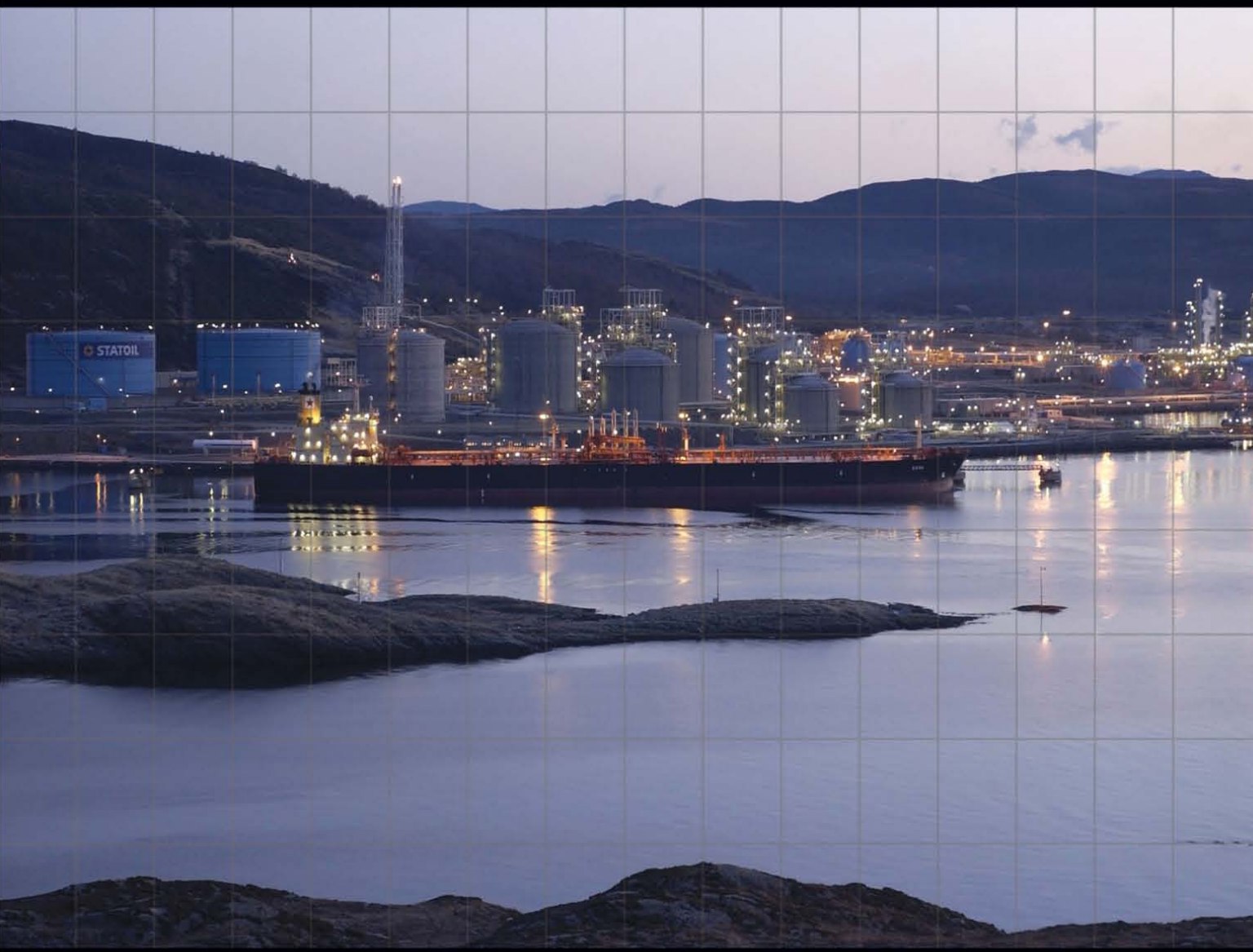
Week of Mar. 8, 2010/US$10.00

OIL&GAS JOURNAL

International Petroleum News and Technology / www.ogjonline.com



OGJ Focus: Processing

Upstream, refining results mixed in 4Q 2009
Field seen pointing to S. Florida offshore oil potential
Europe pursues Baltic transit debottlenecking

Our record in refinery clean fuels, solar, and carbon capture projects is enhanced with new ventures in micro-crop biomass for clean fuels. This capability, coupled with our focus on sustainable projects in chemicals, upstream, power, and pharmaceuticals, makes Foster Wheeler your partner of choice for the exciting projects that are changing our industry.

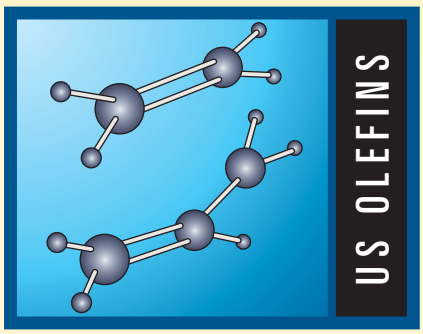
Our green is growing.

www.fwc.com/green

OIL&GAS JOURNAL®

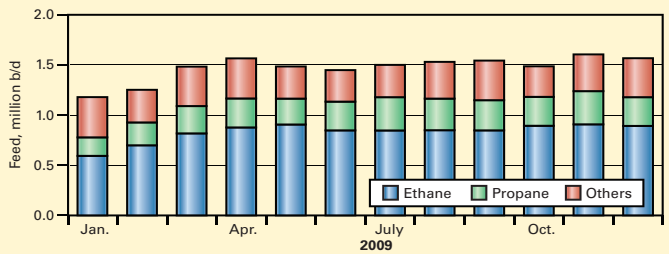
Mar. 8, 2010
Volume 108.9

OGJ Focus: Processing



US ETHYLENE PLANT FEED SLATE

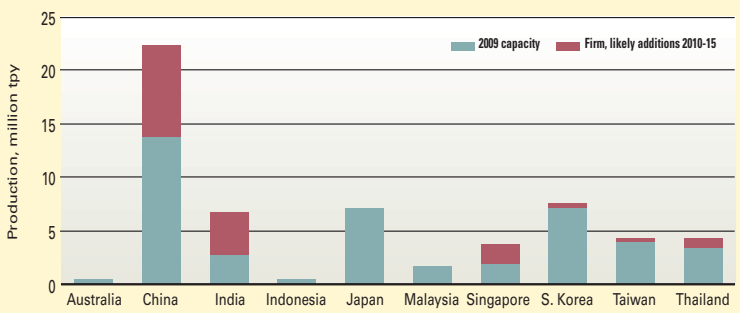
Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

ASIA-PACIFIC: ETHYLENE CAPACITY

Fig. 1



Regular Features

Cover

Statoil's Karsto gas plant (cover) is a major supplier of feedstock to the Borealis ethylene plants in Norway. A major expansion at Karsto in 2005-06 to handle Statoil's Kristin development in the Norwegian Sea increased ethane production capacity by more than 50%. This issue of Oil & Gas Journal focuses on petrochemicals beginning on p. 40 with OGJ's semiannual review of the US olefins market and followed on p. 46 by a look at Asia's petrochemical industries by FACTS Global Energy. Photo by Dag Magne Søyland, Statoil.

Blast Resistant Modules Designed to fit Your Needs!

New! "Multi-Section" BRMs

A Box 4 U introduces the "Multi-Section" BRM - Effectively doubling the width of the 12' BRM to 24' and more! All of the usual A Box 4 U features are standard, including A Box 4 U's world renowned Blast Resistance - More safe space!

A Box 4 U's Multi-Section BRMs' open design floor plans enable A Box 4 U to custom design and engineer any number of specialized, safe work environments.

New! QUAD POD Two Story BRMs

The answer to limited safe space in the workplace! The QUAD POD features a standard A Box 4 U BRM and then stacks the second BRM on top. Available in A Box 4 U's standard leasing sizes: 8'x20', 8'x40' & 12' x40'. The new QUAD POD is engineered to meet or exceed API 753 and are designed for ease of installation and teardown without welding on the job site.

A {RELIABLE • AFFORDABLE • PROTECTIVE • VERSATILE} BOX FOR YOU!

8' Wide BRMs

Transportability

All A Box 4 U BRMs feature complete and easy mobility - Via truck freight, rail, local deliver or overseas via container shipment.
You get it, when you want it, where you need.

12' Wide BRMs

Finished to Fit Your Needs

- Overhead lighting and wall mounted electrical outlets - Where you need them!
- Telephone/Internet connections prewired
- Reliable HVAC provides working comfort
- Several levels of interior wall finishes to choose from

"Tool Crib" BRMs

5' Shelving Sections for Custom Layouts.

All above counter shelving is equipped with locking latches and blast doors. Your workforce will appreciate the ease and convenience of having tools, parts, and substances in their blast zone workplace.

A BOX 4U

The "Red Box" Company...

Call today and learn about Industry Leading Module Options, Lease Units & World Wide Solutions

Get More Info! Blast Resistant Modules Online WWW.ABox4U.net • Toll Free 877.522.6948

General Interest

Exploration & Development

Technology

 Oil & Gas Journal (ISSN 0030-1388) is published 46 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. 2,200 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. 108, No. 9) 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 enclosure 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
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor/News Writer Leena Koottungal, lkoottungal@ogjonline.com

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

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

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

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

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
Audience Development Manager Tommie Grigg, tommieg@pennwell.com

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

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

Member Audit Bureau of Circulations & American Business Media

Solution for massive losses
NFS-Super Squeeze™
"Hole-In-One" Process

NFS-Super Squeeze Process is a dewatering system that can be applied directly into the well bore to create a strong bridge. NFS-Super Squeeze is a single sack application that can be easily mixed in all types of fluids. NFS-Super Squeeze requires no setting time and is contaminant friendly.

Mixed and placed in a API filter press a 90 ppb of NFS-Super Squeeze. Applied 100 psi pressure, dewatered and formed a cake. Punched a ¾" hole.

Sealed ¾" diameter hole by squeezing 90 ppb of NFS-Super Squeeze with just 100 psi.

The new technology with >3,000 psi compressive strength

Advantages/Benefits:

- **No setting time required**
- **No spacer required**
- **Simple mixing**
- **Mixes in all types of fluids**

◆Successful field trials.

Mix it, pump it, seal it, and GO BACK TO DRILLING

Guaranteed Results!

NFS–Super Squeeze has a broad PSD range to address sealing and bridging of large fractures, cavernous, and vugular formations.

NFS New Fluid Solutions, Inc.™

The Fluid Specialists℠

6161 Savoy Dr. Ste 248 * Houston, Texas 77036
713-780-3600 * Fax: 713-780-3611 * 1-877-NEWFLUID (877.639.3584) * www.newfluid.com

OGJ Newsletter

Mar. 8, 2010

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

General Interest — Quick Takes

Anadarko hikes spending to $5.6 billion for 2010

Anadarko Petroleum Corp. on Mar. 2 said it plans capital expenditures of $5.3-5.6 billion this year compared with $4.6 billion in 2009.

Jim Hackett, Anadarko chairman and chief executive officer, said the company ended 2009 with record production, nine deepwater discoveries, and "significant" cost reductions.

Based on expected growth from natural gas shale plays and major oil projects, Hackett forecasts Anadarko could surpass 3 billion boe of proved reserves by yearend 2014 compared with 2.3 billion boe as of yearend 2009.

Hackett said $1.1 billion is allocated toward 2010 exploration programs, with much of it focused on worldwide deepwater exploration.

Anadarko plans to drill as many as 13 exploration and appraisal wells off West Africa, 7-10 wells in the Gulf of Mexico, 4-6 wells each in Brazil and Mozambique, and 3-5 wells in Southeast Asia.

"We are targeting approximately 400 million boe of net discovered resources in 2010, a 12% increase over our record 2009 results," Hackett said. "At the same time, we are actively appraising several of our recent discoveries—Wahoo in Brazil, Tweneboa in Ghana, and Lucius, Vito, and Heidelberg in the Gulf of Mexico."

Firms realign Permian, Midcontinent segments

Occidental Petroleum Corp. and Apache Corp. separately realigned Permian basin and Midcontinent business units as of 2010.

