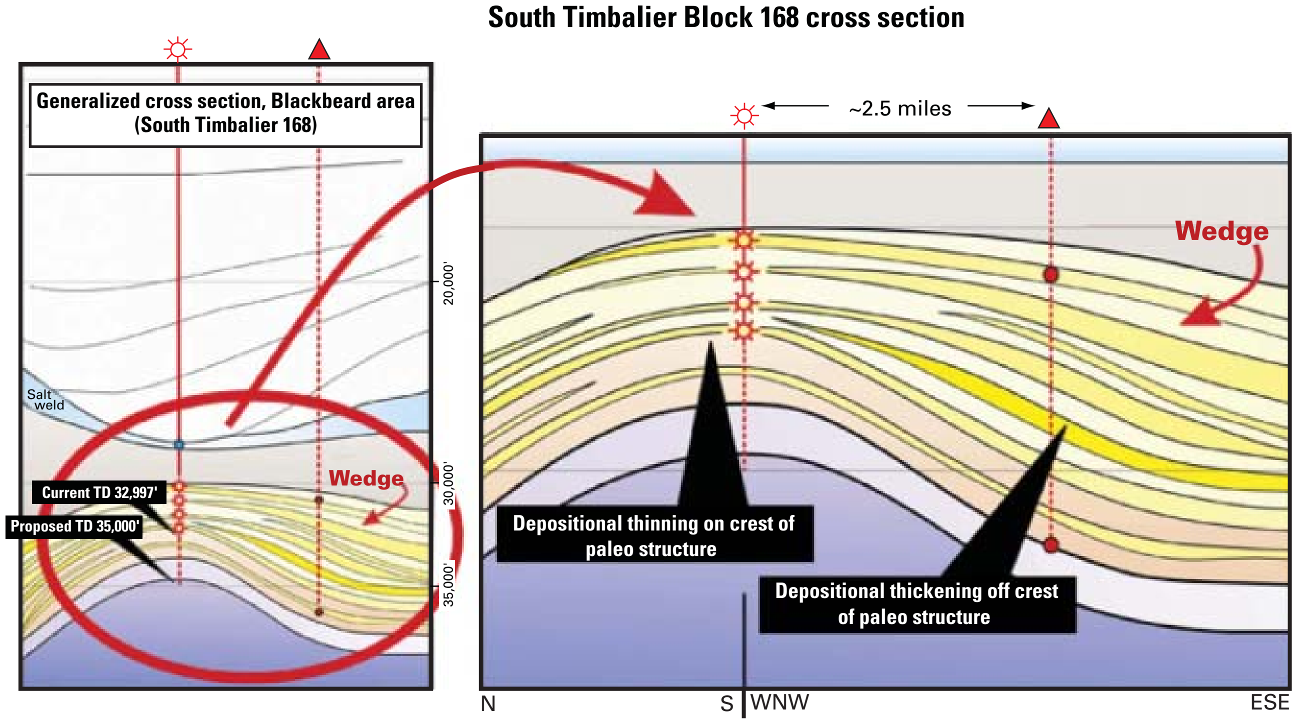
Moffett said, "No one ever tried to flow a well at these depths." The well is presently cased to 27,000 ft.

About 18 months after previous operators gave up on the well after drilling to just below 30,000 ft, McMoRan's group took over. It deepened the well routinely except for a 3½-week period of lost returns, penetrated a normal stratigraphic section, and ran conventional logs to the new total depth, Moffett said.

Wide area impact

The well is on the crest of a massive structure covering more than 10,000 acres, and test results have implications out to a 50-mile radius of the well, Moffett said.

DEPOSITIONAL WEDGE CONCEPTUAL MODEL*



*Based on McMoRan interpretation of operator data from K2 discovery, Green Canyon area.
Source: Energy XXI USA Inc. from McMoRan Exploration Co.

"Seismic data on the prospect indicates the potential for significantly thicker sands on the flanks of the structure as confirmed in recent major deepwater discoveries," McMoRan said. "Based on information obtained to date in the South Timbalier Block 168 well, McMoRan believes additional drilling on the flanks could result in significant reserve potential."

A drillsite 2½ miles southeast of the Blackbeard well, for example, might encounter a depositional wedge in which the same formations are two to three times as thick as at the crest, Moffett said. The great thickness and large areal extent makes for large recoverables.

Moffett said this conclusion is based on McMoRan's interpretation of data made public by the partners in the K2 deepwater field 90 miles south-southeast on Green Canyon Block 562, where sands were transported from the onshore Mississippi River Delta.

Operators naturally drill the top of structures in deep water because they lack well control and historically found the greatest chance for hydrocarbons is at the crest, Moffett noted.

McMoRan's confidence in Blackbeard is further bolstered because it is exploring for the same formations as at its large Flatrock discovery in 10 ft of water on South Marsh Island Block 212 about 100 miles north-northwest of Blackbeard. The Rob-L formation encountered at 28,000-35,000 ft at Blackbeard is producing gas at 14,000-16,500 ft at Flatrock.

Flatrock discovery

Flatrock field, with five successful wells, is producing gas from Rob-L and the underlying Miocene Operc formation.

The Flatrock-6 delineation well, expected to spud in the current quarter, targets deeper Rob-L sands than those producing, Operc sands, and possibly the even deeper Miocene Upper Gyro sand section of the Flatrock/Hurricane Deep structure. It is projected to 19,700 ft and will probe the south half of Flatrock.

Successful wells can be placed on production quickly through Tiger Shoal field facilities.

McMoRan said the Flatrock-4 well tested 109 MMcfd of gas and 2,500 b/d of condensate on a 50/65-in. choke with 8,170 psi flowing tubing pressure. The same sand is producing 100 MMcfd in the Flatrock-2 well, which went online in July.

The first three Flatrock wells are producing a combined 170 MMcfed of gas and condensate, and wireline logs indicated 100 net ft of pay in the Rob-L section of the Flatrock-5 development well. That well is drilling towards 18,400 ft to deeper Rob-L and Operc sands.

A McMoRan group is also preparing to drill the Ammazzo prospect in South Marsh Island 251. It is 16 miles and 11 miles south-southeast of Flatrock and JB Mountain fields, respectively, and lies along the structural axis of a ridge trending from Flatrock. Objectives are the same three Miocene formations.

Ammazzo is one of the largest undrilled structures on the gulf shelf, McMoRan said.

Deep shelf economics

Moffett pointed out that the deep shelf play is not so price sensitive as onshore shale plays, for instance, because the reserves are large, the gas is found in conventional, soft rock that requires no horizontal drilling or frac treatments, and production infrastructure is everywhere.

The South Timbalier Block 168 No. 1 well, formerly Blackbeard West, is the deepest ever drilled below the mud line in the gulf. It is in 70 ft of water 115 miles southwest of New Orleans (see map, OGJ, June 7, 2004, p. 40). The prospect covers a number of leases in the South Timbalier and Ship Shoal areas.

McMoRan operates the well with 32.3% working interest. Plains Exploration & Production Co. and Energy XXI USA Inc., both of Houston, have 35% and 20%, respectively.

McMoRan is one of the largest acreage holders on the gulf shelf with rights to 1.5 million gross acres including 450,000 gross acres associated with the ultradeep trend. ✦

Albania

Stream Oil & Gas Ltd., Calgary, will plan a development program for Ballsh-Hekal and Gorisht-Kocul oil fields in Albania based on initial results of its well remediation work.

After starting the first phase of radial jetting on four wells in the two fields in mid-August, the company reported higher recovery rates from all wells through September. It placed progressive cavity pumps in the wells in October and will report production results once stabilized.

"In general a twofold increase in production from those wells is sustained and upon optimization of the PCP pump flow this can increase even further," the company said.

Stream Oil & Gas also plans a second phase of radial jetting for Cakran-Mollaj field once the appropriate rig is mobilized early 2009, subject to the company's ability to raise the required funds. It let a contract to Seismotech Ltd. to deploy microfracture monitoring equipment, initially at Cakran-Mollaj and then at the two other fields, to map preferential fracture zones around the wells and direct radial jetting accordingly.

New Zealand

Canadian consulting engineers confirmed a prospective resource of a most likely 12.6 billion bbl of 50° gravity oil in the Paleocene Waipawa and Paleocene-Cretaceous Whangai fractured shales on two blocks held by Trans-Orient Petroleum Ltd., Vancouver, BC, in New Zealand's lightly explored East Coast basin.

The consultants assigned the prospective resource on the basis of well log data, core pyrolysis, and the company's field measurement of outcrops and oil and gas seeps.

Trans-Orient Petroleum holds 100% interest in PEP 38348 and 38349 totaling 2.2 million acres onshore in the basin, and the estimate is based on less than 10% of the acreage. Depth to the shales is 1,500-1,750 m.

Spain

Saxon Oil Co. Ltd., a Canadian company based in Dallas, signed a definitive agreement in a transaction that would give Saxon the rights to a proposed coalbed methane project in northwestern Spain.

Saxon plans to buy the stock of Picogina Holdings BV, which owns 100% of Hidrocarburos del Cantabrico SL, a private company that holds full interest in five hydrocarbon exploration licenses totaling 237,000 acres in the Asturias region 225 miles northwest of Madrid.

HDC's plan is to seal existing coal mines and extract methane to generate electricity. Saxon will ask its shareholders to vote on the acquisition on Nov. 20 and would close the purchase a few days later.

Quebec

Brownstone Ventures Inc., Toronto, completed the acquisition of a farmout from X-Terra Resources Corp., Rouyn-Noranda, western Quebec, of three oil and gas licenses in Quebec's St. Lawrence Lowlands.

Brownstone becomes operator with 50% interest in the Rimouski and Rimouski North licenses near Rimouski and the Shawi license on the St. Lawrence River north bank near Trois Rivieres. The licenses, to be explored for gas in Ordovician Utica shale, total 159,991 ha.

California

Tri-Valley Corp., Bakersfield, plans to drill three more horizontal wells to shallow Pliocene Vaca tar sand at Pleasant Valley in Ventura County near Oxnard, Calif., where it has seven wells on cyclic steam production.

Tri-Valley was to begin cyclic steaming in late October at four existing vertical wells on the Lenox Ranch lease at Pleasant Valley. The vertical wells are not as productive as the company's horizontal wells, but the 19 existing vertical wells drilled by a prior operator appear responsive to reworking.

A rig is expected to spud at Lenox Ranch in mid-November, and the company aims to drill at least 10 more Vaca horizontal wells there in 2009.

Colorado

The US Fish & Wildlife Service, surface owner of the Baca National Wildlife Refuge in Saguache County, Colo., has issued a finding of no significant impact for the proposed Baca gas drilling project operated by Lexam Explorations Inc., Toronto.

The finding, which followed a 15-month review process, is the final approval required before Lexam can proceed with exploration, although legal challenges are possible.

Lexam drilled two exploration wells in the San Luis subbasin in the 1990s when the surface was privately owned and plans to drill two more with 75% interest and ConocoPhillips has 25% (OGJ, Sept. 1, 1997, p. 78). The F&WS acquired surface ownership in 2000 and operates the refuge.

New York

Norse Energy Corp., Lysaker, Norway, reported having completed 11 successful gas wells in fractured Silurian Herkimer sandstone in south-central New York.

The company holds mineral rights to more than 130,000 acres in Broome, Chenango, and Madison counties. It estimates 1.2 bcf/well recoverable and has laid a gathering system near Norwich, northeast of Binghamton, in eastern Chenango County.

The wells have cut 250-380 ft of gross pay, and the company has identified 250 locations on seismic so far on its acreage. The company also plans to test the Ordovician Utica and Devonian Marcellus shales, which are indicated to be promising on logs.

Pennsylvania

Cabot Oil & Gas Corp., Houston, is averaging 4-5 MMcfd of gas from five vertical Devonian Marcellus shale wells in northeastern Pennsylvania.

The company expects to exceed its goal of producing 6-9 MMcfd by the end of 2008.

Cabot completed its first horizontal well, which will be on line shortly, with only three of six planned fracs. The company will run the other three fracs in a few weeks.

Two more horizontal wells are cased awaiting completion, and five vertical wells are in various stages of completion, all of which are expected to be flowing to sales by yearend.

Texas

Gulf Coast

Calgary independents Sharon Energy Ltd. and Diaz Resources Ltd. took positions in the Cretaceous Eagle Ford shale play in South Texas.

Each firm reported acquiring 5,400 gross acres, and Sharon is operator with a 50% working interest with its partner in 4,250 net acres.

Sharon didn't specify the location of its holdings but said they are on trend with a Petrohawk Energy Corp. gas-condensate discovery in LaSalle County and a large Apache Corp. drilling program (OGJ Online, Oct. 21, 2008).

Apache, with acreage in Washington, Burleson, and Brazos counties, has completed four horizontal Eagle Ford wells in Burleson at an initial 170-345 b/d of oil after four to nine frac stages each.

Sharon said its acreage has numerous existing wellbores that it believes can be reentered, horizontally drilled, and have staged fracs applied in the Eagle Ford. It is preparing a development plan.

Study analyzes nine US, Canada shale gas plays

A recent study has estimated that nine US and Canada shale-gas plays may produce as much as 24 bcfd by 2018.

The Oct. 6, 2008, Tristone Capital Inc. study evaluated the gas resources in the Bamett (Fort Worth basin), Deep Bossier, Haynesville, Fayetteville, Woodford, and Marcellus shales in the US and the Montney, Hom River (Muskwa), and Utica shales in Canada (Fig. 1).

The study expects companies ultimately to recover from these resources 261 tcf of gas, based on various risk factors applied and a long-term average gas price of $8.50/MMbtu. Without the risk factors, Tristone Capital says these shales have a 743-tcf recovery potential (Fig. 2).

Fig. 3 shows the study's estimated production from these plays, and Fig. 4 shows its US well completion forecast.

Several emerging shale plays with limited well control also may contribute additional gas to future production, according to the study. These include the Pearsall shales in the Maverick basin of South Texas, the Niobrara shales of Western Colorado, and the Barnett shale in the Delaware basin of West Texas.

Shale play comparison

The study says that shale-gas plays owe their success to a balance of various parameters along with constantly evolving drilling and completion techniques and infrastructure. "It is commonly said that no two shale gas plays are exactly alike," the study says.

Table 1 summarizes shale-gas play attributes, and Fig. 5 compares the arithmetic average of the attributes. The study notes that the most productive core portions of plays may deviate from the averages.

Multistage hydraulic fracturing along a horizontal lateral and improvements in stimulation are main factors influencing shale-gas development economics.

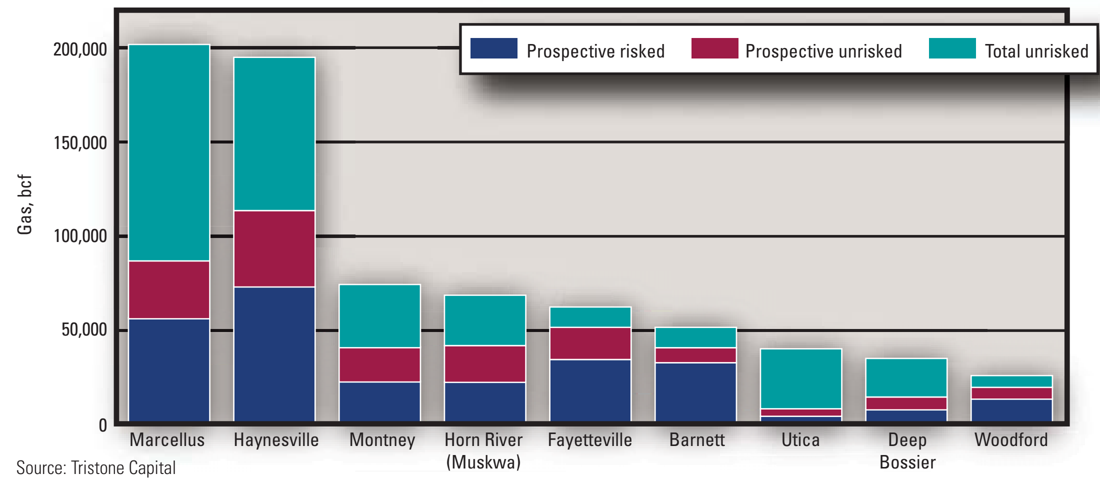
DEVELOPING SHALE GAS PLAYS

Fig. 1

Source: Tristone Capital

RESOURCE ESTIMATES

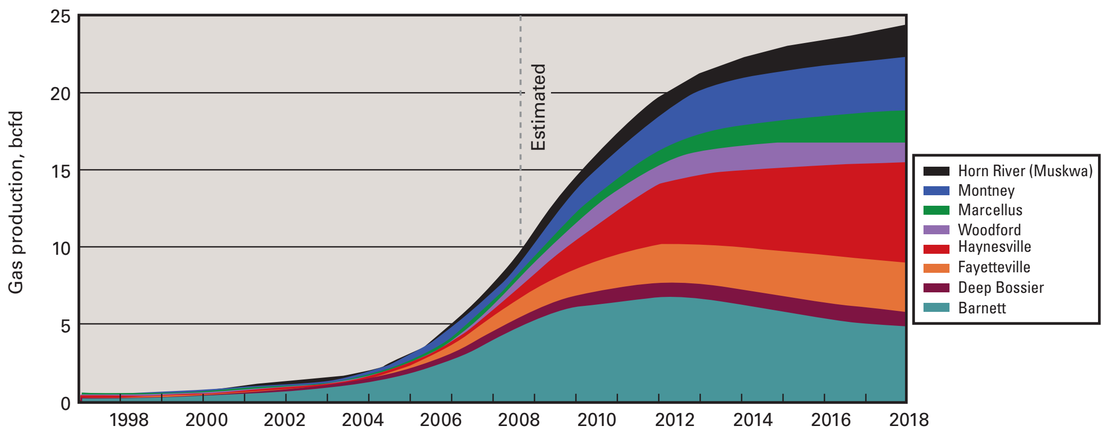
Fig. 2



Source: Tristone Capital

RISKED PRODUCTION ADDITIONS

Fig. 3



Source: Tristone Capital

The study says these factors have improved economics by more than three times from that of vertical well developments by improving both ultimate recovery and initial production rates.

Table 2 compares typical lateral lengths and frac treatments for the nine plays.

The three types of frac fluid noted are slick water, CO_2-polymer, and gelled cross-linked oil-based fluid.

Slick-water fracs use a nongelled fracturing fluid with low proppant concentrations and a friction-reducing chemical additive that allows pumping the water into the reservoir faster. The fluid often is a brine or potassium chloride (KCl) water to inhibit swelling of clays. The study notes that this fluid is less expensive than hydrocarbon-based fluid and works best in low-permeability reservoirs

Companies pioneered slick-water fracs first in the Fort Worth basin's Barnett shale.

The CO_2-polymer frac fluid contains emulsified CO_2 in a methanol-water mixture of 5% water and 20% methanol. The study says the mixture appears to minimize reservoir damage and maximize fluid recovery from multiple diversions in the well. Including CO_2 also reduces by 25% the fluid required and provides extra energy, as the gas expands, during

GEOLOGIC ATTRIBUTES

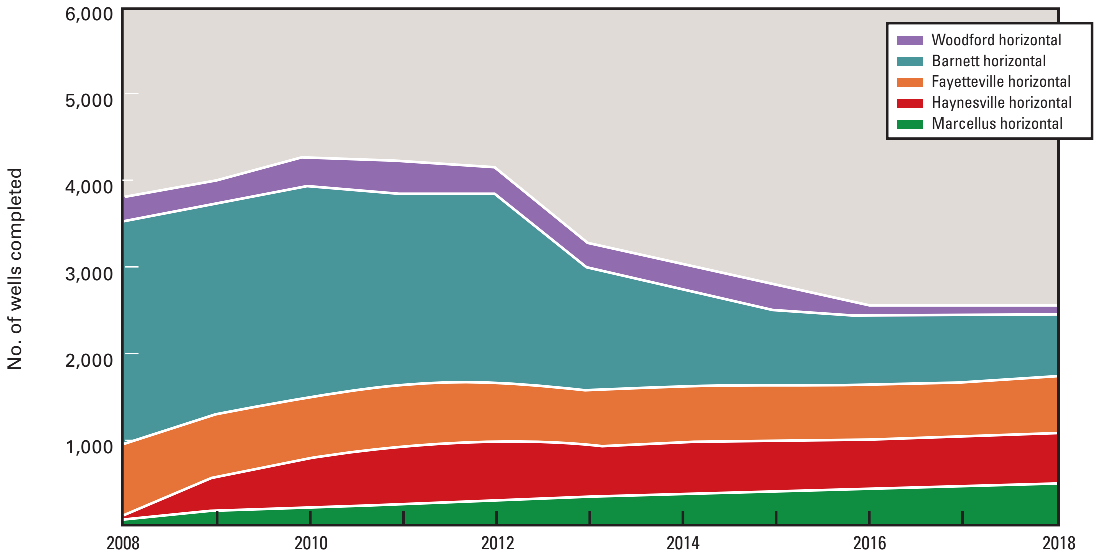
Table 1

	Depth (m)	Net thickness (m)	Total organic content (%)	Total porosity (%)	Pressure gradient, psi/ft	Gas-in-place, bcf/section
Barnett	2,000-2,800	75-200	3.5-8.0	3.0-4.8	0.46-0.50	35-185
Fayetteville	450-2,000	15-105	4.0-9.5	2.0-8.0		25-65
Haynesville	3,200-4,000	60-80	3.0-5.0	8.0-12.0		150-250
Horn River	2,000-3,000	150-175	0.5-10.0	2.0-4.5	0.65	130-320
Marcellus	1,000-2,000	15-75	1.0-12.0	1.6-7.0	0.45-0.60	20-100
Montney	900-3,000	150-300	2.5-6.0	2.0-8.0	0.44-0.70	55-90
Utica	500-3,500	90-300	0.3-3.1	2.2-3.7		25-160
Woodford	1,800-2,600	15-60	2.0-10.0	6.0-8.0		40-120

Note: One section = 640 acres.
Sources: Company reports, Tristone Capital estimates

US SHALE COMPLETIONS

Fig. 4



Source: Tristone Capital

TYPICAL LATERAL LENGTH, FRAC STIMULATION

Table 2

	Lateral, ft	Frac size, tons/frac	No. of frac stages	Frac fluid
Barnett	2,500-3,000	100	4-6	Slick water
Fayetteville	+3,000	100	6-8	Slick water
Haynesville	3,000-6,000	100	9-11	Gel cross-linked oil
Horn River	+2,000	100	6-8	Slick water
Marcellus	2,000-6,500	100	6-8	CO_2 polymer
Montney	1,700-3,000	100	6-8	Slick water
Utica		100	8	Slick water
Woodford	+3,000	100	6-8	Gel cross-linked oil

Sources: Tristone Capital, company reports, Halliburton

frac fluid flow-back greatly to shorten cleanup time, the study says.

The Montney formation in British Columbia is where companies use this fluid. The study notes that stimulating a horizontal well in the Montney typically involves perforating, isolating, and fracturing 6-11 zones at a cost of about $100,000- 120,000/frac interval. It is common to spend more than $1 million for fracturing these wells, the study says. The study describes these jobs as needing 8-10 pump trucks or about 18,000-22,500 hp and taking more than 1 week to complete.

The study notes that companies initially used gelled cross-linked oil-based fluids as the "fluid of choice" for hydraulic fracturing because of its compatibility with most formations and its cold weather attributes. In several basins, slickwater fracs have replaced oil-based fracs because the slick water uses less water and costs less, the study says.

To prevent swelling and permeability loss in the shales, companies typically continue to use oil-based frac fluids in formations that contain extensive water-sensitive clays. The study notes that these fluids are used in the Fayetteville, Haynesville, and Woodford shales.

Fort Worth basin Barnett

Development activity continues to evolve with part of the current activity in urban sites such as Fort Worth and the Dallas-Fort Worth airports.

The study notes that as of Aug. 18, 2008, the Barnett had 8,416 gas wells drilled in 19 counties. Production had increased to 3.8 bcfd in first-quarter 2008 from 219 MMcfd in 2000. The study expects the shale to produce 6-7 bcfd in the next 5 years.

Some of the newer techniques in the play noted in the study are:

- Longer horizontal laterals, up to 3,500 ft, often drilled from pads with multiple wells, especially in the urban areas.
- Testing of tighter well density with laterals, spaced 250-ft apart (25-30) compared with 500 ft between laterals (50-acre spacing).
- Simultaneous fracing of wells to increase recovery.

Deep Bossier

Wells in Deep Bossier of East Texas reach a 15,000-20,000 ft depth, have pressures of about 15,000 psi, and have tested at 65 MMcfd. The study notes that these wells are expensive, costing $10-20/million for a vertical well.

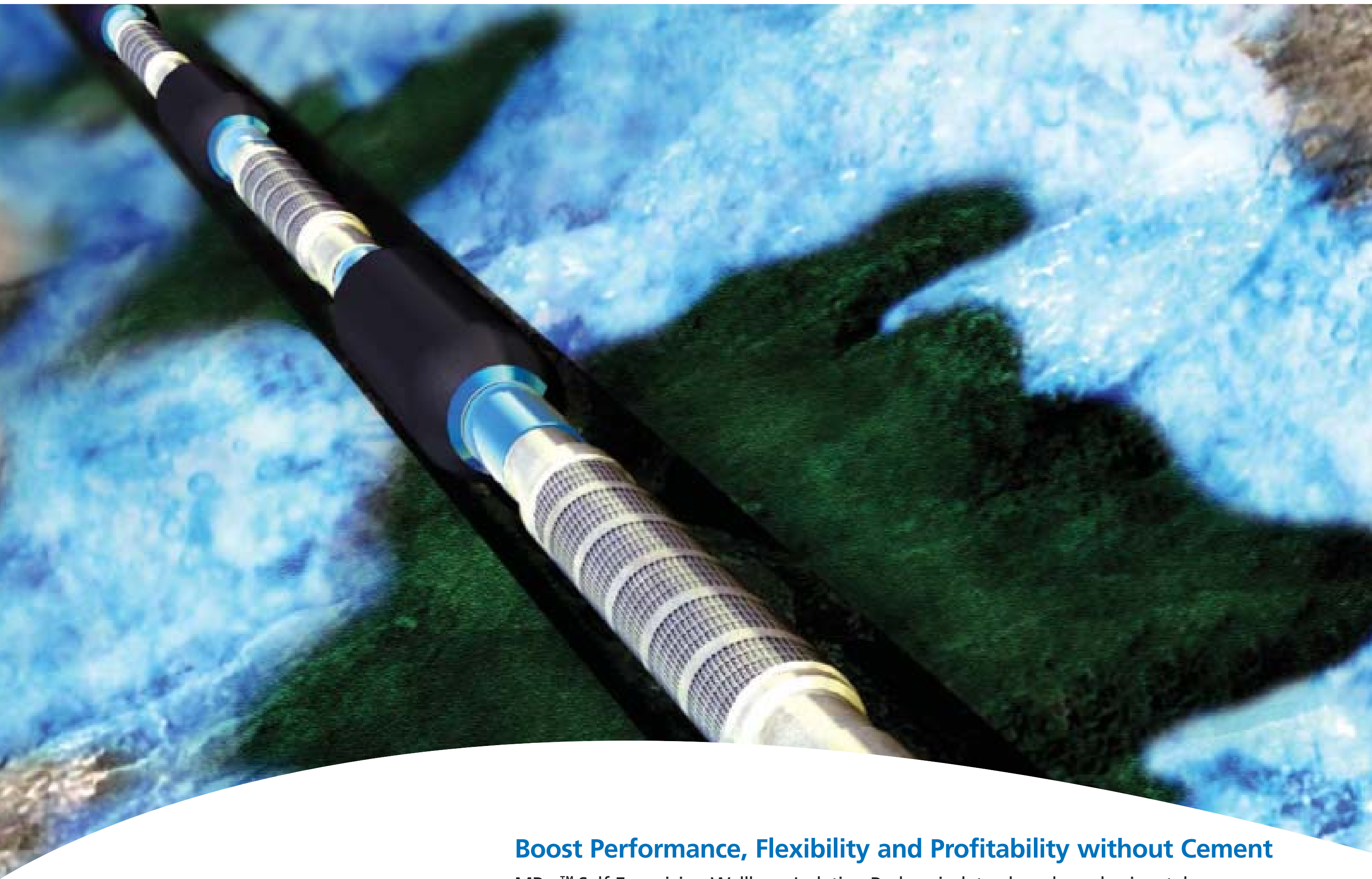
Currently the play has six main fields in four counties: Robertson, Leon, Freestone, and Limestone.

Fayetteville

The Fayetteville shale in Arkansas is the shallower and thinner equivalent of the Barnett shale. The core of the play is in five counties in central Arkansas: Cleburne, Van Buren, Conway, Faulkner, and White.

The study says as of May 31, 2008, the play had 877 producing wells, with production in July of 740 MMcfd compared to only 90 MMcfd in December

Isolate This!



Boost Performance, Flexibility and Profitability without Cement

MPas™ Self-Energizing Wellbore Isolation Packers isolate along long, horizontal, open-hole wellbores to manage water and maximize production, reserves, profitability and well life—without cementing or perforating.

More than 2,000 MPas Packers help operators

- isolate gas caps where exact top and base positions are unknown
- isolate lost circulation and water in high-angle wells that would be difficult to plug back with cement
- enhance EQUALIZER™ Reservoir Optimized Completion System performance by sealing between sections of varying permeability"
- improve production an average of 2,000 bbl/d
- improve incremental recovery as much as 60%

Get the benefits of MPas Wellbore Isolation Packers in your open-hole wells.

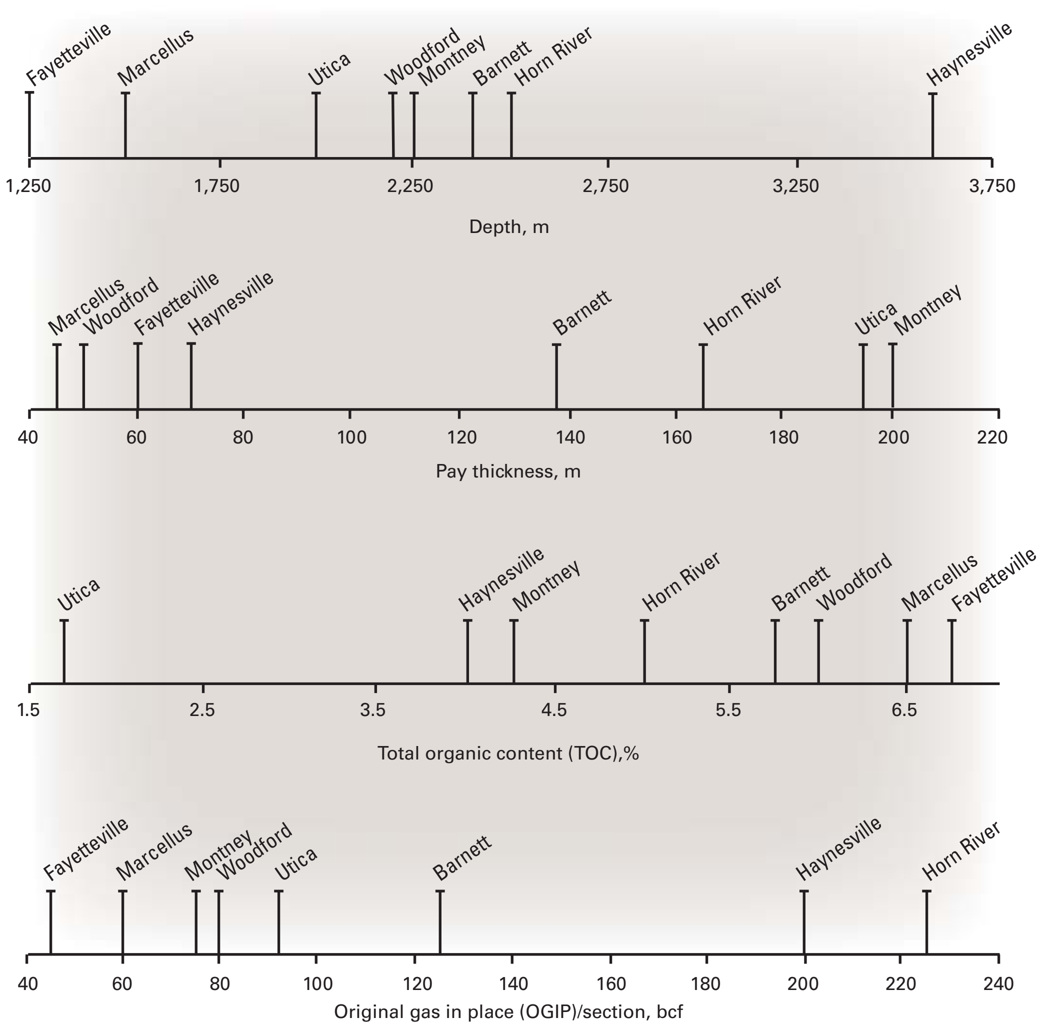
www.wellboreisolation.com
wellbore.isolation@bakeroiltools.com

BAKER HUGHES Baker Oil Tools

THE Completion and Intervention Company

GEOLOGIC ATTRIBUTES

Fig. 5



Source: Tristone Capital

It says Marcellus production has been minimal to date because of the need to expand the existing infrastructure to accommodate the high-pressure gas that the gas transportation system in Appalachia cannot at this time handle.

Most companies have so far drilled mostly vertical wells to delineate the play, but the study expects horizontal wells to be the primary means for developing the formation.

Montney

The Montney shale lies in the east-central part of British Columbia. The study notes that continued drilling should increase production to 1 bcfd by yearend 2009 from the current 600 MMscfd in early 2008.

Operators typical include five to eight fracs/well, and the study expects estimated ultimate gas recovery to increase to 7 bcf/well from the current 5 bcf/well as technology innovation continues.

Horn River basin

The Horn River basin in Northeastern British Columbia extends into the Northwest Territories. The Devonian Muskwa shale is the main play although the basin also has other shales with large original gas in place such as the Fort Simpson, the study says.

2006. The study expects the play to produce 3.15 bcfd by 2018.

Haynesville

The Haynesville shale is in northwestern Louisiana and East Texas. Wells in the play initially have produced 5-20 MMcfd, the study said. The study expects wells to have ultimate gas recovers of 4-8 bcf.

Currently, companies have drilled about 20-25 horizontal wells in the play, and the study expects about 60-80 rigs could be active in the play by yearend 2008, with most of the drilling in Caddo and DeSoto Parishes in Louisiana.

Woodford

The Devonian-aged Woodford shale lies at 6,000-14,000 ft depths in the Arkoma basin of southeast Oklahoma. The study notes that the $6 million well cost in the Woodford is more than the $2-3/million/well cost in the Fayetteville and Barnett shales.

The study estimates that an 80-acre well in the Woodford will recover about 4 bcf of gas.

Marcellus

The Marcellus shale in the Appalachia basin extends over several states, although most wells drilled to date have been in Pennsylvania, the study notes.

Initial well production rates have ranged from 2 to 8.8 MMcfd with wells with more fracs stages producing better, the study notes. The study says estimated ultimate gas recovery ranges from 4 to 6 bcf/section.

Utica

The Utica and the overlying Lorraine shales are relatively new plays in Quebec with only a few wells testing the formations to date. The study estimates that recoverable gas could be as much as 40 tcf (150 bcf/section).

An initial vertical well tested at 1 MMcfd; rates should be higher for horizontal wells with multiple fracs, according to the study.

Emerging plays

Three emerging shale plays listed by the study are Pearsall shales in the Maverick basin of South Texas, the Niobrara shales of Western Colorado, and the Barnett shale in the Delaware basin of West Texas.

The study says the Pearsall is as deep as 3,500 m in places, has a 200-300 m thickness, and contains about 30-175 bcf/section of original gas in place. It notes reports that say initial horizontal wells flowed at 0.8-3.8 MMcfd.

The Niobrara shales outcrop in Kansas and Nebraska, but are at more than 2,500 m depths in western Colorado. The study notes that in the eastern shallower portion of the play, the shales are underpressured and wells have low initial rates, while in the deeper overpressure portion, wells may produced at 1 MMcfd and recover 100-150 bcf of gas/section.

The Barnett in the Delaware basin is twice a deep as the Barnett in the Fort Worth basin and therefore holds much more gas per section. One estimate is that the Delaware Barnett has 500 bcf/section compared with 150 bcf/section in the Fort Worth basin. The study notes that developing Delaware Barnett gas will be more complicated and costly. ✦

Refiners should consider Monte Carlo analysis to assess expansion projects

John Stone
Deloitte Financial Advisory Services
Philadelphia

Due to robust growth in the global demand for refined products, refiners often face the tough decision of whether to spend significantly to accelerate expansion projects or stick to existing time frames. This is where a Monte Carlo analysis can frequently prove helpful. Using this analysis allows the refiner to compute thousands of scenarios to reflect the different variables and conditions that can affect an overall project schedule.

A Monte Carlo analysis calculates probability durations by representing estimated levels of uncertainty, demonstrating whether a project can be completed in a given time.

The fact that there is no way to guarantee that an expedited project will finish early complicates the refiner's decision. This is mainly because traditional risk-assessment methods used to accelerate a project do not account for the full range of variables (weather, a shortage of resources, poor planning, and differing site conditions).

To illustrate a Monte Carlo analysis for a typical refinery project, we conducted one for a hypothetical project team trying to decide if it should expand a refinery to meet an expedited deadline. The analysis will help the team answer some basic questions that could dramatically affect the project. For example, does it make sense to accelerate the project or would it represent an unwarranted gamble? And what sort of savings might the project realize?

The Monte Carlo simulation applied uncertainty factors to the hypothetical project schedule and simulated how the project's completion date would change given a certain confidence level. Despite the strength of a Monte Carlo simulation, sound professional judgment is still required. It is important, therefore, to increase the probability of an effective analysis by selecting the appropriate inputs.

The Monte Carlo simulation software that we used was Pertmaster Project Analytics. In December 2006, Pertmaster was acquired by Primavera Systems Inc.

Monte Carlo overview

Traditional approaches to evaluating project schedules include the critical-path method, program evaluation and review technique, and bar chart. Those approaches, which use single-point estimates, are limited in their ability to account for uncertainty.

In reality, numerous factors influence project schedules. These factors can include unrealistic timeline estimates, poor sequencing, insufficient resource availability, lack of vendor support, and scope growth.

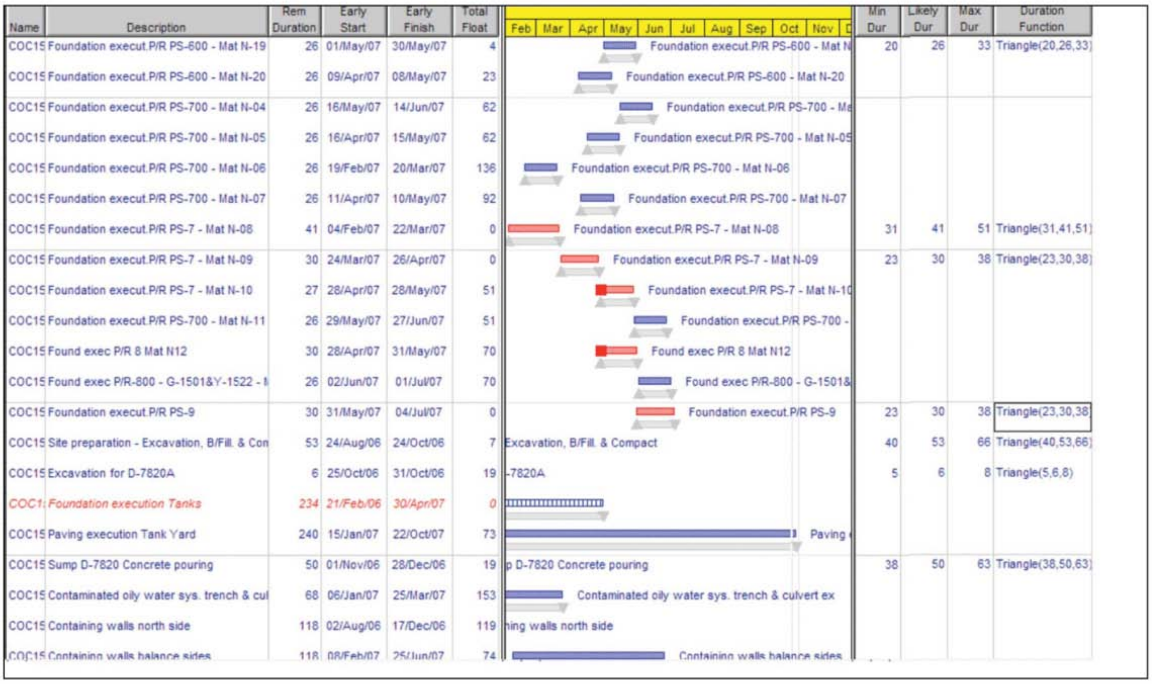
The Monte Carlo technique of statistical sampling approximates solutions to quantitative problems. It randomly generates values for uncertain variables over and over, simulating a model and generating a most likely scenario.

For this test case, the refiner was interested in performing a risk assessment of its accelerated schedule for a major expansion project. We decided to use Monte Carlo simulation analysis to help the refiner assess whether the accelerated project schedule would meet the required completion date.

The first step in the analysis was assigning a probability distribution and uncertain variables to various activities in the schedule. Probability distribution types such as normal, triangular, uniform, or lognormal are chosen based on the conditions surrounding the uncertainty. Risk events and their effect on the planned schedule activities determine the probability factors.

Typically, one assigns a probability factor based on a risk event that has a slight risk of happening, a 50-50 chance, or is a near certainty. A 25% probability factor indicates that a risk event, such as slow productivity, could happen. A much higher probability factor indicates that a risk event, such as the complexity and lack of qualified people working on the planned activity, is nearly certain to happen.

In most cases for this analysis, we used a 25% probability factor. For example, if the original time for an activity was 10 days, its early completion time would be 8 days and its late completion time would be 13 days, due to rounding. The number must be rounded because the simulation software does not accept fractions for days.



This screen shot shows the duration probability distributions for our Monte Carlo analysis (Fig. 1).

Once the foreseeable risks for the activities are identified, the risk analysis should focus on the probability of those events or issues occurring. This is the uncertainty variable. A typical range may be 15-75% with a confidence level of 65-85.