Oxy combined most of its central US gas production into a single business unit called Midcontinent Gas. The business unit includes Kansas Hugoton field, the Piceance basin, and the bulk of its Permian basin nonassociated gas assets, which had been reported as part of the Permian business unit through 2009.

The change will alter Oxy's production to 75% gas and 25% liquids for the Midcontinent unit and 89% liquids and 11%, mostly associated gas, for the Permian unit. Oxy made the change to take advantage of common development methods and production optimization opportunities.

Beginning in 2010, Oxy also will begin expensing 100% of the carbon dioxide injected in the Permian basin, whereas in it capitalized about 50% of it or $69 million in 2009. The change simplifies the process of determining the portion that should be capitalized versus expensed as larger portions of the injected gas support current production.

Apache, meanwhile, created a new regional Permian basin business unit based in Midland, Tex. Apache's Permian area has been part of the Central Region in Tulsa since 2002, but the combined capital program has increased tenfold since then.

Apache plans to operate five rigs to drill 171 net Permian basin development wells in 2010, up from 87 wells in 2009. Apache acquired $187.4 million in Permian basin properties from Marathon Oil Corp. in April 2009. Those properties have 200 quality infill oil locations, Apache said. ✦

Exploration & Development — Quick Takes

Mandy is Mississippi Canyon oil discovery

A group led by LLOG Exploration Co. LLC, Covington, La., private explorer, said the Mandy exploration well on Mississippi Canyon Block 199 is a conventional amplitude oil discovery in the deepwater Gulf of Mexico.

The well went to 7,500 ft true vertical depth in 2,465 ft of water and encountered net oil pay more than 120 true vertical feet thick in a high-quality reservoir. Pressure and samples confirmed the discovery, LLOG said. A follow-up well found a high-quality oil-filled reservoir in a separate fault block with net oil pay more than 100 true vertical feet thick.

Mandy is 45 miles southeast of Venice, La., and just north of Matterhorn oil field.

Scott Gutterman, LLOG's president and chief executive officer, said, "LLOG's deepwater Gulf of Mexico program is very well situated for growth with the recent first production of our Mississippi Canyon 72 field and development projects at Green Canyon 141 and Green Canyon 448 slated for start-up later this year.

"With the discovery at Mandy and continued drilling at Mississippi Canyon 503 and 547, which has recently begun, LLOG is positioning itself for significant production and reserve adds going into the future."

Working interests in the prospect are LLOG 50%, Mariner Energy Inc. 35%, and Apache Corp. 15%. The block was acquired in OCS Lease Sale 206 in March 2008.

Talisman lets Auk North, Burghley contracts

Talisman Energy UK Ltd. has let two lump-sum engineering, procurement, and installation contracts to Technip for development of two oil fields in the UK North Sea.

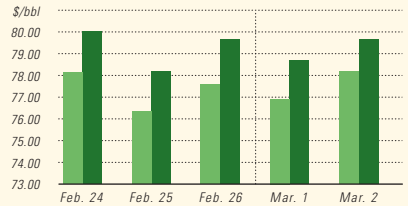
One of the fields is Auk North, which Talisman is developing with three horizontal wells completed subsea with electric submersible pumps and tied back to the Fulmar A Platform about 10.5 km away. Auk North is on Block 30/16.

Technip will fabricate and install the production pipeline and install an umbilical, power cable, and subsea equipment.

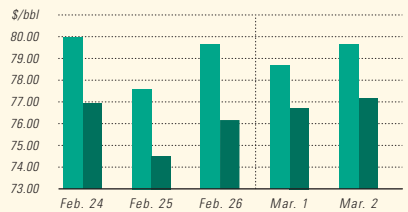
Talisman estimates Auk North reserves at 13 million boe proved and 17 million boe proved and probable.

Industry Scoreboard

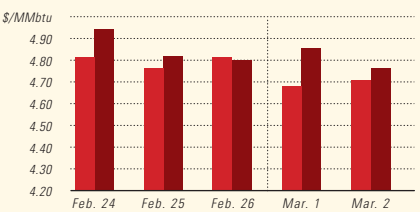
IPE BRENT / NYMEX LIGHT SWEET CRUDE



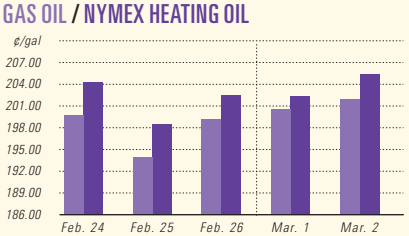
WTI CUSHING / BRENT SPOT



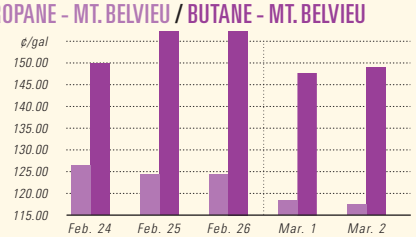
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



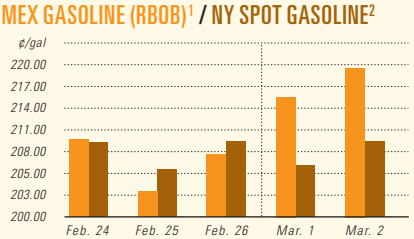
IPE GAS OIL / NYMEX HEATING OIL



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

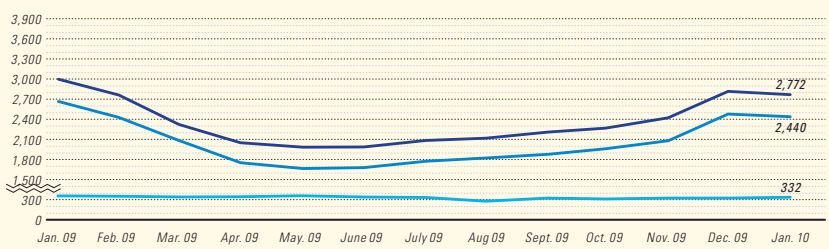
US INDUSTRY SCOREBOARD — 3/8

Latest week 2/19	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	8,741	8,771	–0.3	8,708	8,753	–0.5
Distillate	3,701	3,972	–6.8	3,689	3,995	–7.7
Jet fuel	1,321	1,347	–1.9	1,354	1,349	0.4
Residual	602	575	4.7	546	603	–9.5
Other products	4,730	4,191	12.9	4,627	4,216	9.8
TOTAL DEMAND	19,095	18,856	1.3	18,924	18,916	0.0
Supply, 1,000 b/d						
Crude production	5,466	5,211	4.9	5,462	5,252	4.0
NGL production[2]	2,109	1,830	15.2	2,064	1,821	13.3
Crude imports	8,600	9,436	–8.9	8,507	9,545	–10.9
Product imports	2,860	3,106	–7.9	2,781	3,162	–12.0
Other supply[3]	1,817	1,613	12.6	1,742	981	77.5
TOTAL SUPPLY	20,852	21,196	–1.6	20,556	20,761	–1.0
Refining, 1,000 b/d						
Crude runs to stills	13,733	13,476	1.9	13,772	14,114	–2.4
Input to crude stills	14,049	14,432	–2.7	14,053	14,451	–2.8
% utilization	79.4	81.7	—	79.5	81.8	—

Latest week 2/19	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	337,537	334,503	3,034	351,347	–13,810	–3.9
Motor gasoline	231,170	232,065	–895	215,342	15,828	7.4
Distillate	152,664	153,255	–591	141,634	11,030	7.8
Jet fuel–kerosine	43,650	42,676	974	40,474	3,176	7.8
Residual	40,017	37,851	2,166	36,397	3,620	9.9
Stock cover (days)[4]			Change, %		Change, %	
Crude	24.6	24.6	0.0	24.9	–1.2	
Motor gasoline	26.4	26.9	–1.9	24.0	10.0	
Distillate	41.2	41.2	0.0	34.0	21.2	
Propane	18.7	19.6	–4.6	25.7	–27.2	
Futures prices[5] **2/26**			Change		Change	%
Light sweet crude ($/bbl)	79.37	78.30	1.07	36.99	42.38	114.6
Natural gas, $/MMbtu	4.81	5.23	–0.41	4.13	0.69	16.7

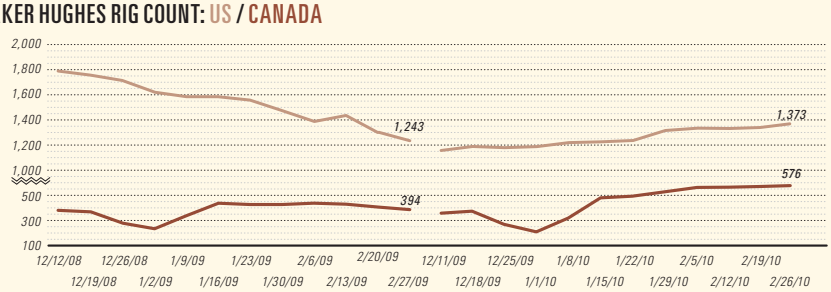
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

PennEnergy jobs

March 30, 2010 • 9:00 AM - 5:00 PM CST

Join us for the energy industry's most advanced career fair event:

The PennEnergy Jobs Virtual Career Fair

Take part in our online-only job fair and experience the full power and reach of online networking. This event is power and petroleum-industry focused and provides industry professionals with the rare opportunity to communicate directly with recruiters and hiring managers.

WHAT TO EXPECT:

- Conduct comprehensive research on industry employers
- Search and apply instantly to job openings
- Chat directly with recruiters and hiring managers
- Visit the comprehensive research center

Visit www.PennEnergyJOBS.com/VCF for more information and to register.

To participate as an exhibitor at this event, contact: sales@PennEnergyJOBS.com.

PennWell® Turning Information into Innovation | Serving Strategic Markets Worldwide since 1910

PennEnergyJOBS.com

It expects production to start in 2011 and to peak at 10,000 boe/d. The Auk North subsea manifold will be able to accommodate as many as six horizontal producers.

Talisman also plans to redevelop nearby Auk South oil field by drilling nine wells and recompleting three wells, adding reserves of 23 million boe proved, 29 million boe proved and probable. South Auk production is to begin in 2012, peaking at 11 million boe/d.

The other Technip contract is for fabrication and installation of production and gas-lift pipelines and installation of an umbilical and subsea structures at Burghley oil field on Block 16/22.

Talisman is developing Burghley with at least two development wells completed subsea and tied back to the Balmoral floating production vessel operated by Premier Oil on Block 16/21 about 8.5 km away.

It estimates Burghley reserves at 2 million boe proved and 3 million boe proved and probable. Burghley production is to begin late this year. According to government filings, it will peak at as much as 15,000 b/d of oil and 2.9 MMscfd of gas.

Talisman bought Auk field from Shell UK Ltd. and Esso Exploration & Production Ltd. at the same time it bought the companies' combined 85.81% interest in Fulmar field under an agreement announced in 2006 (OGJ, Nov. 20, 2006, p. 36).

Apache presses Argentina Gas Plus projects

Apache Corp.'s Argentina unit plans to operate 28 rigs in core areas in 2010 to drill 249 net wells (299 gross), up from 213 net wells (248 gross) in 2009.

Of the 299 gross wells, 223 are development wells and 76 are exploration wells. Ten of the exploration wells are on prospects in Pre-Cuyo, Cuyo, and Springhill reservoirs in the Neuquen, Cuyo, and Austral basins.

The Houston-based independent drilled 32 development wells in 2009 with 97% success. Its production was a net 45,500 boe/d, down 5% from 2008 due to reduced capital spending and lower fourth quarter seasonal takes.

Apache has received government approval for four Gas Plus projects that allow gas sales at higher prices, and the company is progressing three more Gas Plus contracts for approval (OGJ Online, Nov. 17, 2009).

Apache said projects under Gas Plus will lead to sales prices of $4.10/MMbtu on 10 MMcfd and $5/MMbtu on 50 MMcfd in 2011. The Gas Plus programs so far involve three rigs to drill 21 wells in 2010. ✦

Drilling & Production — *Quick Takes*

West Orion semi christened; delivery due

The ultradeepwater West Orion semisubmersible has been christened at Jurong Shipyard, Singapore, and is on schedule for delivery early in the second quarter, reports Sembcorp Marine.

Seadrill Ltd., the owner, will use the semi off Brazil under a 6-year contract with Petroleo Brasileiro SA (Petrobras). Jurong Shipyard is a wholly owned subsidiary of Sembcorp Marine.

The dynamically positioned West Orion will be able to drill to 37,500 ft in as much as 10,000 ft of water.

The West Orion ultradeepwater semisubmersible was christened at Jurong Shipyard in Singapore and is on schedule for delivery early in the second quarter. Photo from Sembcorp Marine.

It's one of 12 Friede and Goldman ExD class semis to be built by Jurong Shipyard, six of which have been delivered.

Four of the units are for Seadrill.

The West Orion is 98.82 m long with a beam of 78.68 m and measures 36 m from keel to main deck. It can accommodate 180 persons.

Pyrenees oil field comes on stream

The first phase of the BHP Billiton-operated Pyrenees oil field development project off Western Australia has been brought on stream several months ahead of schedule.

Start of oil production comes from the WA-42-L license area. The full project comprises 13 subsea wells feeding into an extensive subsea gathering system and a 96,000 b/d floating production, storage, and offloading vessel. Gas will be separated on the FPSO and reinjected into nearby Macedon gas field at a rate of 60 MMcfd for future recovery.

The development wells are being drilled and brought on stream in phases with about half the field now ramping up from the on-stream date and the other half coming into production during the next 6 months.

The $1.7 billion project was originally scheduled to come on stream towards the end of this year's first half.

The project includes development of Crosby, Ravensworth, and Sickle oil fields, which were discovered in 2003 in 169-250 m of water.

Production is via extended-reach horizontal wells tied back to the double-hulled Pyrenees FPSO through an extensive gathering system. Water injection is being used to enhance the oil recovery. The fields are estimated to have a production life of 25 years.

The fields lie about 45 km off Exmouth on the Western Australian coast. They are 20 km east of BHP's Stybarrow oil field.

The WA-42-L joint venture comprises BHP with 71.43% and Apache Corp. with 28.57%.

A section of the Ravensworth field crossed the permit boundary into production license WA-43-L where BHP is also operator but with a smaller (39.999%) interest. Apache has 31.501% while Inpex of Japan has 28.5%.

This separate segment of the Pyrenees project will have its own wells and gathering system. It will be produced through the Pyrenees FPSO under a commercial unitization agreement between the two groups and is expected to come on stream towards yearend.

Santos Group's Henry gas field comes on stream

The Santos Group's Henry natural gas field development in the Otway basin off western Victoria has come on stream.

Gas is being produced from the Henry-2 and nearby Netherby-1 wells, which are connected by subsea pipeline to the group's existing Casino gas system that transports gas to an onshore processing plant near Port Campbell.

The fields were originally slated to start production in mid-2009, but were delayed by the late arrival of the pipelay vessel to install the connecting lines.

The two fields will add about 120 TJ/day of gas to the region's production.

Santos holds 50% interest in the development, while Australian Worldwide Exploration and Mitsui E&P Australia hold 25% interest each.

Nido awards contracts on Tindalo oil field

Nido Petroleum Ltd., Perth, awarded two major equipment contracts for development of Tindalo oil field in the Palawan basin off the Philippines.

Norwegian company Knutsen Shuttletanker Pool AS was awarded the contract for supply of the M/T Tove Knutsen floating storage and offtake vessel (FSO), while Weatherford Asia Pacific Pte Ltd. was awarded the contract for production processing equipment.

The FSO, a double-hulled tanker with capacity to store more than 600,000 bbl of oil, will be initially supplied for 6 months with an option to extend this period for up to 3 years.

The vessel will be positioned near the Tindalo production facility and use its dynamic positioning system to remain on location.

Oil from Tindalo will be sent via floating flowline to the FSO from the production processing unit on the Aquamarine Driller jack up rig.

The Tove Knutsen will be mobilized to the field in April after undergoing some minor refitting in Singapore.

The Weatherford production processing equipment for Tindalo is a modular system being assembled in Batam, Indonesia. It will be used during the initial well-testing program and then remain in place for full field operations.

It is to be installed on the deck of Aquamarine Driller, also expected on station in April, and will process up to 20,000 b/d of oil, including the removal of gas and water from the production flow.

First oil from Tindalo is scheduled for the second quarter with initial plateau rates of 7,000-15,000 b/d. Recoverable oil reserves at the field are estimated to be 1.5 million bbl.

Nido has a 50% interest in the SC54A license while Kairiki Energy Ltd. has 35% and Trafigura Ventures III BV 15%. ✦

Processing — *Quick Takes*

One Chilean refinery due back on line

Chile's state-owned oil company Empresa Nacional del Petroleo (Enap) said its 97,650-b/d Aconcagua refinery will be on line soon but no date could be given for the restart of its 113,000-b/d Bio Bio facility.

Both refineries stopped operating due to damage and electrical problems following an 8.8-magnitude earthquake that rocked the central southern part of Chile on Feb. 27.

The initial quake was followed by a 6.2-magnitude aftershock that struck central Chile, according to the US Geological Survey, which located the epicenter 35 km underground and 109 km northeast of the city of Talca.

Meanwhile, despite earlier assurances about availability of domestic stocks, Enap said it will import 65,000 cu m of diesel to secure the local fuel supply.

That follows an earlier statement by Enap that it had enough gasoline for at least 2 weeks and enough diesel for 10 days, a stance underscored by Energy minister Marcelo Tokman who said there was no cause for concern.

"In terms of oil and gas, the stock is there," Tokman said. "The situation is fine. The problem is distribution and coordination. But in terms of the amount of fuel, we do not see any problem."

However, company officials also left open the option of importing further supplies if needed.

The Aconcagua refinery is the main source of products for the Santiago market, while the Bio Bio facility supplies 40% of products used by the domestic market including fuel oil, LPG, gasoline and diesel oil.

Fire hits Navajo Refinery asphalt tank

Fire at an asphalt tank under construction at Holly Corp.'s 100,000 b/d Navajo Refinery in Artesia, NM, killed at least one contract worker and left another worker missing and feared dead, Holly said.

The company said Mar. 3 that two other workers were seriously injured.

It said refinery firefighters extinguished the blaze in about 90 min. Refinery operations were not disrupted.

At the same refinery on Jan. 17, fire broke out in the crude unit, injuring no one and causing little damage (OGJ, Jan. 25, 2010, Newsletter). ✦

Transportation — *Quick Takes*

PNG LNG capacity fully committed

The ExxonMobil Corp.-led PNG LNG joint venture has completed an agreement with CPC Corp. of Taiwan for the sale of 1.2 million tonnes/year of LNG for 20 years from the Papua New Guinea project (OGJ Online, Dec. 11, 2009).

The CPC contract means all the project's production capacity

has been committed to long-term agreements. All that remains before construction begins is the finalization of financing. This is expected to occur within weeks.

The PNG LNG project will pipe natural gas from oil and gas fields in the highlands region south to the Papuan Gulf and then east along the coast to Port Moresby, where a 6.6-million tpy LNG plant is to be built.

Joint venture interests are ExxonMobil 33.2%, Oil Search 29%, Independent Public Business Corp. (the PNG government) 16.6%, Santos 13.5%, Nippon Oil Exploration 4.7%, Minerals Development Co. (PNG landholders) 2.8%, and Petromin PNG Holdings 0.2%.

Oil Search set on finding more gas in PNG

Oil Search Ltd., Sydney, says it plans to focus exploration efforts this year on finding more natural gas to underpin the expansion of the LNG project in Papua New Guinea.

Oil Search Managing Director Peter Botten said activities include the drilling of the Wasuma, Korka, and Mananda Attic prospects as well as seismic data acquisition both on and offshore.

The company also is hoping to get the most out of its oil assets, including the drilling of one or two development wells in Moran field, appraising a deep play in Agogo field, and carrying out a workover program in Kutubu, Moran, and Southeast Gobe fields—all in the Papua New Guinea highlands.

The deep intervals at Agogo, which had oil in several intervals in the previously untested footwall forelimb compartment, would come in for priority treatment. Oil Search plans to flow test these intervals to determine hydrocarbon content, reservoir productivity, and potential for future development opportunities.

The oil in the Agogo footwall has opened up a new play fairway in the fold belt region and this has significant implications for the development of analogous structures below existing fields as well as the increased prospectivity on trend in adjacent permits.

Botten added that the remaining issues before financial close of the Papua New Guinea LNG project, including the signing of the final sales and purchase agreement, should be resolved within the next month.

Contracts awarded for Singapore LNG terminal

Singapore LNG Corp. Pte. Ltd. announced last month it had awarded a contract to Foster Wheeler AG unit Global Engineering & Construction Group for management consultancy.

Singapore LNG is a unit of the Energy Market Authority of Singapore and is developing an LNG terminal on the southwestern part of Jurong Island, Singapore. The terminal will have initial import capacity of 3.5 million tonnes/year, with provision for expansion to 6 million tpy. Start-up is targeted for 2013.

Singapore LNG and Foster Wheeler will jointly manage engineering, procurement, and construction contractor Samsung C&T Corp. That company announced Mar. 1 it has awarded Fluor Corp. an engineering and related management services contract for the Singapore terminal.

GDF Suez to acquire stake in Nord Stream line

GDF Suez SA reported it will take a 9% stake in Nord Stream AG before construction of that 1,200-km natural gas pipeline that will link Russia and the European Union via the Baltic Sea. GDF Suez also will receive as much as 1.5 billion cu m (bcm) of gas from the line starting in 2015. This will be added to the 12 bcm/year that OAO Gazprom already sends to GDF Suez.

The first stage of Nord Stream is due for commissioning in 2011 with a 27.5 bcm/year capacity. The second stage is to be commissioned in 2015 with a 55 bcm capacity from which GDF Suez will receive its 1.5 bcm/year.

Although memorandum for the gas supply and the 9% acquisition has not been officially signed, both parties confirmed GDF Suez is to acquire 4.5% each from E.On Ruhrgas AG, and Wintershall Holding AG, each of which now hold 20% of Nord Stream. "Some details of this transaction still need to be finalized," a GDF Suez spokesman told OGJ.

When finalized, the Nord Stream joint venture will include Gazprom with 51%, Wintershall and E.On Ruhrgas, 15.5% each, NV Nederlandse Gasunie, 9%, and GDF Suez, 9%.

PetroVietnam to invest in second gas line

PetroVietnam plans to invest $1.3 billion in a proposed second natural gas pipeline from the Nam Con Son basin off southern Vietnam. The new line will carry gas from Blocks 05.1 and 0.52 in the Hai Thach and Moc Tinh projects in the Nam Con Son basin to feed electric power plants in Phu My district in the southern province of Ba Ria-Vung Tau.

The 400-km line will be built in parallel with the current line to transport 6 billion cu m (bcm)/year of gas from fields in the Nam Con Son basin. Stakeholders in the old line include PetroVietnam 51%, BP PLC 32.27%, and ConocoPhillips 16.33%.

The first Nam Con Son line, built by BP at a cost of $1.3 billion, has a capacity of 7.3 bcm/year but normally averages 5.5 bcm/year. PetroVietnam affiliate PetroVietnam Gas Corp. said it carried 5.516 bcm via the Nam Con Son line in 2009.

After the new line comes on stream, the country's onshore gas supply will increase by 30-40% to 10-11 bcm/year, said Phung Dinh Thuc, PetroVietnam general director.

According to analyst BMI, construction of a second Nam Con Son pipeline could provide gas to fuel further increases in power generation capacity in southern Vietnam.

Vietnam's power generation sector consumed 4.6 bcm of gas in 2008, and BMI forecasts this consumption to increase to 12.3 bcm by 2013 as gas-fired power reaches 45.2% of the country's total electricity generation. "In addition, we see total Vietnamese gas consumption of 7.9 bcm in 2008 rising to 15 bcm in 2009 and 21 bcm by 2015," BMI said.