In our model, we filtered activities that had been on the critical or near-critical path and applied a 15-75% (minimum and maximum occurrence) uncertainty variable. The uncertainty variable for each activity is based on a combination of historical data and the analyst's professional judgment and experience.

This was a conservative approach given the types of risks identified along the critical path and near-critical path. We chose a 25% probability factor, however, because we felt that while the project management team had the necessary skills to complete the project early, we believed that lack of vendor cooperation and a labor shortage were risk factors of serious concern.

The Monte Carlo simulation can offer many insights. For instance, it can help with:

• *Contingency scenarios.* These can help the refiner set contingency values for contract milestones and evaluate the exposure to risk in the event that project delays cannot be absorbed by the contingency or overcome by project acceleration. These help the project manager decide to extend the contract's duration, accelerate the project activities, or let the project schedule slip and become absorbed by the contingency or float.

• *Tracking key activities.* The simulation can help project management identify and track how critical-path activities may evolve due to deviations from the original plan. The analysis simulates activity outcomes using random numbers with allocated probabilities. Key activities having the greatest potential effect on the schedule can be identified and evaluated to determine their associated risk, and subsequently provide the project management team with a more accurate expected project completion date.

A Monte Carlo simulation is, however, no panacea. For example, an analysis based on activities not critical to the project's completion will produce unrealistic simulation results. Also, poor judgment in selecting the probability distribution and uncertainty for a chosen event will lower the model's accuracy.

Monte Carlo analysis

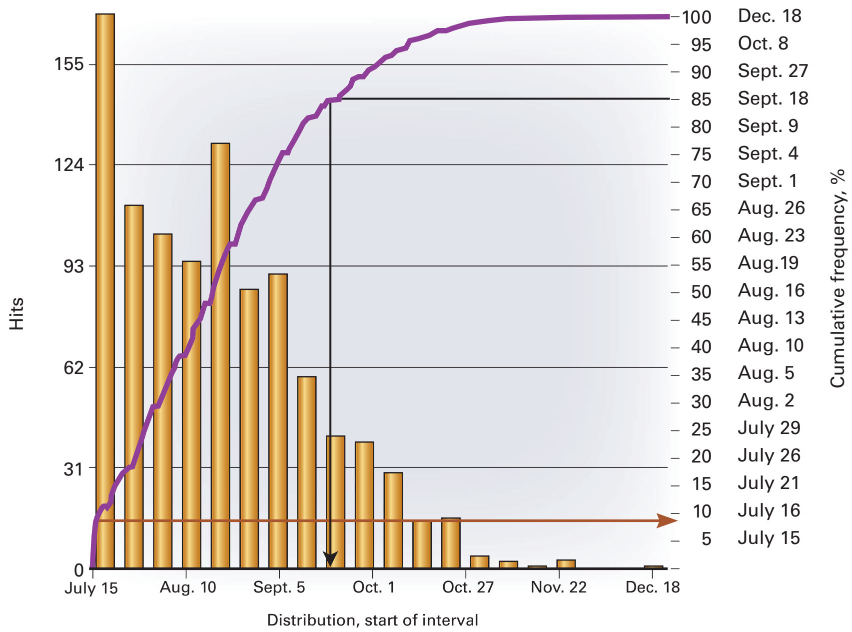
These are the basic elements of the test project we conducted:

• Main scope of work. The refinery project included construction of process units connected to centralized pipe racks; a product storage tank farm area and interconnecting pipe rack; an electrical substation and remote instrument enclosure; ancillary process and utilities piping; and electrical, civil, and instrumentation equipment.

Major work completed included engineering, procurement, construction, commissioning and start-up, civil, mechanical, electrical, and instrumentation and control work.

EXPECTED COMPLETION DATE, 2008

Fig. 2



- Original baseline schedule. The design, procurement, and construction phases spanned 32 months, beginning in February 2006, and included process engineering, procurement of materials, and foundation excavation.
- An original planned completion date of Sept. 18, 2008.
- A proposed accelerated schedule of 30 months. As of Aug. 1, 2006, the project was 16.6% complete, with a project completion date forecast for July 15, 2008, about 2 months ahead of schedule.
- The owner asked: What is the level of risk associated with accelerating the original project schedule? Our recommendation was to assess the reasonableness of the baseline schedule, analyze the risk associated with the schedule reduction, and evaluate various scenarios generated by the Monte Carlo simulation model, including applying additional manpower to critical-path activities.

Probabilities, uncertainties

When conducting a Monte Carlo simulation, one must assign probability distribution and uncertainty variables to each activity. In this simulation run, we selected activities with a total float of less than 20 days and assigned a triangle distribution, and a minimum and maximum duration uncertainty variance of 25%.

A total float of less than 20 days summarized the more than 2,100 activities into a set of 220 to 300 activities that best described sequences that were critical, near-critical, and risk-sensitive to the project's completion.

We selected a triangle distribution because it provided a range of possible outcomes given a low, high, and median occurrence of the risk event. Also, as previously mentioned, we selected the 25% uncertainty variable because issues with vendor cooperation and a labor shortage would probably affect the critical and near-critical activities.

For example, Activity COC 1500, Foundation Execution, has a remaining duration of 41, minimum duration of 31, and maximum duration of 51 (Fig. 1). This means that it is most likely that work for Mat N-08 will be completed in 41 work days; however, there is a 25% chance that the activity will be completed 10 days faster or slower.

This simulation generated a snapshot of remaining duration, early finish, late finish, total float, probability distribution, and uncertainty variables for various activities (Fig. 1).

This analysis used the simulation's histogram and probability distribution results to calculate and report a confidence level of when the project would be completed. We were willing to accept an 85% confidence level for the level of risk in this simulation run. Typically, the industry standard for a confidence level is 75-85%.

A confidence level greater than 85% would provide more certainty, but the same end results, in that the project would be completed after the accelerated project schedule date of July 15, 2008. A lower confidence level would yield less certainty and unrealistic results, which would be too optimistic for our analysis.

Results, recommendation

Overall, our model simulated, tabulated, and plotted the frequency and distribution functions for 1,000 simulated project schedule outcomes.

Before we ran the simulation model, the completion date for the accelerated project schedule was July 15, 2008. Our Monte Carlo simulation results, however, suggested that the project would have an 85% chance of completion by Sept. 18, 2008 (Fig. 2). July 15 was the best-case scenario, with a less than 10% probability. Worst-case scenario was Dec. 18, 2008.

Given these results, we concluded that the contractor would most likely be unable to complete the proposed accelerated schedule within 30 months. Paying the contractor an incentive or overtime premium to complete the project on or before July 15, 2008, would have not been cost beneficial to the owner.

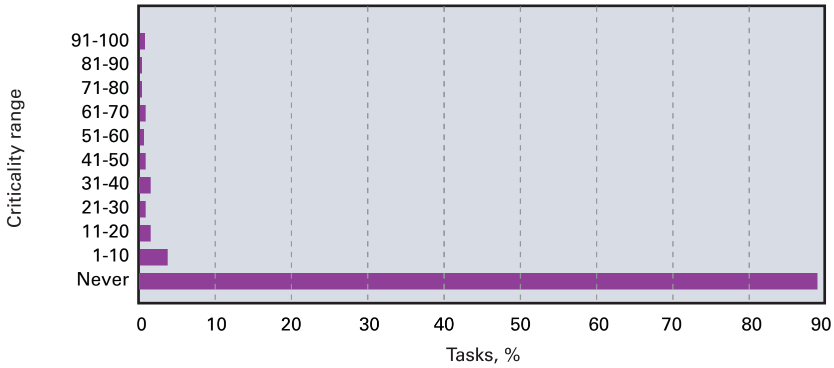
In fact, we estimated that the owner would have paid the contractor $5-7.5 million in incentives and overtime premiums for a project completion date that only had a 10% chance of being completing within the projected 30 months.

CRITICALITY INDEX REPORT

Fig. 3

Number of imcomplete normal tasks: 2,157
Number of critical tasks: 237
Percentage of tasks critical: 10.99%

Criticality range	Number of tasks	Relative percentage
Never	1,920	89
1-10	81	4
11-20	34	2
21-30	21	1
31-40	33	2
41-50	17	1
51-60	9	0
61-70	17	1
71-80	5	0
81-90	2	0
91-100	18	1
Total	2,157	100



Insights into improvements

Although an accelerated schedule would likely carry none of the originally hoped-for benefits, our simulations did identify key activities that the owner and project management team could focus on to improve schedule performance through applying overtime to selected areas.

In the Monte Carlo simulation software, two reports provided information on the sensitivities of uncertainty variables used in the simulation. They allowed us to identify high-risk activities likely to affect the project's expected completion date:

• The criticality index measures the likelihood that an activity will appear on the critical path. We ran the simulation many times to determine the effects of changing the critical and near-critical paths in our project schedule model. The net result is that we could recommend mitigation strategies to improve overall schedule performance.

• The duration sensitivity report measures the duration variance for each activity and allowed us to analyze the uncertainty factors most likely to influence the project's schedule.

Index, analysis

For this project, we used the criticality index and duration sensitivity analyses to identify areas for which risk can be evaluated and managed (Fig. 3). These results guided the project team in narrowing and prioritizing its focus by pinpointing those activities that appear on the critical or near-critical paths.

In this case, 237 out of 2,157 activities with a remaining duration appeared on the critical path or a near-critical path. The other 1,920 activities do not appear on the critical or near-critical path.

We adjusted the confidence limits and analyzed the sensitivities of the input variables relative to activity durations; for instance, we used a 75% instead of 85% confidence level and applied a 20% chance of uncertainty to an activity.

The duration sensitivity report displays only tasks as likely to affect the project schedule. Only instrumentation installation details, piping erection, instrumentation, and piping prefabrication units appeared on the critical path (Fig. 4).

This analysis allows the management team to focus its attention and risk management efforts on an even smaller grouping of work activities.

Benefits

The Monte Carlo analytical tool is well suited for capital infrastructure projects because it:

• Can help address uncertainties. It can readily account for the uncertainty that routinely affects large and complex construction projects.

• Is easy to refine. Refiners can use the results generated during simulation runs continually to refine the applied uncertainty variables and confidence levels to produce a more accurate model.

• Can help pinpoint higher risks. Refiners can use analyses such as criticality and duration sensitivity reports to identify and evaluate the high-risk activities likely to affect the project's completion date.

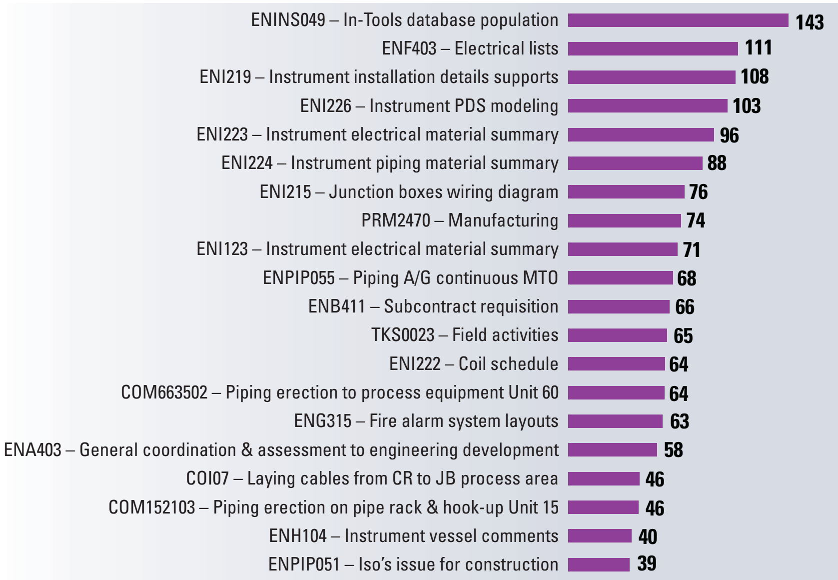
• Can give a view of alternatives. Simulation runs can provide valuable information relative to the probability of completing a project by a certain date, thereby allowing management to make informed decisions regarding the application of labor, equipment, and financial resources.

For this refinery expansion, a Monte Carlo simulation indicated that the requested 2-month reduction in the overall project schedule was, in fact, not reasonably attainable and as such did not warrant the additional application of resources.

Results like these, however, certainly are not a sure bet. In fact, users of this tool must be cautious. To achieve the most reliable outcomes, the Monte Carlo simulation must be based on solid his-

Duration sensitivity report

Fig. 4



torical data and sound professional judgment that informs reasonable estimated activity durations, activity sequencing, and uncertainty risk factors. ✦

Bibliography

Murch, Matthew, Monte Carlo Simulation Presentation, Deloitte Financial Advisory Services, 2006.

"Crystal Ball, Forecasting & Risk Analysis for Spreadsheet Users," Decisioneering Magazine, 1996.

Wendling, Robert V., and Lorance, Randal B., "Techniques for Developing Cost Risk Analysis Models," 1999 AACE International Transactions Risk.02, 1999.

Wendling, Robert V., and Lorance, Randal B., "Integration of Schedule and Cost Risk Models," 1999 AACE International Transactions Risk.09, 1999.

Clark, Dale, "Monte Carlo Analysis: Ten Years of Experience," Cost Engineering, Vol. 43 (2001), No. 6, pp. 40-45.

Kandaswamy, S., "The Basics of Monte Carlo Simulation: A Tutorial," Proceedings of the Project Management Institute Annual Seminars & Symposium, New Jersey, Nov. 1-10, 2001.

Noor, Iqbal, and Tichacek, Robert L., "Contingency Misuse and Other Risk Management Pitfalls," 2004 AACE International Transactions Risk.04, 2004.

Caddell, Christopher P., Crepinsek, Sherri R., and Klanac, Gerald, "Risk Assessments: Value of the Process," 2004 AACE International Transactions Risk.01, 2004.

"Monte Carlo Method," www.risk-glossary.com, 2006.

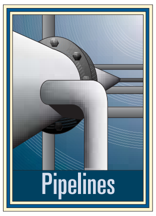
The author

John Stone (jostone@deloitte.com) is a manager in the construction advisory services group of Deloitte Financial Advisory Services LLP, Philadelphia. He has 16 years' experience in project cost assessment and process assessments, project controls, change order analysis, construction field experience, and construction disputes. Stone has been involved in power plant, commercial, transportation, resorts, and educational projects. He holds a BS in civil and construction engineering from Temple University, Philadelphia, and an MSEng from Drexel University, Philadelphia.

CRUDE EXPORT RISER—1

Hybrid riser application provides deepwater crude export solution

Francisco E. Roveri
A.G.Velten Filho
V.C. Mello
L.F. Marques
Petrobras
Rio de Janeiro



The freestanding hybrid riser concept allows decoupling the schedules of riser and floating production unit design, manufacture, and installation, providing flexibility should delays occur during FPU construction. Uncertainties in FPU construction schedules and the low availability of specialized construction vessels pose a risk of delay if the chosen riser concept requires the FPU to be in place at the time of installation.

Petrobras's development plan for the Roncador field offshore Brazil included an FSHR as part of its oil export system.

This first of three articles describes the FSHR in detail before examing its design and installed responses. Subsequent articles in the next two issues will detail FSHR installation and monitoring, as well as its integration with the export pipeline.

Based on presentation to Offshore Technology Conference, Houston, May 5-8, 2008.

Background

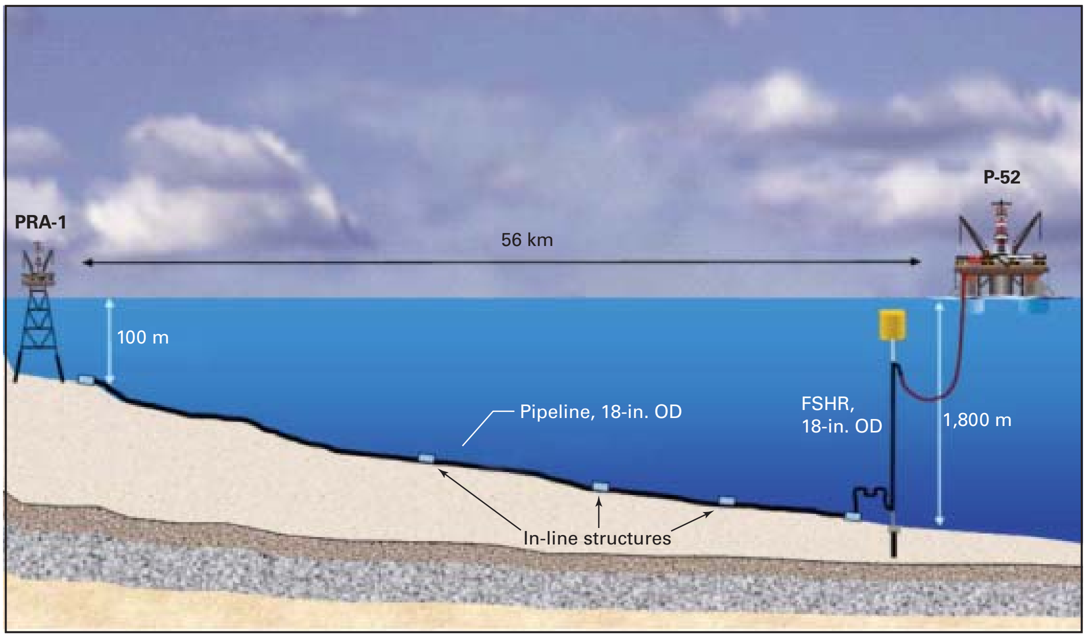
Petrobras's oil flow master plan (PDET) for development of Roncador field in the Campos basin off Brazil consists of the P-52 semisubmersible oil-export system, an 18-in. OD oil-export pipeline, and a freestanding hybrid riser (FSHR) connecting the P-52 floating production unit (FPU) to fixed platform PRA-1, also in the Campos basin. P-52 is stationed in water 1,800 m deep; PRA-1 is in about 100 m (Fig. 1).

A front-end engineering and design (FEED) project contracted to 2H Offshore Engineering and based on technical specifications and functional requirements provided by Petrobras developed the FSHR. Flow-assurance studies required 50-mm thick thermal insulation for both pipeline and the vertical portion of the riser.

The FEED process considered a mobile offshore drilling unit (MODU) for deploying the FSHR system, to take best advantage of local practices and Petrobras's capabilities. Bid requirements allowed some changes to the design and

PROJECT LAYOUT

Fig. 1



installation procedure developed during the FEED phase, in order better to suit the contractor's capabilities. As a result, a pipelay and construction vessel were considered for installation of both riser and pipeline. Technip won the contract, excluding the flexible jumper, awarded to Wellstream, and the foundation, to Petrobras.

High expected production rates at P-52 required an 18-in. oil export pipeline. Instrumented pigging requirements dictate the export riser have the same diameter. This large-bore specification, combined with the deepwater site, put this application outside the present range of flexible-pipe and steel catenary riser (SCR) solutions, both of which present high top-tension loads for installation and operation. Lateral buckling failure in flexible pipes and fatigue damage in the touchdown zone (TDZ) of SCRs further limited design to heavier pipes, compromising hang-off loads.

The reduced dynamic response of the FSHR system results in a motion decoupling between the floating production unit (FPU) and the vertical portion of the FSHR system. FSHR's vessel interface loads are also small when compared with SCRs or flexible pipe, making it an attractive alternative solution for this kind of application. Additional cost savings accrue by having the riser in place before FPU installation.

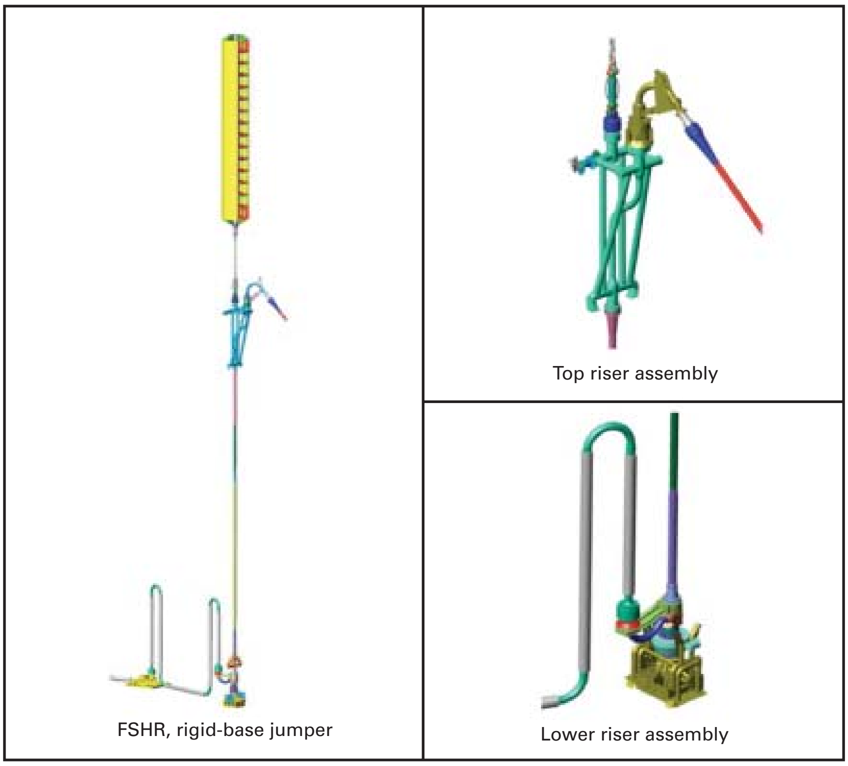
Design changes

The FSHR FEED awarded to 2H Offshore Engineering considered the following requirements:

- Flexible jumper, replaceable at any time.
- Installation by MODU.
- Welded riser joints.
- SPP thermal insulation = 50 mm.

A drilled and grouted pile installed by MODU was to provide FSHR's foundation. During FEED development, Petrobras established that, due to installation and maintenance requirements, the connection of the flexible jumper at the FSHR side would occur on top of the buoyancy can (BC). A detailed structural design analysis considered passing the riser stem through the BC.

FSHR COMPONENTS Fig. 2



Source: Petrobras

Petrobras free-issued a MODU for FSHR installation as an option in the bid package, assuming FSHR foundation and flexible jumper installation as part of its work scope. Petrobras initially issued different offers for pipeline and FSHR. Bid requirements allowed changes to the FEED to suit contractors' capabilites, including locating the flexible jumper connection on the FSHR's side. Bidders only proposed pipelay and construction vessels for installation of the riser and pipeline. The contract awarded to Technip included development of the detailed design, material supply, fabrication, and installation of both pipeline and riser.

FSHR description

FSHR design may have a number of variants. An optimazation study determines actual configuration considering:

- Offset from the foundation to the FPU.
- Net upthrust provided by the BC.
- BC depth.
- Flexible jumper length
- Flexible jumper azimuth (plan view).

The FSHR consists of a single nearly vertical steel pipe connected to a foundation system near the mud line. A BC holds the riser in the proper vertical orientation and is mechanically connected to the top of the vertical pipe by a chain. The BC lies below sea level, beyond the influence of waves and high currents. A gooseneck assembly sits on top of the top riser assembly (TRA). A flexible jumper links the gooseneck to the FPU, effectively decoupling the vertical part of the FSHR from vessel motions. Fig. 2 shows the FSHR's general arrangement.

The FSHR runs from the No. 1 hang-off slot on P-52 to the pipeline-end termination (PLET) near the riser base. The lower end of the vertical part interfaces with a stress joint. Below the stress joint lies an offtake spool, connected to the

The buoyancy can pictured above is 34.2 m long, with a 5.45 m OD. Made of 50,000 psi-yield materials, the BC holds the riser in place by upward pull while also decoupling it from the floating production unit's motions. The truss-type top riser assembly in the photo on the right connects the flexible jumper from the FPU to the riser assembly (Fig. 3).

foundation by a hydraulic connector. A rigid base jumper connects the mandrels at the offtake spool with the PLET, providing the link between the FSHR and the pipeline. The foundation pile is drilled and grouted.

The upthrust from the nitrogen filled BC on top of the vertical pipe provides the tension. The vertical pipe must be kept in tension to maintain FSHR stability for all loads. The vertical pipe consists, from top down, of the upper-taper stress joing (UTSJ), interfacing with the TRA, the upper-adapter stress joint (UASJ), standard joints, the lower-adapter stress joint (LASJ), and the lower-taper stress joint (LTSJ), interfacing with the offtake spool.

At the top of the TRA is the gooseneck assembly. This assembly consists primarily of the gooseneck and an ROV actuated hydraulic connector allowing the gooseneck and flexible jumper to be installed separately from the vertical section of the riser. The gooseneck assembly also includes a cross-brace tied to a reinforced spool to provide support against loads applied to the gooseneck from the flexible jumper.

Attached to the gooseneck is the flexible jumper (FJ). The flexible jumper connects the freestanding section of the riser system to the FPU, and includes bend stiffeners to ensure the range of rotations experienced at the end connections do not damage the jumper due to low radius of curvature. The flexible jumper has sufficient compliance to decouple vessel motions substantially and offsets from the vertical portion of the FSHR system, limiting the freestanding riser's wave-induced dynamic response.

Positioning the gooseneck at the TRA allows for independent installation of vertical riser and flexible jumper. A flexible pipe installation vessel can install the flexible jumper when convenient, minimizing the risk of damage to the flexible jumper during installation. The horizontal offset between the mandrel at the TRA and the BC vertical axis allows installation and retrieval of the flexible jumper. This design also minimizes time needed for flexible jumper retrieval in case of damage while in service to any of its components.

FSHR components

Table 1 presents the main characteristics of FSHR configuration at neutral position. Water depth measures 1,800 m and design life is 25 years. The fatigue safety factor is 10. In the neutral position the FJ is already connected and the system is subject to weight and buoyancy loads only, displacing the TRA

toward the FPU.

The vertical part of the FSHR consists of an assembly of both standard and special joints, such as the stress joints at the bottom and top interfaces. Table 2 presents the main characteristics of the line pipe (standard joints) and its operating parameters.

Table 3 shows the flexible jumper's main characteristics.

Table 4 outlines the main parameters of the 16-compartment buoyancy can.

Buoyancy can

A nitrogen-filled buoyancy can holds the riser system's vertical section in the proper orientation. The BC is cylindrical, 34.2 m long, 5.45 m in diameter, and fabricated from 50,000-psi yield material. Bulkheads separate 15 of the 16 2.28-m tall compartments. The BC's design is pressure balanced, with the internal pressure slightly above the external pressure of water, resulting in a ½-in. thick skin. A 56-in. outer diameter central stem, the 16th compartment, runs along the BC's longitudinal axis.

Ports on the side of each compartment dewater the BC. Each compartment features an inlet and an outlet port. Injecting nitrogen into the BC at pressure for dewatering leads the BC compartment to be slightly overpressurized with regard to the water pressure outside.

The BC design leaves at least one of the 16 compartments permanently water-filled as a contingency. Should one compartment fail in service, a contingency compartment can be dewatered to keep operational tension in the riser string.

Tether chain

A tether chain connects the BC to the top of the vertical riser. Including universal joints at each end of the chain reduces bending moment. The lower part of the chain includes the load monitoring spool, used for measuring the tension provided by the BC. A hydraulic connector links the chain's lower end to the top riser assembly.

Top-riser assembly

The top riser assembly consists of a truss-type structure providing connection to the flexible jumper and the tether chain. The TRA uses a 2,200 mm bend radius spool (>3 diameters), designed to allow vertical connection of the flexible jumper. It has three main forged components. Fig. 3 shows the BC and TRA assemblies.

Stress joints

The taper stress joints are high-specification forged carbon steel components fabricated from 80,000 psi yield-strength material designed to control the bending at the base and top of the riser. They have a linearly varying WT and a profile optimized to withstand both extreme loads and long-term fatigue loading.

A flange at both stress joint bases connects the TRA and offtake spool. Pup pieces connect the UASJ and LASJ to the riser's standard joints, avoiding an offshore weld directly to the tapered joints.

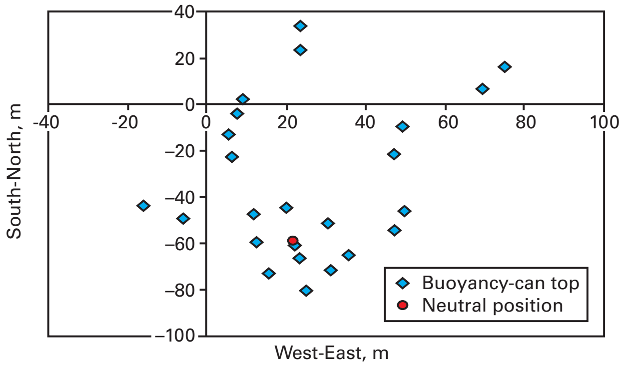
Lower-riser assembly

The lower part of the FSHR, above the foundation, consists of three components: the offtake spool, the LTSJ, and the LASJ. The assembly connects with the seabed foundation at the bottom and the upper pup piece at the top. The offtake spool is a cylindrical forged component. The spool contains a flow path traveling through its top and exiting from the side via an offtake. The offtake includes an upward facing mandrel for connecting the RBJ.

Foundation

The FSHR foundation consists of a drilled and grouted 36-in. OD conductor installed by P-23, a MODU owned by Petrobras. The conductor is 120 m long, with the 12 m long segments joined by Merlin connectors. The first five joints from the top are 2-in. WT X-80 pipe, while the remaining joints are 1.5-in WT X-60. Design considered two cement shortfall cases: at 0 and 25 m from the mud line. Conductor verticality installation tolerance was 1° of vertical axis, any direction. A modi-

BC conditions, operating case Fig. 4



General system configuration, neutral position Table 1

Parameter	Measurement
Foundation-FPU offset	300 m
Depth to top of buoyancy can	164.3 m
Flexible jumper length	425 m
Flexible jumper azimuth, from north	339.7°
In-service effective tension, compact flange lower face	240 tonnes
Gooseneck angle, from vertical	34.5°
Hang-off angle at P-52	10°
BC horizontal displacement	65 m

Riser data Table 2

Parameter	Measurement
OD	18 in.
WT	0.625 in.
Internal corrosion allowance	3 mm
Material Standard API Spec 5L	X-65
Corrosion protection, FBE-adhesive	0.5 mm
Thermal insulation thickness, solid PP	50 mm
Design pressure	109.8 bar
Design temperature	70° C.
Oil mass density	841 kg/cu m

Flexible jumper characteristics Table 3

Parameter	Measurement
OD	535.5 mm
ID	406.4 mm
Weight, empty in air	336.7 kg force/m
Weight, seawater-filled in seawater	244.8 kg force/m
Bending stiffness, operation	2,500 kilonewtons/sq m
Bending stiffness, free hanging	2,900 kilonewtons/sq m

fied drilling base installed on top of the conductor pulled down the FSHR during deployment.

Table 5 presents environmental conditions used for the connected FSHR global analysis.

BUOYANCY CAN CHARACTERISTICS Table 4

Parameter	Measurement
Nominal length	34.2 m
Nominal OD	5.45 m
Water-filled compartments	2
Nominal net uplift, operation	536 tonnes

FSHR design

The overall philosophy for the definition of load cases follows the format adopted by API RP 2RD and considers test, operating, extreme, and survival load categories. Within each category a number of separate load cases exist, each having various combinations of environmental conditions, pressures, and platform offsets. Environmental events occuring across a range of directions required a number of load cases to assess component response. Platform offsets applied in various directions ensured all worst-case loads were covered.

ENVIRONMENTAL CONDITIONS Table 5

	Return period, years		
Description*	Current	Wave	Wind
Extreme, current	100	10	10
Extreme, wave	10	100	100
Extreme, wave only	—	100	100
Maximum operating, current	10	1	1
Maximum operating, wave	1	10	10
Maximum operating, wave only	—	10	10
Opposing current-wind, wave	1	10	10

*First six consider surface current, wave, and wind applied in the same direction. The last represents the case in which the direction of the surface current is opposite the direction wave and wind.

P-52 offsets

Design maximum static offsets measure 5% water depth for the intact mooring system and 7.5% water depth with one mooring line broken but depend on the direction of environmental action. Offset also considered FSHR foundation and P-52 installation tolerances.

Fatigue criteria

The acceptance criterion for fatigue damage = [(installation fatigue damage) + (in-place fatigue damage in 25 years)] × 10 <1.0. Vortex-induced vibrations (VIV) include long-term and storm current profiles (1, 10, and 100 years return period).

Sensitivity analysis

Sensitivity analysis determined the effects of practical variations in riser configuration with time and uncertainties in design parameters. Parameters considered include:

- Hydrodynamic drag coefficient (e.g., Reynolds number, pipe and buoyancy-can roughness, and any amplification due to riser VIV & BC vortex-induced motions).
- Components' weight tolerances.
- Components' installation tolerances.

Riser models incorporated the expected extremes from these parameters. Analysis of previously identified critical load cases quantified parameter changes' effects on response.

Vortex-induced motions

With no strake around the BC, potential fatigue damage with the FSHR system also considered dynamic effects of vortex-induced motions (VIM) from current profiles. Applying the sinusoidal VIM amplitudes (in-line and cross flow) with the associated vortex-shedding periods to the buoyancy can's center of gravity allowed assessment of the induced bending stress ranges within the riser string (including the TRA), chain links, universal joints, gooseneck, taper joints, etc. It also estimates the fatigue damage and the load and motion histograms of each riser component.

This methodology performed the FSHR fatigue analysis induced by BC VIM due to 87 long-term current profiles and 24 extreme current profiles.

The primary motion of a BC under current is perpendicular or transverse to the current directions (crossflow), while the secondary motion is in-line with the current. Together, these trace a figure eight in the horizontal plane. The in-line amplitude is smaller than the cross-flow amplitude, but occurs at twice the frequency of the later.

A conservative approach considered for the full range of current velocities acting on the BC included: cross-flow single amplitude ratio A/D = 1 and in-line single amplitude ratio A/D = 0.2; D = BC diameter, A = single amplitude.

FSHR design

The design of an FSHR typically involves an up-front global analysis of the system to optimize riser configuration. Variable parameters include offset from the production platform, depth of BC, flexible jumper length, net upthrust provided by the BC, and flexible jumper azimuth. Clearance may beecome an issue and interference with adjacent risers or mooring lines drives the choice of the system layout.

Global storm and fatigue analyses to define functional loadings on the critical riser components, as well as stress concentration factor (SCF) requirements, follow selection of the system configuration. API RP 2RD guided riser string design and analysis, while TRA design used API RP 2A-WSD. The 18-in. OD piping components in the TRA used ASME B31.4.

Riser response

Since the riser and buoyancy can lie away from the wave zone and surface currents, direct wave loading on the system is low. The flexible jumper connecting the vertical section of the riser to the floating production unit decouples riser motions from vessel excursions and first order motions. Current and vessel offset drive riser response, causing increased loading in the gooseneck and also at the riser's lower end. Local strengthening of the components, however, can address this increased loading.

At both ends of the flexible jumper, bend stiffeners keep the curvatures of the flexible pipe within allowable limits. Plots of typical bending moment distribution along the riser's length in extreme storm conditions show two peaks; one at the riser base, the other at the interface with the TRA. Large bending loads are present at both ends of the riser, but special components such as taper joints control the curvature and stress, bringing the stress ratios at the ends lower than those found at the riser standard joints.

The free-hanging flexible jumper load case proved important due to the high loads and stresses caused by this survival condition. Sensitivity analysis showed hydrodynamic drag amplification due to VIV inducing higher loadings (shear forces, bending moments, von Mises stress) at the riser base. No clashes exist between the FSHR system and adjacent lines (mooring line No. 16 and the 7-in. production flexible riser) for the load cases considered.

There were also no clashes between the FSHR flexible jumper and the P-52 hull during both intact and damaged-pontoon conditions for the load cases considered. Sensitivity analysis shows the parameters studied to have no impact on minimum clearance.

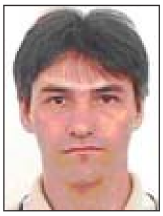
Fig. 4 shows the positions of the BC's top in the horizontal plane for 24 load cases (Operating Design Case 1). The foundation position is (0,0). Fig. 5 also shows the BC's position in the neutral position load case (FJ installed, system subject to only gravity and buoyancy loads).

Acknowledgment

The authors thank Petrobras management for clearance to publish this work. ✦

The authors

Francisco E. Roveri (roveri@petrobras.com.br) is a consultant engineer at the subsea technology group of Petrobras R&D Center, Rio de Janeiro. He has worked for Petrobras for 30 years. He holds an MS (1985) from Federal University of Rio de Janeiro.



A.G.Velten Filho (adolfov-elten@petrobras.com.br) is an equipment engineer at the subsea services department of Petrobras, Rio de Janeiro. He has worked for Petrobras since 2004. He holds a mechanical engineer degree from Federal University of Minas Gerais (1998) and a postgraduate degree in petroleum engineering from PUC-RJ.

V.C. Mello (vcmello@petrobras.com.br) is a contract manager of subsea pipeline projects in the engineering department of Petrobras, Rio de Janeiro. He has worked for Petrobras since 2004. He holds an MS (2004) from Federal University of Rio de Janeiro.

L.F. Marques (luciano.fm@petrobras.com.br) is a project manager of the subsea services department of Petrobras, Rio de Janeiro. He has worked for Petrobras for 29 years. Main activities include offshore platform and module installation, pipeline design and installation, and project management. He holds a mechanical engineering degree from PUC-RJ and an MBA from Federal University of Rio de Janeiro.

Correction

In the article "Natural gas pipeline profits surge; oil flat," by Christopher E. Smith, the Oil Pipelines table (OGJ, Sept. 1, 2008, pp. 65-67) contained errors. Following are corrected versions of the affected portions of the table. The corresponding data have also been updated in the OGJ Energy Database.

Pioneer Pipe Line Co.
MILES
Gathering: --
Crude: --
Products: 563
Total: 563

DELIVERIES ('000 bbl)
Crude: --
Products: 24,806
Total: 24,806

TRAFFIC (million bbl-miles)
Crude: --
Products: 5,162
Total: 5,162

FISCAL ($1,000)
Carrier property: 90,259
Property change: 384
Operating revenue: 23,711
Income: 7,865

2007 totals:
MILES:
Gathering: 14,911
Crude: 46,658
Products: 85,883
Total: 147,452

DELIVERIES ('000 bbl)
Crude: 7,038,083
Products: 6,893,484
Total: 13,931,567

TRAFFIC (million bbl-miles)
Crude: 1,451,245
Products: 2,007,310
Total: 3,458,555

FISCAL: ($1,000)
Carrier property: $35,863,217
Property change: $4,061,205
Operating revenue: $8,993,696
Income: $3,755,352

Product adds corrosion inhibition to its uses

Inhibex 301 kinetic-gas hydrate inhibitor (KHI), which promises performance under a variety of gas types and conditions, now shows—after testing—it to work as a corrosion inhibitor (CI).

Standard CI tests were conducted on metal coupons immersed in 3% sodium chloride to simulate seawater, with 50 ppm and 5,000 ppm (solids) of Inhibex 301 contained in the test brine. Results showed Inhibex 301 to have a high inhibitor efficiency rating of 85% at 50 ppm and 87% at 5,000 ppm, the company reports.

The product is an environmentally friendly V-Cap copolymer that facilitates uninterrupted gas flow in natural gas pipelines whatever the environment, temperature, or working conditions, the firm says.

While Inhibex 301 will not eliminate the need for a separate CI in flow assurance formulations, it will decrease the amount of additional CI required, the firm noted. In addition, its compatibility with most commonly used CIs will help formulators avoid compatibility problems currently occurring between many KHI and CI components.

Source: **International Specialty Products Inc.,** 1361 Alps Rd., Wayne, NJ 07470.

New medium-voltage motor control

The newly released Allen-Bradley OneGear product line provides a range of motor control center and power control center options.

The product line is the next generation of medium-voltage motor control specifically designed for use with full voltage and solid-state, reduced voltage applications, supporting operating voltages up to 15 kv.

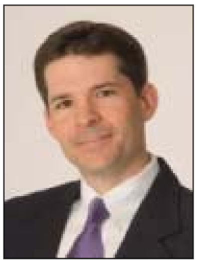
Utilizing vacuum-contactor and circuit-breaker switching technology, the product family offers users a range of flexible product solutions to help meet their application needs. All OneGear products will be available with optional arc-resistant cabinets, which meet IEE C37.20.7 and IEC Type 2 protection.

The product line includes the full voltage nonreversing controller, intelligent protection systems, and 10kV to 15kV SMC Flex controllers featuring ArcShield cabinet design and Allen-Bradley PowerBrick technology.

Source: **Rockwell Automation Inc.,** c/o Rockwell Automation Response Center, 10701 Hampshire Ave. South, Bloomington, MI 55438.

Deepwater Specialists Inc.,

Houston has appointed Trey Lambert president. He will be responsible for overseeing the company's day-to-day operations and developing its business development strategy. Former Pres. Phillip Landry will assume the role of DSI chairman. Lambert has been with DSI for more than 6 years and was formerly the executive vice-president of DSI before moving into his new role. With more than 14 years of experience in the oil and gas industry, his expertise includes electrical and control systems engineering, deepwater oil and gas facility design, construction, commissioning, and facility start-ups. In addition, he has served as either an electrical and instrumentation commissioning engineer or commissioning superintendent on four Gulf of Mexico projects for DSI.


Lambert

Lambert is a part of Louisiana's Professional Engineering and Land Surveyor Board as a registered professional engineer (inactive) in electrical and control systems disciplines, as well as a member of the Instrumentation, Systems, and Automation Society. He has a BS in electrical engineering from Louisiana State University.

DSI, part of international energy services company John Wood Group PLC, is one of the world's leading providers of facilities commissioning services to the international oil and gas industry, function checking and proving the integrity of all systems after construction is completed and prior to the introduction of hydrocarbons.

Wood Group is an international energy services company, providing a range of engineering, production support, maintenance management, and industrial gas turbine overhaul and repair services to the oil and gas and power generation industries worldwide.

Alliance Engineering,

Houston, has promoted Charles W. (Chuck) Law Jr. to vice-president of its onshore business unit. He has more than 28 years of experience in the natural gas industry and has been with Alliance since 2004, most recently as general manager of its Denver office. Law's 28-year career encompasses senior engineering and management positions with other engineering as well as gas transmission companies. He is a registered professional engineer in Colorado and a certified project management professional. Since 2001 he has been an instructor for both the Gas Machinery Research Council and the Gas Technology Institute.