The analyst said the new pipeline could "also be used to supply rising residential and industrial demand in the area, which contains a number of fertilizer and steel plants." ✦

Correction

A Conasauga shale prospect in Alabama should have been described as having 0.5% to 1.5% total organic carbon and 500 bcf/sq mile of gas in place, not 500 bcf of gas in place (OGJ, Feb. 22, 2010, p. 36).

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.

2010

MARCH

Middle East Geosciences Conference and Exhibition, Manama, +973 17 550033, +973 17 553288 (fax), e-mail: fawzi@aeminfo.com.bh, website: www.aeminfo.com.bh/geo2010. 7-10.

Middle East Geosciences Conference and Exhibition, Manama, +973 17 550033, +973 17 553288 (fax), e-mail: fawzi@aeminfo.com.bh, website: www.geobahrain.org. 7-10.

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-9.

Purvin & Gertz LPG Seminar, The Woodlands, Tex., (713) 331-4000, (713) 236-8490 (fax), website: www.purvingertz.com. 8-11.

CERA Week, Houston, (617) 866-5992, e-mail: info@cera.com, website: www.cera.com. 8-12.

NPRA Security Conference & Exhibition, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-10.

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

Annual European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 9-12.

SPE European San Management Forum, Aberdeen, +44 1224 495051, e-mail: Alexandra.stacey@hulse-rodger.com, website: www.spe-uk.org. 10-11.

NACE International Corrosion Conference & Expo, San Antonio, (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org. 14-18.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 845-1835 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 15-18.

API Spring Committee on Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 15-18.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 16-18.

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

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

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

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

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

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

ACS Spring National Meeting & Exposition, San Francisco, (202) 876-4600, e-mail: help@acs.org, website: http://portal.acs.org. 21-25.

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

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

Gas Turbine Users International (GTUI) Annual Conference, Calgary, Alta., +9714 804 7738, +9714 804 7764 (fax), e-mail: info@gtui.org, website: www.gtui.org. 21-26.

Middle East Downstream Week & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-25.

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

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

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 23-24.

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

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

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

DistribuTECH Confernece & Exhibition, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.distributech.com. 23-25.

✦SPE Aberdeen Section, Edinburgh Meeting, Aberdeen, +44 1224 646658, e-mail: spe@hulse-rodger.com, website: www.hulse-rodger.com. 24.

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 24-25.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 28-30.

APRIL

ATYRAU North Caspian Regional Oil, Gas and Infrastructure Exhibition, Atyrau, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-8.

Calendar

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 6-8.

Oil & Gas WestAsia Exhibition in conjunction with SPE EOR Conference, Muscat, +968 24660124, +968 24660125 (fax), e-mail: omanexpo@omantel.net.om, website: www.ogwaexpo.com 11-13.

SPE EOR Conference at Oil & Gas West Asia, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-13.

AAPG Annual Convention and Exhibition, New Orleans, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org 11-14.

Annual Asian Petcoke Conference, Panaji, Goa, India, (832) 351-7828, e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 12-14.

✦Annual World Congress of Well Stimulation and EOR, Chengdu, 0086 411 84799609 821, 0086 411 84799629 (fax), e-mail: Kalin@bitpetrobio.com, website: www.bitpetrobio.com/wsepr2010. 12-14.

IPAA OGIS, New York City, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 12-14.

SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Rio de Janeiro, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

IADC Well Control Europe Conference & Exhibition, Aberdeen, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 13-14.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), e-mail: gpa@gasprocessors.com, website: www.gasprocessors.com. 15.

International Liquefied Natural Gas Conference and Exhibition, Oran, +44 (0) 20 7596 5000, +44 (0) 20 7596 5111 (fax), website: www.lng16.org. 18-21.

Oil & Gas WestAsia Conference, Muscat, +968 24660124, +968 24660125 (fax), e-mail: omanexpo@omantel.net.om, website: www.ogwaexpo.com. 19-21.

Hannover Messe Pipeline Technology Trade Show, Hannover, +49 0 511 89 0, +49 0 511 89 32626 (fax), website: www.hannovermesse.de. 19-23.

Texas Alliance Annual Meeting and Expo, Wichita Falls, (940) 723-4131, (940) 723-4132 (fax), e-mail: texasalliance@texasalliance.org, website: www.texasalliance.org. 20-21.

API Pipeline Conference and Cybernetics Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 20-22.

SPE Improved Oil Recovery Symposium, Tulsa, (918) 366-7033, (918) 366-7064 (fax), e-mail: IOR@SPEIOR.ORG, Website: www.speior.org. 26-28.

Middle East Fertilizer Symposium & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 26-28.

API Spring Refining and Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 26-28.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27.

MAY

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org/2010. 3-6.

GPA Permian Basin Annual Meeting, Midland, Tex.,

(918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 4.

Asian Biofuels, New Feedstocks and Technology Roundtable, Singapore, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

OGU/Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 11-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 11-13.

✦*APPEA Conference & Exhibition*, Brisbane, +61 (7) 3802 2208, +61 (7) 3802 2209 (fax), e-mail: jhood@appea.com.au. website: www.appea.com.au. 16-19.

✦*Annual Global Refining Summit*, Rotterdam, +44 (0) 20 7202 7690, +44 (0) 20 7202 7600 (fax), e-mail: andrew.barrett@wtgevents.com, website: www.refining-summit.com. 17-19.

Mediterranean Offshore Conference & Exhibition, Alexandria, Egypt, +20 2 27065210, +20 2 25184980 (fax), e-mail: conference@omc.it, website: www.moc2006.com. 18-20.

NPRA National Safety Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 19-20.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 20.

SPE International Conference on Oilfield Corrosion, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 24-25.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200. (202) 326-8660, e-mail: info@ilta.org, website: www.ilta.org. 24-26.

Petrotech Middle East Refining and Petrochemicals Exhibition & Conference, Manama, +973 1755 0033, +973 1755 3288 (fax), e-mail: fawzi@aeminfo.com.bh, website: www.mepetrotech.com. 24-26.

NPRA Reliability and Maintenance Conference and Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. May 25-28.

SPE International Conference on Oilfield Scale, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-27.

SPE Western North America Regional Meeting, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-30.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 1-4.

AchemAsia, Beijing, 0049 69 75 64 0, 0049 69 75 64 201 (fax), website: www.achemasia.de. 1-4.

ASME Annual Meeting, Pittsburgh, (800) 843-2763, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 4-9.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Victoria, BC, (713) 651-1639, (713) 951-9659 (fax), website: www.spee.org. 5-8.

Asia Oil & Gas Conference, Kuala Lumpur, 65 6338 0064, 65 6338 4090 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 6-8.

IAEE International Conference, Rio de Janeiro, (216) 464-5365, (216) 464-2737 (fax), e-mail: iaee@iaee.org, website: www.usaee.org. 6-9.

PIRA Canadian Energy Conference, Calgary, Alta., (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

SPE International Oil & Gas Conference and Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-10.

SUBSEA Asia Conference, Kuala Lumpur, +65 6233 6777, +65 6233 6768 (fax), e-mail: gerald@iemall-world.com, website: www.subseaasia.org. 9-11.*IPAA OGIS London*, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

EAGE Conference and Exhibition/SPE EUROPEC, Barcelona, Spain, +31 88 995 5055, +31 30 634 3524 (fax), e-mail: eage@eage.org, website: www.eage.org. 14-17.

ASME Turbo Expo, Glasgow, Scotland, (800) 843-2763, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 14-18.

GTI Global Unconventional Gas Conference, Amsterdam, (847) 768-0783, website: www.gastechnology.org/gug2010. 15-17.

IADC World Drilling Conference & Exhibition, Budapest, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 16-17.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

AAPL Annual Meeting, Vail, Colo., (817) 847-7700, (817) 847-7704 (fax). e-mail: aapl@landman.org, website: www.landman.org. 16-19.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 17-18.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), Perth, (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 19-23.

International Offshore and Polar Engineering Conference (ISOPE), Beijing, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 20-26.

Mixing oil and Wasser

Steven Poruban
Senior Editor

As parts of the US and elsewhere experience one of most relentless winters on record, it's only human nature to entertain thoughts of warmer-weather activities, such as walking along a sandy beach or even taking in a splash-filled day at a water park. One thought that probably won't occur to bathers at a particular water park in the Pfalz town of Landau in Germany, however, will likely be: "How is all this water being heated?"

That's because this summer, German oil and gas producer Wintershall will be providing that town's La Ola municipal water park with warm water and heating that is generated by geothermal power from a former crude oil reservoir about 1,100 m underground.

Wintershall, a BASF subsidiary, reported that 22,000 l./hr of water will be circulated within a closed loop system at La44, a decommissioned production well that is one of 75 wells operated by the company in the Landau region.

Before the well can be used for geothermal power, however, technical modifications will have to be made, the company said.

The heated water for the park will be pumped to the surface via the tubing string at the decommissioned well. A heat pump and four heat exchangers will then supply the leisure pool, which is just 500 m away, via a district heating pipe. "This cooperation will provide us with over 1 million kw-hr of environmentally friendly energy for a year," explained Thomas Hirsch, managing director of Stadtholding Landau in der Pfalz GMBH, the town's operating and holding company.

Location, location, location

It's Landau's location in the Upper Rhine Plain that offers ideal conditions for tapping geothermal energy, said Thomas Ruttmann, head of Wintershall's Landau operations. "With deep drilling, the temperature increases by an average of 4.7° every 100 m," he said, adding that this is considerably higher than the average increase in temperature of 3°/100 m elsewhere. "That's why there are a relatively high number of geothermal projects in the Landau region compared to other regions," he said.

In order to develop the former La44 oil well, the current concessions three shareholders—Wintershall, ExxonMobil Production Deutschland GMBH, and Internationale Tiefbohr GMBH & Co. KG—have teamed with EnergieSudwest AG subsidiary Lan Tec GMBH, which specializes in the use of renewable energy and also already serves as operator of several district heating networks in the Pfalz region.

Landau is home to the largest crude oil field on the Upper Rhine Plain, Wintershall said. The field is comprised of eight blocks on which a total of nearly 200 wells have been drilled. Production from Landau started in 1955, the same year the field was discovered with the Landau 2 well. Since then, more than 4.3 million tons of oil have been produced in Landau.

CO_2 reduction benefit

Wintershall, which holds a 50% share in the concession, also recently took over as operator. In addition to supplying the water park, the production operations in Landau currently use more than 13 million kw-hr of geothermal heat energy by treating the reservoir water. The energy generated this way is equivalent to the average consumption of more than 350 households.

With each German household responsible for about 13 tons/year of carbon dioxide emission, this means a reduction of more than 4,500 tons/year of CO_2, Wintershall calculates.

Chances are good, however, that this thought, too, won't cross the minds of many of the water park's attendees this summer.

Only, "Pass the sunblock." ✦

Oil production in Landau in der Pfalz began in 1955. Current production yields about 24,000 tons/year of oil. Photo from Wintershall.

Under the Patronage of
H.E Abdullah Bin Hamad Al-Attiyah
Deputy Prime Minister & Minister for Energy and Industry

OFFSHORE MIDDLE EAST

Conference and Exhibition
12 – 14 October 2010
Doha • Qatar

UNIQUELY FOCUSED UNIQUELY OFFSHORE

Now in its third successful year, Offshore Middle East Conference & Exhibition plays an important role in the region. It provides a high level forum that focuses on the advancement of the offshore exploration & production industry. The event comprehensively addresses the technological challenges associated with safely and cost effectively developing resources.

Whether your organization is looking for a platform to showcase ground-breaking new technology or looking to raise its profile as an industry leader, Offshore Middle East provides it all.