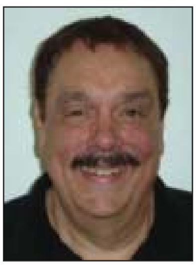

Law

Alliance, part of international energy services company John Wood Group PLC, is an independent services provider to the domestic and international oil and gas industry, specializing in engineering, design, procurement, project management, and construction management of onshore and offshore upstream oil and gas facilities and structures. Capabilities range from feasibility studies through complete turnkey installations.

Wood Group is an international energy services company, providing a range of engineering, production support, maintenance management, and industrial gas turbine overhaul and repair services to the oil and gas and power generation industries worldwide.

Gremada Industries Inc.,

Houston, has named James P. Kowske president of its subsidiary Laser Cladding Services Ltd. In addition to the new appointment, Kowske will continue in his role as vice-president of sales and marketing for Gremada Industries. Previously, he served as Gremada and LCS vice-president of sales and marketing, where he was responsible for overseeing marketing, product, and channel development, as well as strategic planning. Kowske has 35 years of experience in the manufacturing industry and has held several senior management roles for Blackmer, a Dover company; Vickers Inc.; Ace Controls; and Heritage Hydraulics. He has a BA in marketing from Lewis University and has continuing education courses in international marketing from the University of Chicago and Thunderbird School of Global Management. Kowske maintains memberships in the American Marketing Association and is an active participant in The Remanufacturing Institute.


Kowske

LCS provides high-quality laser cladding technology for the oil and gas, mining, food, chemical, and fluid-handling processing markets.

Technip,

Paris, has appointed Julian Waldron chief financial officer. He is also a member of Technip's executive committee. Waldron succeeds Olivier Dubois, Technip CFO since June 2002, who is leaving the company to give a new direction to his career. Waldron previously was CFO at Thomson SA from 2001 and Thomson interim CEO from March 2008 to August 2008. He started his career at UBS Warburg, where he spent 14 years. Waldron is a graduate of Cambridge University.

Technip is a world leader in project management, engineering, and construction for the oil and gas industry, offering a comprehensive portfolio of innovative solutions and technologies.

LECG,

Emeryville, Calif., has appointed veteran energy consultant Paul O'Rourke managing director and the head of its energy practice. He has more than 30 years of experience in energy consulting, including extensive experience working in North America, Europe, the Middle East, and Asia Pacific regions. He will be based in LECG's Cambridge, Mass., office. O'Rourke has worked extensively in all segments of the energy industry, including oil, natural gas, coal, electricity, and renewable resources. Since 1985, he has managed energy practices at Putnam, Hayes & Bartlett, CRA International, and Booz Allen Hamilton. He has also worked with trade associations, including the Electric Power Research Institute, Edison Electric Institute, and the Gas Research Institute. His experience includes strategy development, technology and market assessment, marketing management, and organization assessment. O'Rourke has an MBA in finance and marketing from the Wharton School of the University of Pennsylvania and a BS in chemistry from Stanford University.

LECG is a global expert services and consulting firm, with more than 800 experts and professionals in 33 offices around the world, providing independent expert testimony, original authoritative studies, strategic advisory, and financial advisory services to clients including Fortune Global 500 corporations, major law firms, and local, state, and federal governments and agencies worldwide.

Halliburton,

Houston, has inaugurated its manufacturing and technology center in Singapore, marking the company's second expansion in the Asia-Pacific region this year. The center produces sophisticated electronic sensors used in the company's signature logging-while-drilling tools and openhole wireline logging services. The facility also serves as a repair and maintenance facility for drilling tools used throughout the region. The 20,252 sq m facility is located in the Jurong industrial area in western Singapore and hosts production, technology research and development, logistics, and operations activities. At peak activity, about 400 people will work in this facility and will include PhD-level physicists, scientists, and engineers as well as procurement, financial, and logistical support staff. Halliburton has been active in the Eastern Hemisphere energy services market since 1926 and established operations in Singapore in 1973, continually growing to now offer a full range of technology and services across the company's completion and production and drilling and evaluation divisions.

Halliburton is one of the world's largest providers of products and services to the energy industry.

Swagelok Ltd.,

Isle of Man, UK, has commemorated the first phase of expansion of its new 880 sq m, state of the art warehouse at Tromode, Isle of Man. The expansion will enable the streamlining of processes and help the company meet increased demand. Swagelok Ltd. is the Isle of Man operation of Swagelok Co., a leading provider of fluid system technologies. Its manufacturing helps to complete the company's piping and regulator product offering for the oil, gas, and petrochemical industries. From the Isle of Man facility, Swagelok also serves local niche markets that require quick turnaround on high-added-value and specialized products.

Swagelok Co., headquartered in Solon, Ohio, is a major developer and provider of fluid system solutions, including products, assemblies, and services for the oil and gas, power, petrochemical, alternative fuels, research, instrumentation, pharmaceutical, and semiconductor industries.

Sensornet,

Elstree, UK, has appointed Dan Watley chief technology officer and Peter Kean vice-president, production and technology.

Watley

Watley will be responsible for establishing Sensornet's technical vision and leading all aspects of the company's technology development through research collaborations and strategic partnerships. He will also be responsible for the management and enforcement of intellectual property rights. He has authored 15 journal and conference papers and has filed seven patents to date. Watley joined Sensornet in 2002 after 10 years with Nortel Networks, where he was involved in the research and development of optical communications systems. Upon joining Sensornet, he was responsible for the development of Distributed Temperature Strain Sensing technology before accepting responsibility for coordinating the development of the company's entire product range. Watley is a chartered engineer with a masters and PhD from Cambridge University.

Kean has more than 15 years of experience in research and development of fiber optic systems. He will be responsible for the execution of the company's technology development, bringing new products to market, as well as production of the company's instruments and customer support management. Kean previously worked for Nortel Networks, where he was involved in product development for fiber optic communications systems. Since joining Sensornet in 2003, he has been responsible for the production of the company's Distributed Temperature Sensing product range. Kean has authored more than 20 journal and conference papers and is a co-inventor on two patents. He is a member of the Institution of Engineering and Technology and Institute of Physics, holds a PhD from St Andrews University, Scotland, and has worked within both university and industrial organizations.

Kean

Geokinetics Inc.,

Houston, has appointed T. Diane Anderson to the newly created position of vice-president, general counsel, and corporate secretary. She will be responsible for the oversight of legal affairs worldwide, working closely with the board of directors, executive management, and operations teams. Previously, Anderson served as Geokinetics' corporate counsel and secretary since June 2007 and as corporate counsel since January 2007. Prior to that, she served in a consulting capacity for Geokinetics from August 2006 until January 2007, focused on SEC reporting and corporate governance and compliance matters. She has more than 14 years of corporate securities, business transactional and regulatory experience. Anderson brings leadership experience in both legal and business roles, having worked closely with executive management teams and boards of directors in leading initiatives related to strategic planning, corporate development, mergers and acquisitions, intellectual property strategy, corporate governance and compliance, and SEC reporting with several large public companies, including El Paso Corp., BMC Software, and TXU. Anderson has BA and JD degrees from Southern Methodist University and an MBA in finance from Dallas Baptist University.

Geokinetics is a leading global provider of seismic acquisition and high-end seismic data processing services to the oil and gas industry.

Imports of crude and products

	— Districts 1-4 —		— District 5 —		Total US		
	10-24 2008	10-17 2008	10-24 2008	10-17 2008	10-24 2008	10-17 2008	*10-26 2007
	1,000 b/d						
Total motor gasoline	823	1,062	8	0	831	1,062	1,238
Mo. gas. blending comp.	625	744	0	0	625	744	611
Distillate	273	181	0	0	273	181	325
Residual	345	108	0	78	345	186	235
Jet fuel-kerosine	34	79	4	6	38	85	174
Propane-propylene	137	243	8	5	145	248	212
Other	642	737	84	145	726	882	932
Total products	**2,879**	**3,154**	**104**	**234**	**2,983**	**3,388**	**3,727**
Total crude	**9,224**	**9,354**	**1,113**	**1,046**	**10,337**	**10,400**	**9,381**
Total imports	**12,103**	**12,508**	**1,217**	**1,280**	**13,320**	**13,788**	**13,108**

*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

	*10-31-08	*11-2-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	72.37	101.45	–29.08	–28.7
Brent crude	60.65	71.76	–11.11	–15.5
Crack spread	11.72	29.69	–17.97	–60.5
FUTURES MARKET PRICES				
One month				
Product value	70.15	100.95	–30.80	–30.5
Light sweet crude	65.44	93.57	–28.13	–30.1
Crack spread	4.71	7.38	–2.67	–36.2
Six month				
Product value	77.96	103.68	–25.72	–24.8
Light sweet crude	68.31	89.04	–20.73	–23.3
Crack spread	9.65	14.64	–4.99	–34.1

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

Purvin & Gertz LNG netbacks—Oct. 31, 2008

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	10.90	9.55	10.02	9.44	9.30	9.94
Everett	5.43	3.62	5.16	3.71	4.16	5.72
Isle of Grain	9.82	8.28	9.52	8.17	8.90	9.49
Lake Charles	3.90	2.09	3.72	2.26	2.49	4.39
Sodegaura	9.56	12.49	9.82	12.16	11.37	8.82
Zeebrugge	11.60	9.43	11.00	9.32	10.06	11.00

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

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	13,140	48,980	27,477	8,489	49,285	13,790	4,499
PADD 2	61,283	48,296	17,928	6,610	26,884	1,375	23,372
PADD 3	170,330	65,146	32,125	11,346	35,625	17,570	29,705
PADD 4	14,372	6,455	2,254	580	2,908	319	[1]2,667
PADD 5	52,748	26,113	20,733	8,966	11,927	5,568	—
Oct. 24, 2008	**311,873**	**194,990**	**100,517**	**35,991**	**126,629**	**38,622**	**60,243**
Oct. 17, 2008	**311,380**	**196,497**	**101,016**	**36,579**	**124,304**	**37,359**	**61,111**
Oct. 26, 2007[2]	**312,683**	**195,132**	**89,980**	**41,543**	**135,279**	**36,958**	**61,931**

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

Refinery report—Oct. 24, 2008

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,520	1,514	2,145	111	476	108	60
PADD 2	3,211	3,182	2,007	176	1,014	47	211
PADD 3	6,979	7,038	2,773	604	2,186	281	575
PADD 4	562	560	300	23	170	11	[1]143
PADD 5	2,757	2,557	1,623	376	586	153	—
Oct. 24, 2008	**15,029**	**14,851**	**8,848**	**1,290**	**4,432**	**600**	**989**
Oct. 17, 2008	**14,925**	**14,562**	**8,961**	**1,388**	**4,439**	**488**	**1,021**
Oct. 26, 2007[2]	**15,034**	**14,927**	**8,917**	**1,407**	**4,115**	**687**	**1,096**
	17,610 Operable capacity		**85.3% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 10-29-08	Pump price* 10-29-08	Pump price 10-31-07
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	221.3	267.8	285.7
Baltimore	230.7	272.6	275.6
Boston	224.5	266.4	270.6
Buffalo	190.8	251.7	285.7
Miami	212.6	264.2	304.7
Newark	223.7	256.3	275.3
New York	209.9	270.8	285.6
Norfolk	213.4	251.8	270.6
Philadelphia	217.7	268.4	280.7
Pittsburgh	219.1	269.8	282.6
Wash., DC	232.3	270.7	289.5
PAD I avg	217.8	264.6	282.4
Chicago	206.2	270.6	305.5
Cleveland	208.0	254.4	284.1
Des Moines	210.3	250.7	280.7
Detroit	205.9	265.3	294.1
Indianapolis	200.9	260.3	294.1
Kansas City	204.7	240.7	273.9
Louisville	219.8	260.7	294.1
Memphis	204.9	244.7	270.7
Milwaukee	214.0	265.3	299.0
Minn.-St. Paul	210.6	254.6	293.0
Oklahoma City	185.4	220.8	269.8
Omaha	188.2	233.5	281.3
St. Louis	211.5	247.5	266.6
Tulsa	189.1	224.5	264.2
Wichita	197.4	240.8	268.0
PAD II avg	203.8	249.0	282.6
Albuquerque	214.5	250.9	283.5
Birmingham	193.4	232.7	275.4
Dallas-Fort Worth	201.7	240.1	265.7
Houston	188.7	227.1	270.7
Little Rock	198.4	238.6	270.6
New Orleans	215.5	253.9	272.7
San Antonio	207.7	246.1	269.7
PAD III avg	202.8	241.3	272.6
Cheyenne	232.1	264.5	279.9
Denver	249.4	289.8	295.5
Salt Lake City	231.6	274.5	291.0
PAD IV avg	237.7	276.3	288.8
Los Angeles	238.9	306.0	312.9
Phoenix	255.6	293.0	271.8
Portland	261.3	304.7	302.6
San Diego	245.9	313.0	322.9
San Francisco	251.0	318.1	335.3
Seattle	247.1	303.0	312.1
PAD V avg	250.0	306.3	309.6
Week's avg.	**216.3**	**261.9**	**285.2**
Oct. avg.	**272.3**	**317.6**	**280.9**
Sept. avg.	**322.7**	**367.2**	**280.4**
2008 to date	**306.1**	**350.2**	—
2007 to date	**230.4**	**274.0**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

Spot market product prices	10-24-08 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	169.70
Gulf Coast	142.95
Los Angeles	160.84
Amsterdam-Rotterdam-Antwerp (ARA)	146.60
Singapore	155.24
Motor gasoline (Reformulated-regular)	
New York Harbor	163.20
Gulf Coast	149.20
Los Angeles	166.84
Heating oil No. 2	
New York Harbor	195.77
Gulf Coast	192.06
Gas oil	
ARA	202.49
Singapore	178.33
Residual fuel oil	
New York Harbor	112.21
Gulf Coast	118.76
Los Angeles	184.69
ARA	134.61
Singapore	116.36

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

BAKER HUGHES RIG COUNT

	10-31-08	11-2-07
Alabama	5	7
Alaska	8	9
Arkansas	57	49
California	45	42
Land	45	41
Offshore	0	1
Colorado	124	114
Florida	1	0
Illinois	1	0
Indiana	2	2
Kansas	13	14
Kentucky	12	8
Louisiana	190	167
N. Land	88	60
S. Inland waters	19	26
S. Land	29	34
Offshore	54	47
Maryland	0	1
Michigan	2	1
Mississippi	16	9
Montana	9	10
Nebraska	0	0
New Mexico	91	69
New York	4	8
North Dakota	85	48
Ohio	10	14
Oklahoma	197	193
Pennsylvania	29	18
South Dakota	1	0
Texas	911	854
Offshore	6	8
Inland waters	0	2
Dist. 1	27	22
Dist. 2	34	32
Dist. 3	61	66
Dist. 4	89	91
Dist. 5	186	180
Dist. 6	132	116
Dist. 7B	29	32
Dist. 7C	62	62
Dist. 8	125	112
Dist. 8A	26	24
Dist. 9	41	43
Dist. 10	93	64
Utah	36	39
West Virginia	30	32
Wyoming	78	75
Others—NV-4; OR-1; TN-3; VA-5; WA-1	14	12
Total US	**1,971**	**1,795**
Total Canada	**443**	**368**
Grand total	**2,414**	**2,163**
Oil rigs	408	335
Gas rigs	1,552	1,455
Total offshore	65	57
Total cum. avg. YTD	**1,883**	**1,761**

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	10-31-08 Rig count	10-31-08 Percent footage*	11-2-07 Rig count	11-2-07 Percent footage*
0-2,500	86	3.4	61	6.5
2,501-5,000	143	51.0	98	59.1
5,001-7,500	273	14.6	232	25.0
7,501-10,000	458	2.4	422	1.6
10,001-12,500	444	1.1	454	2.4
12,501-15,000	383	—	275	—
15,001-17,500	165	—	108	—
17,501-20,000	77	—	68	—
20,001-over	31	—	34	—
Total	**2,060**	**6.4**	**1,752**	**7.8**
INLAND	31		38	
LAND	1,972		1,663	
OFFSHORE	57		51	

*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]10-31-08	[2]11-2-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	19
Alaska	682	709
California	658	659
Colorado	62	66
Florida	5	6
Illinois	27	27
Kansas	103	108
Louisiana	999	1,200
Michigan	14	15
Mississippi	59	59
Montana	96	94
New Mexico	163	162
North Dakota	125	129
Oklahoma	173	172
Texas	1,262	1,334
Utah	52	53
Wyoming	148	148
All others	65	75
Total	**4,712**	**5,035**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	10-31-08 $/bbl*
Alaska-North Slope 27°	110.67
South Louisiana Sweet	71.00
California-Kern River 13°	54.35
Lost Hills 30°	62.75
Wyoming Sweet	52.81
East Texas Sweet	63.75
West Texas Sour 34°	59.75
West Texas Intermediate	64.25
Oklahoma Sweet	64.25
Texas Upper Gulf Coast	60.75
Michigan Sour	57.25
Kansas Common	63.25
North Dakota Sweet	54.00

*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]	10-24-08
United Kingdom-Brent 38°	65.54
Russia-Urals 32°	64.45
Saudi Light 34°	63.93
Dubai Fateh 32°	60.99
Algeria Saharan 44°	67.81
Nigeria-Bonny Light 37°	70.34
Indonesia-Minas 34°	71.45
Venezuela-Tia Juana Light 31°	66.66
Mexico-Isthmus 33°	66.55
OPEC basket	66.82
Total OPEC[2]	64.38
Total non-OPEC[2]	64.59
Total world[2]	64.48
US imports[3]	62.81

[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]

	10-24-08	10-17-08	10-24-07	Change, %
		bcf		
Producing region	938	918	1,039	–9.7
Consuming region east	2,004	1,985	1,994	0.5
Consuming region west	451	444	457	–1.3
Total US	**3,393**	**3,347**	**3,490**	**–2.8**
	Aug. 08	**Aug. 07**	**Change, %**	
Total US[2]	**2,867**	**3,017**	**–5.0**	

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

Statistics

Worldwide crude oil and gas production

	Aug. 2008	July 2008	8 month average production 2008	8 month average production 2007	Change vs. previous year Volume	Change vs. previous year %	Aug. 2008	July 2008	Cum. 2008
	Crude, 1,000 b/d						Gas, bcf		
Argentina	630	618	602	629	–27	–4.3	130.0	134.2	1,003.13
Bolivia	40	40	40	44	–4	–9.1	43.0	43.0	336.60
Brazil	1,840	1,824	1,801	1,755	45	2.6	39.0	38.0	295.00
Canada	2,663	2,673	2,561	2,616	–55	–2.1	450.1	470.2	3,766.76
Colombia	600	580	573	522	51	9.8	24.0	24.0	181.00
Ecuador	500	500	500	501	–1	–0.3	1.0	1.0	8.00
Mexico	2,759	2,782	2,835	3,123	–288	–9.2	216.0	214.0	1,653.80
Peru	113	118	110	113	–3	–3.0	11.4	11.5	74.90
Trinidad	115	110	113	123	–10	–8.1	117.0	115.0	921.72
United States	4,961	5,110	5,107	5,097	10	0.2	1,856.0	1,864.0	14,382.00
Venezuela[1]	2,310	2,310	2,358	2,390	–33	–1.4	75.0	75.0	594.00
Other Latin America	81	81	80	80	1	1.0	5.5	5.5	43.62
Western Hemisphere	**16,612**	**16,745**	**16,678**	**16,992**	**–314**	**–1.8**	**2,968.0**	**2,995.4**	**23,260.52**
Austria	16	16	16	17	–1	–7.3	4.9	4.9	40.10
Denmark	285	288	290	313	–23	–7.5	25.0	26.5	226.83
France	20	20	20	19	1	4.1	2.8	2.9	23.64
Germany	54	65	61	68	–8	–11.2	41.6	42.3	362.78
Italy	95	95	102	109	–7	–6.6	25.0	25.0	201.00
Netherlands	35	30	35	41	–6	–14.9	140.0	140.0	1,890.00
Norway	2,057	2,302	2,163	2,284	–121	–5.3	208.0	266.7	2,281.05
Turkey	43	42	41	41	—	–0.4	—	—	—
United Kingdom	1,105	1,317	1,408	1,528	–120	–7.9	172.9	152.8	1,718.09
Other Western Europe	4	4	4	4	—	–8.0	1.2	0.9	14.83
Western Europe	**3,715**	**4,178**	**4,139**	**4,425**	**–287**	**–6.5**	**621.4**	**662.0**	**6,758.31**
Azerbaijan	700	1,100	937	853	84	9.9	35.0	33.0	256.00
Croatia	16	15	15	16	–1	–5.7	5.6	5.7	44.99
Hungary	14	15	15	16	–2	–10.1	8.2	7.7	58.56
Kazakhstan	1,400	1,300	1,380	1,075	305	28.4	85.0	85.0	628.00
Romania	90	90	94	99	–5	–5.2	18.0	18.0	141.00
Russia	9,760	9,740	9,739	9,883	–144	–1.5	1,650.0	1,700.0	15,250.00
Other FSU	400	400	400	450	–50	–11.1	400.0	400.0	3,690.00
Other Eastern Europe	46	43	49	47	1	2.7	15.9	15.0	132.71
Eastern Europe and FSU	**12,426**	**12,703**	**12,628**	**12,439**	**189**	**1.5**	**2,217.6**	**2,264.5**	**20,201.26**
Algeria[1]	1,370	1,360	1,380	1,345	35	2.6	280.0	280.0	2,205.00
Angola[1]	1,897	1,948	1,920	1,655	265	16.0	5.0	5.0	39.60
Cameroon	85	84	86	84	2	2.6	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	610	610	618	641	–24	–3.7	135.0	135.0	1,080.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.48
Gabon	240	240	233	230	3	1.1	0.3	0.3	2.45
Libya[1]	1,650	1,680	1,729	1,695	34	2.0	34.0	34.0	270.00
Nigeria[1]	1,980	2,020	1,950	2,158	–208	–9.6	85.0	85.0	633.00
Sudan	500	500	485	469	16	3.5	—	—	—
Tunisia	90	90	84	99	–16	–15.8	8.0	7.8	45.89
Other Africa	217	217	217	218	–1	–0.5	9.1	9.1	71.30
Africa	**9,219**	**9,329**	**9,281**	**9,174**	**107**	**1.2**	**556.5**	**556.3**	**4,347.72**
Bahrain	170	170	170	173	–3	–1.7	25.0	25.0	193.88
Iran[1]	4,100	3,970	3,970	3,915	55	1.4	300.0	290.0	2,350.00
Iraq[1]	2,330	2,470	2,417	1,986	431	21.7	20.0	20.0	155.20
Kuwait[1,2]	2,615	2,635	2,609	2,411	198	8.2	45.0	45.0	328.00
Oman	710	730	721	715	6	0.9	60.0	60.0	466.00
Qatar[1]	880	880	858	800	58	7.2	190.0	190.0	1,445.00
Saudi Arabia[1,2]	9,365	9,365	9,133	8,500	633	7.4	225.0	225.0	1,745.00
Syria	390	390	386	391	–5	–1.3	18.0	18.0	141.00
United Arab Emirates[1]	2,660	2,660	2,649	2,574	75	2.9	130.0	130.0	1,055.00
Yemen	300	310	310	344	–34	–9.8	—	—	—
Other Middle East	—	—	—	—	—	–10.0	10.7	11.1	83.86
Middle East	**23,520**	**23,580**	**23,222**	**21,808**	**1,413**	**6.5**	**1,023.7**	**1,014.1**	**7,962.94**
Australia	464	464	440	458	–18	–3.8	116.9	121.6	894.30
Brunei	160	148	161	179	–19	–10.5	34.0	32.9	266.48
China	3,784	3,818	3,799	3,758	42	1.1	224.0	218.4	1,914.20
India	683	672	675	683	–8	–1.1	87.2	86.0	682.27
Indonesia[1]	870	860	861	843	19	2.2	200.0	200.0	1,600.00
Japan	15	16	17	17	—	2.6	9.9	10.1	86.79
Malaysia	770	700	753	745	8	1.0	150.0	140.0	1,165.00
New Zealand	57	54	59	25	34	135.8	15.0	14.0	103.90
Pakistan	65	66	67	68	–1	–2.1	120.8	123.7	983.39
Papua New Guinea	40	40	42	49	–7	–14.3	1.0	1.0	7.70
Thailand	240	228	227	212	14	6.7	45.0	44.0	357.00
Vietnam	250	280	285	315	–30	–9.5	15.0	15.5	120.00
Other Asia-Pacific	42	41	40	35	5	14.5	99.5	99.0	784.06
Asia-Pacific	**7,440**	**7,388**	**7,425**	**7,386**	**39**	**0.5**	**1,118.3**	**1,106.2**	**8,965.10**
TOTAL WORLD	**72,931**	**73,923**	**73,372**	**72,224**	**1,148**	**1.6**	**8,505.5**	**8,598.5**	**71,495.85**
OPEC	32,527	32,658	32,332	30,271	2,061	6.8	1,590.0	1,580.0	12,427.80
North Sea	3,466	3,925	3,879	4,144	–265	–6.4	447.6	487.6	4,790.23

[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.

NOVEMBER 18 - 20, 2008 | THE HOUSTONIAN | HOUSTON, TEXAS

www.accessanalyst.net

Targeting the Buy-Side Community

Join Us In 2008 For The 2nd Annual Houston Energy Financial Forum

Don't miss this opportunity to hear public energy companies present operations and up-to-date financials in "the energy capital of the world" Houston, TX. This forum's unique neutral format, along with PennWells 106 years of industry coverage, makes this forum an annual "must attend" event.

Last year the Houston Energy Financial Forum had over 560 on-site attendees, 1,010 webcast registrants, 55 presenting companies and 13 sponsors for its inaugural event. PennWell will build upon this success by targeting more institutional investors, expanding the presenter field to over 90, and develop more networking opportunities between analysts and presenters.

PennWell and the Oil & Gas financial Journal are pleased to present this event and we look forward to seeing you at the 2008 Houston Energy Financial Forum. Join us in making this one of the oil and gas industry's premier investment forums.

For more information, visit www.accessanalyst.net

Hosted By: CIT CAPITAL REDEFINED

Exclusive Sponsor: أرامكو السعودية Saudi Aramco

Communications Partner: PR Newswire United Business Media

Event Sponsors: CAMERON, FLOTEK, Legal Knowledge. Human Wisdom. GARDERE, SMT, Turnberry Tower

Participating Sponsor: Bucking Horse Energy, HALLIBURTON, TC Technologies, CyrusOne

Flagship Media Sponsor: OIL&GAS FINANCIAL JOURNAL

Supported by: OIL&GAS JOURNAL, Offshore, Oil, Gas & Petrochem EQUIPMENT

Owned & Produced by: PennWell

Your marketplace for the oil and gas industry

DEADLINE for CLASSIFIED ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to CLASSIFIED SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-831-9776,
email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $375 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED CLASSIFIED: $4.00 per word per issue. 10% discount for three or more CONSECUTIVE issues. $80.00 minimum charge per insertion. Charge for blind box service is $54.00 No agency commission, no 2% cash discount. Centered/Bold heading, $9.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $80.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN CLASSIFIED SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR CLASSIFIED AD.*

EMPLOYMENT

SAMSUNG

SAMSUNG HEAVY INDUSTRIES

LNG Design engineering & Research

SAMSUNG Heavy Industries Co., Ltd. (SHI) located in Geoje City in South Korea is world-renowned industry building FPSOs, LNG FPSOs, Production Platforms, Drillships and other special offshore vessels. For further information please visit us at www.shi.samsung.co.kr

SHI wishes to recruit experienced Engineers in the following fields.

1. LNG liquefaction Design Engineering (Process/Mech/Instrumentation)
- SHI has a number of positions available in our LNG Design Engineering team. You will possess a Bachelors degree as a minimum with 10 years relevant LNG design experience in the petrochemical and/or offshore oil and gas industry. Your strong communication skills and technical knowledge will allow you to coordinate interfaces between the production and project management teams. FPSO, LNG liquefaction plant experience would be highly desirable.
- Available position: Process/Chemical/Mechanical/Instrumentation Engineer.

2. Research Engineer
- The position calls for a Chemical / Petrochemical Engineer processing a Masters degree. Ideally you will have +5 years research and design experience in the LNG industry combined with oil and gas process experience. In addition you will be well versed in dynamic simulation tools such as HYSYS and be familiar with LNG liquefaction plant operations.

SHI offers competitive remuneration, accommodation, international exposure, Exciting team environment, challenging projects.
Qualified candidates may send their resume including contact information and compensation requirement to the e-mail ID given below so as to reach on or before 31st December 2008. Selected candidates will be contacted by e-mail to arrange interview. Contact us if any further information is required.

E-Mail: hojung.park@samsung.com
Address: 530, Jangpyung-dong, Geoje, South Korea 656-710
Telephone: 82 55 630 3167

Weatherford in Houston TX seeks Global Reliability Technical Coordinator. Req's: Master's in Mech. Eng. & 2 yrs in job or as MWD/LWD Field Eng w/exposure to design & dvlpmnt of MWD/LWD tools & proj. engineering computations.
Please fax or e-mail resume to HR at 281-260-4732 or Joanna.wilson@weatherford.com

Norgas Americas Inc., Houston, TX, seeks a Chartering Manager to develop, implement and manage existing and potential business opportunities in the oil and gas shipping market. International travel required up to 10% of the time. Mail resume to: Norgas Americas Inc., Two Houston Center, 909 Fannin, Ste. 3300, Houston, TX 77010 <Job Code NAI/CM>

E-mail your ad to:

glendah@pennwell.com

EQUIPMENT FOR SALE

FOR SALE / RENT
5.2 MW MOBILE GEN SETS
CALL: 800-704-2002

SOLAR TAURUS 60

- GAS - LOW NOx (OIL)
- 60 Hz - 13.8KV or 50 Hz - 11KV
- LOW HOUR - SOLAR SERVICED

DIESELS • TURBINES • BOILERS

24/7 EMERGENCY SERVICE
IMMEDIATE DELIVERY

www.wabashpower.com | info@wabashpower.com
Phone: 847-541-5600 Fax: 847-541-1279

wabash POWER EQUIPMENT CO.
444 Carpenter Avenue, Wheeling, IL 60090

NATCO Producing Solutions

Water, Oil and Gas Treatment/Conditioning Equipment

For Sale, Lease, Contract Service
Separators, Hydrocyclones, Float Cells, Filtration, Electrostatic Oil Treaters, Amine Units, Glycol Units, JT-Plants, Refrigeration Units, LACT Units

For Information Call 713.895.1744
www.NATCOGroup.com

REFRIGERATION AND J.T. PLANTS

7.5 MMSCFD, 1000 PSI, NATCO

4.0 MMSCFD, 1000 PSI, NATCO

6.5 MMSCFD, 1250 PSI X 400 PSI, H&H J.T.

2.0 MMSCFD, 1000 PSI, PROCESS EQPT.

OTHERS AVAILABLE

PLEASE CALL 318-425-2533, 318-458-1874

regardres@aol.com

EQUIPMENT FOR SALE

Process Units

Condensate Stabilizer
6,500 BPSD

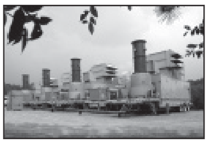
200 T/D Methanol Plant

FCCU UOP
17,000 – 22,000 BPSD

BASIC Engineering, Inc.
Please Call: 713-674-7171
Tommy Balke
tbalkebasic1@aol.com
www.basicengineeringinc.com

FCC Unit -- 10,500 bpd
Alkylation Unit -- 6,500 bpd
Both Units Completed 1996
Excellent Condition
Doug Wood
Plant Process Equipment
281-333-7700
dwood@plant-process.com

Solar Taurus 60



MOBILE GEN SETS
5.2 MW
Solar Maintained
Low Time

- 7 Units (Gen 1) & (Gen 2)
- All Natural Gas
- Low Nox 25 ppm
- Mobile PCR U.G. Switch gear
- 60 Hz • 13.8 kV
- 50 Hz Conversion Available

Mid America Engine, Inc.
662-895-8444 · Fax: 662-895-8228
205-590-3505 · Fax: 205-590-3885
Keith: kcoleman@maegen.com
Art: asigler@maegen.com
Greg: gposey@maegen.com
Wesley: wtuggle@maegen.com

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS: 10 - 600 MMCFD
AMINE PLANTS: 120 – 1,000 GPM
SULFUR PLANTS: 10 - 180 TPD
FRACTIONATION: 1000 – 25,000 BPD
HELIUM RECOVERY: 75 & 80 MMCFD
NITROGEN REJECTION: 25 – 80 MMCFD
ALSO OTHER REFINING UNITS
We offer engineered surplus equipment solutions.
Bexar Energy Holdings, Inc.
Phone 210 342-7106
Fax 210 223-0018
www.bexarenergy.com
Email: info@bexarenergy.com

Read OGJ Classifieds

EMPLOYMENT

GE Oil & Gas

Whether it's managing the world's largest LNG compression trains, re-injecting high sulfur gas, or enhancing the safety and productivity of oil and gas pipelines in some of the harshest environments on earth, GE Oil & Gas is addressing the biggest engineering and application challenges of our time.

As a Field Service Engineer you will manage site activities, from planning, assigning and supervising resources to providing specialist technical assistance, acting as a single point of contact between customers and GE Oil & Gas headquarters. A qualified electrical or mechanical engineer, with a good knowledge of oil and gas equipments and experience in the field, you'll have the analytical and problem solving skills to implement technical drawings and lead individual and group tasks.

This is a critical moment for the industry and your talent is crucial. That's why we won't just offer you a first rate salary and benefits package. After all, you should expect that from any top employer in this field. At GE we go further to reward our best people, operating a policy of always promoting from within before any external sources are taken into consideration. This, combined with our industry-leading training and development programmes, ensures that your rise within GE is as far-reaching as your imagination.

Field Service Engineers
As part of the rapid expansion of the technology base of GE Oil and Gas, we're looking for Field Service Engineers with extensive experience working with Gas turbines, compressors & rotating equipment. You must be prepared to travel on a regular basis between sites.

To discover more about an environment where new ideas, enthusiasm and diversity are supported by competitive rewards and outstanding international prospects for career development, send your CV and covering letter to **FSEJOBS@ge.com**

GE is an equal opportunities employer

GE imagination at work

Classified Advertising

EQUIPMENT FOR SALE

50,000 BOPD 150 MMCFD
OIL AND GAS INITIAL PRODUCTION FACILITY

Components Mfg in 2004, Engineered and Constructed by Expro

FAS, Export Packed, Customs Cleared, Port of Korsakov, Sakhalin Island Russia
Available for Export Mid-December 2008—Mid January 2009

Included:

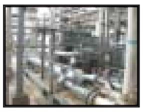
- Two Wauk L7044GSI Ariel JGK-4 Gas Compressor Units
- Two Wauk L36GSID Bingham 2x3x6.5A VCR Crude Export Pumps
- Two Gas Generator Sets CAT G3516 LE 975 kW 400V Units 50 hertz
- Low Temperature Separator Unit
- Ethylene Glycol Regenerator Unit
- Two Steam Generator Units
- Crude Oil Cooler Unit
- Gas Inlet Cooler Unit
- Crude Oil Train Unit
- Heater Exchangers/Transfer Pump Skid
- Crude Oil Coalescer & Export Meter Skid
- NGL Injection Pumps Skid
- Gas Inlet Separator Skid

Offered by Material Management Resources, Inc.
Contact: Dennis K. Burke
Office: (713) 656-5613 Fax: (262) 313-1191
E-Mail: dennis.k.burke@exxonmobil.com
Alternate E-mail: dennisb@materialmg.com

Network INTERNATIONAL
A WORLD OF SURPLUS ENERGY EQUIPMENT ONE SITE

GAS TO LIQUIDS PLANT AUCTION

NOVEMBER 20, 2008



400 BBL/D GAS TO LIQUIDS PILOT PLANT & PLANT TECHNOLOGY PACKAGE

Trey • (713) 590-1623 • TValentino@Networkintl.com

www.OneSiteForEquipment.com

BUSINESS OPPORTUNITY

Want to purchase minerals and other oil/gas interests. Send details to: P.O. Box 13557, Denver, CO 80201.

DRILLING PROSPECTS

WANTED

Oil Drilling prospects. Less than 3,000 ft.
Southwest Minerals, Inc.
Harvey Estes, Pres.
813-376-4075
Harveylv@aol.com

DRILLING PROSPECTS

FIELD DEVELOPMENT PROSPECT FOR SALE

4,074 contiguous, leased acres, Prospect, where oil & gas has been discovered in Roosevelt County, NM. IP 171 bopd from a 50' thick payzone within the San Andres formation at 4,300'. Accepting only written inquiries addressed to P.O. Box 6874, Santa Rosa, CA 95406. Will respond only to inquiries from established O&G companies capable of immediately entering into an aggressive field development project.

CONSULTANTS

MB OPERATING operates, does billing, drilling and completions and workovers. We also seek fund raisers to work with. 817-797-6719.

Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment-120 specialists upstream, downstream gas and biofuels.
Email: contato@expetro.com.br
Web: www.expetro.com.br-Rio de Janeiro, Brazil

Hiring?

Selling Equipment?

Need Equipment?

New Business Opportunity?

Contact: Glenda Harp
+1-918-832-9301 or
1-800-331-4463, ext. 6301
Fax: +1-918-831-9776

Why just tell them you're an expert when you can show them?

Article reprints are a low-cost, credible way to promote your business or technology.

For more information contact Sherry Humphrey at 918.832.9379 or sherryh@pennwell.com.

Advertising Sales / Advertisers Index

Houston
Regional Sales Managers. Marlene Breedlove; Tel: (713) 963-6293, Fax: (713) 963-6228, E-mail: marleneb@pennwell.com. Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com. Mike Moss; Tel: (713) 963-6221, Fax: (713) 963-6228: E-mail: mikem@pennwell.com. PennWell - Houston, 1455 West Loop South, Suite 400, Houston, TX 77027.

Southwest / South Texas/Western States/ Gulf States/Mid-Atlantic
Marlene Breedlove, 1455 West Loop South, Suite 400, Houston, TX 77027; P.O. Box 1941 Houston, TX 77251; Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com.

Northeast/New England/Midwest/North Texas/ Oklahoma/Alaska/Canada
Charlene Burman, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com.

Scandinavia/Denmark/The Netherlands/Middle East/Africa
David Betham-Rogers, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France; Tel: 33 2 33 282584, Fax: 33 2 33 274491; E-mail: davidbr@pennwell.com.

United Kingdom
Linda Fransson, Warlies Park House, Horseshoe Hill Upshire, Essex EN9 3SR, UNITED KINGDOM Tel: +44 (0) 1992 656 665; Fax: +44 (0) 1992 656 700; E-mail: lindaf@pennwell.com.

France/Belgium/Spain/Portugal/Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33 (0)1 3071 1224, Fax: 33 (0)1 3071 1119; E-mail: danielb@pennwell.com, France, Belgium, Spain, Portugal, Southern Switzerland, Monaco.

Germany/Austria/Northern/Switzerland/Eastern Europe/Russia
Sicking Industrial Marketing, Kurt-Schumacher-Str. 16, 59872, Freienohl, Germany. Tel: 49 (0) 2903 3385 70, Fax: 49 (0) 2903 3385 82; E-mail: wilhelms@pennwell.com. Andreas Sicking, Germany, Austria, Northern Switzerland, Eastern Europe, Russia, Former Soviet Union.

Japan
e. x. press Co., Ltd., Hirakawacho TEC Building, 2-11-11, Hirakawa-cho, Chiyoda-ku, Tokyo 102-0093, Japan, Tel: 81 3 3556 1575, Fax: 81 3 3556 1576; E-mail: manami.konishi@ex-press.jp; Manami Konishi.

Brazil
Grupo Expetro/Smartpetro, Att: Jean-Paul Prates and Bernardo Grunewald, Directors, Ave. Erasmo Braga 22710th and 11th floors Rio de Janeiro RJ 20024-900 BRAZIL; Tel: (55-21) 3084 5384, Fax: (55-21) 2533 4593; E-mail: jpprates@pennwell.com.br and bernardo@pennwell.com.br.

Singapore/Australia/Asia-Pacific
Michael Yee, 19 Tanglin Road #09-07, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel: (65) 6 737-2356, Fax: (65) 6 734-0655; E-mail: yfyee@singnet.com.sg. Singapore, Australia, Asia Pacific.

India
Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91-11-6283018/19, Fax: +91-11-6228928; E-mail: rajan@interadsindia.com.

Italy
Vittorio Rossi Prudente, UNIWORLD MARKETING, Via Sorio 47, 35141 PADOVA - Italy; Tel:+39049723548, Fax: +390498560792; E-mail: vrossiprudente@hotmail.com.

EIA: New US gas saved $4 billion in first 7 months

Anyone concerned about imported energy should find useful the simple proposition that raising production lowers imports unless consumption rises by the same amount.

It would seem, in fact, that politicians overtaken by hope for energy independence, which means no imported energy at all, should lead crusades for domestic oil and gas production.

The Editor's Perspective

by Bob Tippee, Editor

Yet most of them use energy independence mainly as a marketing slogan for conservation mandates and subsidization of nonfossil energy.

Energy independence is, in any case, unachievable. It's useful as a concept only as a test for the presence of an adult sense of proportion.

To acknowledge the futility of energy independence, however, is not to deny the value of domestically produced energy.

In an Oct. 22 report, the US Energy Information Administration highlights the value of lowering high-cost imports by raising lower-cost domestic production.

The energy in this case is natural gas, US production of which has undergone what EIA calls "an historic shift."

After 9 years of little change, US gas output rose by 4% in 2007. In the first 7 months of this year, it leapt by 9% year over year.

"The increased production in the United States meant that the country has needed to import less natural gas in 2008 than in 2007, especially in the form of LNG," EIA notes (see the proposition above). "For the first 7 months of 2008, LNG imports fell by 64% compared with the same period in 2007, continuing a trend of reduced imports that started in the second half of 2007."

EIA then estimates the value of producing instead of importing gas.

In the first 7 months of 2008, it says, US wellhead gas prices rose to an average of $9/Mcf. In the same period, LNG sold in Japan for $13.30/Mcf.

At those prices, buying LNG would have cost about $4 billion more than the new US production during January through July, EIA reckons. The savings probably were higher in August and September, when US wellhead gas prices fell and Asian LNG prices rose.

Domestic production is good business, something besides energy that the US now desperately needs.

(Online Oct. 31, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Oil futures post biggest monthly loss

In a surprise rally in the last few moments of trading Oct. 31 on the New York Mercantile Exchange, the front-month December contract for benchmark US light, sweet crudes surged upward to close at $67.81/bbl, up $1.85 for the day. Just 2 days earlier, NYMEX registered the highest 1-day percentage gain in crude prices since June.

Trading for the December contract was volatile Oct. 29 at $63.65-69.24/bbl before it closed at $67.50/bbl, up $4.77 that day, as the Federal Open Market Committee lowered its target for overnight interest rates by a half point to 1%.

"Oil's rise was mainly the result of the US dollar's biggest 1-day fall in 23 years on news that the Fed cut the fund rate," said analysts in the Houston office of Raymond James & Associates Inc. (RJA). "Oil and gas both posted solid gains of 7.6% and 4.6%, respectively, and energy stocks followed suit."

Yet neither rebound could prevent crude futures sales during October from posting the biggest monthly loss for front-month crude prices since that commodity began trading in 1983. At one point, Olivier Jakob at Petromatrix, Zug, Switzerland, said, "West Texas Intermediate came close to but failed to test the support of $60/bbl and finished the week [ended Oct. 31] higher by $3.66/bbl, but most of these gains were made in the final 10 min of the week and of the month. The front-month NYMEX crude price was down 32.6% during October, or $32.83/bbl, for the month and 54% below a record-high of $147.27bbl in July. So far this year, front-month crude prices have tumbled 29.4% on NYMEX."

Jakob said, "[North Sea] Brent was up by $3.27/bbl for the week. Heating oil for December gained $4.80/bbl, and the front-month November contract for reformulated blend stock for oxygenate blending (RBOB) increased by only $1.94/bbl. Natural gas was higher by 5%. WTI is now $28/bbl lower than a year ago, and this was the first in 5 weeks with a higher weekly close."

Heating oil holds the line

Some said the rally apparently began in petroleum products, with an end-of-month squaring of market positions. Jakob said: "Heating oil values continue to hold the oil complex above water and is the only product providing some support to refining margins, but the Commodity Futures Trading Commission data continues to show a dearth of speculative activity on heating oil with positions showing close to no change in the week. For heating oil, all the activity is happening in the commercial section or through small speculators (small speculators are holding more of the open interest in heating oil than large speculators.) In RBOB, large speculators continue the action of last week and are adding to net length and covering short positions while the crack is in negative territory." Meanwhile, The University of Michigan/Reuters index released Oct. 31 showed a fall to 57.6 in late October, compared with a reading of 70.3 in late September. Earlier in October, the reading was down to 57.5.

The US Commerce Department said gross domestic product contracted in the third quarter to the lowest quarterly figure since third quarter 2001. For the most recent quarter, GDP fell at a seasonally adjusted 0.3%/year rate between July and September. The US Energy Information Administration reported US oil use in August was the lowest since December 2001, down 8.4% from the same period a year ago (OGJ Online, July 31, 2008).

RJA analysts said crude prices were lower in early trading Nov. 3 on concerns of continued slowing energy demand. Over the weekend, Chakib Khelil, president of the Organization of Petroleum Exporting Countries, warned that member countries must make further production cuts to stabilize oil prices between $70-80/bbl. "The downward demand pressure is partly a result of continued uncertainties around the global financial crisis, but [the] US presidential election may alleviate some of the uncertainty by providing more clarity around future government policies," said RJA analysts.

Meanwhile, supply disruptions blurred domestic gas production growth in August. The latest US Energy Information Administration's Form-914 natural gas production survey, released Oct. 31, laid out total US volumes averaging 63.3 bcfd in August—up 5.4 bcfd (9.3%) from a year ago. "While volumes fell 100,000 bcfd sequentially, we would point out that production was negatively impacted by hurricane-related (Gustav) shut-ins, which the Mineral Management Service pegs at 300,000 MMcfd, and operational issues (compression, shut-ins, etc.) in Wyoming. While this 'sloppy' data point is 2 months stale, it provides support to the bearish natural gas injection numbers seen in August, running 3.5 bcfd looser (on a weather-adjusted basis)," RJA analysts said.

(Online Nov. 4, 2008; author's e-mail: samf@ogjonline.com)

Atlantis

supplement to:

PennWell Custom Publishing

VP, PennWell Custom Publishing
Roy Markum
roym@pennwell.com

Petroleum Group President
Michael Silber
msilber@pennwell.com

Art Director
Paul Schmitz
pauls@pennwell.com

Editorial
John Lloyd
jlloyd281@comcast.net

Ray Viator
rviator@yahoo.com

Profiles
Robert Kemmy
Rpkem@aol.com

Photography
Marc Morrison
Bpphotoservices@aol.com

Production Manager
Dorothy Davis
dorothyd@pennwell.com

Circulation Manager
Tommie Grigg
tommieg@pennwell.com

PennWell Petroleum Group
1700 West Loop South, Suite 1000
Houston, TX 77027 U.S.A.
713.621.9720

P.C. Lauinger, 1900–1988
Chairman, Frank T. Lauinger
President/CEO, Robert F. Biolchini

PennWell Corporate Headquarters
1421 S. Sheridan Rd.,
Tulsa, OK 74112

Supplement to:

Oil & Gas Journal | Oil & Gas Financial Journal | Offshore

Sponsored by

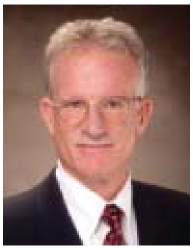
bp

bhpbilliton
resourcing the future

Cover - Atlantis Production Quarters Platform, view from the flaring tower.

Contents

Atlantis, a signature BP-operated project for the ages



"The ultimate measure of the success of Atlantis will be based on a report card turned in many times over during the life of the field. I see first oil only as the critical milestone that marks the beginning of its journey on a path toward remarkable achievements. What I find more intriguing is the very real potential that 10 years after startup we'll wake up and see a fresh article in Oil and Gas Journal that highlights another landmark achieved by Atlantis."

– Greg Sills, Project General Manager, Atlantis

A legendary Greek isle may have inspired the name of BP's Atlantis project in the Gulf of Mexico, but this stunning technological achievement is neither mythical nor ancient. The Atlantis Field is located in the Gulf of Mexico about 185 miles south of New Orleans, Louisiana, in Green Canyon Block 743. The field is in a region known as the Western Atwater Foldbelt and lies beneath a structure known as the Sigsbee Escarpment. The escarpment is a thousands-feet-high steeply sloping hill that tops out in water about 4,400 feet deep, with its base reaching a water depth of just over 7,000 feet as the seabed becomes less contoured.

The Atlantis host facility is located about two nautical miles from the field in adjacent Green Canyon Block 787. Moored in 7,074 feet of water, Atlantis was the world's deepest semisubmersible production facility when installed, and, at a displacement of more than 97,700 tons, it is second in size only to BP's Thunder Horse production, drilling and quarters facility. BP operates Atlantis and holds 56 percent interest in the project, with co-owner BHP Billiton holding the remaining 44 percent interest. The oil and gas is exported to markets ashore via the BP-operated Mardi Gras transportation system, the world's highest capacity deepwater transportation system. Mardi Gras consists of some 490 miles of oil and gas pipelines and is designed to move more than 1 billion barrels of crude oil and 1.5 billion cubic feet of natural gas daily.

The Atlantis host, a production quarters facility (PQ) that is without a drilling rig, is designed to process 200,000 barrels of oil and 180 million cubic feet of natural gas daily. Initial development of the field calls for 16 production wells and four injection wells, with growth into adjacent areas not only expected but planned for from the start of the project. Like many of the fields found in the Gulf of Mexico, more than 60 percent of the Atlantis Field structure lies beneath salt and the Sigsbee Escarpment, making the decision on the type of facility and drilling unit crucial to successful exploitation of this extremely valuable asset.

BP partnered with Global Santa Fe for a purpose-built drilling vessel for Atlantis. Drilling and completion team members worked with Global Santa Fe on the design and construction of the company's new GSF Development Driller II (DD2), and BP's input helped result in a design that delivered more functionality than the basic ability to drill and complete wells and install trees. DD2 has significant construction capabilities that enable it to install and remove major portions of the subsea architecture, and its design allows it to more safely conduct a variety of complex tasks.

Atlantis proudly achieved first oil on October 6, 2007, the highlight of a journey that began in 1998, a journey shrouded in uncertainty and huge risks. A key part of BP's $15 billion investment in the Gulf of Mexico, Atlantis was scheduled to be the fourth of four signature projects to startup, with Holstein, Mad Dog and Thunder Horse preceding it. The high expectations surrounding these world-class developments extended beyond BP, garnering global recognition by a giant banking firm that included them in its report describing 50 energy projects that could change the world.

Time would prove it impossible for the Atlantis team to predict the upcoming, unprecedented changes in technology, the new weather patterns in the Gulf of Mexico and the unforeseen quadrupling of oil prices that spread rate and cost increases across the industry. Through it all the team not only persevered, but used their ingenuity and expertise to reach an exceptional level of success on a world-class project, while confronted by some of the most daunting challenges faced in the energy industry to date.

Development plan confronts uncertainties

January 30, 1998, marked the spud of Green Canyon 699, the discovery well in what would become the At-

Sunset at Atlantis Platform.

lantis Field. It was drilled based on a 2D grid of 3D Kirchoff-method prestack depth migrated seismic data. The results were considered marginal at best by many within BP. The well verified hydrocarbons were present, but in a relatively thin reservoir with only 90 feet of oil over five intervals. Green Canyon, block 699 had penetrated thick sands with multiple oil-water contacts, providing clues that despite sparse initial results from the reservoir, substantial resources might yet be there. The challenges of imaging and drilling through salt on an escarpment in very deep water would draw serious scrutiny by the decision makers at BP who were tasked to approve or reject Atlantis. The capital at risk was significant, even for an energy major and its co-owner.

Drilling the Green Canyon 743-1 appraisal well began on April 22, 2000, and two main sands—about 500 feet of total pay—were revealed. John Oldroyd, a geologist who has served continuously with the Atlantis team since its inception nearly nine years ago, recalls the doubt surrounding the project's prospects as the team prepared for the arduous sanction process with top-level management: "Atlantis was 'teetering on the edge of do-ability' according to one BP vice president, and that was a reasonable assessment based on what we knew at the time and what technology was available to us".

The project team faced the difficult task of creating a viable development plan that would take into account the field's potential while best preparing for the uncertainties that existed in the reservoir. To do this, BP and co-owner BHP Billiton assembled a fully integrated team consisting of a diverse group of personnel with extensive backgrounds in facilities, wells delivery, commercial aspects and—for the first time on a BP deepwater Gulf of Mexico team—subsurface expertise.

Together they developed a comprehensive development plan with four major facets: a reservoir depletion plan, a flexible development concept, an innovative drilling plan and a reservoir management plan. Building on what was learned by earlier BP projects such as Horn Mountain, Holstein and Mad Dog, they built in some unique solutions to the obstacles that might confront Atlantis in the future. They decided upon production from wet trees transported through manifolds to a moored semisubmersible production quarters located away from the drill center, a dedicated semisubmersible drilling unit to be located above the primary drilling center, and consideration for future multiple drill centers rather than just one.

Path to project sanction

For Performance Unit Leader Greg Sills, the project's general manager, his work on the Atlantis team is the longest he's ever been on a single project in his decades-long career. "I joined the team during what's known as the 'appraise stage' in the BP Capital Value Process (CVP)," said Sills. Sills noted that CVP has five distinct stages: appraise, select, define, execute and operate.

During the "appraise" stage a project's alignment with BP's business strategy and the project's feasibility are determined. If the project passes scrutiny, funding and resources for the "select" phase are approved to study development options and choose the appropriate plan. In the "define" stage, the development option selected receives the level of planning and design needed to determine the scope of the project and to develop cost and schedule estimates.

After the project scope is fully defined and agreement is reached to go forward, then project "sanction" is granted and the funds and resources to deliver an operating asset are made available. The "execute" stage follows sanction, and includes engineering, procurement, construction and all other steps to achieve startup. Throughout this stage, careful oversight is maintained to help achieve cost, schedule and operability targets. The final phase is "operate," which begins when a fully operational asset is delivered. The goal going forward in this stage is to sustain maximum performance and return on investment.

The upper-echelon BP executives who conducted the CVP review of Atlantis lauded the detail and scope of work of the integrated project development team. The executives were able to understand clearly how the risks of such a complex project were balanced by potentially large reserves, and that the carefully developed project plan provided appropriate mechanisms to handle both the significant upside potential and the subsurface downside uncertainties. They concluded possible rewards from Atlantis outweighed its risks, and the project achieved sanction on November 18, 2002.

An unexpected vision

"Together, we will make Atlantis the safest, cleanest, most reliable and best performing asset."

– Atlantis Vision Statement

According to Sills, people participating in the exercise to create a vision statement for Atlantis were not prepared for the notion that a project team in the early phase of design would create a vision that not only went beyond first oil, but didn't even allude to it. "We're in the business to find and develop the biggest fields we can, not just build and operate assets. To develop and exploit these huge opportunities in the Gulf of Mexico requires planning for the future from the very beginning." Sills adds that even though the main function of the Atlantis project team was to bring the asset into the operate phase and turn it over to the BP operations team, they needed a "longer-wavelength" vision. "Note the vision statement doesn't even talk about startup. That surprised a lot of people," said Sills. "We deliberately aimed way beyond first oil."

"We made sure that BP's brand values were embodied in all stages of the Atlantis CVP," added Sills. "The development concept itself limits the amount of hydrocarbon inventory the PQ is exposed to. The team worked to reduce risks to people and the environment throughout the design. To do that, we carried out extensive assessments to verify that we had accomplished the correct amount of risk mitigation, and it paid off."


Technicians Service the Steel Catenary Risers Pull In Unit at Atlantis

Offshore morning meeting

Sills noted that during the original concept selection, a preeminent decision factor was process safety. "We compared which design would have more inherent safety, principally from the standpoint of preventing an uncontrolled hydrocarbon release. We had a rigorous suite of process safety assessments, so much so that one contractor noted that the tedious and time-consuming effort to answer all questions we raised during hazard identifications (HAZIDs) and hazard and operability analyses (HAZOPs) might impact the delivery schedule. We decided to stay the course and spend the time to do it right."

Atlantis teamwork crucial to success

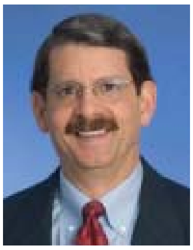
Sills related that projects like Atlantis are on the boundary between science and engineering, somewhere between what is now considered "normal" deepwater project work and an expedition into new frontiers fraught with the unexpected. "It's one thing to be a record holder for one reason or another, but I see that as more of an indicator of the degree of difficulty that the team has to cope with," said Sills. "Step changes in size or water depth in a mega-project like Atlantis are not only risky, they bring with them things that by definition people haven't encountered before."

To prepare for and cope with such challenges, the Atlantis team developed a reputation for exceptional planning. From day one they implemented and developed a deep respect for the discipline of project controls and used it for incredibly detailed planning, scheduling, estimating and performance analysis. "Still, you have to be able to handle the unexpected because you can't plan for and predict everything," said Sills. "If you have a well-integrated team that communicates across functions and is flexible and innovative in the face of problems, you are best prepared to handle the problems that certainly will arise when you're pushing the envelope of what is possible in deepwater operations."

Many organizations across a variety of industries discuss issues through silos and top-down management and other structures that impede successful communication and delivery of business results. The Atlantis team was the antithesis of that, fostering a style of leadership and cooperation that was inclusive, promoted creativity and individuality, recognized exceptional performance, and avoided micromanagement. "We were able to attract some of the best talent in BP and the industry to the Atlantis team," Sills said. "We had exceptional leaders and team members at all levels of the organization. I am extremely proud of their innovations and resiliency in the face of incredible and sometimes seemingly insurmountable challenges. Above all, they produced ingenious solutions that have become the hallmark of the success of Atlantis to this day."

Introduction

Working Together to Capture the Prize



"The Atlantis project is a key piece of the foundation for BHP Billiton Petroleum's worldwide oil and gas portfolio. Overcoming the significant technical challenges to create this large business is an accomplishment that we are very proud to be part of."

– J. Michael Yeager,

Chief Executive BHP Billiton Petroleum

In the mid 1990s, BHP Billiton Petroleum made the decision to enter the deepwater Gulf of Mexico (GoM) at the same time BP was looking for a partner to drill its Neptune prospect, which would later lead to the discovery of Atlantis. BHP Billiton not only joined BP in the Neptune test well, but was able to establish a larger area of mutual interest around the Neptune prospect area. The move significantly positioned the company as a major player in the ultradeepwater GoM, leading to significant developments at Atlantis, together with BHP-operated facilities Neptune and Shenzi.

As a nonoperator with 44 percent interest in Atlantis, BHP Billiton Petroleum lent expertise in areas where the company felt it could add value, contributing team members to the BP-led project team and working to develop subsurface design and well placement. The experience working on one of the most complex and, at the time, most ambitious deepwater projects in the world led to BHP Billiton's ability to achieve substantial growth in the Gulf of Mexico.

The company has garnered technical and commercial learnings from Atlantis, specifically in the areas of subsurface interpretation, facility design practices, regulatory

Good relationships among BP and BHP Billiton negotiators contributed to Atlantis co-ownership success

Crewboat approaching Atlantis

approval management, and contract strategy and management. The field remains one of the largest in the world, and it presented many challenges that were eventually overcome. From the integration of the hull and topsides, manifold replacement, service vessel waiting lists, hurricanes and more, each solution to an obstacle became part of a playbook for future company projects in the GoM.

Atlantis and beyond

Atlantis stands as a key part of BHP Billiton's business. On a global scale, Atlantis greatly added to the company's global production. In fiscal year 2007, BHP Billiton Petroleum produced on average 320,000 barrels of oil equivalent (boe) a day. The company will soon produce on average over 500,000 boe a day. That number is expected to grow as more projects come on stream.

This achievement is only possible because of the strong relationship and trust developed with BP over the course of the Atlantis project. The ingenuity and attention in working together on what some has previously called a "technological impossibility" set the stage for sustainable success.

BHP Billiton Petroleum continues to work with BP to optimize development and contribute in areas where the company feels it can add value. The goal of BHP Billiton Petroleum is to work with BP to ensure every barrel is produced as cost effectively as possible with zero harm to people and the environment.

Subsurface team took long-term view

As subsurface resource manager, Pramod Singh sees the two dozen members of his team as stewards of the Atlantis resource base.

In addition to leading the initial evaluation of the potential resource opportunities in Atlantis, Singh's team was also responsible for preparing the development plan and moving it forward. Once online, the team has been accountable for understanding the performance of the reservoir, including any changes, optimizations or adjustments to ensure that Atlantis achieves the best performance possible.

The team includes professionals from a variety of specialties, including reservoir engineers, production engineers, geologists, geophysicists, petrophysicists, and petrotechnologists. He notes that the Atlantis leadership team was able to convince senior management of the value of bringing on skilled people early in the development process and then keep them together as a cohesive team.

Understanding Atlantis

Singh describes Atlantis as a huge and complex field that from a resource base perspective requires a variety of highly technical subsurface skills.

Initially overshadowed by other fields in the Gulf of Mexico, Singh believes Atlantis benefited from the situation.

"The Atlantis resource base was recognized, but the project wasn't thought of as the largest field or the one with the most potential," he says. "We benefited by being able to work as one team with Mad Dog and gained a lot of experience and mutual learnings. Also, because Atlantis was not in the spotlight as much, we could do a lot of good groundwork and solid evaluation of the resource base."

By the time it reached sanction, Atlantis was also fortunate to have built a strong database from the discovery and appraisal wells, core samples, fluid samples, and pressure samples, Singh says. "We were able to understand the complexity of the field well and make good decisions around a concept of how the field should be developed."

Singh notes that the business case for the resource base that was sanctioned in 2002 is still valid more than five years later.

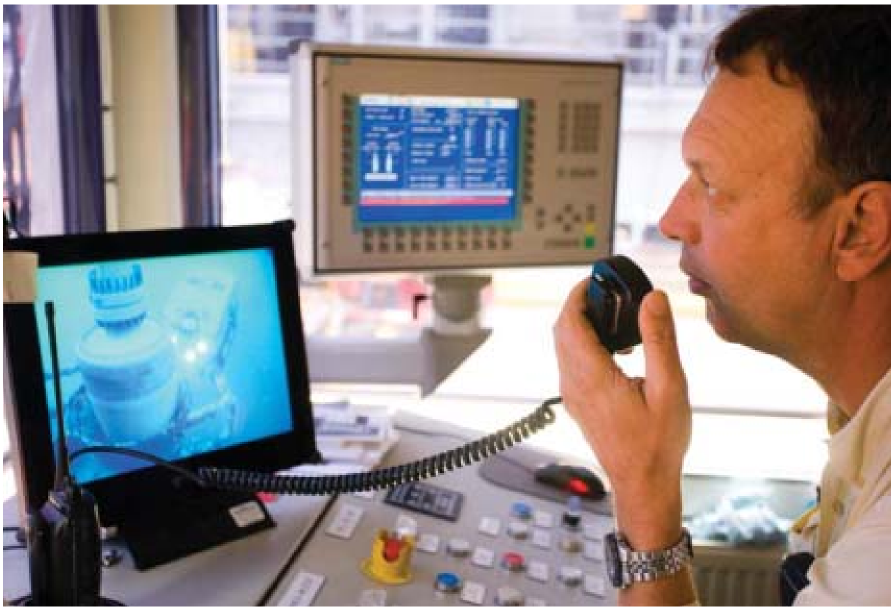
"Subsurface is always challenging, especially imaging under salt, and some projects sometimes fall short later."

In fact, he notes, Atlantis is one of the very few, if not the only project where BP sanctioned a subproject (the North Flank) even before it had brought online the original sanction area. "That was a big vote of confidence in both Atlantis and the Atlantis team."

Connie Bargas, reservoir engineering advisor, says an important part of the role of the subsurface team for Atlantis was to try to paint as complete a picture of the Atlantis Field as possible and get a range of the potential.

"Our job from a subsurface standpoint was to bracket the range around the resource size and the number of wells that would be needed," Bargas says. "We knew that Atlantis had a big footprint, and we thought we would need quite a few wells to produce the field.

"We also anticipated that we would have to inject water, but one of the uncertainties was how much energy we would get naturally. And one of the risk mitigation options was to plan on water injection."



Steel Catenary Risers Pull In Unit Control Room at Atlantis

Input on initial decisions

One of the first critical decisions that had to be made for Atlantis was whether BP would use a stand-alone facility and whether it should be a spar or a semisubmersible.

Atlantis team members spent six months assembling all the information available to help frame the discussion and then held a two-day review during which about 20 team members representing all of the various subgroups gathered to try to answer the big questions and to weigh the pros and cons of various options.

"We decided fairly early on that we did not want to utilize a spar with our subsea wet trees, so we ruled that out as an option."

The team also spent time looking at whether it could straddle the Sigsbee Escarpment, which would have a big impact on costs.

"But the technical issues led us quickly to discard that option," Bargas says.

"We eventually decided on a semisubmersible instead of a spar for several reasons, including the fact that we would likely have upwards of 20 wells—and probably more. That would have required the world's largest spar," Bargas notes.

The team also anticipated the need for water injection.

"We could see high processing rates, which would require large facilities. In the end, several aspects of the reservoir led us to decide that, for Atlantis, a semi seemed more appropriate than a spar."

The team also grappled with the issue of deciding where to position the drilling rig.

"We looked at a semi with and without a rig. We began looking at the huge footprint of the reservoir, which is almost six miles by three miles," Bargas says. "We realized that it would be very difficult to reach all of the field from a single spot, so we thought it would be very important to be able to have a drilling rig that we could move around. If we put it on the production facility, we wouldn't be able to do that."

The subsea and topside teams drove the decision on where to locate the facility in relation to the escarpment. "The critical issue that we focused on was the realization that there would need to be several flow lines and the technical challenges of running them up the escarpment, "Bargas says.

Size matters

The teams also grappled with how to size its plans for nameplate ratings.

The Subsurface Team started by putting together scenarios on low, medium and high cases for Atlantis, ranging from 100,000 to 200,000 barrels per day.

With the uncertainty of Atlantis from a reservoir standpoint, Bargas says, the team considered what would make the most sense commercially as well as trying to determine the subsea needs for the number of flow lines and their size and how many wells would be needed.

The team ended up recommending a footprint of four, four-well manifolds and five flowlines. In 2002 and 2003, the cost constraints made it tough, Bargas says, but the team put together a strong case. "We recognized that the cheapest time to be able to provide those capabilities is before the infrastructure was built, and we believed in the potential of Atlantis to grow as warranted."

Steel Catenary Risers Pull In Unit Control Room at Atlantis

While the team didn't have enough information to justify providing everything that might be needed in the future, the goal was to provide a solid foundation so that future teams could make those decisions once there was more production data and experience.

Planning ahead

"In other older projects that I've worked on, I wanted to be at the front end to address needs 10 years or more down the road," Bargas says.

A good example was the design for the riser and umbilical hang-offs on the pontoon.

"Two-thirds of them are empty. We put those in place for future expansion. We've all had experiences in which we would have liked to bring in a small field off the main reservoir but couldn't because we didn't have a place to hang them."

As a result, the Atlantis subsurface team wanted to provide flexibility for future tie-ins. The Atlantis topsides have facilities on three sides, but the fourth side is completely bare.

"The Na Kika team had designed space for future expansions, and we thought that was a valuable lesson that we wanted to apply on Atlantis," Bargas says.

Early on, the Facilities Team led a process to brainstorm on future possibilities for Atlantis, including more water injection, more compression, a third oil train, produced water handlings and a number of other options that would require space and payload.

The Facilities Team, working with the Subsurface and

Commercial teams, gave the group a variety of options that could be evaluated for space and payload.

"While some specific items may never be needed, we have given ourselves a lot of flexibility," Bargas says.

It would have been easy to increase the size of various pieces, but the team made a conscious decision to give future teams the flexibility to add capacity or equipment.

The Subsurface Team also worked to make the design tie-back friendly. The decision has paid off, Bargas said. "We actually ended up taking advantage of it quite quickly since we added a fifth manifold to the north.

Depletion plan

Atlantis has a number of reservoirs that are stacked, so one of the challenges that the Subsurface Team addressed was where to start, including the more standard practice of starting at the bottom and working one's way up the reservoir.

"We decided to start with something in the middle. We selected what we call the M-54 and M-55 zones for the reasons that they have the best quality sand, the best quality oil and the most oil that we found in any of the Atlantis reservoirs," Bargas says. "They provide the real foundation, but we also wanted to leave ourselves the ability to produce both above and below these two."

The initial depletion plans call for future sidetracks and recompletions as well as deepenings to finish out development of the M-54 and M-55 zones and other sands above and below.

"We will reuse well slots and well bores where possible to get double duty, but we know that some work will be easier than others," Bargas notes.

Water injection

In planning for water injection, Bargas says under one scenario Atlantis could need water injection in late 2008. The production chemists and subsurface teams are working together to plan the program. "It's important to do a good job and get the right chemistry. Water injection involves the entire project and will depend on production data, so we will be carefully monitoring production."

Teamwork

For the Subsurface Team, Atlantis represented an opportunity to capitalize on their joint experiences on the Na Kika Field.

"We already had good working relationships. One of the lessons that I learned while working on Na Kika is the importance of working well together as a team," Bargas says. "We brought that learning to Atlantis, along with the ability to trust each other and enjoy the project together."

Bargas also underscored the importance of communications. "At the time, it can feel like things are taking longer than is needed, but I think you actually save time, you don't have to redo it since you are really communicating."

KOS Riggers Mooring Atlantis

Seismic nodes reap rewards from atop the ocean bottom

"The Atlantis Ocean Bottom Seismic (OBS) node survey marked BP's first deployment of this cutting-edge technology. It was the largest and deepest OBS survey anywhere in the world, and it garnered a lot of industry attention, and for good reason. The results were quite remarkable."

– Pramod Singh,
BP Atlantis Subsurface Manager

Although careful in producing of "serial number one" items, the BP-operated Atlantis project team decided the time and location were right to pioneer the use of Ocean Bottom Seismic (OBS) nodes. OBS nodes, which are self-contained seismic recorders placed directly on the bottom of the seabed to collect and store seismic data, mitigate many of the problems encountered with towed-array seismic data collected near the ocean surface. "Typical deepwater Gulf of Mexico seismic operations include a vessel towing long cables, known as streamers, in the water above the area being surveyed," said John Howie, BP's Atlantis New Wells and Reservoir Description Team Leader. "Hydrophones on the streamers collect reflections of sound energy generated when an airgun fires a shot (a pulse of high pressure compressed air) into the water."

With water above the Atlantis Field well over a mile deep, and much of the field sitting beneath a complex cover of salt, it became obvious to the team that a new method to collect seismic data was needed to better see what lay beneath the surface. "The data sets collected by using towed streamers were processed in many ways using BP's state-of-the art technology, but we still weren't able to get satisfactory visibility," added Howie. "The very nature of towed streamers is that they are linear; they produce what's referred to as 'narrow azimuth' recordings, which didn't meet our needs."

Fortunately, BP's Exploration and Production Technology Group (EPTG), recognizing the growing need for improved subsalt imaging for company operations around the world, had begun an effort in 2001 to explore improved methods to recover such information. Their conclusion: seismic data acquired from many directions around a reservoir with "wide-azimuth" technology would markedly improve subsalt imaging compared to the linear towed-array methods commonly in use.

This finding would shift into high gear the effort to design, build, test and deploy a wide-azimuth acquisition system that employed self-contained OBS nodes, nodes that could be accurately and safely deployed in a complex subsea environment such as Atlantis. Jerry Beaudoin has been the project manager in EPTG responsible for delivering this revolutionary acquisition system. BP worked with several companies to conduct exhaustive prototype and sea-trail tests of different OBS node designs. Following prequalification of potential vendors and careful evalution of proposals submitted, based on Health, Safety, Security and Environmental (HSSE), commercial, quality and delivery-capability criteria, BP selected Fairfield Industries for field-scale OBS acquisition at Atlantis. In essence it would move BP's OBS node wide-azimuth application vision from the "lab" to "reality."

The OBS nodes were built and warehouse tested, in which they were repeatedly charged and discharged and checked for operability and consistent battery life (about 30 days). Whether in the warehouse or on the seismic vessel, the nodes were kept on charge, a single light indicating if they were in the "alive" mode. By design, the data collected by the node was stored and still recoverable even if the battery died while still on the sea floor.

Node handling and deployment

Some 900 nodes were constructed, each weighing about 200 pounds and equipped with a four-component recording system consisting of three perpendicular geophones and a hydrophone. A contract vessel with two remote operated vehicles (ROVs) was used to transport and install the nodes on location. BP placed the 900 nodes over the Sigsbee Escarpment for a seismic shoot then retrieved them, downloaded the data collected, and placed about 700 nodes below the escarpment for a second shoot. Throughout the process, safety and protecting the environment were preeminent considerations. In preparation for the survey, Fairfield aligned their HSSE management system in response to BP's requirements and encouragement.

BP recognized early-on that these large 200-pound cylinders, much like a heavy barrel, required a careful health, safety and environmental review to ensure they were handled safely. A back-deck handling system with containment baskets and cranes virtually eliminated hazards to personnel when moving the nodes. "The system was designed so no people were required on the deck of the vessel because of the hazard posed by the weight and large number of the nodes," added Howie. When loaded, a containment basket held about 25 nodes. It was moved near an ROV, and from it 10 nodes then were loaded into the ROV's basket. Two very large work-class ROVs were used for these challenging tasks, one stationed amidship and one at the stern of the vessel.

The vessel crane system then would lift the fully loaded ROV, weighing well over one ton, over the side into the water and lower it as deep as 7,000 feet to reach the target area. Onboard the ROV, a suction-cup arm was used to retrieve a node from the ROV basket and place it on the sea floor; then the ROV would lift off and fly to the next location as a conveyor-belt system moved the next node in place to be lifted. "Through repetition we became proficient enough to safely install about 30-40 nodes a day," said Howie. "For the first time we used a hydroacoustic-aided inertial navigation HAIN system. The HAIN system helped us place each node with a +/- 2-3 meters accuracy on a regular grid with about 400 meters distance between each node. In nearly 7,000 feet of water, this is incredible positioning accuracy."

OBS Node Project Wins BP Corporate Award

BP conducts an annual Helios Award program to recognize the outstanding contributions people make to the success of their business and to celebrate team achievements in six categories that reflect BP's brand attributes. Judged by a cross-section of BP people, including experienced specialists and senior managers, each event garners well over 1,000 applications from teams at locations around the world. The Atlantis OBS project team won the 2006 Helios "Partnership" Award for their success in working toward mutual advantage. The citation noted that the Atlantis Project team and BP's Exploration and Technology Group (EPTG)… "developed the world's first commercial deepwater, wide-azimuth seismic acquisition system to improve subsalt imaging. This will revolutionise (STET) 80 percent of BP's operations in the Gulf of Mexico and have significant impact on our subsalt portfolio worldwide."

The irregular features of the ocean bottom in the Atlantis Field posed installation challenges. Extensive bathymetry data from sonar surveys assisted in identifying locations where a node likely could be placed. While each node had to be in direct contact with the seabed, they didn't have to be in a perfect pattern and could be tilted up to a 10° angle off of vertical. "We had as much as 50 meters of leeway in the placement of some nodes, which helped us find a suitable spot to land them," said Howie. This was essential, considering some areas had slopes up to 30 degrees. "When viewed from the larger scale of the entire grid of 900 nodes, we were able to find what amounted to 'flat spots' to properly place the nodes to give us the seismic data we needed."

Node data and recovery

"The OBS nodes are sometimes referred to as 'dumb' nodes because there is no communication with them," added Howie. He feels that term is a bit of a misnomer because each node has an impressive flash memory capable of recording 2-millisecond samples throughout its 30-day battery life. "It took about 30 days to lay the node "patch." So a few days following the start of node deployment, the separate source vessel began shooting over the top of the nodes. The progress of the ROV vessel deploying nodes and the source vessel has to be carefully choreographed to make sure the right shots are fired when the node is in place and still "alive." By the time we'd placed the 900 nodes, we immediately returned to the edge of the patch where we had started and began picking them up," said Howie. "Since our first outing with the nodes on Atlantis, their battery life has improved to 60 days, a key enhancement considering the time it takes to place and retrieve the large number of nodes needed for a field the size of Atlantis."

Nodes were individually marked and aligned in station numbers in lines along the grid. ROV video and shot information helped track the location of each node. When nodes were retrieved, cross-checks were conducted to ensure the correct node was where it was supposed to be. Howie noted that the team adopted the motto "no nodes left behind" despite the relatively small size of a node when taking into account the depth of water and size of the field. Every node used was recovered, and no harm to people or the environment resulted from the placement, use and recovery of the nodes. Just as important, the team achieved node operability of 99.2 percent which is an incredible performance for a new seismic acquisition system on its first deployment.

Using dual air-gun sources, the seismic vessel fired shots above the node patch about every 50 meters. Amazingly, a full 12-seconds elapsed as the sound energy went down from the surface some 30,000 to 40,000 feet subsurface and bounced back up to the nodes where the data was recorded. Unlike a towed array, shooting over nodes was much easier and safer in the work environment around the Atlantis Field. This seismic survey conducted in close proximity to the GSF Development Driller II (DD2) was possible because the small seismic source vessel could easily maneuver in the vicinity, unlike a vessel with towed arrays that could become tangled with nearby vessels and objects in the water. "Towed-array seismic operations would have been more difficult if not impossible as close to the DD2 as we were able to work," said Howie. "We planned for both the DD2 and the Atlantis production quarters platform to be nearby when we conducted acquisition over the OBS nodes, and this new technology paid off." The OBS node survey for Atlantis commenced in late October 2005 and was complete by March 2006.

Data processing crucial to success

OBS nodes increase the potential to illuminate parts of the subsurface beneath the salt to determine what hydrocarbons might be there. The wide-azimuth seismic data collected by the nodes is particularly advantageous when shooting over complex salt formations because the shape of the salt formation isn't necessarily known. However, a step change in technology and some innovative solutions to data processing were required to efficiently and accurately process the large amount of data collected.

Rapid turnaround processing of the OBS nodes data set is possible through the close partnership of the BP High Performance Computing Center (HPCC) and EPTG's Advanced Seismic Imaging (ASI) team, both in Houston. The ASI team has developed sophisticated migration algorithms to conduct prestacked depth migration processing of seismic data, but the massive computing power of the HPCC is critical to allow fast turnaround of the results. "Until relatively recently, we didn't have computers fast enough to evaluate the data in a timely manner," said Howie. "The entire OBS data set can be migrated in a day on the current system. This is quite remarkable when you consider that just a few years ago such processing would likely have taken several weeks," said Howie.

The OBS processing has been ongoing while we have been improving the complex salt model through an iterative process of migration and interpretation. The team is encouraged by improvements in the seismic image so far. We now have a much improved image that is impacting our current and future field development planning.

OBS Nodes and the future

Howie notes that OBS nodes may be back again in the Atlantis field. There is potential for 4-D or time-lapse seismic monitoring of production. This approach examines the reservoir sands to see what fault blocks or individual sands are being drained and what changes in pressure and oil saturation are occurring. Four D may also help identify isolated areas and provide opportunities for future wells.

"We're still developing an understanding of how to fully use OBS nodes," said Howie. "We see the potential for a number of applications worldwide for nodes, many outside of sub salt imaging. In particular, in places with extensive platform infrastructure, the nodes have the capability of seamless acquisition where it would be very difficult with towed streamers."

OBS nodes now represent one of several technologies in the BP toolkit for imaging beneath salt. Sub salt imaging is a key technology leadership area for BP with an important intellectual property strategy. In the wide-azimuth acquisition area, besides the seabed positioned nodes, BP has also been the industry leader in the implementation of wide-azimuth towed streamer (WATS) technology. WATS provides the capability of collecting large swaths of wide-azimuth data for sub salt exploration objectives.

ROV loaded with OBS nodes ready to deploy to the seafloor

Partnership key to success

The success of the OBS node system at Atlantis results in many ways from successful partnership in the project at many levels. The close linkage within BP between the Atlantis asset team and the EPTG technical team tasked with making it happen was critical. From EPTG, Jerry Beaudoin (project manager), Alan Ross (operations manager), Per Gunnar Aas (HSE manager), and Scott Michel (processing manager) all worked successfully to create an integrated project team connecting all the involved companies—BP Atlantis, ETPG, Fairfield Industries, Northern Canyon and Geo Century.

Aside from being the "first" full field OBS acquisition at scale in deepwater, the nodes and the node handling system were designed from scratch. The project was completed, from contract award to acquisition, on time and on budget. Not to mention that it was done safely and with no harm to the environment, "No nodes left behind." Project award to acquisition completion occurred in only 15 months.

Unlocking the secrets of Atlantis

Planning and teamwork prove keys to success for drilling and completions teams

Ask the teams involved in designing and managing the drilling and completions program for Atlantis about their experience and several key themes quickly emerge: the detailed and comprehensive planning that went into developing the drilling and completions programs; the close working relationships, coordination and integration among the different teams; and the unique capabilities of the GSF Development Driller II (DD2).

During the program, the BP team would need all three—extensive planning, exceptional teamwork and world-class equipment—to successfully overcome all of the challenges to unlocking the tremendous potential of the Atlantis Field.

Planning for success

From day one, each of the teams worked together to put a massive plan together and schedule it all out, says Jonathan Sprague, wells delivery manager for Atlantis.

"We also put [the schedule] in pictures and images to help everyone understand and take interest in the plan. It was a powerful tool. We gave it to all the teams and the DD2 crew. The more people saw it, the more they took an interest in it."

Allen Pere, Drilling Team Leader for Atlantis, says his team invested about four months of work in planning each well's drilling program.

"The Drilling Team worked very closely with the Subsurface Team in designing the correct well path, evaluating seismic data, the geologic model, where faults were located and where we needed to place the well," Pere says. "We looked at multiple well paths and ranked our options based on which one would provide the most value to the project."

"The operations roadmap that the team put in place to help coordinate the simultaneous operations was a remarkable piece of work," says Mick Leary, wells manager for the Gulf of Mexico for Development and Production. "I have never seen anything as planned and orchestrated to the level of detail as with this project. And it has served us well, especially when external forces required us to change. We were able to quickly assess and reprioritize or resequence, almost without a hitch."

The team also invested a lot of time on completion planning and procedures.

"Our team focused on making sure that the wells piece did not become a critical path to deliver first oil," Leary says. "They have overcome a number of obstacles as we have gone through the process of delivering this project."

"We developed detailed plans on how we would execute completions, and then we incorporated lessons learned after every completion," says Bruce Rogers, completions operations leader for Atlantis. "We included feedback from everyone involved, from the drillers and engineers to roughnecks and service company personnel. If there was a suggestion on how to do it better, we reviewed it and assessed whether it was something that should be included in the future."

DD2: a world-class tool

In many ways, the DD2 is both a real and symbolic representation of the program's vision and innovation.

Selection of the DD2 involved a large number of considerations from a variety of Atlantis teams.

Interest in a vessel like the DD2 was driven in part by the decision to go with wet trees for completions, says Rogers.

"Once we made the decision to go with wet trees, the team recognized that it would need a rig that could do development work," Rogers says. "Wet trees have a lot of challenges in terms of access to the trees. You have to have lot of quality control at the tree in order to stay functional for the life of the well. This means that we would need a floating rig to access the tree and that we would have to rely on ROVs for a lot of functions."

As part of the selection process, the team looked at different rigs and developments around the world and then developed specifications for the drilling rig and vessel.

"Our first exposure to the GSF Development Driller II was at the Offshore Technology Conference when it was in late design stage," Rogers says.

With a huge subsea infrastructure yet to be installed, the team recognized that it needed a rig that could do subsea installations completely offline, if possible, while also drilling or completing a well.

"We were asking more from a rig than has ever been done in the Gulf of Mexico," Rogers says, noting that until the DD2, the primary focus for rigs in the Gulf was on drilling rather than completions.

"With a typical deepwater rig, you're drilling for years before you do completions so earlier deepwater rigs often hadn't done many completions," Rogers says. "On the Atlantis project, we'd spend at least 50 percent of our time doing completions, so it became an important consideration."