Call For Abstracts Open: Deadline 18 May 2010
Submit Online Today Via www.offshoremiddleeast.com

For further information on the conference contact:

Eldon Ball
Conference Director
T: +1 713 963 6252
F: +1 713 963 6296
E: eldonb@pennwell.com

Niki Vrettos
Conference Manager
T: +44 (0) 1992 656 630
F: +44 (0) 1992 656 700
E: nikiv@pennwell.com

Owned and produced by: PennWell EST. 1910 100TH ANNIVERSARY

Flagship Media Sponsors: Offshore, OIL&GAS JOURNAL

Hosted by: Qatar Petroleum

Platinum Sponsor:

Supported by:

Editorial

Al Gore and the IPCC

Nobel Propagandist Al Gore has reemerged to dogmatize again about global warming, responding this time to the collapse of scientific arguments for abandoning fossil energy. The former US vice-president wants everyone to quit worrying about the obvious surrender by science to politics at the Intergovernmental Panel on Climate Change, the United Nations creation lately forced to recant claims about melting glaciers, rising sea levels, and irreversible warming. In a Feb. 28 column in the New York Times, Gore sees little of importance in the mistakes.

"The reality of the danger we are courting has not been changed by the discovery of at least two mistakes in the thousands of pages of careful scientific work over the last 22 years by the [IPCC]," he writes. After glossing over the two errors and attributing politically motivated manipulations by data handlers in the UK to "an onslaught of hostile, make-work demands by climate skeptics," Gore proclaims "that the overwhelming consensus on global warming remains unchanged."

A tired point

His argument progresses little beyond that tired point. The rest of his long column is a harangue against imported oil, people who disagree with him, "media organizations" he dislikes, free markets, the Senate's failure to pass cap-and-trade legislation, and "political paralysis," national and global.

Name-calling riddles the screed. In addition to villainous "skeptics," Gore berates "market fundamentalists," "polluters refusing to act," and "showmen masquerading as political thinkers who package hatred and divisiveness as entertainment." Redeploying an overworked and altogether silly analogy, the former vice-president likens businesses that resist regulation of carbon emissions—which he calls "unrestrained pollution of the atmospheric commons"—to the tobacco industry. And, as always, he disparages dissenters without acknowledging their arguments. Failure to submit to the Gore evangel, for example, condemns his contemporaries to being remembered by their grandchildren as "a criminal generation that had selfishly and blithely ignored clear warnings that their fate was in our hands."

These are the blind swings of a political pugilist caught against the intellectual ropes with his arguments bruised and bloody. Gore's attempt to scoff away the IPCC's lapses is pathetic. The errors were not trivial. IPCC's 2007 warning about melting Himalayan glaciers made headlines and intensified the alarm fueling pressure to implement costly remedies. Its overstatement of sea-level rise in the Netherlands had the same effect. Indeed, other errors not brushed aside by Gore have emerged, such as IPCC's exaggerated claims about vanishing rainforests.

The pattern is clear: IPCC errs on the side of climate alarm. Leaked e-mail messages from the University of East Anglia foreclose all possibility that the errors just happened to fall on one side of the political issue. The messages showed scientists responsible for crucial climate data maneuvering to prevent publication of views contrary to their own, scheming in other ways against opponents, and withholding or misplacing data. The thoroughly politicized mayhem in full electronic view defines the consensus to which Gore alludes. In a growing number of ways, parties to it have been caught tricking away their credibility.

Gore does his own standing no good with his whiny, unconvincing attempt to reduce these events to insignificance. Now, more than ever, he looks like a prophet of hollow prophesy. "What is at stake is our ability to use the rule of law as an instrument of human redemption," he preaches in his Times column. That's too heavy a load of moral certitude for a lame mule like the IPCC to carry.

Grand outcomes

If Gore truly worried about grand outcomes levered by minor precedents he'd object to the Environmental Protection Agency's plan to regulated emissions of greenhouse gases under the Clean Air Act. Thanks to a Supreme Court ruling on legal standing and definitions, a federal agency is moving to assume control over much economic decision-making in the US. The ruling didn't address climate science; it merely settled a question about statutory intent. It nevertheless provided for an historic expansion of government.

Because EPA's move increases pressure on Congress to cap carbon emissions, Gore won't fight it. His real concern is politics, not science. ✦

unconventional gas *redefining* Success

reasons to attend

- Share best practices in unconventional gas recovery
- Stay up-to-date on the latest products and technologies featured at the exhibition
- Network with colleagues, prospects – even competitors

And, new this year:

- Experience the financial forum featuring senior executives from unconventional gas operators who will discuss their company's unique experiences in various plays

register online and save!

Before September 3, 2010 and save $100!

UNCONVENTIONAL GAS INTERNATIONAL CONFERENCE & EXHIBITION™

October 5–7, 2010
Fort Worth Convention Center
Fort Worth, Texas USA
www.unconventionalgas.net

For more information and to register, visit
www.unconventionalgas.net

Owned & Produced By:

PennWell

Flagship Media Sponsors:

OIL&GAS JOURNAL | OIL&GAS FINANCIAL JOURNAL | Oil, Gas & Petrochem EQUIPMENT | Offshore | PennEnergy

US, Canadian firms post weak 4Q 2009, annual results

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

For some oil and natural gas producers, fourth-quarter 2009 earnings improved from a bleak quarter a year earlier, but feeble demand for products hurt refining and marketing results.

Annual results for 2009 reveal that lower oil and gas prices and lower demand for energy products in light of weakness among the world's developed economies created challenges for most companies.

OGJ looked at the fourth-quarter 2009 and full-year 2009 results of three samples of companies and found that with one exception, each of the groups—US-based operators, Canadian producers and pipeline firms, and service and supply companies—collectively posted weaker earnings reports from a year earlier.

The sample of oil and gas producers and refiners based in the US recorded an improvement in combined net income for the 2009 fourth quarter, as fewer of these companies incurred a loss for these 3 months vs. the final 2008 quarter.

During last year's fourth quarter, the front-month futures price of oil on the New York Mercantile Exchange recorded a higher average than during the final 2008 quarter, at $76.13/bbl vs. $59.06/bbl. But the average gas futures price in the recent quarter was $4.927/MMbtu, down from $6.398/MMbtu a year earlier.

US operators

A group of oil and gas producing companies and refiners with headquarters in the US posted a combined return on revenues of just 5% in the fourth quarter of 2009.

The group's total earnings were $13.1 billion in the recent quarter. This compares with a combined net loss of $30.6 billion a year earlier, when ConocoPhillips recorded a $31.7 billion net loss for the quarter (OGJ, Mar. 16, 2009, p. 30).

Seventeen of the companies in the sample of 53 US-based firms recorded a net loss in the 2009 fourth quarter, while 27 of these companies incurred a loss for the final 2008 quarter. For the year, however, the number of companies that recorded a loss was 32. For 2008, there were 16 companies in this group that incurred a net loss.

Some of the operators in the sample improved on their fourth-quarter 2008 results, including Murphy Oil Corp. and Occidental Petroleum Corp. Meanwhile, others such as Apache Corp., ConocoPhillips, and Hess Corp. posted positive net income after recording a loss for the last quarter of 2008.

ExxonMobil Corp. and Chevron Corp. reported a decline in earnings for the final 2009 quarter compared with fourth-quarter 2008 results. Both of these integrated firms announced a climb in upstream earnings and a decline in downstream results.

ExxonMobil announced its fourth-quarter 2009 upstream earnings were $5.78 billion, up $146 million from the fourth quarter of 2008. Higher crude oil realizations increased earnings by $1.8 billion, while lower gas realizations reduced earnings by $1.2 billion. Lower gains from asset sales decreased earnings by $600 million. On an oil-equivalent basis, the company's production increased nearly 2% from a year earlier.

Downstream operations recorded a loss of $189 million in the recent quarter, down $2.6 billion from a year earlier, ExxonMobil reported, while its chemicals earnings of $716 million were $561 million higher than in the fourth quarter of 2008.

Chevron's annual earnings decreased 56% in 2009 as a result of lower oil and gas prices and a decline in refined product sales margins, driven by a weak global economy.

Fourth-quarter 2009 earnings declined 37% from the final 2008 quarter. But upstream results benefited from higher oil prices as Chevron's net oil-equivalent production for the quarter

US OIL AND GAS FIRMS' FOURTH QUARTER 2009 REVENUES, EARNINGS

	Revenues 4th quarter		Net income 4th quarter		Revenues Full year		Net income Full year	
	2009	2008	2009	2008	2009	2008	2009	2008
	Million $							
Anadarko Petroleum Corp.	2,417.0	2,927.0	238.0	794.0	9,000.0	15,162.0	(103.0)	3,283.0
Apache Corp.	2,555.2	1,936.9	585.8	(2,945.0)	8,614.8	12,389.8	(291.7)	706.3
Berry Petroleum Co.	132.6	134.7	13.0	(12.0)	506.7	649.2	54.0	133.5
Bill Barrett Corp.	165.8	146.8	12.5	6.1	598.2	617.9	50.2	105.3
Brigham Exploration Co.	21.5	30.5	2.5	(180.6)	70.3	127.8	(123.0)	(162.2)
Cabot Oil & Gas Corp.	233.5	232.5	36.4	43.7	879.3	945.8	148.3	211.3
Cheniere Energy Inc.	85.6	0.7	(23.2)	(111.1)	181.1	7.1	(161.5)	(373.0)
Chesapeake Energy Corp.	2,222.0	2,981.0	(499.0)	(995.0)	7,702.0	11,629.0	(5,805.0)	604.0
Chevron Corp.	48,676.0	45,203.0	3,102.0	4,901.0	171,636.0	273,005.0	10,563.0	24,031.0
CNX Gas Corp.	177.8	206.1	41.1	57.5	683.4	789.4	164.5	239.1
Comstock Resources Inc.	90.2	100.1	(6.8)	(96.4)	290.9	563.7	(36.5)	252.0
ConocoPhillips	43,625.0	44,904.0	1,246.0	(31,745.0)	152,840.0	246,182.0	4,936.0	(16,928.0)
Continental Resouces Inc.	207.6	135.8	49.5	11.2	626.2	960.5	71.3	321.0
Denbury Resources Inc.	270.8	222.5	3.5	43.8	889.2	1,371.1	(75.2)	388.4
Dorchester Minerals LP	14.4	15.2	8.8	9.6	43.6	89.9	21.7	66.8
Encore Acquisition Co.	221.6	167.7	(28.7)	267.1	685.4	1,135.4	(97.9)	485.1
EOG Resources Inc.	1,760.9	1,633.7	400.4	461.5	4,787.0	7,127.1	546.6	2,436.9
EQT Corp.	344.0	408.9	55.4	33.5	1,269.8	1,576.5	156.9	255.6
Exco Resources Inc.	106.6	272.4	241.5	(1,161.4)	585.8	1,490.3	(496.8)	(1,733.5)
ExxonMobil Corp.	89,841.0	84,696.0	6,139.0	8,424.0	310,586.0	477,359.0	19,658.0	46,867.0
Forest Oil Corp.	214.5	282.0	45.2	(1,382.6)	768.5	1,650.8	(923.1)	(1,026.3)
Frontier Oil Corp.	4,237.2	6,498.8	(83.8)	226.1	1,088.5	1,348.1	(75.1)	119.0
Helix Energy Solutions Group Inc.	180.0	534.4	(55.7)	(861.2)	1,461.7	2,114.1	101.9	(639.1)
Hess Corp.	8,558.0	7,248.0	370.0	(80.0)	29,569.0	41,063.0	807.0	2,357.0
HKN Inc.	3.1	1.1	(1.5)	(27.1)	12.4	20.2	(3.3)	(26.9)
Holly Corp.	1,664.4	922.8	(22.4)	54.0	4,839.3	5,871.2	53.3	126.6
Key Energy Services	267.5	478.1	(13.6)	(42.9)	1,078.7	1,972.1	(156.1)	84.1
LINN Energy LLC	79.1	1,044.0	(65.4)	888.5	273.1	1,435.0	(298.2)	999.6
Lucas Energy Inc.	0.5	0.7	(0.5)	(2.0)	1.3	3.0	(1.3)	(1.2)
Marathon Oil Corp.	16,066.0	14,701.0	355.0	(41.0)	54,139.0	78,130.0	1,463.0	3,528.0
Murphy Oil Corp.	5,873.9	4,411.1	318.9	127.4	19,059.1	27,432.3	837.6	1,740.0
Newfield Exploration Co.	414.0	338.0	113.0	(789.0)	1,338.0	2,225.0	(542.0)	(373.0)
Noble Energy Inc.	760.0	573.0	8.0	305.0	2,313.0	3,901.0	(131.0)	1,350.0
Occidental Petroleum Corp.	4,539.0	4,021.0	938.0	443.0	15,403.0	24,217.0	2,915.0	6,857.0
Penn Virginia Corp.	236.9	225.7	11.4	7.7	815.1	1,220.9	(77.4)	181.5
Petrohawk Energy Corp.	354.9	270.7	34.5	(545.1)	1,083.6	1,095.2	(1,025.5)	(388.1)
PetroQuest Energy Inc.	53.9	66.3	(39.3)	(153.5)	218.9	314.0	(90.2)	(97.0)
Pioneer Natural Resources Co.	463.7	468.8	54.2	(63.2)	1,711.5	2,284.8	(42.3)	231.7
Plains Exploration & Production Co.	367.7	328.2	48.1	(1,568.7)	1,187.1	2,403.5	136.3	(709.1)
Questar Corp.	890.8	878.8	150.9	123.3	3,038.0	3,465.1	395.9	692.8
Range Resources Corp.	242.1	223.8	(16.8)	93.6	839.9	1,226.6	(53.9)	351.0
Southwestern Energy Co.	624.5	500.1	157.8	104.2	2,145.8	2,311.6	(35.8)	568.5
St. Mary Land & Exploration Co.	242.0	258.2	1.0	(127.1)	832.2	1,301.3	(99.4)	87.3
Stone Energy Corp.	199.3	166.1	(64.1)	(1,316.5)	714.4	801.0	(211.7)	(1,137.3)
Sunoco Inc.	8,973.0	8,641.0	56.0	243.0	31,312.0	51,076.0	(200.0)	889.0
Swift Energy Co.	114.9	145.4	14.6	(452.5)	370.4	820.8	(39.1)	(257.1)
Tesoro Petroleum Corp.	4,669.0	4,241.0	(179.0)	97.0	16,872.0	28,416.0	(140.0)	278.0
Unit Corp.	177.3	291.0	28.5	(119.8)	708.9	1,358.1	(55.5)	143.6
Valero Energy Corp.	18,867.0	17,832.0	(1,408.0)	(3,278.0)	68,144.0	113,136.0	(1,982.0)	(1,131.0)
W&T Offshore Inc.	176.1	108.3	64.0	(851.4)	611.0	1,215.6	(187.9)	(558.8)
Whiting Petroleum Corp.	316.0	223.9	(5.8)	(3.0)	979.4	1,222.1	(106.9)	252.1
Williams Cos. Inc.	2,084.0	2,326.0	132.0	222.0	11,890.0	8,255.0	1,592.0	361.0
XTO Energy Inc.	2,342.0	1,961.0	537.0	351.0	9,064.0	7,695.0	2,019.0	1,912.0
Total	**277,421.4**	**266,565.8**	**13,099.9**	**(30,612.3)**	**956,358.5**	**1,474,179.9**	**33,023.2**	**77,954.5**