Since BP had planned to batch set its initial producing wells, the remaining producing wells would be done with the riser down.

"That meant that the drilling activities were only going to last 30 to 40 days, and our completion activities were scheduled for 25 to 45 days per well. So we're spending at least half our time on completion activity."

More than a drilling rig

Craig Wright, well site leader for Atlantis, is quick to point out that the DD2 is "above and beyond a drilling rig. It's rightfully named, it's a development vessel."

"You could have the main center drilling, bottom hole assemblies going on the auxiliary rotary, two ROVs on bottom, the winch putting a jumper in place, and unloading a crew boat using a crane," Wright says.

"The auxiliary rotary can be used to feed the main well drill center so that we minimize downtime, or we can use it to do things off the critical path to get ready for an operation on the main well center," Wright points out.

The No. 7 winch is a converted anchor winch with 10,000 feet of nonrotating wire that can be used to run all of the subsea components, including jumpers, trees and manifolds, concurrently with activities at the main well center.

In terms of completions, the dynamically positioned DD2 also provides the flexibility to maneuver the vessel as needed in order to change rig headings. "We can do a move in 10 to 15 minutes," Wright says.

"If you look at what we have been able to accomplish with this rig, we've demonstrated an ability to do some things that haven't been done in the past, and now we have the opportunity to use this experience in other parts of the world," Leary adds.

"This type of rig gives us another tool in our kit to consider in our planning efforts as we look to do other projects in the Gulf of Mexico and areas around the world."

DD2 advantages

Selection of the DD2 provided offline capabilities for both the drilling and completions teams.

"On the drilling side, we can make up casing strings and rack them," Rogers explains. "While on the completion side, we can use the auxiliary rotary to make up all of our downhole equipment assemblies as well as our production tubing and stands and then rack them back to be ready."

For example, Rogers says the team can run a subsea test tree to land the tubing hangar. "We can make it up offline and test it and then transfer it over to the tubing hangar when we're ready. That helps us avoid a lot of

Ingleside, TX. Installing the gas compression unit on the platform.

potential downtime."

Running main and auxiliary rotaries at the same time also enables the crew to keep the main rotary busy as much as possible.

Fluid-handling capabilities

Another important consideration was the DD2's fluid handling system, which features separate tanks and systems for drilling mud fluids and brine completion fluids.

"Most rigs share the pits, which requires cleaning between drilling and completion," Rogers notes. Having separate systems provides more flexibility and helps prevent completion fluids from becoming contaminated. It also means the team can have completion fluids on board and ready to do a riser displacement even while drilling is being completed, Rogers points out.

Taking advantage of the opportunity to provide input into the final design of the DD2, Rogers says his team recommended adding a deck for the subsea test reel for umbilicals and designed a riser bay deck for other completion equipment.

"The riser bay deck is movable when we're running the riser and then use the space for other completion equipment," Rogers says. The deck for the subsea test reel lets the team keep the reel on location, helping reduce handling and costs.

When the DD2 was brought on board, it was a new rig that had never worked in the field. Getting a new rig up and running efficiently can be a challenge, Leary stated.

"There has been a mixed track record on the efficiency of new rigs when they first start working," Leary notes. "While DD2 had its challenges in getting it up to speed, it was remarkable how the team adjusted on the fly to those challenges and reprioritized and moved the schedule around to keep us on the path to first oil. They overcame some big challenges."

Team Atlantis

Another hallmark of the Atlantis project, Rogers stated, is that it has not operated as separate teams with separate goals.

"We had common goals. That's the secret to our success. We all understand what our goals are."

Sprague agrees, noting, "I've always tried to put what's best for the project, in terms of value, first; and I've given my team the space and the empowerment to freely work with any other team to get the best solution for the project."

While acknowledging that may not always be best for the drilling and completions side of the team, "at the end of the day if it's adding more value to the project, that's what's important," Sprague says.

When there were differences of opinion, the teams were able to resolve them. There was initial pushback from the Drilling Team, for example, on running long strings and how wells were suspended, Rogers stated.

"It took more planning and effort by the Drilling Team, but after doing a few they liked it and found it to be better. And it's a much more efficient way for us to get a jump start on completion."

Rogers also points out that the management team approached the Atlantis project differently than others by bringing in both drilling and completion teams from the very beginning.

"We started looking at the project development with completion activities in mind from the start. We worked with the drilling teams on the design of the wells and the casing strings to deliver the rates that our production team wanted. There was a lot of thought up-front to deliver the flow rates that we wanted."

The coordinated effort also meant that the two teams had the opportunity to design a work string that would work for both drilling and completion activities.

"For completions, we wanted a plastic internal coating that would hold up to abrasion during frac jobs to minimize the amount of scale. We also wanted gas-tight connections, and metal-to-metal seals for frac operations since we would be doing high-pressure frac jobs," Rogers says.

The team also was able to make the case for buying the work string and landing string for the rig itself so that they could use it for every completion instead of renting it out.

Sprague notes that Project Leader Greg Sills was instrumental in instilling a sense of commitment among employees to the project. "You have to care about success and care about other people on the project. Because we cared, we went the extra mile to communicate." As a result, the team never fell apart whenever it had challenges, Sprague stated.

Teamwork and leadership

"When you look at a project like this, the leadership has a major role to play. Greg Sills has been with this from the beginning. It's been remarkable that we've been able to hold the core of the team together since the beginning in 2001 and through the development period. That's a long time to hold a core team together for any company," Leary notes.

"People are proud to put Atlantis on their Curriculum. They are proud of being part of a team that is delivering a world-class project," Leary says.

"Everyone has learned from the Atlantis experience. We have taken people with pieces of knowledge and expertise and molded them together to collectively deliver a great project. It is really a remarkable collection of exper-

Team picture at Ingleside, TX.

tise that was brought together for Atlantis," Leary says.

The Atlantis project also has proved to be an outstanding development opportunity.

Louise Jacobsen Plutt, for example, had the opportunity to serve as a drilling engineer on Atlantis and be involved in planning and executing drilling operations.

Compared with her previous experience in the relatively simpler onshore Wamsutter gas fields, Jacobsen Plutt says the Atlantis project was a unique opportunity to be involved in the total process of planning and drilling some of Atlantis' first wells.

"We were all working on the same goals to get first oil, but we also understood that some things may come before drilling," Jacobsen Plutt says. "Unlike other projects where drilling is the primary activity on a rig, this requires more coordination and accommodating other teams, and we were able to do that quite well."

Productivity

The combination of planning, teamwork and world-class equipment also paid big dividends in productivity.

Sprague says Atlantis has been able to achieve one of the best completion performance records in the industry.

"We originally thought there would be 21 days of downtime on drilling and completions, but instead it's been virtually hours," says Sprague. "The key was good planning, scheduling and communicating continually. As a result, we were able to shift priorities as the project dictated rather than as one team dictated."

Sprague notes that Atlantis also had one of the lowest records for nonproductive time (NPT) and expects its drilling performance to be in the first quartile on future wells.

"We may suffer a little on drilling time, but we are able to make up for it on completion and overall delivery," Sprague says.

After the initial four wells were drilled, Pere's team conducted a detailed analysis of NPT during the drilling program and focused on ways to eliminate or mitigate it.

"When we did our analysis, we realized that one of the biggest sources of NPT was in obtaining appraisal data using wireline logging," says Pere. Working with the service provider, the team began using a new technology to take formation pressures on drilling tools using logging-while-drilling (LWD) tools instead of wireline management.

"The advantage is that while drilling the well we are obtaining logging data instantly. After we reach total depth, we can obtain formation pressures and then come out of the hole and run production casing. It enables us to reduce the process by one trip," Pere says.

"In addition, in an effort to optimize its performance during well completions, two completion engineers were assigned to the rig crew during operations. The experience paid big dividends," says Terry Miglicco, Atlantis

Completion Team leader.

"Because of their experience with the operations team, our average NPT was about 18 percent, which is excellent when you consider the complexity of the completions."

By comparison, the industry average is 30-plus percent NPT for smart well completions in the Gulf of Mexico.

"We estimate it saved us about 29 rig days on our well completions," Miglicco says.

Complex flowback operations

Another important example of the value of detailed planning and teamwork for Atlantis involved flowback testing of the initial wells performed in the fall of 2007.

"We invested a year in preparing and planning for flowback operations," says Miglicco. "We conducted a thorough series of HAZOP reviews and detailed planning for every aspect of the operation."

Communications was a big key, especially considering the number of teams and vessels involved.

"The flowback operation required six vessels: the DD2, two tugs managing the DD2, a hose handler, the barge and a chaser boat to ensure that no other vessel encroached on the 500-meter exclusion zone," Miglicco says.

The team developed robust contingency plans, including emergency disconnects from the barge.

The first three wells were flowed back to a moored barge. During the tests, the wells reached a maximum flow rate of 17,000 bpd.

In addition, the team decided to run production logs concurrently with the flowback tests.

"The production logs gave us great insight. We thought the first completion was perfect, and if we hadn't tested them, we would have done all the others the same way," says Jerry Sharp, PQ Base Management Team leader. "By doing flowbacks, we were able to understand some problems downhole that we weren't aware of."

By adjusting the program and changing the perforation strategy, the wells are now coming in at top quartile in performance.

The planning and extra testing paid big dividends, Sharp stated, and helped protect a significant amount of production capacity for both the initial wells and the ones that followed.

"At the end of those three flowbacks we had a very good completion design that would have a tremendous impact on our operations," Miglicco says.

Pushing the envelope

Another hallmark of the Atlantis project's drilling and completion program was the willingness of service providers to develop new techniques or tools.

Halliburton, for example, developed a new perforating gun just for Atlantis, Rogers notes. The team wanted to be able to have large-diameter holes with low debris to maximize the flow rate without jeopardizing the well bore from debris.

Halliburton developed an 18-shot- per-foot big hole charge. The new seven-inch gun "gave us everything we wanted," with one-inch-diameter perforating holes.

Rogers notes that, initially, designers didn't think they could meet the specification, "but they kept persevering and were able to deliver it."

The team also decided that, wherever possible, it wanted fit-for-purpose equipment, even if it meant asking different contractors to work together.

"That's exactly what happened with Schlumberger, Baker Hughes and Weatherford when we asked them to develop our sand control system," Rogers says.

The Cyber Rig Drillers Console on the Transocean's GSF Development Driller II.

Atlantis subsea team ready for the unexpected

"We always thought that the subsea team had two customers—the operations and subsurface teams. Maybe it's a mistake if you don't consider management as one of your customers, but that's the way I lead my teams. We put together a 'fuzzy' organization in which people were assigned specific roles and responsibilities, but were encouraged to work proactively across functions to fill gaps when they appeared. The results were great! When the subsea team was faced with a problem,we tackled it together. In the end, that made management and the entire Atlantis team very satisfied with our performance."

– Gene Hall, BP Atlantis Subsea Manager

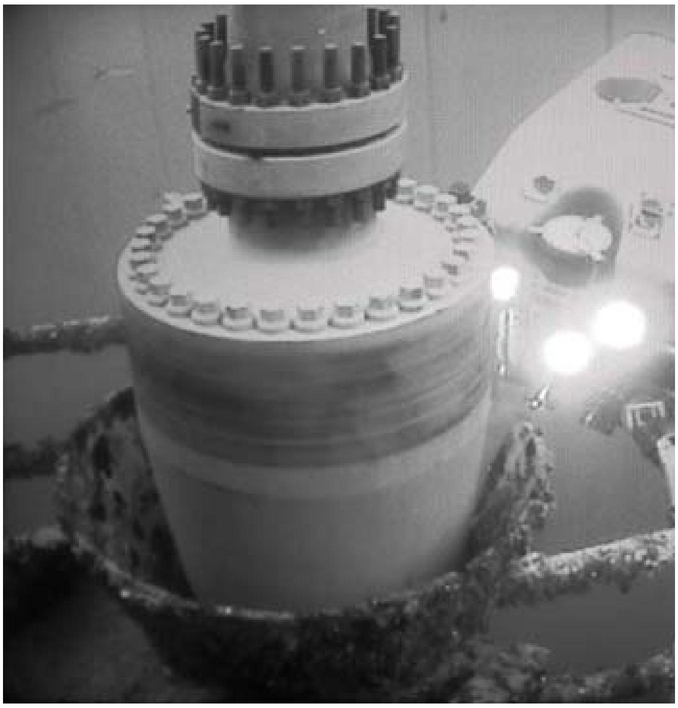
BP and co-owner BHP Billiton had a lot to look forward to when the Atlantis project subsea layout was envisioned. The design concept wasn't unprecedented, but it certainly was a bit unusual for the Gulf of Mexico. Reaching consensus on which way to proceed took tremendous planning, a reliance on past experience, and a thorough understanding of what challenges and opportunities might lie ahead in the difficult environment of the Atlantis Field.

Rising to the occasion was a mixed team of experts with varied levels of experience in subsea, subsurface, facilities, drilling and completions. "We evaluated many different concepts," said Gene Hall, BP's subsea manager for Atlantis. "At the time BP had announced four major projects: Holstein and Mad Dog, which were spars, Thunder Horse, which was a production and drilling quarters semisubmersible, and the Mardi Gras pipeline to interconnect them." Atlantis would come in as the fifth major BP-operated project in the Gulf of Mexico, and the extra time afforded by being last in line would enable careful consideration of all options.

"We looked at spars with wet trees, spars with dry trees, a semisubmersible production drilling quarters and some concepts not even in the books," said Hall. Spars had advantages, but with the limited number of wells going to the surface, a spar could limit the upside potential the project had to offer. At the early stages of the project, the subsurface team's evaluation of the reservoir had a lot of uncertainty because so much of the field is subsalt. "We were concerned that selecting a spar might limit our production options, and that selecting a production drilling quarters might restrict access to the drilling center, already crowded by its proximity to the Sigsby Escarpment," said Hall. The team tried to make "apples to apples" comparisons on concept selection, cost assumptions and production opportunities, and the result was to go forward with a subsea development.

Decisions based on experience

The team decided on a subsea development with a stand-alone production quarters semisubmersible, remote subsea wells and a long-term development rig. Hall and Atlantis Subsea Team leader John Hughes both had experience working on the Amoco Liuhua project in the South China Sea. There, a dedicated vessel was used for drilling and other work. "Gene and I had unique learnings from Liuhua, so we relied on that wealth of



Remotely Operated Vehicle Observing SCR Flex Joint Installation knowledge to provide input on the decision-making process for Atlantis," said Hughes.

The rig concept team quickly arrived at the conclusion that the vessel should be much more than a drilling and completions platform. "The team decided it should be a construction vessel as well, which would require us to look on the market to find the right vessel, or have one built by the right company that could modify it to suit our multiuse needs," Hall added.

According to Ryan Malone, Atlantis Subsea Deputy manager, some key points of the Atlantis development concept would have major impact on the path chosen. "With the host platform moored two miles from the drill center and the round-the-clock availability of a dedicated vessel, we could easily work directly over the drill center," said Malone. "This would result in fewer simultaneous operations and would preclude the need to move the host platform to gain access to the field." At a time in the global energy industry when the limited pool of vessels soon would become difficult if not impossible to charter, a dedicated modular drilling unit with added-on capabilities would prove to be a prophetic choice.

Modifications to fit subsea needs

The rig team was consumed with the process of getting the right rig with the right equipment and selecting the specific alterations necessary to make it the proper long-term development vessel. Modifications to winches, extra quarters to accommodate the people needed to execute a larger scope of work, and space to stow and operate two large work-class remotely operated vehicles (ROVs) were part of this effort. Global Santa Fe would be the company selected, and their newly constructed dynamically positioned GSF Development Driller II (DD2) would prove to be the vessel that could be outfitted to deliver what the Atlantis team needed.

Modifications to the subsea kits included sizing them to fit through the moon pool aboard the DD2 and restricting their weight so rig cranes could lift and land them and other subsea components onboard the DD2 for testing. Of particular note, the Atlantis manifolds do not contain hydraulically actuated valves linked to a control system. All valves in the original design were ROV actuated, which kept the process simple, reduced interfaces and increased reliability, and kept down the weight

Coiled Tubing Unit Testing at Ingleside, TX of the manifolds, making it possible for the DD2 to install them. Thousands of pounds of weight were saved without the normal valve actuators.

"Very early on, the subsea team decided that with the proper modifications and equipment, the majority of the subsea components could be installed off the DD2," said Hughes. "We established the goal to do as much subsea construction work from the DD2 as possible. It was a unique situation to be able to achieve so much work from a drilling rig and not impact drilling and completion operations to a significant level."

Subsea team tackles large scope and scale

The Atlantis subsea team was multidisciplined and was responsible for fabrication and delivery of components, integrating with the broader Atlantis team to manage interfaces among drilling, hookup, commissioning and operations, and blending their scope of subsea work as seamlessly as possible with other teams to help achieve key project milestones.

On Atlantis, the subsea team is responsible for the subsea trees, manifolds, jumpers to connect the manifolds to the trees and pipelines, flowlines, umbilicals to control the subsea wells and other subsea control systems, the ROVs on the DD2, interface equipment on the DD2 used to test and run the equipment, all gear on the PQ required to pull risers and for coiled tubing operations for gas lift in the riser, and the control systems for subsea wells. "Our responsibilities are mechanical, electronic, hydraulic and in diverse locations, so it's a lot to manage," said Hall.

The fabrication aspects of subsea operations effort were larger than some might expect. They included all the trees, manifolds, jumpers, pipeline end terminations (PLETs), pipeline end manifolds (PLEMs), and what some called a project within a project, an extensive flowline and riser system. "We've built and installed one of the more complex flowline and riser systems in the world," said Malone. The subsea team also designed the hang-off baskets on the PQ that the risers land into, and managed or closely supervised several sites onshore that fabricated the flowlines, the jumpers, the manifolds and the trees.

The first version of the manifolds built for the project, Hughes remarked, were extensively tested on land before anything was taken offshore. "We conducted comprehensive tests for about six months by setting up two complete manifolds and two trees onshore to mimic what we were going to place on the seafloor. We put many of the system components together and ran through system interfaces to look for clashing, and we trained people and verified our operating procedures," said Hughes. "When subsea kit items were delivered to the DD2, our team members were able to take them off the delivery vessel, touch them to the water and send them to their designated position on the seabed without delay. We had to be certain that everything would fit and work as designed, and it did."

The initial Atlantis subsea architecture reflected the team's efforts to maximize production while providing for future growth. Drilling Center 1 (DC1) would be located in some 6,818 feet of water two miles north of the moored production quarters. It would feature six flowlines: four for oil and gas production, one for testing and one for water injection. Five manifolds, four for production and one for injection, would rest on the seabed. Some 20 well slots would include 16 oil and gas production wells and four injection wells. Six hydraulic and two electrical umbilicals, 46 jumpers and some 59 flying leads would finish out the subsea kit. An additional drill center some two miles to the north was planned for future development. DD2 would work in place directly atop DC1.

Arranged in a building-block pattern instead of a fixed template, the Atlantis subsea architecture allows for future add-ons to handle production growth, and it mitigates well slot losses. "If we're drilling and going through various casing sizes and we damage a casing string, we can move over some distance and drill another hole as opposed to having to completely eliminate a slot like we'd have to within a fixed template," said Malone.

The eight umbilicals are another significant portion of the Atlantis subsea kit. Six are hydraulic and two are electric and fiber optic, which operate the trees. Signals from the PQ are carried to the trees to operate the valves through the subsea control modules (SCMs), also known as a control pods. The SCM relays data on pressures, downhole temperatures and tree temperatures back to the PQ, and the modules can be used to inject chemicals such as methanol, paraffin inhibitor and low-dosage hydrate inhibitors (LDHI) at the trees and below the seabed.

Subsea selectively employs innovations

The Atlantis subsea kit has some items that set it apart from other projects. Among those are the hydrate remediation system and the coiled tubing riser system.

Atlantis subsea kits have a hot-water hydrate remediation system on all of the manifolds, jumpers, trees, PLETs and PLEMs. It consists of one-inch stainless steel insulated tubing attached on the outside of the pipe walls. To activate the system, an ROV stabs into a port and with its electrical pump takes on seawater, heats it and pumps it slowly through the stainless steel tubing until the adjacent hydrate melts. "The size of the pump and heater maintains a steady temperature of about 100 degrees Fahrenheit," said Malone. "That way it dissociates the hydrate slowly to avoid rapid melting and gas expansion."

The hot water is in a closed loop system, and its carefully controlled temperature protects against dangerous expansion of gases when the gas entrained in the hydrate breaks out into bubble form. "If you use an electric heater you can't be sure of the heat you'll generate with the resistor," said Hall. "The temperature gauges on the closed loop circulation system indicate the inlet and outlet temperatures and enable you to balance the hot water temperature and calculate the energy differential. Using hydrate association curves, you can manage the temperature carefully and keep pressures under control so you don't rupture a line."

For the coiled tubing riser system, Hall relied on his experience on the BP-operated Na Kika project that used typical valves to keep water and gas for lift separate. "If you have any seepage at these depths you can potentially wind up with a hydrate problem, even with two-valve protection," said Hall. The team studied this and came up with the idea of coiled gas lift tubing inside the risers, forming a conduit for gas. "The advantage is that we're pumping relatively cold gas down a 2-inch coiled line inside a 10-inch diameter riser; and by the time it reaches the bottom where hydrates might form, it's up to the temperature of the fluids in the riser flow path." This design also helped to fight potential hydrates forming in the riser system itself.

Rapid response to the unexpected

Atlantis had installed its manifolds by January 2006. They commenced testing trees, running completions and testing manifold valves until that June. Then, the unexpected happened. Welding issues on another deepwater Gulf of Mexico project occurred; and because Atlantis had similar welds, everything already in place or under construction for the subsea architecture was scrutinized.

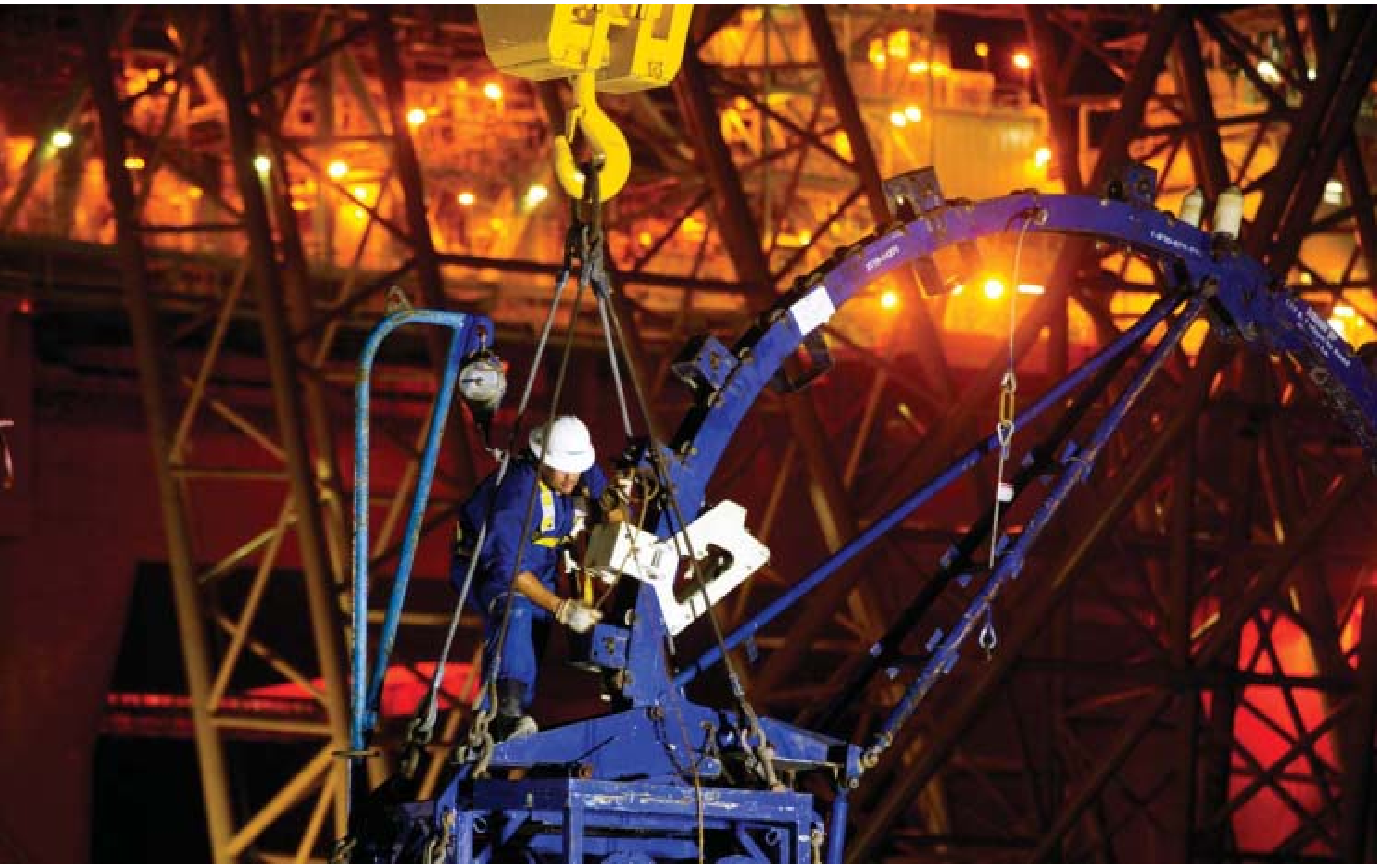
Fortunately for Atlantis, the experience and vision of subsea manager Gene Hall prepared them for this eventuality. "My philosophy is that you must plan for your kit to be on the seafloor for 20 years, and 98 percent of the time that plan will hold true. However, I insist that we must be able to retrieve whatever we place on the bottom, and we should be able to retrieve it quickly and safely. We were prepared," said Hall. Atlantis equipment impacted by the weld issue included the manifolds, jumpers and production PLETs.

When the weld challenges were discovered, the Atlantis project already had installed four manifolds but no jumpers were connected. All of the production PLETs were still on the surface. The Atlantis team had to decide on a path going forward. Fortunately, Hall's insistence that they be able to retrieve what already was in place soon would pay off.

"Considering the metallurgy concerns and other issues, we made the decision that it would take many months to determine the root cause of the weld failures, so we made the proactive decision to remediate all the affected components and put in place what we deemed a 'Phase 1' system to enable us to achieve our goal of first oil in 2007," remarked Hall.

The "fuzzy" organization Gene Hall had put in place years before was about to take one of its most important steps forward for the project. "When we heard about the welds, we proactively sent all of our running tools offshore in anticipation we'd be given the order to pull the manifolds," said team leader Hughes. "That was on a Wednesday. The following Monday we had two manifolds sitting on the dock in Galveston." The team

Spooling Winch Wire at Ingleside, TX



Coiled Tubing Unit Testing at Ingleside, TX

philosophy of having a captured asset—the DD2,—and a plan to use it to retrieve the kits made it possible for the Atlantis project to meet head-on some potentially show-stopping conditions.

If the manifolds had not been designed for retrieval by the DD2, a heavy-lift vessel would have been required. The retrieval process would have taken many weeks or even months to source a heavy-lift vessel, develop the necessary procedures, and complete the hazard identifications and hazardous operations reviews to ensure it could be done safely. "We likely never would have been able to achieve first oil in 2007," added Hall.

Steel markets were such that the raw materials needed for forgings and the industrial capacity to machine new components didn't exist. The Atlantis team decided they'd have to cannibalize other components already constructed to build a workable system in time to meet their schedule. "We pulled up four manifolds, cannibalized them for workable parts, and made some major changes to them," said Malone.

Existing components from PLETs, jumpers and manifolds were sent through an exhaustive process for rework and put back into unaffected portions of the equipment at various stages. Hundreds of components had to be cut up. They included the nine-inch gate valves in the PLETs, hubs—the upward facing components that the jumpers land on, connectors—the portions of the jumpers that latch on to the hub, and many others. Each manifold had 21 valves and 16 hubs that had to be removed.

"We removed all the valves and controls, literally turning the manifolds into simple headers," added Hall. "Luckily, we'd decided a long time ago that dual jumper trees, which allowed going from production to a test line, were a good idea; and that application allowed us the flexibility to create the simple Phase 1 manifold system that we installed after the weld problems were discovered." Within a year, the Phase 1 manifolds were already back on the ocean floor.

The simpler Phase 1 manifold system is scheduled to be replaced by the more capable original manifold designs in the future, possibly in 2010. If the recently sanctioned North Flank of Atlantis is ready for tie-in by that time, the subsea team will provide their input on the decision to suspend production from the field and install the Phase 2 subsea architecture. In the meantime, Atlantis is enjoying much earlier production.

Well flowback tests yield important data

"This is the first time that any BP team in the Gulf of Mexico has conducted a flowback test on wells in deepwater to a dynamically positioned vessel with a barge tethered to it to receive produced oil. The effort required extensive planning and precise execution. It was well worth the effort. The Atlantis team benefited greatly from the successful outcome of this complex operation."

– Terry Miglicco,
BP Atlantis Completion Team Leader

The Atlantis reservoir, with much of the field situated subsalt, required careful consideration by BP and co-owner BHP-Billiton. The team determined that after each of the first three Atlantis wells was completed, it would need to conduct flowback tests on each to confirm the completion design and productivity. Any problems could be corrected immediately and any lessons learned applied to future wells. This was much easier said than done; about two years of design work, planning, procurement of specialized equipment and training were needed before the team was ready to proceed. Their painstaking efforts proved worthwhile for not only the well being tested, but for all future wells in the Atlantis field.

"It was very important for the team to test the completion design and execution program prior to proceeding with field-wide operations," stated Terry Miglicco, BP's Atlantis completions team leader. The location of Atlantis, about 185 miles south of New Orleans, Louisiana, in about 7,000 feet of water, made this endeavor an ultimate test of the Atlantis team's ability to plan and execute a complex and potentially hazardous marine operation far from shore.

Flowbacks a challenge in deepwater

"We worked together with other Atlantis teams to figure out the most economical completions that made the most sense to maximize production," stated April Partridge, BP Atlantis completions engineer. "Our initial wells provided us the opportunity to do flowbacks on a mixture of single and stacked wells, which would show us if the assumptions about the reservoir and our choice of completions were correct." The wells tested were the DC-143 G5, DC-123 E4, and the DC-124 J (stacked intervals), the later a stacked frac pac to make it the first commingled well in Atlantis.

According to Partridge, one of the longest lead-time items was identifying what equipment was needed to safely bring the live hydrocarbons to the surface. "Because of the extreme water depth of Atlantis we had to use a dynamically positioned vessel, the Transocean's GSF Development Driller II (DD2), so we needed the ability to very quickly close off the inner tree string," added Partridge. "We had to be able to shut all the valves and fully isolate the hydrocarbons in case the DD2 had to disconnect and come off location for some reason." To live up to BP's brand values and health, safety and environmental concerns, all hydrocarbons would have to be safely contained, with none entering the water.

To accomplish the operation, the DD2 was dynamically positioned on the surface above the wells, with riser and blowout preventer (BOP) stack down and a single mooring line fair-lead to a 400-foot barge that received the oil via a large-diameter floating hose. Two tugs, one in the specially designed notch on the rear of the oil barge and another assisting, helped keep the barge, which had no propulsion system, in proper position relative to the DD2. A chaser vessel kept curiosity seekers clear of the operations area and a hose-handling vessel rounded out the fleet of six vessels needed to execute the flowback tests.

In this case, the term "barge" is somewhat misleading because it was capable of holding some 120,000 barrels of oil and looked more like a floating production storage and offloading (FPSO) vessel. The barge couldn't be anchored because of the very deep water above the field, so maneuvering the dynamically positioned DD2 and the barge and tugs in tandem was complicated by wind, currents and sea state, as well as the need to keep the flare boom pointed in a safe direction. Motion analysis was conducted to determine how the barge and DD2 would react while moored together, with particular attention paid to prevent pontoon damage to the DD2 from the barge and tugs as well as the large hawser made of a combination of chain, wire rope and nylon line that was used to tie-off the barge to the DD2.

A specialized temporary well-test skid provided by Schlumberger was loaded aboard the DD2 to receive the oil. This large manifold like device covered almost the entire deck, and enabled well control at the surface through choking back pressure. It also provided the mechanism to run the oil through separators and tanks, and ultimately to direct it to flow at low pressure through a long floating hose line to the storage tanks in the oil barge keeping station alongside.

Preparation pays off

Extensive hazard identification and hazardous operations studies led to comprehensive training and preparations that proved critical during the very first flowback test. All kinds of HAZIDs and HAZOPs were conducted according to Miglicco, with communication considerations playing a key role in the contingency planning. "You can understand the concern that if you need to quickly conduct an emergency disconnect from the well for whatever reason you have to manage a riser and BOP stack that runs well over a mile deep beneath the DD2.

"We planned with an extraordinary amount of caution in mind," said Partridge. The Atlantis team deliberately developed redundant layers of safety for this complex marine operation. "We installed tensometers to maintain the proper strain and catenary on the hose and mooring line, pelican hooks and breakaway couplings if a quick disconnect was required, and we could rapidly sever the hawser in the event of an emergency."

Subsea board at offshore Control Room

The extreme safety measures built into the flowback tests also enabled those conducting the operation to sever the internal pipe and entire BOP stack in less than a minute, then safely sail away the vessels and pipe if necessary.

The first flowback was abbreviated by the report of a fire aboard the barge. "The team had extensively planned, trained for and communicated emergency response procedures. When the fire was announced, there was no delay as the well was immediately shut in at surface and downhole without incident," said Miglicco. Everything worked exactly as planned. Operations were terminated to investigate the cause of the fire.

Results lead to improvements

Fortunately, sufficient data was gathered on the first flowback test before the fire was reported so that it wasn't necessary to resume testing. "We met the primary objectives of data gathering on that well," said Partridge. "We'd flowed it for more than eight hours and reached a peak instantaneous rate of about 17,000 barrels per day."

The results were reviewed by a multidisciplinary group that included subsurface, completions and production team members. Fluid samples collected were subjected to a rigorous chemical analysis, and together with detailed scrutiny of pressures and all remaining data, the group was able to piece together evidence that the chemistry mix downhole wasn't what was desired.

"On our first completion, because of the uncertainties, we used an extensive chemical program to help clean up the well," said Miglicco. "We had a lot of acid and emulsifiers, and it turned out we were trying to do too much." The group determined that the single primary acid package would do well enough and that additional acid wasn't needed. "Our next acid job was very simple, using only hydrochloric acid (HCL)," added Miglicco. As a direct result of the flowback, hydrofuoridic acid was removed from all subsequent completions, and other lessons learned resulted in a change to step rate tests and frac job methods to prevent near wellbore damage.

Miglicco concluded that the flowbacks were well worth the time and expense. "I'm very proud that our team was able to anticipate the challenges of this complex and potentially hazardous operation, and then execute the operation safely and efficiently. The team efforts to protect people and the environment really paid off. We flared very little natural gas and burned absolutely no oil—all the oil recovered went to the oil barge.

World-class Atlantis facilities draw industry attention

There are many superlatives that can be used to describe the Atlantis production facility. Given its tremendous size, even oilfield veterans are awe-struck when they see photos and drawings, much less visit the facility for the first time.

For the teams involved in building and commissioning the Atlantis facility, however, the words that are used most often are "world-class" and "state of the art."

Unlike many other semisubmersibles in use today, the Atlantis production facility does not have drilling capabilities and was developed as a production quarters (PQ) facility.

At the time of its installation about 185 miles south of Louisiana in the Gulf of Mexico, the Atlantis PQ or host facility was the world's deepest moored floating oil and gas production platform designed to process 200,000 barrels of oil and 180 million cubic feet of natural gas daily. At a water depth of 7,070 feet, the PQ floats on four ballasted legs and is moored by 12 tension cables to the seabed.

The hull fabrication for the PQ platform was undertaken by Daewoo in Okpo, South Korea, while the topside production modules were built in Morgan City, Louisiana. Integration of the facilities was at the KOS yard in Corpus Christi, Texas.

The field's first set of wells are being drilled by a separate vessel, the Transocean's GSF Development Driller II (DD2) at a drill center to the north of the PQ. The wells flow into subsea manifolds and from there flowlines carry the oil, gas and water to the PQ where they are processed. After processing, the hydrocarbons are moved through the Caesar oil and Cleopatra gas pipeline systems—part of the Mardi Gras system—to existing shelf and onshore interconnections.

The Atlantis PQ quarters consists of three 5,000-ton modules for: production, compression and generation. The production module houses all of the equipment associated with oil production, including separators and pumps. The compression module houses all of the gas compression and treatment facilities. The generation module includes three turbine generators and a variety of utility systems. The turbine generators are dual-fueled, enabling the facility to run on diesel initially until natural gas production from the field is sufficient to power the generators.


Atlantis offshore Control Room

"On October 6, 2007, we opened our first well," stated Rickey Harrison, offshore installation manager for Atlantis. "Production from well DC-111 was 20,000 barrels per day (bpd) and 14 million cubic feet of gas a day (mmscfd). By mid-January 2008, we opened six wells and were producing more than 110,000 bpd and more than 56 mmscfd of gas per day."

"The original design for Atlantis called for it to produce 150,000 bpd," stated Dirk Smit, Atlantis PQ delivery manager. But while the team was fabricating the topsides, it became apparent that the reservoir was capable of more than that. After engineers did a review of the systems and determined that the system could handle 200,000 bpd, the team moved forward with the higher capacity in mind.

Even after accommodating the higher production capacity, the facility has been designed with even more growth in mind, Smit says that Atlantis has the capacity for an additional module when future production warrants it.

"Atlantis has three modules in horseshoe shape, so a fourth module could go in the open end of the horseshoe," Smit says.

Atlantis sailaway from Texas on August 7 2006 to offshore location.

Capitalizing on lessons learned

The successful journey from concept to commissioning and first oil on the Atlantis PQ was made possible by a dedicated team of professionals, many of whom have seen the project through from beginning to end.

Throughout the project, Harrison stated the teams involved embraced the overall Atlantis vision of working together to make Atlantis the safest, cleanest, most reliable and best performing asset.

For the Atlantis facilities team, one of the keys to success has been the ability to capitalize on earlier experiences and lessons learned as a result of being the last of four major deepwater projects that BP already had under way when construction began.

"Atlantis was able to fabricate topsides more efficiently because of the lessons learned from other deepwater jobs," Smit says.

Atlantis also benefited from a highly skilled construction management team that was assembled for the job. "We were able to work with McDermott to plan and execute the work so that we were able to increase efficiency."

"We set up an Atlantis management team that had expertise in all the construction disciplines," Smit says. "Then, working with McDermott, we were able to put together a well-integrated construction plan."

The strong plan and experienced team proved critical as unexpected challenges emerged when the hull arrived and required additional work and refitting. In addition, lessons learned prompted a number of changes and upgrades to improve the overall safety and functionality of the Atlantis PQ.

Commissioning hits milestones

In his role as PQ delivery manager, Smit was responsible for overseeing commissioning across the entire project, including topsides, subsea, wells commissioning and startup operations.

"Our goal was to make sure there were no gaps in the overall commissioning program and provide assurance that everything was ready for startup," Smit says.

As part of that effort, Smit was accountable for the project schedule as well as coordination with various delivery teams to make sure there was a fully integrated schedule for first oil and beyond, when the facility ramped up to its target production capacity.

As the facility moved closer to completion, Smit's team started the offshore commissioning scope of work, including running equipment as much as practical.

"We took advantage of the time to work with the operations team," Smit says, providing them an opportunity to learn the systems and begin assuming ownership of the facility.

As Smit sees it, one of the biggest challenges from a facilities perspective was "scope growth." The team had earlier planned to complete hookups by January 2007 but had to extend the target date after discovering new work that needed to be done.

Despite the additional work required, Smit says the team was able to remain productive because of open communications.

"We worked with operations teams on the PQ so that they felt comfortable raising questions and asking for help when they thought something needed attention. The ability to address things on an ongoing basis and get it out into the open was very critical to our overall success."

The skills of the people involved in the project also were critical.

"The contractors, especially major contractors, and commissioning and construction management had a wealth of experience that they brought to the table. The construction contractors—Bay, Brand, MMR, Rig Blast, Dresser Rand—are top-notch people. They get things done."

The Facilities Team also benefited from the strong engineering team onshore that was able to quickly address any issues that arose on the PQ, Smit stated.

"We had great procurement and onshore logistics teams who continually performed miracles in terms of getting the material that we needed when we needed it."

Smit also says he was continually impressed by the Facilities Team. "We had a number of serious challenges and the team never gave up. They took on each challenge, put together a plan, executed the plan and just kept after it."

Commissioning milestones

Commissioning is the last step in the quality assurance process for a new facility, Smit points out, but commissioning a major facility like Atlantis can be a challenge because of the number of delivery teams involved, each with different areas of responsibility.

As a result, an important part of Smit's role was to work with each of the commissioning teams to make sure Atlantis had a fully integrated commissioning program "from the wellbore to the point of sale," and ensuring that there were no gaps between the various teams.

That meant asking some tough questions: "How do we know that we looked at everything that we need to look at? When we say we're ready for first oil, how do we know we really are?"

To answer those questions, Smit led a rigorous and comprehensive commissioning review during which every aspect of the facility was reassessed. "Each commissioning team looked at their portion of the work as well as how it affected other areas to ensure that there were no gaps and that we were ready."

Capitalizing on experience

"The Atlantis PQ has several things in common with the other major BP facilities," stated Ken DeJohn, facilities engineering manager for Atlantis.

DeJohn says Atlantis was able to take advantage of the specification work done on the front end for several major pieces of equipment, including the facility's turbine generators, compressors and large pumps.

"It enabled us to hold down costs while also ensuring delivery at the right time."

The Atlantis team was also able "to turn lemons into lemonade" when design changes forced delays in the project.

"Some of the delays helped give us more time to buy equipment and to continue work on the design. We also had time to do more studies, and we were 50 percent complete on engineering when we started fabrication."

That compares favorably with the industry average in which only 20 percent of engineering design is completed before fabrication begins on major construction projects.

BP also launched a marine assurance team as part of the organization.

"The marine assurance team has made significant contributions to our process safety programs," DeJohn says.

The team is staffed by specialists from BP Shipping who have marine expertise, DeJohn says, "so now we have more people with ship design and ship operations experience who have accountability for the marine portions of the facility."

Forward momentum

Maintaining a facility like Atlantis is an ongoing process, says Alastair Taylor, facilities manager, who notes that integrity management is a continuing theme that will become more prominent on Atlantis as time goes on.

"The work of the Facilities Team has to be totally coordinated and integrated from a safety and operations point of view," Taylor says.

As a result, he sees his team continuing to focus on engineering and integrity management.

On the engineering side, Taylor's team focuses on both future work as well as remediation of any issues, from the simple to the complex, including the replacement of upgrades to major pieces of equipment. His team is also responsible for execution of any engineering work.

For integrity management, "our goal is to make sure processes are sound and that we have the correct monitoring programs in place so that there aren't problems in the future with equipment or pipelines," Taylor says.

His integrity management and assurance staff works closely with the operations team on all aspects of the facility to ensure the long-term viability of the asset "so that it's still producing in 20 to 25 years."

Strong staffing plans and technology help ensure smooth, safe startup and operations

As with other aspects of Atlantis, the Operations Team has benefited from the strategic decision to bring in people early, capitalize on the experience of other BP deepwater teams and leverage technology wherever possible.

"We brought in expertise and built a strong team of people with three to 20 years of experience," says Jerry Sharp, PQ Base Management Team leader. "The mixture of experience also gave us a lot of opportunity to mentor and develop new staff. The opportunity to startup a field this size doesn't happen often in a person's career and we believe it's been an advantage to both the individuals and to the project to share that experience."

Sharp, who has been with BP for over 22 years and involved in deepwater operations for more than 10 years, says Atlantis was able to staff up with production engineers early and benefited from partnering with teams from other BP projects.

In his role as PQ Base Management Team leader, Sharp was responsible for getting Atlantis ready for production, including managing all base production activities to maximize production, improve efficiency, and understand the well and reservoir performances.

"Our team focused on how we started the wells and our plans to ramp up to target rates. That included establishing the limits of the well and predicting how they would perform in the next 12 months."

It also covered the integrity of the wells in order to prevent failures and protect project investments, along with well surveillance, well testing allocation, completion testing of each well, and the overall production plan for the field.

"While our team tends to focus on the shorter term, 12 to18 months, we work closely with the Reservoir Management Team, which focuses on the longer term—from eight months through the life of the field," Sharp explains.

As he was building his team, Sharp also pushed for the opportunity to bring on additional production engineers early in the project.

"For a variety of reasons, we were able to bring on someone about three years before first oil to make sure that what we were designing and installing was appropriate for the operation."

"This is a dream project. There are few opportunities in the industry to go from zero to our production rates in such a short period of time, so it was exciting to be able to deliver good performance and operating efficiencies," Sharp says.

By completely staffing up front, Sharp adds the team was able to do a lot of work before first oil "so we were able to define the upside potential before day one, before we opened the first choke. This was one of the most prepared and forward-looking projects that I have been involved in."

"We came in with the mindset of how can we be more successful than anything we had done in the past? The role of a production engineer is a key value that is not always recognized in being able to deliver the business. We have been able to leverage the discipline and show what it could deliver."

Atlantis offshore Control Room

Getting a jump start on operations

"Another step that the Atlantis team took to help ensure a smooth startup was to embed operations personnel into the commissioning teams that fabricated the equipment," stated Rick Oneto, Atlantis Operations manager.

"We had 18 people in Morgan City, Louisiana, where the topsides were fabricated and another 20 in the shipyard in Daewoo's facility in Korea with the floating systems team during fabrication of the hull," Oneto says. "Our goals were to assist the construction teams by providing input about maintainability and operability."

Oneto says the initiative and input proved to be valuable particularly during the initial phases of construction.

While on site during construction, the Operations Team also played a role in preservation of equipment that would not be used for several months or longer between installation and final startup operations in the field.

Oneto also had team members assigned to documenting and developing maintenance and operating procedures and work processes. "Good documentation is extremely important, and we were able to utilize learnings from previous projects in development of our processes."

Another goal was to have the entire operations organization in place one year prior to startup.

Startup typically means when a field is ready to begin producing oil. But startup for the Atlantis Operations Team began almost a year in advance of first oil when the team began operating hull systems after the integration of the topsides equipment and mooring out on location.

Maintenance work at Atlantis

"At that time, we had to have personnel operating and maintaining equipment on a full-time basis on an operational mode," Oneto says. "That's a departure from a traditional startup schedule and almost two years before first oil."

Capitalizing on technology developments

Coming onstream when it did, the Atlantis team was also able to capitalize on several new technology developments to help plan and manage operations.

One of the most significant technology tools has been the Integrated Surveillance Information System (ISIS) and ProcessNet, a high-level automation software tool that provides both visual and analytical capabilities for monitoring production operations.

"Technology continued to advance in the four years since we started this team," Sharp says. "We had the opportunity to implement the latest technology with ISIS and have a fully automated surveillance and information system monitor real-time pressure, with intelligence."

With ISIS, Sharp says, the team has been able to raise the bar on the levels of surveillance and understanding of the wells.

ISIS provides the team not only with significantly more data, but also with the means to better understand and monitor the data.

The monitoring system on facilities a few years ago, for example, provided about 3,000 data tags, Sharp stated. "But on Atlantis we're using 40,000 data tags."

With so much information, Sharp says it would be easy for a production engineer to be overwhelmed with the data and miss some of the opportunities. But ISIS screens visually display the data and are easily programmed to alert the Operations Team to deviations from the normal performance standards that they have set.

ISIS has made a significant contribution to the integrity standards of the Operations Team and helps them to avoid potential problems.

Sharp says sand production monitoring and continuous bottom hole well pressures are two good examples of the utilization of the ISIS capability.

"All wells are frac-packed to prevent sand production from the unconsolidated sands, so we have devices on tress to monitor sand count. We can set up independent alerts for sand detection. We can also set alerts on annulus pressure to make sure thermal pressure doesn't increase above certain limits."

The automated system provides live data on all the variables on trees and wells.

"We can monitor from almost any place. We can log into the system on our laptops from any location, so we're not chained to the office and can monitor continuously."

Using ISIS, Sharp's team in Houston can see the same thing as the Operations Team on site. "They tend to focus on real time in the field, but we tend to look at the data over time. We can provide guidance while looking at the same data."

ISIS also helps the Atlantis team understand how the well is behaving in the reservoir. "We will have seven wells producing, and it's possible that some wells could communicate with an adjacent well. With ISIS, we can tell if one well is having an impact on an adjacent well. We couldn't do this even just a few years ago."

Sharp's team can also model performance of the wells and the subsea system and then change parameters in the model to create potential test results before actually trying changes in the field.

Atlantis also has benefited from this high level of preparedness, Sharp stated.

"We were the first to start up with ISIS. Our data management systems were fully in place so we had full surveillance capability from the beginning," Sharp says. "The level of rigor we put in helped enable us to identify upside opportunities in completion capacity."

Another technology tool that has helped ensure safe and reliable operations for Atlantis is the Advanced Collaboration Environment (ACE) located in Houston.

ACE is designed to replicate many of the control systems on board the Atlantis PQ. "We also have full video conference capabilities and multichannel systems to see the same thing they see offshore. During startup and critical times when we want face-to-face conferencing, it adds another layer of integrity and support to our operations."

Coordinating operations

"With a project as large and complex as Atlantis, one of the most important elements of success is communications because so much activity is going on at the same time in the field," stated Gary Imm, deputy project manager for Atlantis.

"With subsea work, drilling and completions, PQ operations, flow lines, umbilicals, seismic work all going on, it's important to make sure everyone is aware of what others are doing and to coordinate all vessels in the area."

At any one time, there are numerous vessels in the field, Imm notes. In addition to the PQ and DD2 and their associated ROVs, there is the Balder, which handles mostly flowlines and pipeline-related work, and a floatel with 80 living quarters and two more ROVs.

Another development to improve operations and coordination was the creation of a position known as the "admiral of the fleet."

In the past, each project worked independently with contractor vessels, Imm stated, but now BP designates a primary manager for vessels for all projects in order to address and manage the work.

Focusing on safety

In preparing for first oil and ongoing operations, Imm says the team invested a lot of time focusing on equipment safety and process safety.

"We conducted a lot of assurance work to make sure that all of our systems are safe and that our people are qualified in handling and managing lifts offshore. We worked with the MMS on the Atlantis system, which is acknowledged as state of the art in the industry."

Offshore operations meeting

The system developed by the Atlantis team for every major lift involves creating a computer model to profile the water current and where the facility and vessels are located.

"Using the model, we can then compute where a piece of equipment would fall based on the shape and size of the object as well as the current. If needed, we can then position the vessel to the side of the field so that we can lower the equipment without risking that it would land on anything in the field if it should happen to come loose during the lift."

The Atlantis teams also installed a hotline between the DD2 and the PQ.

One of the goals of the hotline is to have the ability to quickly shut in a well in the event of a drop during a major lift, Imm stated. Fortunately, the teams have never had to use the hotline, having completed 2,000 major lifts without a problem.

Robust Project Services Team Contributes to success

"The Atlantis Project Services Team took a lot of the workload off of engineers, which enabled them to focus much more on technical delivery of the project. Our team of dedicated professionals, many of whom were embedded in the technical delivery teams, rigorously managed the project schedule, cost estimates, and the progress we were making with each activity in the schedule. We used the data they compiled to gain a more comprehensive view of the project, reduce conflicts and help keep it on track."

– Bill Naseman, Project Services Manager, Atlantis

With delivery of a world-class project like Atlantis on the line, the question in mind for many in BP and BHP-Billiton was: "How do we keep something so large with so many complex parts on critical path?" What became apparent to Atlantis management was the need to find a way to take a detailed look at important activities to determine which ones were part of the critical path to completion, while at the same time also looking at the myriad other events that might lead to conflicts and knock the project off schedule.

"We needed a method to identify possible conflicts that specific activities might encounter and help the delivery teams find different means to accomplish tasks or change the order in which tasks were executed to prevent problems," said Bill Naseman, Project Services manager for Atlantis. Naseman noted that while there may be one so-called critical path on a huge project like Atlantis, measured by the longest cumulative duration to finish all of the activities necessary to complete the project, the project team concluded that there would be more than a dozen significant items just off the critical path. If any of these significant items began to slip behind schedule, their importance would elevate to critical and potentially cause major delays to the project. For this reason, the critical path and float paths, and all the major items that could impact them, became objects of intense scrutiny for the project team to track and forecast.

To put the importance of this detailed tracking in perspective, Atlantis planning and scheduling lead Joe Faulkerson found the project analogous to an elephant. "If you compare a large project like Atlantis to an elephant, when it's a great distance from you, as in the earliest stages of work, it's easy to cover it up just by holding up your thumb," he said. "But when the elephant is almost in the room with you because the scheduled project delivery is at hand and there are challenges, holding up your thumb won't cover up much of anything." To have everything properly covered would require a well-organized team of experts to systematically follow and review project activities and reflect the true status of the project and where it was headed.

Properly staffed team drives improved results

According to Naseman, Atlantis top-level managers were supportive of maintaining the right-sized staff required to support the project's complex work scope. "We built a right-sized Project Services Team to support the project, which is one reason we've been able to deliver what the project team needed," Naseman said.

He added that the depth of his team provided the flexibility to move resources around to help hit "hot spots" that needed extra attention from time to time. Comprised of some 40 people at peak staffing, the Atlantis Project Services Team was organized in a matrix structure with central records management, a scheduling team and cost teams, plus project services organizations dedicated to specific technical delivery teams.

The records management staff worked with the engineering groups to compile drawings, equipment descriptions, technical data, tag numbers, maintenance records and other useful links into a computer program easily accessible to operations staff. Using a Documentum software product, up-to-date information on every piece of equipment was available onshore or offshore to anybody who needed access. "Rather than having to wait for months to have important equipment data available, the Project Services Team records management staff and the computer tools they employed provided fresh and very detailed information to the people who needed it most," noted Naseman.

The project services scheduling team provided each major Atlantis technical delivery team with at least one planner/scheduler to support their efforts. The small but indispensable central cost team pulled together all of the cost forecasts from the individual delivery teams and combined them with their own forecast of nonteam specific costs to develop a total project view.

The supporting Project Services organization that supported each technical delivery team was staffed by a leader, several cost engineers and analysts and was embedded in each major delivery team. Each team's makeup was slightly different, driven by the unique needs required to support the technical delivery team's remaining work scope. For example, the wells, subsea, production quarters and operations teams each had a project services organization colocated with them, typically consisting of five to six professionals. These project services organizations delved into the details of their delivery team's efforts and generated forecasts that matched the timing of the remaining work scope and assessed progress against the overall plan, as well as assisting in processing invoices and researching audit claims. "We managed these project services organizations to meet the needs of the technical delivery teams while simultaneously gaining and sustaining an overall project perspective," said Naseman. "This worked better than anybody could have imagined. When project services staff completed employee surveys, many identified their work group as the delivery team they were supporting rather than project services. That made me proud because it demonstrated that, even though we are a matrix organization, our professionals don't feel like outsiders.

"We've built a best-in-class schedule from my perspective," said Naseman. "Atlantis is a unique major project in that it's fully integrated schedule includes all activities, not just facility construction and commissioning activities. We looked at the work holistically and included drilling and completion activities, subsea architecture installation, flowline installation, umbilicals and controls, as well as the usual facility construction, installation and commissioning work. Many project schedules wouldn't include the wells work scope; but with the Transocean's GSF Development Driller II dedicated to Atlantis and our primary vessel for installing subsea architecture, it made perfect sense to us."

Hull construction in Korea

Project services a fresh approach, not a legacy

To the Project Services Team, the road to success was winding and bumpy to say the least. "The rigorous use of scheduling tools traditionally isn't high on the radar for a lot of the technical folks, but I have confidence in what those tools can bring to a project," said Faulkerson. "In the old days in the field, a lot of things were done by the seat of your pants. That approach rapidly disintegrates when you're confronted by the extraordinary complexity and extensive scope of a project like Atlantis." Faulkerson compared Atlantis to a groundbreaking research and development effort rather than something more traditional, such as building cars or airplanes on an assembly line.

Faulkerson recognized that the role of the project services matrix organization was to ensure, as much as humanly possible, that the full scope of the Atlantis project was entered into a usable scheduling tool. Such an effort would take time, people and money. He first began work with the drilling team, in which he and his staff gathered as much detail as possible, right down to single-hour and multiple-hour activities—almost unheard of in the energy business. They hit a rough spot when they switched to a new version of the Primavera software they were using, which created a learning curve for his schedulers and slowed their ability to track the project.

Faulkerson helped the team to persevere through this delay and gave his staff the extra time they needed to get the knack of the new and improved software. "I didn't want to stick with the old process, which was satisfactory but didn't provide the detail across all portions of the project that we needed," remarked Faulkerson. "To reduce schedule conflicts and help everyone understand how various events might interface, we ultimately were able to create a way for technical staff to look at precisely what work was planned for execution in their and other parts of the project, not just the simple summary of other work provided by the older software."

Sticking with the new version of Primavera software and improving BP's computer server capability helped boost the project services effort. Faulkerson next piloted a program with an interface between the Atlantis drilling and subsea teams. "We didn't tell them how to work—we asked them to give us time with key individuals to gain information on their jobs so we could fit that into a very detailed, step-by-step schedule. When they understood how we were trying to help them, they provided the people we needed, and the appreciation for our role increased."

With the assistance of several technical staff with engineering backgrounds, the Project Services Team developed a project schedule into an extremely detailed format. The goal was to recognize that in the Atlantis work environment there likely would be many changes. If those changes could be properly reflected as soon as they occurred, their future impact on the other parts of the project could be predicted. Soon, more and more of the technical delivery teams were coming around to the concept of rigorous use of the scheduling tools.

Installation of the generation unit at Ingleside TX.

"There wasn't a particular event like a 'eureka moment' that convinced the delivery teams that our project services efforts were the right thing to do," noted Faulkerson. "It was more the result of healthy disagreements, persuasion, and a cumulative courtship that became more amicable as time went on.

"After we developed such a critical mass of activities across the project, Project Services demonstrated how its efforts helped the technical staff effectively manage the details to avoid surprises, reduce work conflicts and make best use of the people and assets at hand."

Augmentation, not control

Known to some as project controls, the spirit of Project Services is about augmentation, not control of events. A common misconception some held earlyon was that the Project Services Team was attempting to reach too far down in the weeds in areas that weren't their turf. "We didn't micromanage the delivery teams; in fact, we didn't manage them at all," said Faulkerson.

"Our job was to find out what the teams wanted to execute, accurately reflect that in the schedule, then track it for them." Embracing the value of this huge undertaking evolved over time. At first people referred to the schedule by Faulkerson's first name—"Joe's schedule,"—then, to various teams it became known as "our schedule" before finally becoming what is appropriately called the Atlantis "master schedule."

A benefit of the schedules developed by the project services organizations was that the people doing the "grunt" work—the employees, contractors, all the engineers, the roughnecks, the afloat crew members, and the operations and technical staff—were helped by the detail available to them when executing their work plans. Faulkerson noted that in the past a lot of schedule assumptions were generated at the upper levels of project teams and then forced down the chain of command. These assumptions were at best uncertain; and in the reality of the field or offshore, they usually proved to be incorrect. "We took input from the bottom up and carefully organized sets of activities at a level of detail that some might think of as minutia but was important to the people actually carrying out the tasks. From this highly focused look we intelligently lumped together activity sets and provided a thorough overview of the true schedule and how different events were interrelated. We discovered that work that seemed relatively insignificant could have a big impact if not conducted properly or at the right time."

Safety and protecting the environment also came into play. One consideration was landing the hangers on the BOP stacks. The hanger, made of nonshearable material, could pose a challenge if an emergency disconnect was required. The schedule provided visibility of where the hangers would be relative to events such as a construction vessel arriving for a remote pull-in. The hangers then could be kept suspended above the BOP stack until conflicting operations were complete and out of the area. Operators found they could refer to the detailed project services organization schedules to help them make decisions on when and where simultaneous events might occur and plan how to avoid or work around them.

Schedule changes also drive costs, and cost tracking by the Project Services Team proved pivotal in demonstrating their worth. When it was decided to retrieve the Atlantis subsea manifolds, the project services organization worked hand-in-hand with the subsea team to deliver a high-level estimate of what that work would cost. Their estimate turned out to be very close to the final numbers. "From the Project Services Team's perspective, it's really about matching our estimates to the level of scope definition. When we had less-defined scope and execution plans, we added provisions to our estimates to address the uncertainty.

"As the technical team improved the technical definition of our scope of work, then updated our cost forecasts and the schedule to reflect that definition," said Naseman.

Commercial Team partners with Project Services

The Atlantis Commercial Team, led by Dan Elmer, worked closely with the Project Services Team. Elmer and his two commercial analysts are one of the smallest commercial teams for BP's Gulf of Mexico operations. "We're focused on commercial aspects and are generally unburdened with additional duties and functions like some commercial teams," said Elmer.

Elmer and his team were responsible for all of the economic aspects of the Atlantis project. They kept accounting of the financials on track, managed the group financial objectives and long-term plan, and reported performance upward in the BP organization. They also helped write fi-

Platform final assembly in Ingleside TX

Atlantis reaches its offshore location

The Project Services and Commercial Teams worked together to help forecast cost changes. When changes were found, Project Services worked with the line team to better understand how to communicate them to the Commercial Team, who then would take the issues up to project management. Project Services and Commercial proved to be meticulous functions that looked at dollars and schedules constantly.

"You can't get into a situation where people are throwing money where they shouldn't," said Elmer. "Commercial and project services function as team members for sure, but in another respect we're the ones who raise a red flag from time to time, sort of a check and balance for the performance unit."

nancial memoranda to justify proposals in the project, and filed requests for supplemental funding when money beyond the originally sanctioned amount was needed.

"Atlantis is considered a top-notch asset at BP, but we had to go through the same process [as every other asset] to acquire more funding when we needed it," said Elmer. "You have to be able to withstand extreme vetting by senior managers, which requires accurate processes." Elmer noted that the Commercial Team received a tremendous amount of support from the Project Services Team. "We worked with project services and assembled sufficient detail to precisely tell the Atlantis story without putting it into the excruciating details one might expect from an accountant. Feedback from top management revealed that the clear, concise information we presented helped them understand our numbers, avoid surprises and justified the funding we requested."

Unpredictable events would change the landscape for Atlantis and the Commercial and Project Services teams. Storms that struck the Gulf of Mexico tightened the regulatory environment for the entire industry. Internal challenges such as repairs and increased costs impacted the entire project. Current high prices created cost pressures around inflation as the prices we had to pay for everything we needed went up as well," said Elmer. A noteworthy result of the rigorous project services scheduling effort was economized use of expensive assets such as vessels, which are limited in number and in high demand in the increasingly busy global exploration and production environment.

Balancing act pays off

"We're an early warning system in a way," said Naseman. "We work with the delivery teams to help them understand and predict impacts on costs and schedules. We remove some of the administrative burdens from the engineers and work teams, and help them communicate changes. While all the delivery teams, project services and the commercial analysts can't always be in agreement, we've discovered that if you have the means to track issues, get them on the table early and discuss them, you can reach solutions to challenges much more amicably and efficiently."

Top-level management continues to sing their praises. "We were blessed with some very strong Project Services Team leaders, including Bill Naseman, David Tomasko and Martin Thomas, and they've been a major part of the Atlantis success," said Greg Sills, Atlantis Performance Unit Leader. "Having a group of project services professionals is only part of the story. Line managers themselves must understand the value of meticulous planning and have the drive to reach that level of detail. Together, their tireless efforts built the foundation for the Atlantis reputation of excellent planning and developed the resiliency to expertly deal with the unexpected."

Looking to the future

After successfully overcoming a number of challenges on its path from discovery to commissioning and first oil over the past seven years, the Atlantis Field has a very big future ahead of it and will serve as a model for future deepwater projects in the Gulf of Mexico and around the world.

"Atlantis is already a giant and it has the potential to be a super giant," says Simon Todd, performance unit leader for Atlantis. "It is awesome what we have already delivered. The sanction of the Atlantis North Flank speaks to the huge potential of the field. And over the next few years we have the opportunity to further increase the number of options that we have to work with in the Atlantis area."

To capitalize on future expansion opportunities throughout the field, the Atlantis team had the foresight to build in expansion capacity on the Atlantis PQ, giving it the flexibility and capability for future tie-ins.

During the final stages of Atlantis construction and commissioning, Todd's team began focusing on making sure the business processes and culture that are required of a production operation were in place.

"We wanted to hit the ground running as a production revenue-generating business and build off the strengths of this major project," Todd says.

The detailed planning that was invested in Atlantis, combined with the lessons learned from other recent deepwater projects in the Gulf of Mexico, put Atlantis in an enviable position. As a result, Atlantis was able to both quickly ramp up production and deliver superior operating efficiency.

"My job is to find the most expeditious path to realizing those resources. It is an exciting challenge to find the right balance between developing an excellent operation and developing sustainable options for the future."

Gary Imm, deputy project manager for Atlantis, believes Atlantis will be a showcase field for a very long time. "Atlantis has lots of capabilities and functionality that could keep it busy for the next 25 years or more."

Culture of success

The future of Atlantis also is being influenced by the teams and culture of the organization.

"There is something magical about the culture of Atlantis that Greg Sills and the other leaders have created over the last few years. There is tremendous potential and people with great capability on the Atlantis team. I'm motivated by the opportunity to unleash that magic and potential. There is a high level of enthusiasm and a feeling of esprit de corps," says Imm.

Atlantis also represents the overall company's direction in how it manages projects and teams. "There is a deeper listening and engagement taking place, especially with the team on the PQ. It represents where we as a company want to go," Todd says. "There is tremendous capability around collaboration and inclusion of people, ideas and experiences, both within and outside the project. The notion that we need to carry forward is that

Sailaway ceremony in Korea

Atlantis is a big and complex asset and that when we meet challenges we have to address them with integration and collaboration."

Challenges ahead

Despite the success of Atlantis to date and the bright outlook for the field, team leaders also recognize that more challenges await them in the future because the project is on the cutting edge in terms of both technology and complexity.

Some of the challenges of the Atlantis PQ and subsea systems are the result of being on the boundary of science and engineering, which underscores the need for strong collaboration in managing a very complex system, Todd stated.

"But if you put in the proper front-end engineering and planning, the result is usually success, especially for complex projects, and can pay dividends in the end."

Future design options

While the success of Atlantis has substantiated the wisdom of its overall design and innovative approaches, Imm also sees the potential for different approaches for major fields in the future.

"I see us building more standardized facilities for smaller production volumes," Imm says. "Future Atlantis-sized fields might have two or three facilities that are staged over time. With Atlantis, we had so much confidence that it made sense to build a big facility. But with other fields in the future you could start with a 60,000 bpd facility and then you could add another if you see production warrants it."

Imm also believes that going to more standardized facilities may enable the industry to have a facility ready in a shorter time frame.

"I would be surprised if many future fields will be large enough that you would have the confidence to put all your eggs in one basket like we were able to do with Atlantis. Instead, we could see a more staged production approach," Imm says.

Capturing lessons learned

An important goal of the Atlantis management team has been to ensure that lessons learned are captured and transferred to future projects either in operation or in planning stages.

"While our people were focused on Atlantis delivery, we also wanted to transfer those lessons to other teams," says David Tiffin, Completions Excellence Advisor for the Gulf of Mexico. "Atlantis has been very successful and has done things differently. It had a really good organizational model that can be applied to upcoming projects."

As a result, Tiffin's team and others have looked at all aspects of Atlantis from staffing and planning through appraisal and commissioning.

"Some future completions could cost upwards of $1 million per day so if we can use lessons learned from Atlantis to reduce the number of days required for completion by just a few days on other fields around the world, then we will have made a great contribution to those projects," Tiffin says.

In the Gulf of Mexico, for example, the lessons learned from Atlantis are being considered by the teams planning other deepwater projects.

"There are a number of recommendations based on what Atlantis has done that are relevant to other projects in the Gulf, ranging from the number of people and the amount of time required to properly plan well tests. Based on their track record and success, it would be very beneficial to incorporate those lessons"

Tiffin says one of the lessons from Atlantis has been the importance of focusing on staffing and the development of people. Based on the experiences at Atlantis, he notes that some have suggested earlier allocation of more to plan well tests for other promising major fields.

Working smarter

Terry Miglicco, Atlantis Completion Team Leader, sees more smart wells in the future for Atlantis and other major fields.

Major parts of the Atlantis field appear to have two big zones, and some parts have more potential pay zones. To capitalize on the various pay zones, BP has pursued smart completions for some of its wells.

"Smart completions allow you to produce from different zones either separately or together," Miglicco says. "The advantage is that if you start having water in one zone you can remotely shut in that zone without having to bring in a rig and rework the well. In 7,000 feet of water, it's very expensive to get back on these wells."

Atlantis currently accounts for two of five smart completions in the Gulf of Mexico but Miglicco sees that increasing. "In a few years we may have 15 smart completions in the Gulf."

Planning for the future

Looking ahead, Bruce Rogers, Completions Operations Lead for Atlantis, says a lot of intervention activity is planned for the field as BP goes after different zones during the life of the wells in the field.

"One of the exciting things about Atlantis is that there are multiple pay zones in the wellbore -- maybe an average of six each," Rogers says. "We can't complete all of those at one time.

"In the past, with most wells you would plan to complete everything you could and you never planned on going back into the well. On these, we're planning to go back into the wells in the future. This is a long-term subsea development program."

"We're taking the meat of the field first in the middle horizons. Current smart well technology only lets us complete and manage two zones at a time, but we're looking at increasing that over time as smart well technology improves," Rogers says.

Subsurface plans

Looking forward from a subsurface perspective, says Connie Bargas, reservoir engineering advisor, there is a need to understand reservoir performance very quickly.

"There are areas that we still want to appraise. We have started development of the North Flank, but other areas may have potential as well."

In addition, the team has already identified five drill centers, so there will be lots of construction work over time to fulfill the completion plan.

"That makes Atlantis somewhat unusual since for most fields you usually complete construction and then just produce," Bargas says.

Atlantis Fast Facts

- January 1, 1995, BP and BHPB jointly acquire the Atlantis leases
- January 30, 1998, Spud 699 discovery well
- April 22, 2000 Spud 743-1 first appraisal well
- February 1, 2001, Development concept selection begins
- March 30, 2002, Topsides detailed engineering begins
- November 18, 2002, Atlantis project sanction
- June 25, 2003, Topsides module fabrication begins
- December 1, 2003, Hull construction begins
- December 17, 2003, DDII contract award to Global Santa Fe
- March 31, 2005, Hull sails from Okpo, Korea
- May 26, 2005, Hull arrives in GoM
- June 2, 2005, Topsides module lift to PQ
- August 07, 2006, PQ sails from Corpus Christi, Texas
- August 31, 2006, PQ mooring complete: storm safe!
- FIRST OIL October 6, 2007

Sunset at Atlantis

About BP

Leader in the Gulf

BP is one of the world's largest energy companies, providing its customers with fuel for transportation and energy for heat and light. BP employs approximately 97,000 people worldwide and more than 33,000 in the United States. BP's family of brands includes Amoco, ampm, ARCO, BP and Castrol.

BP is also among the world's most progressive large enterprises and is widely known as the first energy company to acknowledge the need for precautionary action to reduce greenhouse gas emissions. Today BP continues to lead the effort to meet the world's growing demand for sustainable, environmentally responsible energy.

BP in the Gulf of Mexico

BP was an early advocate of oil exploration in the Gulf of Mexico—especially in the deepwater province. The company recognized its promise and began acquiring lease blocks during the 1980s, which has led to BP's leading position in the basin today.

BP's knowledge of the Gulf of Mexico region led to a series of significant discoveries, among them Atlantis and Thunder Horse—world-class fields and recognized among the most significant ever discovered in the Gulf.

Subsea tree

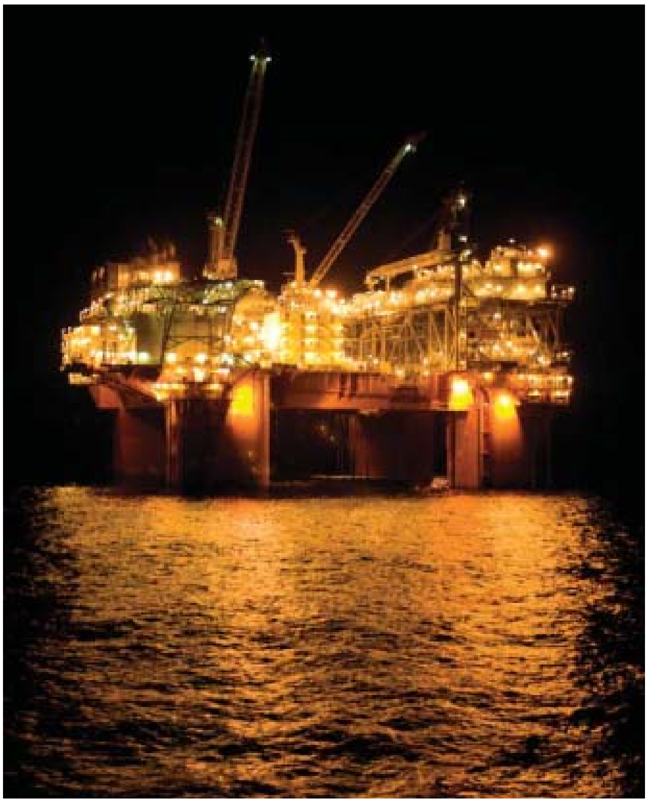
Today, BP is one of the largest acreage holders in the deepwater Gulf, owning more than 400 gross blocks in water depths of 1,200 feet or greater.

For 2000-2010 BP has a $20 billion-plus investment program in the deepwater Gulf of Mexico. The company anticipates its total deepwater production to exceed 450,000 net barrels of oil equivalent per day by 2010 and remain at that level through the next decade.

Gulf of Mexico assets include Pompano (1994), Marlin (1999), Horn Mountain (2002), Na Kika (2003), Holstein (2004), Mad Dog (2005), Atlantis (2007), Thunder Horse (2008) and the Mardi Gras Transportation System (2004) that exports oil and gas to shore.

BP holds interests in a number of other producing and development assets: Diana Hoover, Great White in Alaminos Canyon, Europa, Deimos, Mars, King, Crosby, Princess, Ram Powell, Ursa, and Mica in Mississippi Canyon.

BP operates discoveries that are in appraisal on five exciting prospects for the future: Tubular Bells, Puma, Kodiak, Kaskida and Tucker.



Atlantis by night

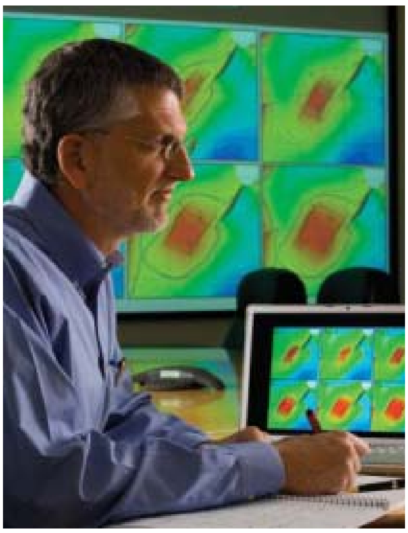
bp

Resourcing the future

BHP Billiton Petroleum, headquartered in Houston, Texas, is one of the fastest–growing business segments of BHP Billiton, the world's largest diversified natural resources company. Being part of one of the world's largest companies, BHP Billiton Petroleum has the financial capability to move swiftly to capture opportunities. Today, the oil and gas company operates in six countries and is conducting significant exploration activities in six others.

BHP Billiton Petroleum prides itself on operating policies that safeguard a highly diverse workforce. With a safety performance record that is in the top quartile of the oil and gas industry, employees and contractors work toward the goal of achieving zero harm to people, to the communities where BHP Billiton operates and to the environment.

The company's exploration focus has been expanded with newly acquired acreage. With a 75 percent increase in exploration spending compared to FY2007, BHP Billiton Petroleum is executing on its largest exploration budget to date. With a significant number of operated prospects, the company focuses on finding acreage that it can ultimately operate during the production phase.



Exploration meeting

With an expanded exploration focus comes a full inventory of developement projects. From the current construction of a tension leg platform in the Gulf of Mexico, to the fabrication of a floating, production, storage, and offloading vessel for Western Australia, a diverse approach to developing future production units instills confidence to continue substantial investments into the future.

Strengthened by sound projects currently in execution, BHP Billiton Petroleum is forecasting the first of several years of double-digit volume growth. With deep and diverse projects already producing across the globe, the goal among all production units is to have 100 percent of wells producing at 100 percent of their maximum rate for 100 percent of the time.

BHP Billiton Houston office

To ensure the company's customers are well served, a marketing team is involved in all aspects of exploration, project development and production. The focused approach to business intelligence coincides with moving into deeper water and in more remote locations than ever before.

bhpbilliton
resourcing the future

bp

Company Profiles

www.bp.com/us

profile: Popham Walter Architects

Enhancing the quality of life by DESIGN

Design and project management of offshore buildings

Since 1978, the rapidly growing offshore oil industry has turned to Popham Walter Architects who specialize in enhancing offshore living and working conditions. PWA's clients range across the industry giants: BP, ExxonMobil, Shell, Chevron, Texaco, Total-Fina, Murphy, BHP, Anadarko, Marathon Oil and many others. In addition to Atlantis, PWA has provided design services for living and working spaces on major structures such as Thunder Horse, Holstein, Horn Mountain, Neptune, Shenzi and Thunder Hawk, to name a few.

Life on an offshore rig has long since gone beyond the work-eat-sleep rhythm for alternating shifts of workers. It has become a home away from home. The growing field of offshore architecture also concerns more than the human environment of basic living quarters, galleys, mechanical buildings, control rooms and the efficient

Consruction of living quarters

use of every square foot on the structure. Equally relevant are the current compliance of regulations and regulatory trends by the USCG, ABS, SOLAS and IMO that govern construction and living conditions aboard offshore platforms.

Popham Walter is a full–service architecture source, including project management for the company developing offshore operations. They work within all the physical dimensions of the rules, regulations, and rating codes to deliver a product of livable work spaces and workable living spaces for the employees who operate this self-sufficient world hundreds of miles offshore. . . a product that exceeds expectations and contributes to the efficiency and functionality of the total operation.

Popham Walter Architects
5851 San Felipe St., Suite 400
Houston, TX 77057
Tel: (713) 850-8575
Fax: (713) 850-8242
Email: pwaoffshore@popwalarch.com
www.popwalarch.com

profile: Delta Catering

A tradition of successful projects & satisfied clients

- Founded in South Louisiana in 1972
- Certified Women's Business Enterprise since 1983

Top: Office & training center in Harahan, Louisiana. Bottom: Delta Catering operates a state-of-the art warehousing & distribution center.

- Providing all the necessities for remote site support:
  - Catering labor
  - Groceries, cleaning supplies & paper products
  - Galley & dining equipment
  - Bed & bath linens
- VIP event planning

A chocolate box created by our offshore baker for a BP event.

- Extensive experience designing galley/dining/living quarters
- State–of–the–art warehousing/distribution, office & training center
- Professional support services: HS&E specialist, dietician/nutritionist
- Global capabilities through international partnership

Delta Catering

Delta Catering Management, LLC
5749 Susitna Drive, Suite 300
Harahan, LA 70123
Tel: 1-800-375-8189
www.deltacatering.com

profile: ABS

Class society ABS guides Atlantis to success

ABS is proud to be the classification society of record for BP Atlantis.

Even before the formal "button push" in the steel plate shop of Daewoo Shipbuilding & Marine Engineering (DSME) Shipyard in South Korea, that signaled the start of production of the BP Atlantis semisubmersible, ABS had been deeply involved in the design. The design required review and approval by the engineers at ABS verifying compliance with the applicable ABS Rules for floating offshore installations.

From the time of the initial steel-cutting ceremony for BP Atlantis, held in South Korea in December 2003, ABS has been proud to have served as the classification society for this technologically advanced semisubmersible.

As production of the unit began, ABS class surveyors stepped in to verify that construction conformed to the approved plans. ABS survey continued after the unit's delivery and final fitting out in the United States and ABS surveyors attended the installation, once again confirming compliance with the society's rules.

In addition to the classification services, ABS coordinated the regulatory review of the unit's design, construction and installation with the U.S. Coast Guard and the U.S. Minerals Management Service, assisting in the award of the needed statutory certification.

Atlantis is one of the most prominent Gulf of Mexico offshore projects. ABS engineers and surveyors have logged thousands of hours as they have worked to support BP in realizing this technologically challenging field development. The Atlantis Field size, water depth and reservoir structure called for demanding requirements on the semisubmersible. For example, the mooring chain for the project called for 4,720 tons of studless chain. ABS surveyors attended the forging at the chain manufacturer to verify conformance with the applicable technical standards.

"Offshore oil and gas exploration has placed much more demanding requirements on mooring chains in terms of reliability and fatigue properties," says Lynnda Pekel, senior engineer, ABS Americas and BP Atlantis project manager.

Pekel was involved with the project for five years. For half of that time she worked from a dedicated office within the project's engineering company, Mustang Engineering. "It is a great help to both the client and to ABS to have a class society representative on site," she said. "It meant that the design engineers could get an almost immediate interpretation of the requirements, prompt answers to their questions and quick resolution of the many technical issues that inevitably arise with such a complex project."

Another successful personnel strategy was having ABS Principal Surveyor Brian Barton, who was involved with the project from its very beginnings in the Korean shipyard, stay involved when the unit was delivered to the United States Barton was reassigned to the Texas Gulf Coast fabrication yard that handled the final outfitting and his knowledge of the structure and systems provided continuity and consistency of interpretations.

Another element of the success of the project was the early involvement of ABS with Atlantis hull designer based in Sweden. "ABS is a global organization," Pekel explained. "These big projects inevitably require a great deal of coordination among the designers, builders and equipment suppliers who may be based in many different countries. We have developed systems and practices that smooth the obstacles that distance can create."

Pekel adds, "We were working with the hull designer from the very beginning and set up a system for submittals that was clear to everyone." "Managing the paper work flow effectively for these huge offshore projects is critical."

No one knows better the scope of work on the Atlantis project than ABS Senior Surveyor David Jackson. Jackson "lived" with the project for an extended period, verifying that the platform met the requirements of the ABS Rules and the Code of Federal Regulations within the Navigation and Vessel Inspection Circular (NVIC 10-82) issued by the U.S. Coast Guard.

"Atlantis is definitely the most technologically advanced semi that I have ever been onboard," commented Jackson, who is now stationed in Corpus Christi, Texas. "The amount of automation is remarkable—from ballast control to fire detection and monitoring, all of which have redundant systems and are operable from two separate control stations."

Although Jackson modestly says he was just doing what any surveyor would do, Pekel insists that he has been a key contributor. "Dave kept me apprised of all issues and opportunities that arose during the commissioning phases," she added. "He was invaluable."

FOUNDED 1862 ABS

ABS
16855 Northchase Drive
Houston, TX 77060
www.eagle.org

Drilling Technology Assurance services save costly overruns

Athens Group is a rapidly growing company providing rig software and control engineering services for major companies such as BP, ExxonMobil, Statoil, Transocean, Total, Chevron, Maersk, KCADeutag and Noble. We help reduce risks, saving time, injuries and costly project overruns on high-end fifth–and sixth–generation rigs.

Development Driller II during commissioning.

On projects like Atlantis, a number of highly competent vendors perfect their systems under both planning and running conditions—and protect their system's integrity in an environment populated by other companies doing the very same for their systems. Unfortunately few of these systems were specifically designed to connect with each other. The result is poor integration that often results in serious incidents of scope creep, schedule slippage and expensive cost overruns.

Implementing a software/control engineering discipline can help minimize these problems by catching them earlier in the cycle when they can be corrected faster and less expensively.

To implement this discipline, somebody—either a member of the customer project team or a third-party specialist software engineer—is assigned to:

- Capture the project's overall requirements
- Review the design
- Develop comprehensive testing
- Manage the integration of many vendor projects into one seamless deliverable
- Maintain the total software quality as changes are made.

We provide a variety of rig software services that can be implemented quickly and cost-effectively. These services speed project completion and ensure software project management best practices. One of the key services, employed on the Atlantis project, was a highly advanced Failure Mode and Effects Criticality Analysis (FMECA).