was 9% higher than a year earlier, driven by new production from several major capital projects.

"In our downstream business, our operated refineries continued to run reliably during the fourth quarter. However, this operational success did not offset the effects of low margins on the sale of gasoline and other refined products due to weak demand and excess supply worldwide," said Chevron Chairman and Chief Executive Officer John Watson.

Refiners

Weak refining and marketing margins continued to plague the results of the refining companies in the sample of US-based firms.

The US gulf coast cash refining margin in the fourth quarter of 2009 fell to average $1.07/bbl, according to Muse Stancil & Co. A year earlier the same margin averaged $5.45/bbl.

Valero Energy Corp. reported that its fourth-quarter 2009 results include $18.87 billion in revenues and a $1.4 billion loss. This compares to a nearly $3.3 billion loss in the final 2008 quarter.

For all of 2009, the San Antonio-based refiner posted a $1.98 billion loss vs. a $1.13 billion loss for 2008. "Weak demand, narrow margins, and low discounts in the fourth quarter exemplified how difficult refining conditions were in 2009," said Bill Klesse, Valero's chairman and chief executive officer.

"While 2009 may have been the bottom for refining profitability, there's

SERVICE-SUPPLY COMPANIES' FOURTH QUARTER 2009 REVENUES, EARNINGS

	Revenues 4th quarter		Net income 4th quarter		Revenues Full year		Net income Full year	
	2009	2008	2009	2008	2009	2008	2009	2008
	Million $							
Baker Hughes Inc.	2,428.0	3,186.0	84.0	432.0	9,664.0	11,864.0	421.0	1,635.0
Cameron International Corp.	1,464.4	1,524.3	97.3	146.0	5,223.2	5,848.9	475.5	580.7
Diamond Offshore Drilling Inc.	890.8	903.2	276.1	293.3	3,631.3	3,544.1	1,376.2	1,310.5
Dril-Quip Inc.	135.5	141.3	25.0	28.7	542.8	540.2	105.6	105.1
Foster Wheeler Ltd.	1,266.6	1,639.2	63.7	105.3	5,056.3	6,854.3	361.4	533.9
Gulfmark Offshore Inc.	84.7	121.9	(11.3)	59.3	388.9	411.7	50.6	183.8
Halliburton Co.	3,690.0	4,914.0	244.0	443.0	14,687.0	18,318.0	1,155.0	2,215.0
Hornbeck Offshore Services Inc.	88.3	121.0	9.3	34.6	385.9	432.1	50.4	115.8
Nabors Industries Ltd.	679.1	1,238.5	(47.3)	(106.7)	3,503.4	5,303.8	(85.5)	475.7
Noble Corp.	940.1	910.2	446.4	418.6	3,640.8	3,446.5	1,678.6	1,561.0
Oceaneering International Inc.	452.3	525.7	46.1	51.0	1,822.1	1,977.4	188.4	199.4
Parker Drilling Co.	175.8	212.4	(4.3)	(40.2)	752.9	829.8	9.3	22.7
Patterson-UTI Energy Inc.	213.6	531.5	(18.2)	79.5	781.9	2,063.9	(38.3)	347.1
Pioneer Drilling Co.	81.2	170.7	(8.4)	(117.9)	325.5	610.9	(23.2)	(62.7)
Pride International Inc.	317.1	491.9	(32.8)	234.7	1,597.2	1,719.4	285.8	851.1
RPC Inc.	152.4	227.9	(5.2)	20.4	588.0	877.1	(22.7)	83.4
Schlumberger Ltd.	5,744.0	6,868.0	797.0	1,150.0	22,702.0	27,163.0	3,142.0	5,460.0
Weatherford International	1,983.8	3,056.4	61.0	268.4	8,218.6	10,770.8	312.2	1,050.1
Smith International Inc.	2,426.1	2,634.6	(27.3)	357.1	8,826.9	9,600.6	279.9	1,388.2
Total	**23,213.8**	**29,418.7**	**1,995.1**	**3,857.1**	**92,338.7**	**112,176.5**	**9,722.2**	**18,055.8**

CANADIAN OIL AND GAS FIRMS' FOURTH QUARTER 2009 REVENUES, EARNINGS

	Revenues 4th quarter		Net income 4th quarter		Revenues Full year		Net income Full year	
	2009	2008	2009	2008	2009	2008	2009	2008
	Million $ (Can.)							
Enbridge Inc.	3,187.0	3,924.0	302.0	266.0	12,466.0	16,131.0	1,562.0	1,328.0
EnCana Corp.	2,847.9	5,105.7	667.9	1,131.0	11,671.0	22,108.2	1,955.3	6,241.9
Husky Energy Inc.	3,605.0	4,701.0	320.0	231.0	15,074.0	24,701.0	1,416.0	3,751.0
Imperial Oil Ltd.	5,864.0	5,942.0	534.0	660.0	21,398.0	31,579.0	1,579.0	3,878.0
Nexen Inc.	1,824.0	1,696.0	262.0	(188.0)	5,804.0	8,237.0	556.0	1,711.0
Suncor Energy Inc.	7,636.0	6,952.0	457.0	(215.0)	25,480.0	28,637.0	1,146.0	2,137.0
Talisman Energy Inc.	1,825.0	1,773.0	(111.0)	1,202.0	6,488.0	9,358.0	437.0	3,519.0
TransCanada Corp.	2,206.0	2,332.0	387.0	277.0	8,966.0	8,619.0	1,380.0	1,440.0
Total	**28,994.9**	**32,425.7**	**2,818.9**	**3,364.0**	**107,347.0**	**149,370.2**	**10,031.3**	**24,005.9**

too much inventory and spare refining capacity in the industry right now for margins to rebound quickly. Economic growth will help demand recover in 2010, but we also expect new refining capacity to come online in the US and around the world. Therefore, 2010 is expected to be another challenging year for the industry while refiners close marginal capacity and wait for demand growth to work down spare capacity," Klesse said.

Canadian firms

A sample of eight oil and gas producers and pipeline operators based in Canada recorded a combined 16% decline in earnings in the final 2009 quarter and an 11% dip in revenues compared with their year-earlier results.

For the year 2009, these companies fared much worse as a group vs. their 2008 results. Earnings for 2009 fell 58%, while the group's revenues declined 28% to $107 billion (Can.).

Imperial Oil Ltd. posted net income for the 2009 fourth quarter of $534 million (Can.), down 19% from the same period in 2008 on a 1% decline in revenues. While upstream earnings in the recent quarter were up from the same 2008 period, downstream earnings were sharply impacted by lower product demand and margins.

Imperial announced that its upstream net income was $491 million (Can.), up 46% from the corresponding 2008 quarter. Increased earnings were primarily due to higher oil prices. Net income from downstream operations was $52 million (Can.) in the fourth quarter of 2009, down 80% from a year earlier.

TransCanada Corp. reported earnings for fourth quarter 2009 of $387 million, up from $277 million in fourth quarter of 2008. The company said that the increase in its earnings, which include results of its power business, was primarily due to higher earnings from natural gas storage, better results in some of its power operations, and lower interest expense from increased capitalization of interest related to the company's capital growth program.

Partially offsetting the increases to

TransCanada's earnings were business development costs associated with its Alaska Pipeline Project with ExxonMobil (OGJ Online, Jan. 29, 2009).

Service, supply companies

A sample of 19 service and supply companies posted a collective 48% decline in fourth-quarter 2009 earnings, with revenues off 21% from a year earlier. Results were impacted by the worldwide contraction in oil and gas drilling activity.

The Baker Hughes Inc. count of active rotary rigs in the US declined to average 1,108 rigs in the final 2009 quarter, down from 1,898 rigs a year earlier.

Only one of these firms in this sample of contractors reported improved, positive results for the recent quarter, while eight incurred a loss for the 3 months ended Dec. 31, 2009. For the year 2009, four of the companies in this sample incurred a net loss.

Offshore drilling contractor Noble Corp. reported that its fourth-quarter 2009 earnings climbed to $446.4 million from $418.6 million a year earlier. This includes a $6.5 million benefit related to a settlement of tax-related issues in the Middle East as well as an increase in the company's drilling services revenues and reimbursements from the 2008 fourth quarter. ✦

Independents converge on Washington as gas advocates

Nick Snow
Washington Editor

Independent producers converged on US Senate and House members' offices Mar. 2 to advocate for federal policies that encourage the development of natural gas.

"So much is at stake. This is a generational opportunity. More domestic natural gas development offers so many energy, environmental, and economic opportunities," said Marc W. Smith, the executive director of the Independent Petroleum Association of Mountain States, who brings several members east each spring.

"But there are proposals under consideration which would severely constrain the transition, especially administration recommendations to end what it considers oil and gas tax breaks and subsidies," he continued.