FMECA is a proven and widely used method of quality engineering hardware analysis. We have extended its application to software and control systems to address the potential for multiple points of error resulting in redundancy problems, unidentified interlocks between systems and unexpected design functionality issues.

To mitigate these threats, we have developed industry-leading expertise in predicting and identifying potential problems, not only within systems but also at contact points between systems.

We have deep, cooperative relationships with all the major vendors of control systems on high-end rigs. We work with them to ensure that commissioning and acceptance on new rigs catches software problems before they cause nonproductive time. Most commissioning and acceptance procedures don't test for software. Integration of systems such as the drilling package, cyber-chairs, vessel management and DP cannot be fully tested until everything is assembled. With Athens Group involved, software/control testing can proceed, even while hardware is being assembled, thus reducing total rig preparation time.

Software and control problems impact your drilling time. Before your next project, we recommend assessing key risk reduction actions that can be taken in a quick and effective way to to reduce NPT and schedule delays.

ATHENS GROUP

Athens Group
11211 Katy Freeway, Suite 315
Houston, TX 77079
Tel: (877) 499-8393
Email: info@athensgroup.com
www.athensgroup.com

profile: ATKINS

Plan, design, enable

We plan, design and enable the delivery of complex capital programs for clients in the public and private sectors across the globe.

Atkins is an engineering and design consultancy, providing expertise to help resolve complex challenges presented by the build and natural environment in Europe, the Middle East, Asia Pacific and the Americas.

Our 18,000 employees have completed successful projects in more than 150 countries, and our clients range across the public and private sectors. They include central and local governments, major financial and retail companies, manufacturers, utilities, and energy providers.

As the problems facing our clients become more complex, we bring real value by continuing to develop and deliver more innovative and practical solutions through our expertise and state-of-the-art technology. Faithful + Gould, a key subsidiary of Atkins, also complements the service portfolio by providing planning and commercial expertise to our clients.

Atkins has been active in the oil and gas industry for more than 30 years, working closely with BP throughout this time. Initially, our activity focused on BP's work in the North Sea, but the last two decades has seen our involvement grow to span the globe. Atkins' service offering can be described as holistic integrity management, supplying technical expertise at all stages of an oil and gas project, more specifically in the areas of

- Facilities engineering
- Structural engineering
- Pipelines and subsea engineering
- Process simulation
- Reliability, availability and maintainability assessments
- Safety and environmental protection
- Project planning and cost engineering

With respect to the Atlantis project, Atkins' involvement has spanned the entire project life cycle and truly delivered our complete "Plan, Design and Enable" service philosophy. We were involved in the early planning stages, completing a number of conceptual engineering and concept studies; throughout the design and execution phases providing technical expertise and assurance in a range of areas.

Working as part of the BP-led Project Management Team, Atkins has provided a range of services to the project, including:

- Concept safety evaluation
- HAZOP/HAZID
- Nonlinear structural assessments
- Execution risk assessments
- Process engineering
- Scheduling and planning (via our subsidiary Faithful + Gould)
- Reliability assessments
- Fire and blast assessments

As the Atlantis development moves into the operational phase, Atkins will continue to provide integrity management support for a wide range of aspects on the facility. Using Fleet Management Systems (FMS), our state-of-the-art Web-based integrity management application, Atkins will give BP the ability to manage the operational integrity aspects of the Atlantis development.

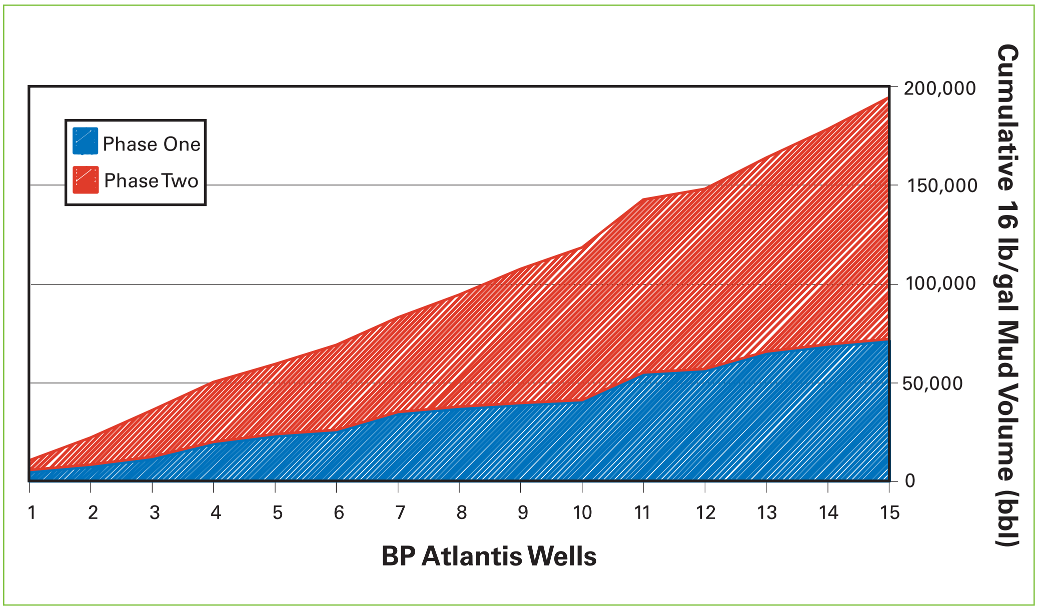
Atkins enjoys a worldwide reputation based on our philosophy of complete life cycle support for our projects. We look forward to continuing our involvement with the Atlantis development.

ATKINS
Kristina McFarland
Marketing and Communications Manager
Tel: (713) 463-6180 Ext: 2006
Kristina.McFarland@atkinslgobal.com
www.atkinsglobal.com

Contributing to BP Atlantis' success through drilling and completion innovations

On the Atlantis development project, Baker Hughes helped BP evaluate complex subsalt reservoirs, drill with efficiency and safety at record water depth, and complete wells with intelligent well controls. Specifically, BP relied on Baker Hughes to provide technology solutions to address critical drilling and completion issues, including:

- High-volume fluids for batch drilling of surface intervals
- Constant rheology fluid for hole integrity and to control mud losses
- Precise 3D well placement in relation to the earth model, guided by while-drilling measurements
- Maintaining ROP and BHA reliability through interbedded sand/shale sequences
- Completion systems capable of sustained production rates up to 40,000 BOPD
- Completions enabling complex, high-rate fracing operations
- Intelligent Well Systems to provide the ability to change flow rates from wells without intervention as reservoir conditions changed.



Baker Hughes Drilling Fluids team delivered high fluid volumes to BP Atlantis wells during DKD riserless drilling.

Ensuring well control through advanced fluids technology

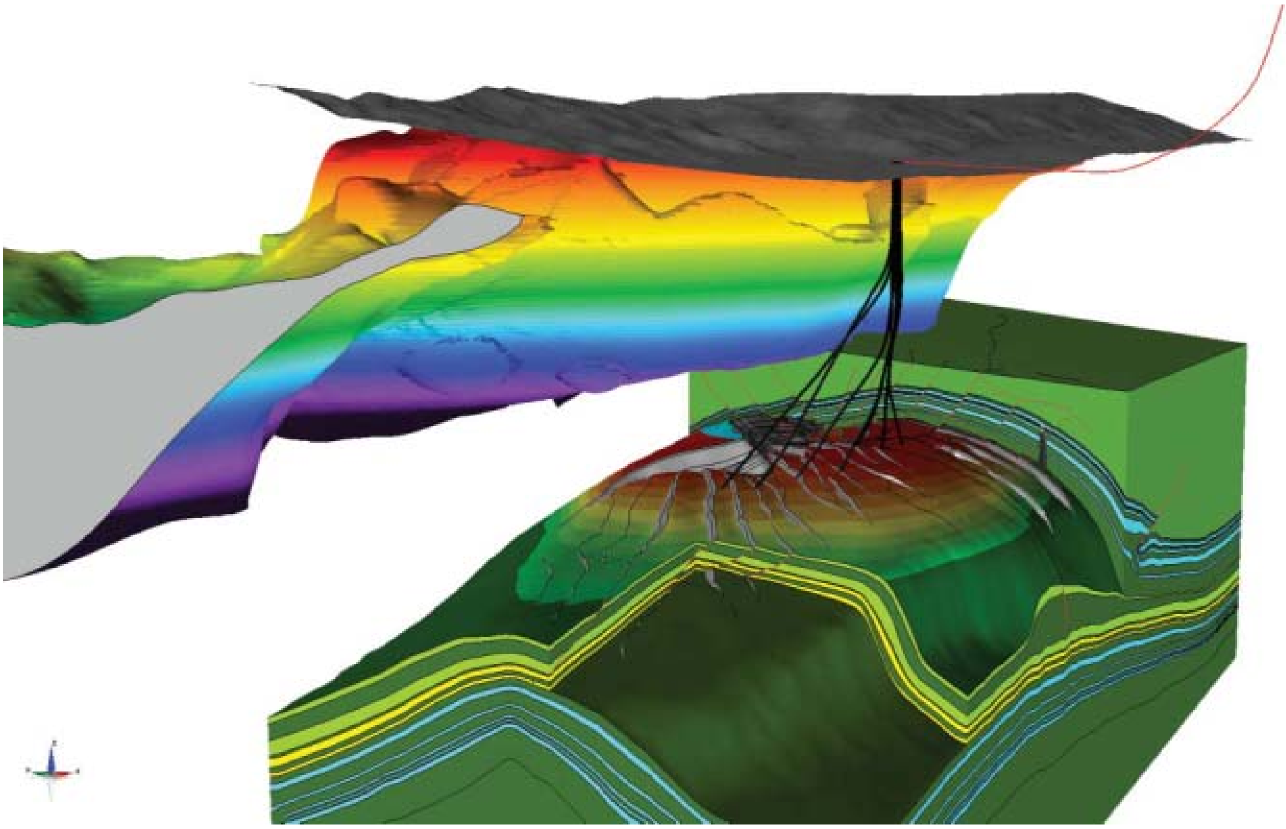
Since the beginning of the Atlantis project, Baker Hughes Drilling Fluids (BHDF) division has been an integral partner of the BP team. Pre-planning, controlled logistics and teamwork delivered a record-setting 193,110 bbl of Dynamic Kill Drilling (DKD) fluid to batch-set 15 development wells using riserless drilling techniques. The BHDF fluids team met the challenge of setting two casing strings in each well while minimizing fluid volume, yet maximizing hole cleaning and ROP. BHDF's Fourchon, Louisiana, supply base delivered the high fluid volumes for these wells. The work was performed ahead of schedule and with no LTAs.

In deepwater applications, managing hydraulic pressure downhole with conventional synthetic-based muds is a major challenge. As a solution, BHDF introduced the RHEO-LOGIC℠ system, a constant rheology synthetic-based fluid to minimize downhole mud losses. The DC112 (U) well was drilled using RHEO-LOGIC fluid with downhole losses of only 86 bbl while running casing, compared to an average of 980 bbl in previous wells. Average circulating times during connections were reduced in all intervals, with a total savings of nearly 20 hours over the course of the well.

Successfully addressing drilling and evaluation challenges

The Atlantis Field presents a number of drilling and evaluation challenges common to subsalt deepwater plays. These include directional control, drilling efficiency and vibration and hole integrity management in salt, geological uncertainty due to poor subsalt seismic resolution, and reservoir uncertainty due to subseismic faulting associated with salt tectonics. Baker Hughes INTEQ provided multiple while-drilling solutions for reliable drilling hazard mitigation, and improved wellbore placement and comprehensive formation evaluation.

For a better understanding of the overburden and subsurface geology, density- and gamma-based borehole images were acquired from the 14.5 inch by 16.5 inch section to the 12.25 inch reservoir section. By obtaining the borehole images via independent OnTrak™ and LithoTrak™ LWD sensors, the BP team received detailed structural information for integration with seismic data, including fault identification and improved geological models, enabling accurate 3D well placement. Petrophysical analysis benefited from resistivity inversion and formation dip correction, improving the certainty of



The complexity of the Atlantis Field is evident in the EarthVision model. Well planning and placement benefit from real-time updates to the model based on LWD data from Baker Hughes INTEQ.

Hughes Christensen's seven-blade, 5/8-inch cutter Genesis PDC pilot bit was used to open 20-inch and 16.5-inch sections in BP Atlantis wells.

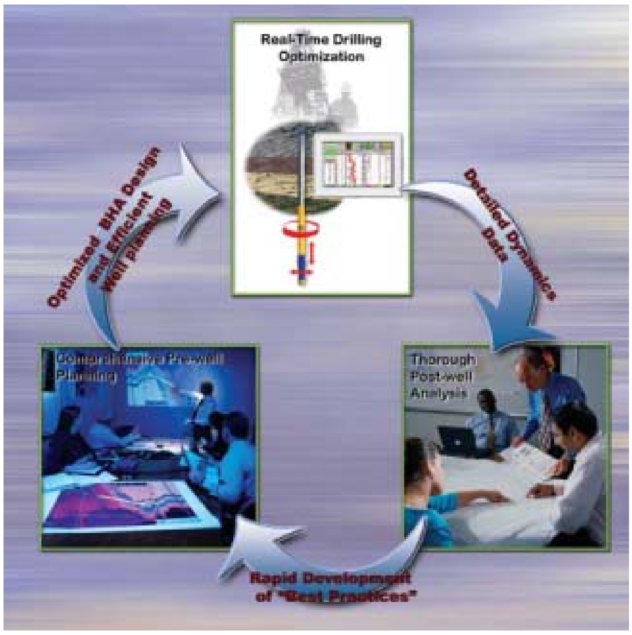
water saturation calculations. INTEQ's TesTrak™ service provided while-drilling pressure measurements to confirm reservoir fluids in shallower sands, and assist in evaluating reservoir connectivity to offset wells and to correlate main reservoir sands across the field. The TesTrak tool's ability to test-while-circulating eliminated the risk of differential tool sticking and helped ensure wellbore stability, while facilitating real-time fluid management in the field's abnormally pressured sub-salt formations.

Drilling optimization through CoPilot℠ service

The CoPilot drilling optimization service has delivered continuous improvement in drilling performance and risk management for the Atlantis project since 2005. This service is based on comprehensive pre-well planning, downhole data acquisition with real-time diagnostics and post-well analysis. Although the CoPilot service has been used throughout all the wells, it has proven particularly useful in the challenging 14.5 inch by 16.5 inch and 14¾-inch by 16.5 inch hole sections, which combined directional work in laminated sand sections and reaming-while-drilling using hole opening devices. In offset wells, this interval had a history of failures with the previous drilling service contractor.

Before the CoPilot drilling optimization approach was introduced, not a single well in this interval had been successfully drilled in one run. The AutoTrak™ G3 system, in combination with the CoPilot service, enabled field service personnel to react immediately to whirl events identified by the CoPilot downhole system, adjust drilling parameters for improved drilling performance, and monitor the hole quality. As a result, these sections were drilled in a single run in the five consecutive wells. All the formation evaluation data acquisition and directional objectives were met with low-hole tortuosity confirmed by CoPilot bending-moment measurement, facilitating superior casing placement. By enabling quick, informed decisions based on real-time data rather than from failure patterns, the CoPilot service has accelerated the well-to-well learning curve for the Atlantis team.

Baker Oil Tools used a milled sleeve to house and protect the Intelligent Well System control line splices.



The CoPilot continuous improvement cycle includes data capture for detailed post-well analysis and identification of "lessons learned" in BHA design, bit selection, and best drilling practices for the next well.

Achieving efficiency through drill bit innovations

The BP Atlantis team used expandable reamers in the BHA to drill through challenging interbedded sand/shale sequences. This drilling configuration can result in destructive levels of vibration. Hughes Christensen engineers analyzed this dynamic condition and developed solutions to achieve the best possible performance.

Vibrations can occur when there is a change in the depth-of-cut (DOC) ratio between the amount of rock removed by the pilot bit and the amount of rock removed by the reamer. For the 20-inch and 16.5 inch hole-opening sections, Hughes Christensen utilized a Genesis™ seven-blade, 5/8-inch cutter bit design for the pilot bits, which included the following stability features:

- High-imbalance cutter layout to correct damaging backward whirl patterns
- SmoothCut™ technology to limit DOC and to balance the drill rate between the pilot bit and the reamer
- Lateral Movement Mitigator™ technology to reduce vibration severity and protect shoulder cutters from impact loads
- Zenith™ cutters to maintain sharp cutting elements for the duration of the run.

Through a Hughes Christensen/BP continuous improvement process, there has been a significant reduction in downhole vibration, leading to fewer downhole tool failures, more efficient drilling and lower cost per foot.

Completions with intelligent well control

Since the planning phase of the Atlantis project, Baker Oil Tools (BOT) has worked to develop optimum completion options to meet stringent BP requirements. Known challenges have included expected production rates of 30,000 to 40,000 bpd. Another concern was providing the ability to frac the production zones at rates of 35 to 45 barrels per minute with proppant volumes of up to 250,000 pound per zone, while monitoring the live annulus. BP also needed to isolate the lower zone while fracking the upper zone.

BOT engineers worked closely with BP staff to provide completion tools and equipment that would meet or exceed the demands of the Atlantis project, including Neptune™ Safety Valves that were also used on BP's Thunder Horse project. From a sand control perspective, BP wanted to maximize its production rates through a monobore completion. BOT supplied its CK Frac™ system featuring a "smart collet" positive locating capability for monitoring of all set-down positions. To isolate the lower zone while fracking the upper zone, BOT used its Injection Control Valve, an upstream pressure regulator that is balanced with respect to downstream pressure. Thus far, BOT has completed successfully seven challenging deepwater subsea Atlantis wells.

The need for intelligent well control was addressed early using HCM sliding sleeves and Premier™ packers with feed-through capabilities. BOT assisted BP in installing the first Intelligent Well Systems completion in late 2006 on the "B" well. The second such completion took place in early 2007, and the third will be run during the second quarter of 2008.

BAKER HUGHES

Baker Hughes Incorporated
2929 Allen Parkway
Houston, TX 77019
Tel: (713) 439-8600
Fax: (713) 439-8699
www.bakerhughes.com

profile: **Champion Technologies**

Champion Technologies, "chemical company of choice," chosen for BP Atlantis

In the past half-century, Champion Technologies has grown from a small regional oilfield service company in the PermianBasin of West Texas to become one of the world's largest and most successful specialty chemical companies serving the oil and gas industry.

A privately-owned company, Champion Technologies has thrived because—throughout our existence—we have focused on understanding the specific needs of each of our customers. Our custom-designed chemical solutions applied as parts of comprehensive production strategies have been demonstrated to enhance well productivity and optimize recovery economics.

Champion Technologies has worked tirelessly to advance the science of oilfield chemistry and to create a knowledge-based company with an industry-leading staff of chemical experts capable of delivering a variety of chemical solutions to fit specific reservoir conditions, wherever in the world our customers are working.

Champion has created a knowledge-based company with an industry-leading staff of chemical experts.

For many production companies, Champion Technologies is the chemical company of choice, with the experience, knowledge, people, financial strength, and global organization capable of providing a complete portfolio of chemical products in producing areas and exploration frontiers around the world.

Champion is known for its focus on oilfield specialty production chemicals. We are equally well-known for our client relationships. For example, our industry-leading R&D program has produced 14 patents in the last five years. Three of these patents were jointly developed with client companies. This is our kind of commitment and cooperation.

BP has had long experience working with Champion. Our management services provide chemicals for BP operations in its Gulf of Mexico Southern Green Canyon block, which includes Holstein, Mad Dog and Atlantis.

From concept through operations, Champion provides expertise in flow assurance, integrity management, production enhancement, and separations.

Our Champion Technologies Depth Team™ is a specialized group of engineers and industry experts focused on deepwater production. Our extensive offshore experience includes production in some of the world's most challenging locations.

To meet these challenges, we have developed proprietary products like our low-dosage hydrate inhibitors Assure® HI-40DW and Assure® HI-43DW. These products, coupled with unique technology applications, allow us to get the most performance and efficiency from operations.

Champion Technologies R&D has developed proven best-in-class performers along with unique application technology and niche products for deepwater applications. From concept through operations, Champion provides expertise in flow assurance, integrity management, production enhancement, and separations. We understand the big picture and bring our customers the people they need, the products that work, and the performance they require.

Champion Technologies growth does not rest solely on technological excellence. We back that up with full account service at every point of contact between the client and Champion. Our people are recognized as team players working with their counterparts in client companies.

But onshore or offshore, Champion supports a fit-for-purpose product line applied by field experts based on thorough analysis and sophisticated modeling technology. In marginal wells, our products and services offer solutions to economically improve production and extend well life in the most difficult applications. We've grown but we're still focused on our customers. Each project still begins with a customer's specific problem—not an inventory of standard chemical treatments.

Champion Technologies

Champion Technologies
3200 Southwest Freeway, Suite 2700
Houston, TX 77027
Tel: (713) 627-3303
Fax: (713) 627-9353
www.champ-tech.com

Fairfield Industries—Z Technology—your solution to imaging and monitoring offshore reservoirs and complex structures

Fairfield Industries is a privately held, full-service geophysical company operating worldwide. We are known for our development and use of advanced technology for seismic data acquisition and data processing. Our hardware, software and people resources provide the oil and gas industry with risk-reducing solutions to solve challenging exploration and production problems.

Fairfield was one of a number of companies that BP invited to compete in the development of the initial system for Autonomously Recording Deep Water Sea Floor Seismometers to function at depths of 3,000 meters. In response to that challenge, we developed the Z 3000, which won BP's 2006 Global Helios Partnership Award for Innovative Technology.

The Fairfield Z 3000 is composed of individual self-contained nodes with no external connection or moving parts, thereby eliminating potential operational problems or failures. Each node is rated for water depths of up to 3,000 meters and utilizes flash memory and state-of-the-art lithium-ion battery packs for cost-effective operations.

A OBS node

the BP Helios Award Partnership winner in 2006

The Z 3000 is the world's first commercial, deepwater, wide-azimuth nodal seismic data acquisition system. Its first application was the world's deepest 3D seafloor survey over the giant deepwater Atlantis Field in the Gulf of Mexico. It proved extremely reliable in these challenging conditions. Its superb signal-to-noise ratio led to a new level of geophysical resolution and interpretation in deepwater fields. Due to its positional accuracy, the Z 3000 is ideally suited for 4D Time Lapse reservoir monitoring.

Fairfield specializes in all phases of data acquisition and processing, including:

- Designing and manufacturing seismic acquisition systems
- Operating exploration crews
- Processing a wide variety of seismic data.

We have a long history of pioneering in seismic work. Our first 2D transition zone program began in Louisiana in 1976. We introduced our first, nonexclusive 3D survey in 1989, and licenses have been granted to more than 125 exploration and production companies operating across the Gulf of Mexico shallow water/transition zone areas. We acquire all data using seismic recording systems designed and built at our own manufacturing facility in Houston.

Our general philosophy is to grow from within. The acquisition of Golden Geophysical in 1987 was our largest expansion, creating a full-service geophysical company. We are careful in controlling the pace of our growth, yet aggressive in our development of technology.

FAIRFIELD INDUSTRIES

Fairfield Industries
Paul Bourgeois
Tel: (281) 275-7646
Email: pbourgeois@fairfield.com

FMC Technologies enables installation and maintenance savings for Atlantis

FMC Technologies' contributions to the Atlantis project are found from topside controls and surface equipment on the platform to proprietary systems installed on the subsea floor. Some of these contributions represent expertise unique to FMC. Each of the contributions is indicative of the company's ability to save operators time and money while ensuring commitment to Health, Safety & Environment (HSE) performance.

For example, its field-proven UWD-15 Rigid Lock Stack Down (RLSD) Wellhead System, rated for 15,000 psi internal pressure and 10,000 feet water depth, was utilized to withstand the torsion and fatigue loads from the dynamically positioned drilling vessel. Used in conjunction with the Drill Ahead Tool (DAT), the system saved time and money by reducing the number of drill pipe trips.

FMC's Enhanced Horizontal Christmas Tree (EHXT) was the tree of choice for BP's Atlantis project. It eliminates the internal tree cap found on traditional horizontal trees and replaces it with a Remote Operated Vehicle (ROV) installable/retrievable tree cap that locks into the tubing hanger. This feature significantly reduced installation time and cost for BP.

The tree was also built with higher reliability standards and improved subsea functionality. At depths of 10,000 feet, breakdowns are incredibly expensive, often requiring time-consuming and costly shut-ins, and the need for specialty vessels to perform maintenance and repairs. FMC equipped its EHXT with ROV retrievable/installable pressure and temperature sensors that can be replaced without pulling out the tree, thus eliminating production downtime and improving reliability by ensuring the sensors are always operable.

Another feature FMC specially designed for Atlantis was a "compact" subsea manifold. Traditional manifolds are large and heavy, requiring costly heavy lift vessels to install them. By contrast, FMC's engineers minimized Atlantis' manifold design, making it small and light enough to permit the drilling rig to perform the installation, providing value and efficiency to BP's Atlantis project.

Exceptional technologies like these are coupled with exceptional HSE performance. FMC has one of the strongest HSE records in the industry, and its efforts do not stop in its own operations. The company requires all parties involved in its projects to follow the same HSE standards; it works closely with its vendors to achieve continuous improvement; and it makes HSE personnel available to help vendors resolve particular issues.

With its deep involvement at many levels of the Atlantis project, and its total quality and HSE commitment to each of those areas, FMC knows first-hand what a superb engineering achievement BP has accomplished and congratulates the project team on its completion, looking forward to a long and challenging association in future offshore projects.

FMC Technologies, Inc. is a leading global provider of technology solutions for the energy industry. The company designs, manufactures and services technologically sophisticated systems such as subsea production and processing systems, surface wellhead systems, high-pressure fluid control equipment, measurement solutions, and marine loading systems. FMC Technologies employs approximately 12,000 people worldwide and operates 33 manufacturing facilities in 19 countries.

A "compact" manifold design allowed efficient installation from the drilling rig.

The Enhanced Horizontal Christmas Tree reduced installation time and costs for BP with its ROV installable features.

FMC Technologies
Subsea Systems
1777 Gears Road
Houston, TX 77067
Tel: (281) 591-4000
Fax: (281) 591-4002

Solving needs to deliver performance-driven results

The Frontline Group is a 15-year-old privately held company that works primarily in oil and gas Exploration and Production. Our mission is to identify performance and efficiency opportunities in areas of Common Process, Continuous Improvement, Quality Assurance, and Lessons Learned. From our offices in Houston and the U.K. we have delivered projects on six continents. Past and present clients include BP, ConocoPhillips, Chevron, ExxonMobil, Marathon, Shell, Saudi-Aramco, Newfield Exploration, Willbros Engineering, MOL Hungarian Oil & Gas, and Schlumberger.

High-performance teams, continuous process improvement, quality assurance, and lessons learned don't just happen on rigs located miles offshore. They require a dedicated team whose job is to recognize and implement process improvement opportunities not only "next time" but this time. That is The Frontline Group's niche in major E&P projects such as Atlantis.

Even in highly specialized fields such as well delivery and rig delivery, bringing together the work of numerous vendors in an optimal way is a dynamic and opportunity-rich area for savings and efficiencies.

The operator and the vendors need a common process. We identify performance goals and provide measures to show where problems reside and how they can be fixed.

The operator also needs a quality assurance process. Errors or unsuitable supplies are costly mistakes on offshore rigs. Our personnel help avoid them by going down the supply chain and establishing quality assurance and continuous improvement processes with vendors. We qualify vendors and tour their sites to audit those processes, thereby reducing unsuitable deliveries and breakdowns at the rig ensuring a sustained reduction in nonproductive time (NPT).

Lessons are learned on every project. But, on a long-term project like the development of the Atlantis Field, they can be lost among the changing configurations of vendors and personnel. We provide a Learning Loop to capture and immediately leverage those lessons. On Atlantis, we introduced a Learning Loop, implemented it, and supported it.

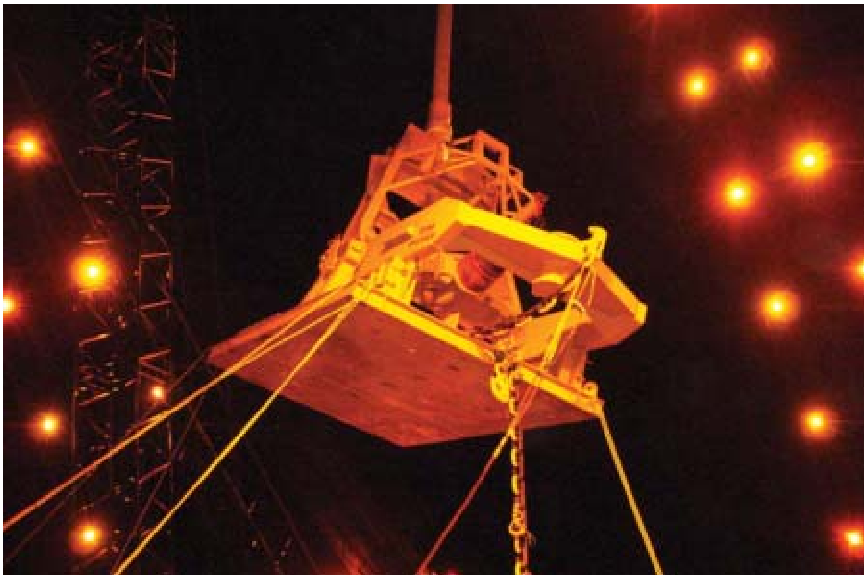
Innovation can be a powerful cost-saver. But the chance to innovate can be lost if no one is responsible for improving the current process. At Frontline, we see decades of Quality Assurance and Total Quality Management as pointing out new ways to solve problems. Many of these are ways in which skillful data collection and process design can be used to turn seemingly isolated incidents into a statistically usable methodology for predicting and avoiding problems. With our partner CSI, we deliver a Six Sigma training program that is already showing measurable results on Atlantis. Frontline Group/CSI solutions are among the earliest uses of Six Sigma in E&P.

We take a lot pride in our contribution to Atlantis, but we feel BP's Jonathan Sprague, BP's Atlantis wells delivery manager, said it best: "The Frontline Group, which has been part of the Atlantis team since the early days of the project, is relentless in their efforts to assure that our business processes and systems are aligned with our culture. Whether implementing a Six Sigma program, providing Quality Assurance in vendor or equipment selection, supporting the BP Common Process or delivering a Special Project, I know I can count on them to help keep our performance best in class."

Frontline Group resources integrate directly into high-performance teams like Atlantis to assist and guide in developing, improving, and fine-tuning key work processes. The result is continuously optimized high-end performance.

HMC designs new solutions at Atlantis project

Heerema Marine Contractors (HMC) is a leading marine contractor in the offshore oil and gas industry and operates worldwide. We have extensive experience in heavy lifting and the design and installation of structures and pipelines in up to 3,000 meters of water depth. We currently operate two deepwater construction vessels, Balder and Thialf, as well as the semisubmersible crane vessel Hermod. For work on projects like Atlantis, we offer the full range of expertise, experience and construction capability.



PLET lifted up to J-Lay Tower.

Unique material

The installation of five Pipe-in-Pipe (PiP) flow lines and risers and one water injection pipe at 2,150 meter water depth marked the last phase of Heerema Marine Contractor's scope of the BP Atlantis Project.

HMC Project Manager Bas Zoon pointed out that HMC's Balder was the only vessel capable of combining the handling of the long mooring lines, suction piles and riser transfer loads, and achieving the high-quality welding requirements for the steel catenary (SCRs) risers of the export and infield pipelines. To have all this work handled by the same installation contractor provided great flexibility, reduced Simultaneous Operations (SIMOPS) and a lowered risk of interface clashes for the client. This project was a clear example of using a former semisubmersible crane vessel to its full capacity as a safe and reliable deepwater construction vessel."

Deputy Project Engineer Arthur van Opstal says, that after a feasibility study of a year, the flow lines and risers part of the project was awarded in August 2005. HMC carried out a detailed pipelay analysis, developed a SCR transfer procedure, detailed calculations of inner-pipe behavior and developed purpose-built lifting tools and equipment. The Atlantis project was HMC's first PiP installation.

New tools

Back in 2002 the balder was upgraded with PiP installation in mind. When the PiP project was awarded, the basic design had to be further developed by fabricating, installing and commissioning various PiP tools.

HMC developed two instruments to keep the inner pipe in place when welded, the Obelix and Idefix tools. The Obelix tool can handle weights of 80 to 100 tonn and the Idefix up to 10 tonn.

Other newly developed tools were a beveling tool and a sliding tool. The latter is able to move the inner pipe independently of the outer pipe to allow easy access for beveling and welding. Because of stringent weld criteria the quality of the welding had to be outstanding.

Bulk head installation: Inner pipe is pulled out to proper inner pipe tension.

Project Manager Dick Wolbers explains that as pipe sizes and water depth of the Atlantis export SCRs were never experienced before, extensive studies were performed on "what-if" scenarios for an accidental, flooded pipe. Based on those studies a limit state approach was taken on the SWLs of certain equipment and rigging.

Point of no return

The SCRs were hung off at the end of the pipeline installation. This is called a "second-end" SCR installation. The second-end method gives a lot of flexibility to the installation schedule—in this case the pipelines were installed and the last portion (the SCRs) was installed after the hull was in place. The downside of a second-end method is generally that during SCR pipelay there is a certain point of no return. When this point is passed either the SCR has to be completely installed or when weather deteriorates the SCR has to be cut back until the point of no return. For both the infield and export pipelines many contingency plans were in place to reduce the required weather window after the point of no return as much as possible.

Once the flow lines, anchor yokes and risers were installed, the flex joint attached to the SCR had to be transferred from the hang-off table on the Balder and hung off in chain jack of the Platform Quarters (PQ). The use of a flex joint combined with a 40-meter spool piece posed some rigging challenges, explains van Opstal. The weight of the pipe, which had to allow for its flooding, required the combined use of the crane and the J-Lay tower. We used an A&R cable of 750 m attached to the top of the crane to hold a part of the weight. We also ran a nylon rope from a winch on the Balder to the PQ. This thrust assistance system helped reduce horizontal thrust levels from high currents and deteriorating weather.

Challenging project

On September 2, 2007, the last flow line was landed in its receptacle porch on the Atlantis PQ. By reaching this milestone the Balder completed the extensive flow lines and risers installation program.

Looking back, HMC Project Manager Wendell Freeman says, "The work was planned, engineered and executed to the last detail; notwithstanding, there were setbacks and unforeseen problems. The best-known problem was the Balder flooding incident. As disruptive as the incident was, the recovery of the Balder in record time while continuing to perform installation activities shows the character of HMC, both onshore and offshore. The success of the Atlantis flow lines project and the groundwork it laid for future projects were a results of the excellent working relationship between HMC and BP and both parties' commitment to safety, quality, production, and attention to detail. The offshore success started with a solid onshore foundation and was followed up by outstanding execution by all involved in the project."

"I have been working for more than 10 years in the offshore installation industry and have to say this project was the most challenging job I have worked on," adds Bas Zoon. "Since this was HMC's first Pipe-in-Pipe job, a lot of new equipment had to be designed and fabricated. Three years of study and engineering and onshore fabrication were required to prepare all equipment and procedures and complete all tests to be able to install the 16-by-10 inch PiP system in over 2,000 meters of water depth. Most systems on board were loaded to their maximum capacity during installation of these heavy pipelines, especially during the transfer of the riser system to the platform. I am deeply impressed by the skill and teamwork that were displayed by the onshore preparation team and the offshore installation crews on the Balder, support vessels and PQ in performing the work."

Inner pipe fixation tool 'OBELIX' installed in welding station

profile: J. Ray McDermott

J. Ray McDermott receives excellence award for Atlantis project

J. Ray McDermott (J. Ray), a leading EPCI offshore field development company with operations in the Americas, the Middle East, the Caspian and Asia Pacific, achieved an industry milestone when it was awarded the Louisiana Contractors 2005 Award for Excellence in recognition of its involvement with the Atlantis project.

J. Ray McDermott constructed three modules for the Atlantis topsides. The production and compression modules are each approximately 5,000 tons, and the power generation module (pictured) is approximately 4,000 tons in weight.

J. Ray's contribution to the project was the fabrication of three topside production modules. Built at the company's Morgan City, Louisiana, facility, J. Ray procured bulk steel and interconnected piping materials and assembled the three modules totaling 13,600 tons (6,700 tons of structural steel, 1,775 tons of interconnect piping and 5,125 tons of engineered equipment).

Project management is key

A project management team was assembled by J. Ray in early 2002 that consisted of 40 individuals: discipline engineers (structural, piping, E&I equipment), project controls and estimating, who initially reviewed key concepts of constructability with the design engineering company.

The management team was charged with developing mutually agreeable engineering-deliverables to support J. Ray's construction schedule. The team also initiated the planning and was then charged with executing the work.

During peak construction, more than 600 J. Ray personnel worked on the Atlantis project, clocking more than 2.34 million man-hours at the Morgan City facility. Upholding safety was a top priority for J. Ray's project management team.

J. Ray's seven-member "project controls" group suggested managing the project using "early curve" data from their scheduling system. This was a critical decision that proved to be a chief contributor to the success of the project.

Dimensional control

J. Ray was responsible for getting the modules to mechanical completion and ready for commissioning. One critical interface of the project was mating the completed modules with the semisubmersible hull.

To safely transfer loads into the floating system, the four legs of each module were placed into specially designed supports in the hull, a proverbial threading of a giant needle. Exact tolerances for both the hull and the modules were carefully monitored at each step.

Building for the future

J. Ray's history is tied closely to the early developments of the offshore oil and gas industry. In 1947, its marine group installed the first steel template platform for Superior Oil in just 20 feet of water. Today, J. Ray operates a diversified fleet of vessels for the marine construction industry and has fabrication facilities and engineering offices worldwide.

For more than 50 years the Morgan City fabrication facility has routinely handled projects for the Gulf of Mexico and the Americas. Recently, it undertook fabrication projects for India and Trinidad and is currently supporting a fabrication project scheduled for construction at J. Ray's new fabrication facility in Altamira, Mexico.

Key features of the Altamira facility include a quayside water depth of 30 feet (to be deepened to 39 feet in the future), a 984-foot bulkhead and two 328-foot skidways. Under the lease agreement, J. Ray has the capability to extend the bulkhead length to 3,280 feet, which will provide the space needed to execute deepwater floating hull assemblies.

J. Ray McDermott
USA
757 N. Eldridge Parkway
Houston, TX 77079
Tel: (281) 870-5000
Fax: (281) 870-5045
Email: businss.development@mcdermott.com
www.jraymcdermott.com

With extensive project experience highlighted by many industry "firsts," KBR and its subsidiaries, GVA and Granherne, offer a broad technical knowledge base and project management skills to support all types of floating installations

The Atlantis Field represents a world-class development in record-breaking water depths with difficult seafloor topography. To tackle these challenges, BP selected a subsea development tied to a host semisubmersible facility. KBR's subsidiary, GVA, was chosen to design the semisubmersible hull, based on its GVA 27000 design. GVA's experience includes over 30 years of semisubmersible designs, and the company has been the industry leader in the development of purpose-built semis for floating production applications. GVA designs offer proven performance, shipyard friendly construction and flexibility to adapt to a broad range of field developments.

To execute the hull design, GVA enlisted the assistance of its parent and sister companies, KBR and Granherne, to assemble an integrated team consisting of experienced personnel from all three companies. Project offices were established in both Houston, Texas, and Gothenburg, Sweden. By combining resources, the project was able to reduce the cycle time for the design while ensuring the best qualified resources were assigned to each aspect of the design. Locating a significant part of the project team in close proximity to the topsides and subsea engineering teams in Houston enabled numerous interfaces to be proactively addressed early in the project.

Atlantis hull during assembly at the DSME yard in Korea.

GVA, Granherne and KBR also provided key technical and project support personnel, which formed the core of the BP floating systems team that was responsible for delivering and installing the hull and mooring system. The companies' roles in the execution of the project encompassed engineering management, procurement support, weight control, interface management, technical specialists, shipyard and integration yard site team personnel, commissioning personnel and offshore installation personnel.

Under BP's leadership, the GVA, Granherne and KBR teams worked closely with other project participants to overcome numerous technical and execution challenges and achieve numerous milestones, including

- Design and delivery of the second largest semisubmersible ever constructed
- Detail design, delivery and installation of the record-breaking deepwater mooring system

GVA, together with KBR and Granherne, were chosen to execute the BP Atlantis semisubmersible hull design.

- Successful management of complex interfaces
- Intensive commissioning and testing efforts to ensure all aspects of the hull were ready for service

Throughout the project, BP's leadership team emphasized safety and teamwork. KBR, Granherne and GVA also share these core values and are proud to have contributed to a project with an exemplary record of safety and teamwork.

KBR

Granherne a KBR company

GVA a KBR company

KBR
601 Jefferson
Houston, TX 77020
Tel: (713) 753-2000
Email: offshore@KBR.com
www.KBR.com/offshore

profile: **Mustang Engineering**

Providing topsides facilities design

Applying lessons learned and Digital & Digestible approach helped make for success.

Mustang Engineering is recognized in the global offshore oil and gas industry for providing quality engineering design that blends fit-for-purpose innovations with operational flexibility, creating high-value assets for our clients. As with previous BP deepwater development projects, Mustang was contracted to provide program management support for the Atlantis effort, including engineering design for the topsides facilities. Mustang's scope of work began with the concept selection, which ultimately utilized a semisubmersible floating production facility and 60-person quarters designed for operation in 7,000 feet of water. This is the deepest of BP's deepwater Gulf of Mexico projects. Mustang was responsible for the topsides FEED as well as the detailed design and procurement services for the topsides.

The design accommodated the facility's nameplate capacity of 200,000 bpd oil, of 180,000 MSCFD of gas and 75,000 bpd water injection capability. The topsides were designed with three major components—one process production module, a power generation module producing 60MW and a 28,000 horsepower compression module.

The power generation design centered around BP's mandates for safety and environmental preservation. After studying several drive alternatives, the all-electric solution with three main turbines was chosen.

As the most recent of the four deepwater development projects to reach detailed engineering, Atlantis allowed Mustang's design team to incorporate 'lessons learned' from its similar prior involvement with projects Holstein, Mad Dog and Thunder Horse. With diligence and dedication, the team was even able to shorten the engineering schedule during the last portion of the detailed design phase.

Weight control was a critical factor and a high priority in designing the topsides.

Atlantis, with Mustang-designed topsides production facilities, begins its journey into Gulf of Mexico waters.

The deck, piping and production facilities were designed with an optimal footprint. Weights were continually monitored to coincide with the hull capacity. This close scrutiny proved significant, since the final dry topsides loadout weight of 14,110 short tons was less than 1 percent of the estimated FEED weight.

Digital and Digestible Engineering® pays off

Mustang utilized Plant Design Management System (PDMS) 3D modeling software for designing the topsides components, piping, electrical and instrument run and eliminated potential clashes while minimizing the topsides footprint. Mustang designers worked closely with the topsides fabricator—J. Ray McDermott. Using its Digital and Digestible Engineering® procedures, Mustang directly provided information to the fabricator's nesting, lofting and materials control functions and facilitated the fabrication yard's computer numerically controlled (CNC) steel plate cutting, accelerating that process and reducing rework. Mustang further accommodated the fabricator by reducing the module sizes so they could be fabricated under roof at McDermott's yard, helping to avoid weather delays.

MAC is key player

Mustang's Automation and Control team (MAC) provided the integration of the Atlantis control systems, programming all the interfaces with the various topsides and marine support systems. The Atlantis system was very large, with an I/O count of more than 12,500 hard points. MAC combined its efforts with Honeywell to utilize its FAST (Flexible Automation Solution Team) approach to assure systems integration success for the complex project.

Leading role in interface

As the topsides engineer, Mustang was the logical hub for the complex external interface management effort. As such, Mustang assisted with the development of the process and provided close interface with providers of the hull, topsides equipment, subsea component, and the fabrication yards.

Mustang's performance on the Atlantis project was consistent with its growing position in the industry as the Deepwater Center of Excellence®.

MUSTANG
A Wood Group Company

Mustang Engineering
16001 Park Ten Place
Houston, TX 77484 USA
Tel: (713) 215-8000
Fax: (713) 215-8506
Email: matt.sellers@mustangeng.com
www.mustangeng.com

Nexans Norway has supplied steel tube umbilicals, electro/optic umbilicals, IWOC umbilicals, and flying leads for BP's Atlantis project

About Nexans

With energy as the basis of its development, Nexans, the worldwide leader in the cable industry, offers an extensive range of cables and cabling systems. The global group is a world player in the infrastructure industry and building markets. Nexans addresses a series of market segments from energy, transport and telecom networks to shipbuilding, oil and gas, nuclear, automotive, electronics, aeronautics, handling and automation.

With an industrial presence in more than 30 countries and commercial activities worldwide, Nexans employs 21,000 people and had sales in 2006 of 7.5 billion euros. More information is available at http://www.nexans.com.

Atlantis umbilicals being spooled to reels before shipment to Gulf of Mexico.

About Nexans Norway:

Nexans Norway AS is a subsidiary of Nexans and the leading supplier of power and telecommunications cables in Norway. It is one of the world's leading manufacturers of subsea umbilicals and high-voltage submarine cables. Nexans Norway's head office is in Oslo, and it has manufacturing plants at Rognan, Namsos, Langhus, Karmøy and Halden. The company is organized into three divisions: Energy, Building and Telecom and Energy Networks, and has approximately 1,100 employees. More information is available at www.nexans.no.

Our cable and umbilical tradition

We have cable design and manufacturing traditions reaching as far back as 1915. This vast experience lies behind the development of Nexans' cable-and umbilical technology. We provide umbilical systems with all necessary steps extends from design, engineering, and manufacturing through testing, installation and commissioning.

Nexans Norway has a tradition of being a technology driver in the offshore umbilical industry. Nexans introduced the super-duplex steel tube umbilical to the market in 1993 with Statoil's Statfjord and Sleipner projects. Nexans also introduced the dynamic super-duplex steel tube umbilical in 1995 with U.S. Shell's Mars project in the Gulf of Mexico. Nexans continues to be an innovator and has a strategic goal of subsea technology leadership.

Based on this long history and wide industrial experience, Nexans was awarded the contract for the supply of steel tube umbilicals, electro/optic umbilicals, IWOC umbilicals, and flying leads for BP's Atlantis project in 2002. Since then Nexans has delivered approximately 37 kilometers of steel tube umbilical and 14 kilometers of electro/optic umbilical. So far, the umbilicals for Drill Center 1 have been installed in water depth of 2,150 meters.

Nexans umbilicals are used in all types of applications: connecting subsea installations; subsea installations and fixed-and-floating platforms (semis) and FPSOs; as well as subsea-to-shore systems.

Nexans' umbilicals are used worldwide, from both the Norwegian and U.K. sectors of the North Sea to the Gulf of Mexico, offshore Brazil, offshore North and West Africa, as well as in the Far East. Serving the offshore industry all over the world, Nexans Norway puts its entire experience and uniquely qualified staff at the customer's disposal.

Omega Natchiq, Inc.—key partner for subsea fabrication on BP Atlantis project

Omega is a full-service provider for the global energy, refining, chemical, power, utility and manufacturing industries, with annual revenues over $80 million. Production platforms are a major Omega focus. Our New Iberia operations include 75 acres of 6,000-ton capacity facilities at Louisiana's Port of Iberia, where we fabricate, refurbish, test, commission, decommission, store oil and gas platforms, and provide a wide range of related services.

We have successfully completed projects for applications in extreme environments from north of the Arctic Circle to south of the equator. Our experience and performance has resulted in the ability to succeed on both domestic and international projects.

One of multiple PLEMs built for BP Atlantis DC1 project.

Subsea fabrication has become an Omega specialty and includes manifolds, PLETs, PLEMs, WYEs, jumpers, sleds and other components. Projects we have provided fabrication on include BP's Mardi Gras and Atlantis, Enbridge Energy Partners' Neptune, ATP Oil & Gas' Mississippi Canyon 711, Noble Energy's Mari-B Field, and many others. The result is that Omega is a recognized industry leader and provider of offshore and onshore component

Installation of the Test Jumper between the PLET & WYE sled for BP Mardi Gras project.

fabrication where quality, performance, cost, and the ability to meet deadlines are critical to clients. Current subsea projects being fabricated include BP's Atlantis DC3 PLETs, Williams' Perdido Norte PLEM, PLET, ITAs, IVAs and jumpers, and the ENI Petroleum Eni Longhorn Development Project manifold.

Omega is comprised of two divisions: Construction and Technical.

The Construction Division provides turnkey fabrication, operations and maintenance services, and ASME pressure vessel design and fabrication with R and U stamp certifications. Products and/or services of the Construction Division include

- Modular construction
- Piping fabrication
- Process facilities
- Structural fabrication
- Onsite construction
- Offsite construction
- Asme vessels/facilities
- Subsea components
- Offshore construction
- Operations/maintenance crews

The Technical Division provides advanced technology integration, automation, monitoring and control system design, fabrication and installation services. It also designs, builds and services electrical and instrumentation systems and panels, fire and safety detection systems, and fire suppression systems. Products and/or services of the Technical Division include

- Automation and controls
- System integration
- Electrical construction
- Electrical services/personnel
- Instrumentation
- Instrumentation services/installation
- Fire and gas design/installation
- Fire and gas services/personnel
- Regulatory compliance
- Navigational aids
- Panel design/manufacture
- Panel installation.

Industry-leading HSE performance and the well–being of our employees is a result of the culture and commitment of Omega Natchiq management and all employees.

Omega Natchiq, Inc. truly represents diversity in business. It is a subsidiary of ASRC Energy Services, a wholly owned subsidiary of the Arctic Slope Regional Corporation (ASRC), the largest of Alaska's 13 Native Regional Corporations. ASRC is the Native Regional Corporation for the Arctic Slope of Alaska, a region that encompasses vast natural resources, including the North Slope oil fields, the National Petroleum Reserve-Alaska, and the Arctic National Wildlife Refuge. Formed in 1971 under the terms of the Alaska Native Claims Settlement Act, ASRC is a private, for-profit corporation that manages five million acres of land and the business interests of its 9,000 Inupiat shareholders. ASRC is the largest Alaskan-owned and-operated company and one of the largest minority-owned companies in the United States.

Pushing the limits for Atlantis

Oil States' innovative design, custom engineering and rigorous in-house testing enable BP to meet demanding requirements

Oil States Industries, Inc. has been providing services to the oil and gas industry for over 65 years. We have a reputation for delivering high-quality solutions and services backed by world-class engineering.

For the Atlantis project, BP looked to Oil States to meet some tremendous engineering and manufacturing challenges. Our Skagit Smatco operation specializes in the design and manufacturing of mooring systems, anchor-handling winches, and pedestal cranes for the offshore industry. And our Houma, Louisiana-based custom engineering and manufacturing company met Atlantis' requirement for a seven-pocket fairleader by utilizing the most sophisticated design techniques and materials. The units were to be placed in a difficult environment and ensure a minimum 20-year design life—all while mooring the rig's 12-point system in the Gulf of Mexico.

The biggest challenge was to ensure the units were structurally sound yet light enough so they could be removed underwater with only the assistance of an ROV. At the time of manufacture, these units were the world's largest for use with a 171 millimeter chain.

Stringent testing parameters were put in place to minimize weight while maintaining design integrity required by the chain's high breaking strength of more than 2.5 million pounds. These extraordinary requirements were met and exceeded by Oil States' design and manufacturing teams, truly putting the capabilities of our suppliers to the test. The units were fabricated and tested in-house at our Houma facility.

Seven Pocket Fairleader for 171 millimeter Chain

Oil States also designed and manufactured Flexjoint® steel catenary riser (SCR) connections for Atlantis' four 10-inch production risers, two 10-inch water injection risers, one 16-inch gas export riser, and one 24-inch oil export riser. We also supplied 16 hull receptacle assemblies for these risers and for future SCR installations.

Finally, we performed considerable work on engineering, fabricating and installing the manifolds for the Atlantis and designed and tested pigging loops for integration with the manifolds.

Manifold fabricated and tested at Oil States Houston

Our multifaceted involvement with Atlantis illustrates Oil States' ability to meet diverse offshore requirements with proven technologies ranging from simple grout packers for jacket installations to deepwater driverless pipeline equipment, innovative FlexJoint® solutions, and Nautilus® marine cranes, winches and marine clutches.

As our customers increasingly globalize their operations, we are expanding beyond our significant North American presence. We now have sales and manufacturing facilities in England, Scotland, France, Norway, Brazil, Singapore, Thailand, Nigeria, Azerbaijan and Vietnam—with more to come.

Our growth not only aligns with the geographic expansion of our customers, it also supports their increasingly complex technology needs. And Atlantis is an excellent example. We are proud to have been selected to contribute to BP's Atlantis project and the engineering marvel it represents.

Schlumberger test trees, real-time multipoint monitoring speed up Atlantis completions

When a fast-approaching hurricane called for a quick disconnect in the midst of a flow-back from a subsea completion that had been deployed from the floating mobile drilling unit, Atlantis project operator BP had reason to be pleased about an earlier choice of completion and test tree equipment. All 16 subsea production wells and four water injectors necessary to fully develop the deepwater field were completed using the Schlumberger SenTREE* 7 completion test trees.

Thanks to the presence of this special subsea package on the second well in the field, when Hurricane Ernesto approached the field in August 2006, operators were able to close the test tree and unlatch the landing string in less than 15 seconds, despite a working water depth of more than 6,820 feet; thereby ensuring the safety of the rig, well, crew and environment.

Earlier, during development planning, BP had opted for a subsea completion package at Atlantis that included the SenTREE 7 completion test trees, each reinforced by the company's Commander* telemetry and monitoring package—the industry's first fast-acting control system. Dual lubricator valves and a surface flow head complete each tree array.

Teamed with the Commander multiplexed control system, customers benefit from intelligent, integrated data transfer that is many times faster than conventional completion landing string systems. Such conventional systems use direct hydraulic control, and the time necessary to close tree valves and disconnect can take 120 seconds or more. Water depth increases the delay even more.

Commander telemetry requires only a simple 1.5 inch diameter, lightweight control umbilical, though the SenTREE 7 tool can accept additional feeds for hydraulic and electrical lines to enable operation of the tubing hanger running tool and to test completion tool functions below the tubing hanger.

Completion and testing services for subsea wells being drilled by dynamically positioned drilling vessels can be performed using the fast-acting SenTREE 7 system.

Flexibility gives wide application range

All SenTREE systems are easily integrated with subsea BOP stacks and third-party hanger systems. They are available in flexible combinations with regard to tool sizes, pressure and temperature ratings, and control system configurations. General specifications for the system used on Atlantis include 10,000-pounds per square inch maximum working pressure and maximum test pressure of 15,000 psi. The standard SenTREE 7 system used on Atlantis has a maximum water depth rating of 10,000 feet.

The performance reliability of SenTREE systems is ensured by thorough testing via in-house factory acceptance techniques and in external testing facilities. SenTREE 7 systems are tested in a hyperbaric chamber at the Schlumberger Reservoir Completions Center in Rosharon, Texas, where pressures can be created to match the subsea conditions for any job.

Thanks to the fast-disconnect feature of the SenTREE 7, BP was able to minimize the time between decision making to withdraw and the complete evacuation of personnel from the Atlantis facility. This also maximized the usable working window due to weather. Six days later, when drilling and service crews returned to the drilling vessel, they quickly reconnected to the subsea tree and resumed the completion activities that had been interrupted by the approaching hurricane.

In addition to using the SenTREE system, BP also requested a new application for use with the Commander telemetry system. During completion of the first Atlantis subsea well, Schlumberger installed a Sensa* fiber optic monitoring system in the chemical injection line of the Commander umbilical to provide BP with temperature measurements over a section of about 6,700 feet. Continuous data collection and uploading of the Sensa temperature data enabled BP to evaluate the flowing bore temperature in the marine riser during well flow-back and shut-in operations. This was the first time such temperatures have been recorded in connection with the SenTREE system.

System allows real-time decision making

But Schlumberger has brought to bear still another well test technology at the Atlantis project, one that brings real-time data directly from the wellbore to desktops practically anywhere in the world.

Specifically, BP chose to use the Schlumberger InterACT© system, which collects and monitors well data (pressure, temperature, and oil and gas flow rates) in real time during the cleanup operations performed with surface well test equipment on the rig and then, using a standard Web browser with a simple Internet connection, links experts in both BP and Schlumberger offsite locations around the globe. With InterACT, these experts can collaborate with the wellsite project team to leverage and focus global resources on each well as it is being tested and completed, regardless of location.

The InterACT system provides field-proven, online workspace for remote surveillance of drilling and wireline operations, stimulation and cementing, and real-time well testing and production surveillance services. Asset teams and partners can gain secure access to project data at many points, which helps stimulate closer teamwork and timelier, collaborative decisions.

The InterACT system, now in operation around the clock for more than 11,000 active users globally, is particularly useful to customers for secure monitoring of well-testing operations. Security lies in 28-bit data encryption.

Real time covers offsite locations, too

Regardless of location, InterACT allows offsite experts—usually those not normally available at the wellsite—to focus on a specific well test so that project teams can make informed decisions and put them into practice in a timely manner. With all pertinent well-testing data and reports in hand, the offsite experts can modify and optimize well test programs while the tests are actually being made.

The InterACT system requires no specialized software. Completion test data from the well are accessible in real time by any number of approved off-site computers equipped with the system's embedded graphical and digital viewers. Comments from any monitoring point about critical operational events can be imposed over the graphic viewer to aid in crafting a common, real-time understanding among all observers. It also is equipped with a chat feature to aid in sharing ideas as they surface.

Another standout feature of InterACT is that at any time during or after testing, the test data can be downloaded and imported into various exploration and production software tools for further analysis. Resulting datasets and reports can be posted back into the system, allowing Schlumberger Data & Consulting Services specialists at one of the company's office to collaborate with operator personnel for relevant interpretation.

Schlumberger field technicians supervise the deployment of the SenTREE 7 test tree and Commander control system used for completion installation and subsea latching/unlatching of the landing string to subsea completion.

About Schlumberger

Schlumberger is the world's leading oilfield services company supplying technology, information solutions and integrated project management that optimize reservoir performance for customers working in the oil and gas industry. The company employs more than 80,000 people of over 140 nationalities working in approximately 80 countries. Schlumberger supplies a wide range of products and services, from seismic acquisition and processing, formation evaluation, well testing and directional drilling to well cementing and stimulation, artificial lift and well completions, and consulting, software and information management. In 2007, Schlumberger revenue was $23.28 billion. For more information, visit www.SLB.com.

Schlumberger

Schlumberger
1325 S. Dairy Ashford
Houston, TX 77077
Tel: (281) 285-1300
Email: welltesting@slb.com
www.slb.com/welltesting

profile: Subsea 7

Subsea 7 one-of-a-kind capability crucial to Atlantis

Subsea 7 is one of the world's leading subsea engineering and construction contractors with a multinational workforce in excess of 5,000 personnel worldwide. Global offshore operations are supported out of the North Sea, Africa, Brazil, the Gulf of Mexico and Asia Pacific. Subsea 7 has a fleet of industry-leading, dynamically positioned ships capable of reeled steel and flexible pipelay, subsea construction, and saturation diving, and has a portfolio of pipeline construction yards worldwide

Subsea 7 was contracted by BP to transport and install six hydraulic/chemical-injection and two (2) electric fiber optic umbilicals in the Atlantis Field. The umbilicals are a vital piece of the Atlantis offshore development because they supply hydraulic power, chemical injection, and signal and control functions to the subsea trees from the Atlantis host platform.

The vessel chosen for the umbilical installation campaign was Subsea 7's multipurpose offshore support vessel Toisa Perseus. The Toisa Perseus has a distinguished track record of deepwater umbilical installation in the North Sea, Asia-Pacific, Brazil, West Africa, and the Gulf of Mexico (GoM). BP was also confident of Subsea 7's capability in deepwater umbilical installation, based on their recent successful campaign on the ThunderHorse project.

Subsea 7 vessel MSV Toisa Perseus.

Despite Subsea 7's experience in the deepwater (GoM), the Atlantis umbilical installation project faced a number of unprecedented challenges. Not least of these was the combination of 7,000-foot water depth and the double-armored design of the umbilical. This unique umbilical design required the use of two, four-track Caterpillar track tensioners operating in series to support the large catenary load, along with specially designed tensioner gripping pads. The Toisa Perseus, with its integrated vertical lay system, was one of the few vessels in the world capable of performing this critical part of the Atlantis development.

Atlantis umbilical reel on MSV Toisa Perseus deck.

Subsea 7 was also responsible for spooling the 27 miles of umbilicals onto installation reels at the manufacturer's plant in Halden, Norway, and transporting them to the mobilization port in Fourchon, La. This was successfully completed in January 2006. The umbilicals and their transportation reels were then placed in storage until the offshore campaign began in March 2007.

The working relationship between the BP Atlantis and Subsea 7 project teams, developed over four years, was excellent. This relationship was instrumental in helping to solve any problems that surfaced during the engineering phase, so that all was in place and approved ahead of the offshore campaign.

BP's key performance indicators for Subsea 7 during the umbilical installation contract focused on the safety of personnel, protection of the environment, integrity of the umbilicals, and completion of the work scope on time. Through the hard work and effort of all those involved, especially the offshore workers, all of the performance targets were achieved, demonstrated by no lost time incidents, no environmental spills, and the umbilicals safely installed on time. As a result, BP was able to complete commissioning of the umbilicals with no impact to the delivery of first oil.

subsea 7

Subsea 7
Tel: 381-966-7600
Email: sandy.fraser@subsea7.com
www.subsea7.com

TESCO completion systems add built-in efficiencies to BP Atlantis project

TESCO was selected to play a key role in the completions segment of BP's Atlantis project. TESCO was selected as the primary service provider by BP's completion team to run chrome tubulars on the project aboard the Global Sante Fe Deep Driller II. Our tubular running experience coupled with proprietary, patented Multiple Control Line Running Systems (MCLRS) equipment packages apt for the challenge made TESCO the likely choice.

Third generation of TESCO MCLRS units

Project tubulars included 5.5 inch VAM Top® HC high-compression, chrome, 13/85 ksi tubing joints so that extreme compressive loads would not damage the string. Stands of 120 feet were pre-built offline and racked back until ready for the main run, a practice we have employed successfully on numerous other deepwater projects.

With TESCO's use of its MCLRS, assurances were in place that nonproductive time (NPT) would be virtually eliminated during the completion run. NPT, especially in the deepwater environment, would be particularly expensive. Our MCLRS is a tool that not only adds efficiency to the completion process, but improves safety as well. The MCLRS allows control lines to be run without manual manipulation and without passing through the slips.

TESCO MCLRS technology consists of a raised platform that elevates the slips six feet above the rig floor, which provides access to the tubing string below the slips. Ten or more control lines feed through the open platform sides without passing through the slips and are clamped to the tubing string below the slips. The MCLRS process separates the control line clamping crew from the rig floor crew, making both operations inherently safer and more efficient. TESCO's MCLRS is also capable of offering control line protection for a variety of Smart/Intelligent well completions as on the BP Atlantis. Control line spoolers may be positioned in various locations to facilitate clamps with protective pockets 180 degrees from one another. Safety is again improved because no one is required to ride a belt to secure sheaves in the already crowded derrick.

The MCLRS is installed with three simple lifts, and rig-up takes less than two hours. However, installation time is quickly recouped with typical running speeds of between 10 and 21 joints per hour. MCLRS technology adds an important component to an operator's tubular services tool box. By eliminating or at least stemming the NTP associated with crimped or broken control lines, TESCO's MCLRS could mean the end of control line inefficiencies and accidents.

TESCO is a global leader in the design, manufacture and application of solutions for the upstream energy industry. TESCO manufactures, sells and rents a series of top drives for land and offshore drilling applications. TESCO's leading technology, CASING DRILLING®, is considered a step change in the way drillers reach bottom in difficult drilling environments. CASING DRILLING® technology can also be applied to the company's a Tubular Services division that also provides conventional tubular running services. TESCO's credo of providing Better Ways to The Bottom™ for its customers is evidenced by the proven technical advances the company has made throughout the entire drilling drive train.

Our domain—Atlantis underwater

From concept to reality: Through project management, project engineering, and field and equipment design to analysis, Technip has developed and delivered the equipment specifications for build, test and installation

Technip undertakes large and complex onshore and offshore projects in challenging environments on an integrated or segmented basis, continuously developing new technologies.

Technip's capabilities translate into many advantages to customers:

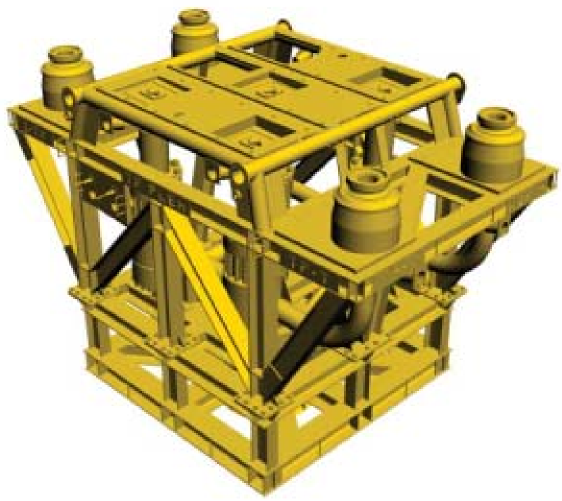
- A priority focus on health, safety and the environment
- Delivering on commitments
- State-of-the-art technologies and equipment
- Responsiveness to customer needs
- Outstanding quality program
- Innovative solutions to customer problems
- Technical excellence

In the United States, Technip provides technology, know-how and services in the following areas of activity: deepwater engineering expertise, pipelay and subsea construction, umbilicals and flexible pipe, floater design, construction and installation.

In support of BP's Atlantis project, Technip provided Well System Integration and Design Engineering Services specifically for the underwater infrastructure, which is located at a depth of almost 7,000 feet of seawater. These services were provided during the Appraise, Select, Define and Execute stages of the project.

Technip places the highest emphasis on Quality, Health, Safety and Environment (QHSE) because these are a key to our continuing business success. In the USA, Technip's Quality Management System (QMS) is certified to the ISO 9001:2000 standard. The QMS focuses on processes that impact our effectiveness in delivering products and services to meet our clients' needs, and provides the framework for continual improvement.

HSE excellence is a core value within the Technip culture. The health, safety and protection of our employees, the environment, clients, company property and communities in which we conduct our business are paramount and will not be compromised. It is our belief that all incidents are preventable.

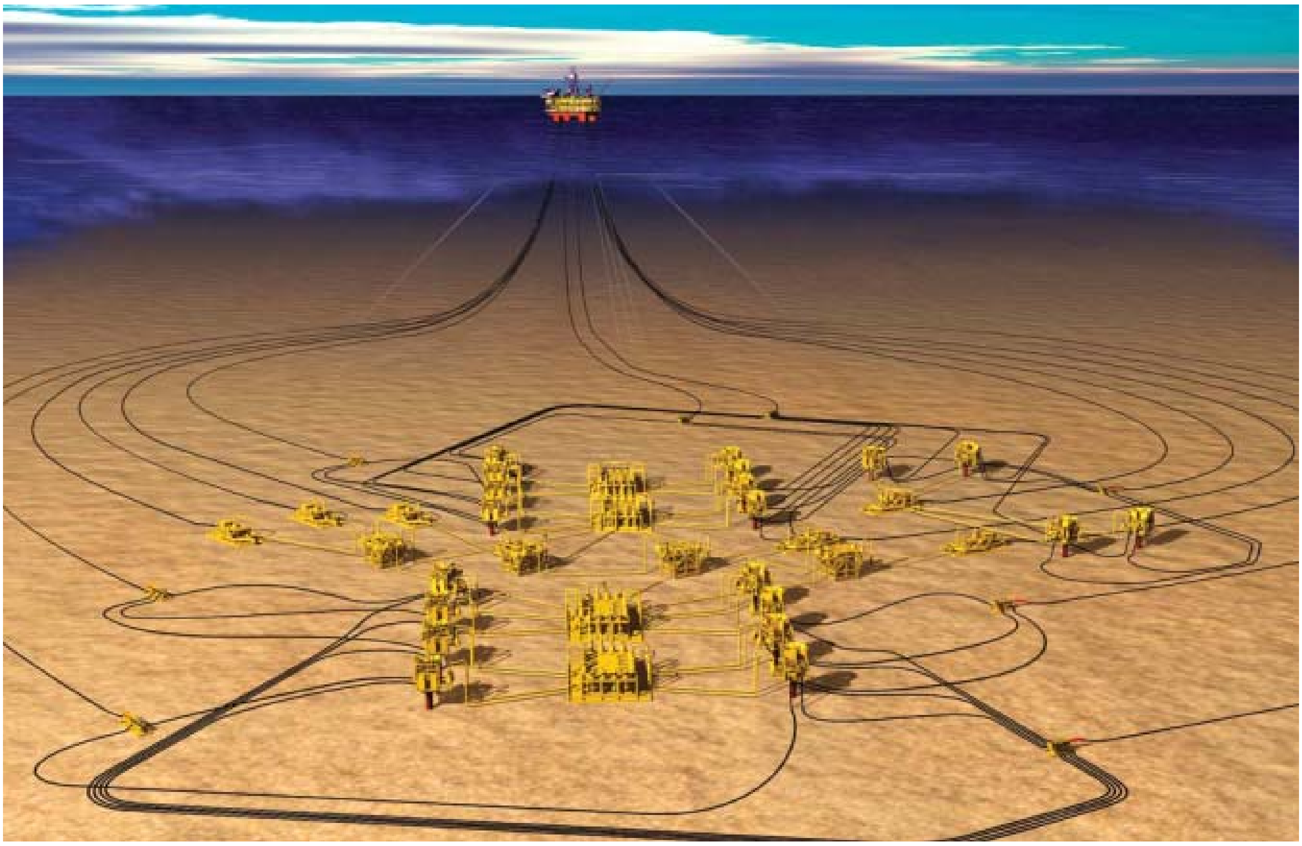


Technip-designed pipeline end manifold.

It is Technip's policy to conduct all its activities in such way as to achieve the following:

- Maintain a safe, healthy, incident-free workplace and avoid damage to the environment
- Meet all applicable laws, regulations, clients' requirements and recognized best practices, with the goal of exceeding those requirements when practical
- Focus on proactive programs and measure by Leading Indicators
- Combine engineering knowledge and technology know-how with sound assessment principles to minimize HSE impact risk assessment and mitigation
- Ensure that the leadership and employees of Technip visibly demonstrate their commitment toward HSE excellence through personal engagement and to integrate HSE

Technip Deep Blue will install the dual 10 inch ANF flowlines in 2008.



Atlantis DC 1 subsea structure

considerations into daily activities

- Provide proper management of our suppliers and contractors
- Provide the resources for security, crisis and emergency management
- Measure our performance and communicate regularly and openly.

All members of the Technip organization have an obligation to fully comply with this policy, and in doing so in Atlantis, created a working environment to continuously improve HSE performance.

Many potential Atlantis development solutions were reviewed during the Appraise and Select stages. Technip was able to assist BP in providing a safe, efficient, and effective subsea layout that meet all operability requirements. Once system selection was completed, system analysis and detailed engineering design was conducted by the subsea team located at Technip's Houston offices. Technip also developed the inspection, maintenance and repair plan of the complete subsea system, including subsea, umbilicals, risers and flowlines.

Four four-well production manifolds (with additional expansion capability) were able to support production from up to 16 FMC horizontal production trees. These production trees are controlled by two styles of umbilical (hydraulic and electro/optical).

Production fluids are delivered to the Atlantis Production Quarters (PQ) host semisubmersible via Pipe-in-Pipe (PiP) flowlines and steel catenary risers (SCRs) designed by Technip. The water depth and the high currents were significant challenges during the design phase of these underwater components. Challenges with pipelines and risers included: water depth, currents, seabed topography, riser installation/weights, pipe and soil interaction, and vortex induced vibration.

The PQ can accept up to 14 production risers and two export risers and 24 umbilicals. A total of six production and two export risers and six umbilicals have been installed for First Oil.

Technip's work scope, which started with the Appraise phase, will continue beyond First Oil supporting further field development. Two 10" connecting pipelines will be welded in Technip's spoolbase in Mobile, Alabama and subsequently spooled onto the Deep Blue for installation on the Atlantis North Flank (ANF) during 2008.

Congratulations on First Oil and thank you BP for allowing us to be a "One Team" member.

Development Driller II: Dynamic partnership leads to a new dimension in contract drilling

Transocean is the world's largest offshore drilling contractor, providing more than 50 years of experience in operations at all water depths. We have worked with national, major and independent energy companies in many challenging environments around the world, setting by far the most world records in our business and drilling some of the first wells for countries and clients. We continuously strive to improve our operations, and the work by the Development Driller II semisubmersible rig on the BP Atlantis project is an example of improvement in action.

In fact, our relationship with BP is a matter of customer focus, shared goals, and a searching for collaboration to redefine a major part of the offshore industry, break down boundaries between vendor and client companies, and move to the next generation of exploration challenges with the next generation of exploration technologies.

Several years ago, we began an exploratory process on how to move from then-current standards to create the next generation of ultradeepwater drilling rigs. What we sought was a still-deeper level of involvement and partnership with the kind of client who would be using this unit when it became available. We felt there were unexplored applications that could now be available through the use of new technologies.

Our invitation to greater client involvement resonated within BP and thus began a collaboration that would create a truly new generation of offshore technology, a generation whose design would start from the seabed and move up to the deck and derrick. The resulting semisubmersible rig with all its new capabilities would be the product of intense customer focus and practical, realistic customer input into the design and construction stages.

What emerged from this joint effort was a versatile drilling tool. From the start, it saved time and money on the job. With more deck space, it could accommodate more personnel and equipment and, most importantly, more simultaneous activities safely and efficiently.

With its additional versatility, the Development Driller II could also perform functions that customarily required specialty vessels that brought greater

Transocean Development Driller II

DDII performing subsea component installation

expense and more scheduling issues. These new applications were adopted and refined over the course of the Atlantis project.

A good example of this is the No. 7 winch. Designed to be used for mooring it was modified to be utilized as a subsea equipment installation winch. This allowed the Development Driller II to install over 90 percent of the subsea infrastructure for the Atlantis field offline. While the winch would lower and install the Subsea equipment to the seabed, drilling or completing the Atlantis wells would be constructed simultaneously on the main rotary.

Seabed activities to date have included installing manifolds, trees, flowline jumpers, electrical and hydraulic flying leads, among other vital equipment. The No. 7 winch has completed over 280 runs so far.

In addition, the Development Driller II successfully completed several flow-line pull-ins with another dynamically positioned (DP) vessel utilizing the #7 winch, a world's first for this type of operation. This saved the project both time and money, as the Development Driller II was able to stay on location and remain connected to the well while the flowlines were installed to the subsea infrastructure 7,000 feet below.

The immediate result of such collaboration between BP and Transocean has been fully logged, and many lessons learned have been noted. These lessons are becoming the basis of the next generation of improvements that are helping our client make additional progress in more-efficient and cost-effective deepwater drilling operations.

About Transocean

Transocean is the world's largest offshore drilling contractor and the leading provider of drilling management services worldwide. With a fleet of 138 mobile offshore drilling units plus eight ultradeepwater units under construction in April 2008, the company's fleet is considered one of the most modern and versatile in the world due to our emphasis on technically demanding segments of the offshore drilling business. The company owns or operates a contract drilling fleet of 39 high-specification floaters (ultradeepwater, deepwater and harsh-environment semisubmersibles and drillships), 29 midwater floaters, 10 high-specification jackups, 56 standard jackups, and other assets utilized in the support of offshore drilling activities worldwide.

Wherever we operate, employees focus on our mission of being the premier offshore drilling company for our customers. Whether our customers are global energy firms, national petroleum companies or independent operators, we seek to provide them the best service through our core values of FIRST: Financial discipline, Integrity, Respect, Safety and Technological leadership.

Transocean excels at constructing oil and natural gas wells in various water depths, including several world records. For example, we hold the current world water-depth record at 10,011 feet, set by the Discoverer Deep Seas in the U.S. Gulf of Mexico. We also set the world record for the deepest water depth achieved by a moored rig, the semisubersible Deepwater Nautilus at 8,951 feet, also in the U.S. Gulf of Mexico.

In addition, we provide rigs for all types of petroleum companies in offshore drilling markets that include the U.S. Gulf of Mexico and eastern Canada; Brazil; the U.K. and Norwegian sectors of the North Sea; West Africa; Asia, including Australia; the Middle East, including Saudi Arabia; India; and the Mediterranean.

Transocean Inc.'s ordinary shares are traded on the New York Stock Exchange under the symbol "RIG."

Transocean

Transocean Inc.
4 Greenway Plaza
Houston, TX 77046
Tel: +1 713 232 7500
www.deepwater.com

profile: Turner & Townsend Inc.

Turner & Townsend delivers innovative "project control solutions" for Atlantis

Success through people, processes, systems and performance

Turner & Townsend is an established global construction and management consultancy with 60 plus years of experience, offices in 54 locations across five continents, and an international staff of over 2,400. Turner & Townsend is recognized as a leading global provider of project services and management consultancy on major capital projects.

Our experienced professional staff, systems, tools and knowledge combine to provide industry best practice applications in support of timely setup and delivery of business processes. The flexibility of our operations allows the deployment of the necessary resources to support the needs of our clients whenever and wherever they are required.

Our assignment as part of the BP Atlantis asset was executed through our specialist Energy Division, which encompassed the provision of project controls and management Consultancy for all phases of the asset's development, from appraisal through execution, close-out and transition into production operations at both home office and various site construction locations. Specifically we:

- Developed budget estimates and plans and validated these through our "Performance Forum" benchmarking initiative, thus assisting the overall sanction process and setting initial business targets for the asset.
- Created project planning, scheduling and control processes, procedures and systems for the project execution phase to deliver a structured and effective means of measuring and predicting performance.
- Developed and implemented risk management processes to assess and quantify threats and opportunities and help identify the appropriate actions to deal with them.
- Developed and implemented timely management reporting and trend analysis to increase visibility of and alert attention to emerging issues.
- Implemented cost management systems to ensure accurate forecasting and financial reporting as well as implemented accounts payable processes to ensure accurate and timely invoice validation and payment.
- Provided site project control and quantity surveying (QS) support for key construction contracts to effect planning, scheduling, cost control and QS validation at major construction sites at onshore and offshore locations.
- Provided assurance services throughout the project when needed for "business process gap analysis and improvement."
- Provided contract administration and claims management services to ensure compliance to contract terms and assist in early dispute resolution as needed.
- Implemented company sponsored knowledge management processes and captured lessons learned to improve ongoing and future project execution efforts.

Atlantis topside installations at Ingleside, TX

Turner & Townsend is a quality-driven organization, delivering value through innovation and best practice, implementing solutions through state-of-the-art system applications and independent assessment throughout the life cycle of asset development, operation and cessation. Turner & Townsend is able to draw on our extensive knowledge and its subject matter experts to provide either an entire team accountable for functional delivery or to embed key personnel as part of the owner's management team. Turner & Townsend are extremely proud of our accomplishments on the Atlantis Project and our continued alliance with the BP organization.

Turner & Townsend
Construction and Management Consultants

Turner & Townsend Inc.
One Westchase Center
10777 Westheimer Road, Suite 1160
Houston, TX 77042
Tel: (713) 457-9400
Fax: (713) 457-9424
Linda Sluder
Email: linda.sluder@turntown.com

Udelhoven provides integrated construction team management

Udelhoven Inc. is a privately held company founded in 1970. Although the company's activities are worldwide, our workforce numbers around 600. Udelhoven's signature contribution to major projects is to provide companies like BP with an unparalleled management corps for building what is often a first-of-its-kind-and-size asset on time and on budget.

When a company like BP undertakes a major project like Atlantis, it can't just redistribute its own managers to new construction duties. It needs a ready-to-go construction management team dedicated to high standards, able to deliver them over long-term projects, and bring the project in.

Many companies claim their people are their most important asset. At Udelhoven, we mean it and our clients know it better than anybody. Our people are highly skilled, with years in the industry.

Many of our field personnel are name-requested by clients who also often ask that whole teams from previous projects be brought together for upcoming projects. It is common for many UI personnel to follow a project from the first milestone to the last, often as a team. And this was the case with Atlantis and Udelhoven.

For Atlantis, we provided a ready-made core team including the construction manager, the materials manager, the commissioning manager, the Quality Assurance manager, the discipline construction field engineers, the discipline construction superintendents, and turnover personnel in the fabrication yard in Morgan City, La. This is a construction management resource team second to none for our clients.

Fabrication in Morgan City, Louisiana.

When Atlantis transferred to the integration site at Ingleside, Texas, many of our personnel transferred with it. There we took on the additional responsibility of commissioning for the topside and hull integration, providing the management, supervision, and technical support.

For many Udelhoven personnel, the sail away was simply the end of the land-based construction phase. There was still much to be done. Our personnel worked with the offshore hook-up, with BP operations, and BP Subsea to complete still more Atlantis milestones: commissioning, COI from the Coast Guard, first gas and first oil.

Udelhoven not only provides the project management, we also provide the management systems to insure the end product meets all client and industry standards. For example, the BP Atlantis project saw one of the first uses of an emerging technology by Udelhoven affiliate Industry Systems Software, Inc. (ISSI), based in Louisiana.

Atlantis leaving Corpus for installation in the Gulf of Mexico.

Daqart software is used for electronic tracking of construction, inspection, and commissioning activities using the latest tablet PCs for field access to engineering and certification documents. After online beta testing in Morgan City, Louisiana, early in the project, ISSI implemented a system in Ingleside, Texas, for use by commissioning personnel during the final stages of onshore and offshore testing.

Udelhoven, on behalf of its many Atlantis-experienced employees, wants to thank BP for the chance to participate in this great enterprise. We are proud of the project and of our contribution. We look forward to being with you again on the next one.

UDELHOVEN UNITED STATES GULF COAST

Udelhoven, Inc.
184 E. 53rd Avenue
Anchorage, AK 99518-1222
Tel: (907) 344-1577
Fax: (907) 522-2541
www.udelhoven.com

One team, one goal: "Best-in-class documentation"

Wilson & Associates (WA) is a five-year-old technical editing firm dedicated to supporting wells teams and helping them deliver "Best-in-Class" documentation for drilling and completion operations.

From design to startup, documentation plays a key role in the safety, environmental compliance, communications and technical excellence of each operational phase of a project. And the specialized project editor keeps up with that documentation throughout each phase.


WA and BP Atlantis team meeting

The WA-embedded technical editor on Atlantis, Peggy Stautberg, has handled the team's documentation for three years, freeing up the engineers' time so that they can focus on what they do best: engineer. This also ensures that the editing, formatting and version control of project procedures remains a priority and follows consistent standards.

Peggy started out as the technical editor assigned to the Completions Team. After some time, however, the Drilling Team determined that their procedures needed updated formats as well. Others on the Atlantis Wells Team eventually followed suit, so that Peggy and her co-editor, Jeff Staples, soon were kept busy working on procedure books, end-of-well reports, and other materials for Completions and Drilling, as well as specialized documentation projects for the Dropped Objects Team, SIMOPS coordinator, and Atlantis Phase II.

The concept of an embedded editor is different than using an administrative or a temporary editor to tidy up documents. The embedded editor is a degreed professional with years of editing experience and a team-oriented, "can-do" attitude.

The editor participates in review meetings and painstaking, line-by-line edits of the procedures by team engineers and vendor reps taking care of the all-important "what" of procedure content. In addition, the editor ensures the consistency of the documents and helps incorporate lessons-learned into the procedures.

The embedded editor grows with the team. Taking the long-term view, the editor knows and understands the history of the documents, and why they are formatted a certain way—thus completely avoiding redundant learning curves and countless reinventions of the proverbial wheel that may happen as new team members join the project.

WA provides fully screened, seasoned technical editors to several of BP's GoM wells teams. This collaborative mind-frame has several advantages:

- Editors exchange information via a SharePoint site and weekly meetings.
- The "team" concept shortens the learning curve for new editors, since they have a place to go with their questions; and there is continuous improvement through the editing team's own lessons-learned process.
- By avoiding the "silo" approach, the GoM team of editors ensures that high-quality documentation in approved templates are used across the Business Unit.

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