"Their logic and spin are wrong," added George H. Solich, president of IPAMS and of Cordillera Energy Partners in Greenwood Village, Colo. "These are cost-recovery mechanisms that are part of any business. It just happens that independent producers have to deal with intangibles. Taking them away would remove 40% of the capital being used to fund new domestic energy resource development."

IPAMS's member call-up this year was part of a bigger effort by the Independent Petroleum Association of America to bring producers to Washington for meetings with other members of Congress as well as their own representatives. "When taxes are increased, investment goes down and production drops," explained IPAA Chairman Bruce H. Vincent, who also is president of Swift Energy Co. in Houston.

'Shut in immediately'

"Natural gas clearly needs to be a part of any American energy solution and should be advocated," he told reporters during a Mar. 1 briefing at IPAA's headquarters. "If the government took away incentives such as percentage depletion, some of the nation's production would be shut in immediately."

IPAA and IPAMS members received materials outlining key issues to raise. They included environmental regulations, from greenhouse gas emissions to efforts to place hydraulic fracturing under federal controls; the White House's tax reform proposals; commodity regulation reforms; and access to federally managed resources.

The Obama administration is sending mixed signals, according to Vincent. "The president has expressed support for developing more natural gas and making tough decisions about oil and gas on the Outer Continental Shelf. But when I look at how the [US Department of the Interior] is implementing administration policies, I'm not convinced they're serious about developing more domestic energy resources," he said.

IPAA members were meeting with members of Congress not only from their own states, but others who had been identified (sometimes by producing states' members and staffs) as potential supporters of more aggressive gas development. "This could put pressure on [DOI]," Vincent said.

Smith said that 32 high-ranking political appointees in the Obama administration came from environmental organizations representing a broad range of views, which may be creating confusion. "I don't think it's unusual for policies in an administration's first couple of years to seem disjointed," he told OGJ on Mar. 2. "Within the environmental community, however, there's a strong effort to preserve more federal land as wilderness competing with efforts to address climate change and, implicitly, use more natural gas."

The biggest change for gas has been its movement from declining domestic supplies to an abundant resource in the last 36 months, Solich said. "During most of my career, I've had to work with just-in-time inventories. We can now say that we have more than 100 years of domestic supplies, and potentially 300 years in some parts of the world," he noted.

'Eye-opening experience'

"How we got here is important," said Solich. "We've been in a drilling boom the last decade that's been fueled by technology and prices. We find ourselves having spent massive amounts of capital to get this far and wondering [why] more of our economy doesn't want to use more gas. It's an eye-opening experience."

He said that gas's potential contribution now is dramatically different from the 1970s when energy policymakers considered it suitable only for heating homes and businesses, and looked more to coal to generate electricity. "We have an opportunity now to look again at the power generation mix, which is 44% coal and 24% gas, much of which is underutilized," Solich said. "We also are learning more about wind and solar power, which are intermittent, and which fuel works best to back them up without creating more greenhouse gases."

Continued federal efforts to control GHG emissions by putting a price on carbon dioxide or administratively imposing onerous limits could cause serious damage, Vincent warned. "Having an environment with fewer emissions is a goal we can all agree on," he said. "But [the US Environmental Protection Agency's] GHG endangerment finding bypasses the legislative process and relies on questionable data. My view is that Congress should decide major policy shifts, not a government agency."

He said capital markets have become more cautious in their outlook toward the domestic oil and gas industry since the 2008 election because so many questions about the administration's energy, environment, and economic strategy haven't been answered. The uncertainty also is hurting independents' operations, Smith and Solich told OGJ.

"Better technology not only lowers costs but also increases initial production. But you can't do it in a start-and-stop mode," said Solich. "If you put a rig and crew together, you'll build efficiencies as you continue to use them. They learn about a play's characteristics as they work it, but it has to be continuous."

"We've seen plays emerge in Utah over decades," said Smith. "But permits have dried up there now and companies are shipping crews elsewhere. Local officials realize that jobs are disappearing, which is why our groups include county commissioners from Utah and mayors from Wyoming. We could see a real grass-roots effort to get [DOI] to move ahead in the next few months." ✦

CFTC official wants more energy market transparency

Nick Snow
Washington Editor

Energy commodities regulators worldwide will need to move carefully and cooperatively if they expect to make global oil markets more transparent, US Commodity Futures Trading Commission member Scott D. O'Malia said in Tokyo on Feb. 26.

"We have to acknowledge that we've witnessed a paradigm shift in the global oil market over the past decade," he said in remarks to the International Energy Agency and Institute of Energy Economics Japan's Forum on Global Oil Market Challenges. "The paradigm has shifted in two significant ways…. First, oil is now a financial asset and its price movements are correlated to economic growth. Second, the growth in oil demand is being led by developing nations."

O'Malia noted that Daniel Yergin, chairman of IHS Cambridge Energy Research Associates, said that developing nations accounted for 85% of global oil demand over the past decade, and that the US Energy Information Administration predicts that oil demand will grow by 44% between now and 2030.

"Future demand can readily be anticipated since China is now the largest automobile market in the world," O'Malia continued. "The oil demand shift, however, has resulted in less transparency in oil usage and reserve capacity in these nations. This is a very troubling trend."

Spare market capacity is an important factor, he said. "The price of oil peaked in 2008 at $147/bbl, in part, because the global demand had virtually eliminated any spare capacity in the global oil markets. In fact, during the price spike, there was less than 2 million b/d of spare capacity," O'Malia said.

Temporary condition

The global economic recession has reduced oil demand and created some temporary spare capacity, the CFTC official said. He forecasts that this spare capacity will be depleted by 2015 and the world's oil markets could see a return to conditions similar to 2008. "It's imperative that oil markets have accurate and timely data regarding tightening in market conditions if we hope to avoid the future price spikes that will undermine our economic growth," he said.

Dramatically different markets make transparency imperative, according to O'Malia. He said that since its formation in the 1970s, IEA has coordinated energy policy among its member countries and published energy utilization, refining, and reserve capacity for the world's largest markets. "However, with the growth in oil demand anchored in developing nations, more must be done to make these developing markets as transparent and open as IEA member countries," he said.

Publishing data regarding oil in-transit will reduce uncertainty about

what is being stored at sea or withheld from the market, he said. "In addition, we must call into question the practices of certain oil traders that buy oil and put that oil into storage, if such practices are designed to extract money from consumers and producers," said O'Malia.

He said changing oil demand patterns mean that IEA member countries must be committed to expanding the organization's membership or creating another data collection entity which has the confidence of developing nations. "As a consensus on this entity develops, G20 member nations, as set force in their Pittsburgh communique, must lead by example in collecting and reporting all oil market data to make sure that the markets are completely transparent," he suggested.

"The G20 nations now represent the largest oil users and the top producing nations," O'Malia said. "The IEA can facilitate the data collection in order to prepare this data for the G20 meeting to be held in Toronto in June." ✦

Salazar defends proposed increased costs for producers

Nick Snow
Washington Editor

US Interior Secretary Ken Salazar defended plans to increase oil and gas royalties and fees on federal leases as he testified Mar. 3 before a US Senate committee on his department's fiscal 2011 budget request. He did not respond directly to one senator's strong attack on the Obama administration's proposed oil tax reforms, however.

Salazar also told the Energy and Natural Resources Committee that the US Department of the Interior is moving as quickly as possible to complete a new 5-year Outer Continental Shelf plan as it simultaneously tries to resolve problems with the current one. "The OCS and how we move forward has been one of the huge issues within the DOI. We hope we can make an announcement on how we plan to move forward [later] this month," he said.

Other committee Republicans strongly criticized plans which would increase producers' operating costs on federal leases. "I remain concerned about the administration's apparent war against oil and gas production, and particularly jobs. These are hard-working people who have invested blood and sweat," said John A. Barrasso (Wyo.). "The administration likes to talk about the future of natural gas, yet it also has proposed regulations which could drive this industry into the ground."

Saying that between 2006 and 2009, the average oil and gas lease sale held by the US Bureau of Land Management produced a half million dollars in revenue, Robert B. Bennett (Utah) noted that the most recent one in his state offered four tracts and sold one, producing $3,526 in bonus bids. "My state's legislature and governor get very concerned about the amount of revenue that's been lost which they were used to getting" as their share, he said.

Salazar said county commissioners from Utah and members of the Independent Petroleum Association of Mountain States, "which has not been particularly friendly toward our program," met with DOI officials Feb. 2 at the department's headquarters. "With all due respect, Senator, I would beg to differ," he told Bennett. "I believe dramatically lower natural gas prices have reduced interest in leasing. The overall economics have driven down the numbers you alluded to, and not the changes we are making to create more streamlined, certain leasing."

'Rush to lease'

Responding to Barrasso, the secretary said the Obama administration supports oil and gas leasing but believes it should take place in the right way. "The reality is that most of the leasing, and the rush to lease, during the previous administration led to significantly more protests and challenges. There was a failure at the top to consider where leasing should take place. We believe it should be where oil and gas is most likely to be found. We want to be proactive with the industry in determining that," he said.

Earlier in the hearing, Salazar observed that DOI's 2011 budget request reflects current economic conditions. "When you think of the deficit situation this country is immersed in, the [higher oil and gas] fees are all consistent with what we think is appropriate. I don't think any of the fees we're talking about are going to put anyone out of business. There is an oil and gas resource on our public lands that's still going to be out there," he said.

Committee Democrats were generally more complimentary, including Mary L. Landrieu (La.). "There's a tremendous amount of positive oil and gas development, both onshore and offshore," she said. "I have just been given information about the Haynesville Shale that suggests we have just found 250 tcf there from just one discovery. The discoveries of natural gas in this country are beyond what even the industry expected, and you have to be optimistic to be in that business.

"It seems very contrary to place heavy taxes on this industry when we want to be energy-sufficient. I want you to deliver that message to the administration," she continued. "There's fierce bipartisan opposition to [the White House's] proposals to tax this industry. They are counter to creating jobs and counter to energy independence."

Mark Udall (Colo.) told Salazar he has taken a balanced leasing approach while remaining a strong advocate for more domestic gas development. When Robert Menendez (NJ) sought assur-

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

A controversial position

His position hasn't won him many friends among coastal property owners where he lives, but Bruce Allen still says that the best way to reduce pollution from oil seeps in the Santa Barbara Channel is to increase offshore production.

"It's now been shown that the effects of offshore oil production have been positive," the cofounder of Stop Oil Seeps California said Feb. 24 at the Heritage Foundation, where he presented the group's new television documentary, "A Crude Reality."

Allen said, "Forty years ago, when you'd walk along the beach in Santa Barbara, you'd get oil on the bottoms of your feet. That's less the case now."

Pressurized reserves make 70,000-80,000 bbl/year of oil seep into coastal waters off Santa Barbara, he said. By comparison, the US Minerals Management Service says that the amount of crude spilled from offshore production since 1970 has been less than 870 bbl, according to Allen.

Stuck in past

Politicians who repeatedly cite the 1969 Union Oil Co. spill in the channel as a reason for halting new production there disregard the industry's technical progress, Allen maintained. They also ignore a 1999 study that documented that production from the Holly offshore platform reduced natural seeps, he said.

"A 2005 seep event killed about twice as many birds as the 1969 spill," said Allen. "We estimate about 20,000 birds have died this way since 1969 compared to about 4,500 from all California offshore production."

More production from Santa Barbara coastal formations could make it less necessary for California refiners to import crude, he suggested. It also would help the state address its budget crisis and improve local economies, which was why the county's board of supervisors passed a resolution backing it 2 years ago.

2009 effort

It also was why Gov. Arnold Schwarzenegger and California legislative leaders tried to get state approval early last summer for Plains Exploration & Production Co. to drill directionally into formations beneath state waters from an existing platform on a nearby federal lease.

The proposal failed, but Allen said several participants want to revive it, this time from sites onshore. "With that approach, there would be no risk of an ocean spill although other environmental issues would need to be addressed," he said. But the idea has been endorsed by candidates running for governor and for California's senate and assembly, he added.

Richard L. Ranger, a senior upstream policy advisor at the American Petroleum Institute, said pollution from seeps was clearly visible off Santa Barbara when he worked in the area in the 1980s as an ARCO employee. "The difference between then and now is noticeable," he said.

Asked if he thought alternative energy has promise, Allen said that he does and that solar power is California's long-term solution. "Producing this oil instead of letting it seep into the ocean could help us get there," he said. ✦

ance that US Minerals Management Service policies and enforcement will keep a major oil spill from occurring on the OCS, the secretary responded that MMS is doing everything it can to minimize problems.

Moving ahead

Lisa Murkowski (R-Alas.), the committee's ranking minority member, said Alaskans were still upset about the US Army Corps of Engineers' recent aquatic resource designation decision within the National Petroleum Reserve-Alaska and asked if it will affect leasing activity there. "We plan to examine what happened and try to find a solution that works," Salazar said. "When you work with the executive side of government, there are lots of players. We don't control the Corps of Engineers or [the US Environmental Protection Agency]. It is our intention to continue moving forward with leasing on NPR-A. We have a lease sale scheduled for this summer, and vast amounts already have been leased. We do not intend to move back."

Murkowski told him that Alaskans also are concerned about uncertainties centered on the administration's OCS plans. "You are correct in saying it's one thing to issue a lease and another to support its development. We are not yet at a final point with respect to the OCS. We are attempting to pull together a final plan which will cover both existing and future activities," Salazar replied.

"It has been difficult to do that, in large part, because of the failure in the 2007-12 plan to perform the necessary environmental studies that the court required," he continued. "I had no intention to revisit it when I became secretary, but the second-highest court in the land said that [DOI] had not followed the necessary environmental procedures. We established that we could go ahead on the Gulf Coast part of the plan but had to address other segments. I hope we are close to making a final

plan that will survive environmental challenges."

Salazar said with respect to the next 5-year plan, "We held hearings and sought comments. We are going through what we received and are very close to deciding where we want to go. When you see 500,000 comments, they are out there and available for public viewing. You, as members of the US Senate, and other people in this country are entitled to know where we're going on the OCS, and I hope we can provide some clarification within this month." ✦

US lawmaker requests hearings on OCS delay costs

Nick Snow
Washington Editor

US Rep. Bill Cassidy (R-La.) urged House Natural Resources Committee leaders to schedule hearings on the economic costs of continued delays in offshore oil and gas development a week after the first major report on the subject was released.

Referring to a study by Science Applications International Corp. that was commissioned by the National Association of Regulatory Utility Commissioners, Cassidy, who serves on the committee, noted that not allowing more energy activity on the US Outer Continental Shelf would cost 13 million jobs, reduce gross domestic product by $2.36 trillion, and increase US energy costs $2.35 trillion by 2030.

Cassidy said the report also indicated that such delays could raise natural gas prices by an average 17%/year, electricity prices 5%/year, and gasoline prices 3%/year. Domestic production of crude oil, meanwhile, could drop by 9.9 billion bbl, or an average 15%/year; and of gas by 46 tcf, or 9%/year, while US imports from Organization of Petroleum Exporting Countries members could increase 4.1 billion bbl at a cost of $607 billion, according to the report, he said in a Feb. 23 letter to the committee's chairman, Nick J. Rahall (D-W. Va.), and its ranking minority member, Doc Hastings (R-Wash.).

"Despite these projections and similar previous warnings, the [Obama] administration has continued to impose a moratorium on new energy development on federal lands," said Cassidy. "The Department of Interior has repeatedly delayed new energy leasing activities, halted the 2010-15 offshore leasing plan, and withdrawn areas that had been planned for new oil and gas production. The administration's 2010 and 2011 budgets have each contained tens of billions of dollars in tax increases on domestic energy production."

He asked that the committee schedule hearings before Mar. 26 to address "the administration's actions and inactions, particularly in light of the [NARUC-commissioned] report's projections of the consequences that the ongoing energy moratorium will have for the American economy." ✦

CO_2 injection under way in Alabama EOR pilot project

Nick Snow
Washington Editor

A project team has begun to inject carbon dioxide into Alabama's Citronelle field as part of a $7.9 million pilot project to determine whether the field is ideal for simultaneous enhanced oil recovery and CO_2 storage, the US Department of Energy said on Mar. 1.

Study results of the 7,500-ton CO_2 injection will provide estimates of oil yields from EOR and storage capacity in depleted oil reservoirs, DOE's Fossil Energy Office said. Scientists from the University of Alabama at Birmingham (UAB) are leading the 5-month injection, which aims to prove whether oil remaining in domestic formations can be economically produced, it indicated.

UAB initially proposed the project involving the state's largest oil field 30 miles north-northwest of Mobile to DOE in 2006. Denbury Resources Inc., which owns and operates the field, is a partner, along with Southern Co., the Alabama Geological Survey, Alabama A&M University, and the University of North Carolina at Charlotte.

The field may be ideal for a CO_2-EOR demonstration because it is composed of sandstone reservoirs in a simple structural dome and has existing infrastructure which includes deep wells, according to DOE's National Energy Technology Laboratory (NETL).

"Because of the presence of the regionally extensive Ferry Lake Anhydrite seal, four-way structural closure, and lack of faulting, it is naturally stable with respect to CO_2 storage," NETL indicated in January. "However, the geology of the heterogeneous siliciclastic rocks in the field is very different from those where CO_2-EOR has been applied commercially, such as in the carbonate strata of the Permian and Williston basins."

A successful demonstration could make incremental oil recovery at Citronelle field 60% greater than from the conventional secondary recovery which has occurred there, DOE's Fossil Energy Office said. It noted that Advanced Resources International of Arlington, Va., estimates that some 64 million additional bbl could be recovered with EOR

at Citronelle, which was discovered in 1952.

The field's geologic structure and lack of faulting also may make it ideal for CO_2 storage. NETL said that capacity of depleted oil reservoirs and saline formations in the Citronelle Dome was estimated, by static calculations, to be 500 million-2 billion short tons of CO_2, "sufficient to sequester the carbon dioxide from a nearby 1,500 [Mw] coal-fired power plant for 35 years."

The project has entered its second phase, which will include injection, associated validation of models, and determination of oil-CO_2 mixture properties. CO_2 containment at the test site also will be monitored in the ambient air, soil and vegetation, the Fossil Energy Office said.

If the project is successful, it could encourage operates to apply CO_2-EOR to other fields containing highly heterogeneous, discontinuous sands, NETL said. "Documentation of air, soil, and vegetation conditions before, during, and after the pilot tests, and the absence of environmental effects will advance the implementation and acceptance of [CO_2] capture and storage by industry and the public," it added.

DOE is providing 60% of the project's financial support with an anticipated $4.7 million outlay. The remaining $3.2 million will come from the other partners. ✦

Trinidad and Tobago ramps up crude oil production

Curtis Williams
OGJ Correspondent

Trinidad and Tobago says it is taking steps to increase crude oil production in an effort to balance its energy portfolio.

Energy Minister Conrad Enill said the twin-island nation has become too reliant on natural gas and too vulnerable during times of weak gas prices.

Over the last 15 years, Enill said, the country placed too much emphasis on gas production with the construction of four LNG trains and several downstream plants. This has occurred while crude production continued to fall.

Enill said, "We recognize that oil production has been on the decline and the country has become gas-based, however, we would like to encourage a mix that is more balanced."

He said the country's state-owned Petrotrin will play an important role in delivering on this objective.

"We have challenged its leadership to organize in such a way as to support this requirement for increases in oil production. Petrotrin in response has begun to deliver on this mandate." Enill told an energy conference in Port of Spain.

He pointed out that Petrotrin had already granted seven sublicenses for smaller companies to produce stripper fields in eastern Trinidad and work is about to start.

"We anticipate that gains in production volumes will be realized from this initiative," the minister said, adding, "Petrotrin also has been mandated to develop a program for the efficient and effective management of the Trinmar asset."

Since its acquisition of the Trinmar asset from the former Texaco Inc., Trinmar's oil production has fallen from close to 100,000 bo/d to less than 40,000 bo/d.

Enill said Petrotrin will also be pursuing a 3D seismic program over its assets in the North West district and API's Oropouche farmout area of South Trinidad and is intended to guide the future exploration on land and is intended to result in the identification of more oil drilling locations.

Helena Inniss-King, the country's director of resource management, said rebalancing is crucial and pointed out that the Central Range (Shallow Horizon), Central Range(Deep Horizon), Guyaguyare (Shallow Horizon), and Guyaguyare (Deep Horizon) that were allocated in 2009 are all expected to produce oil.

Inniss-King said Trinidad and Tobago will also be exploring the possibility of producing its significant reserves of heavy oil if the economics allow it.

Trinidad and Tobago produces 4.1 bcfd of gas and 110,000 bo/d and is the largest exporter of LNG to the US. ✦

TIPRO uses convention to push increased US gas use

Bob Tippee
Editor

The Texas Independent Producers & Royalty Owners Association used its annual convention in Houston to a call for increased use by the US of natural gas produced in the US.

Keynote speaker G. Steven Farris, chairman and chief executive officer of Apache Corp., and former independent producer T. Boone Pickens both urged expansion of the fleet of vehicles fueled by gas.

Because of growing supplies of gas from shales, combined with environmental and security advantages, Farris said, "We are heading toward natural gas."

Rapidly spreading shale development gives the US at least a 100-year supply

and maybe twice that, Farris said, adding "It has taken the exploratory side out of the business."

He said, "Conversion of 25% of the US vehicle fleet to gas would lower oil imports by 5 million b/d."

And increased gas use would help the US reduce emissions of greenhouse gases as a remedy for climate change.

"At some point we're going to get legislation," Farris said. "If we are serious about carbon dioxide then we will be serious about natural gas."

Attention due

Pickens said the plan to increase gas consumption that he has promoted in Congress will receive attention when Washington, DC, moves away from health care.

"I've nailed myself to a date," he said. "Memorial Day."

Pickens has spearheaded efforts to create tax incentives for gas-fueled vehicles. Bills containing such incentives have been introduced in the House and Senate (OGJ, July 20, 2009, p. 33).

"I don't want any subsidies for natural gas," Pickens said. "All I want is encouragement to get our heavy-duty vehicles over to natural gas."

Asked about incentives for construction of gas-fueling equipment, he said, "Let private industry provide the infrastructure."

Pickens focuses his arguments on cutting imports of oil from members of the Organization of Petroleum Exporting Countries, saying, "We're dependent on oil from countries that hate us."

He targets heavy-duty vehicles because gas is the only practicable substitute for the diesel they now burn. If the 8 million trucks now on US roads burned gas instead of diesel, Pickens said, the country would import 2.5 million b/d less oil—half what it now imports from OPEC members.

Also at the convention, Regina Hopper, president and chief executive officer of America's Natural Gas Alliance, offered TIPRO members political advice for promoting natural gas.

"We need to communicate very effectively that this clean American product is available right now," she said. ✦

BP seeking to boost profits by $3 billion/year

Paula Dittrick
Senior Staff Writer

BP PLC on Mar. 2 outlined its annual strategy presentation in which Chief Executive Tony Hayward said the company hopes to boost its profits before taxes by more than $3 billion/year within 3 years.

Speaking to analysts, Hayward said BP forecasts its oil and gas production will grow by 1-2%/year on average during 2008-15 based upon oil prices of $60/bbl. Last year, BP said it produced 4 million boe/d, up 4% from 2008.

Hayward sees more opportunities to improve operating and cost efficiencies in both upstream and downstream operations.

He said a restructuring is under way in BP's exploration and production operations to centralize project management, improve cost efficiencies, and ensure what he called "greater consistency into operations."

"Whichever way you look at it, there are significant opportunities for improvement and in every case firm plans are in place to close these gaps," said Hayward, adding, "We believe we have made a good start—but it's only a start."

Upstream plans

Hayward said BP's medium-term upstream growth is focused on deepwater production, global gas production, and managing giant oil fields. BP's finding and development costs in 2009 were $12/boe—the lowest in 5 years.

In the next 2 years, 24 new major projects will reach final investment decisions. BP intends to start 42 major projects by 2015, which are expected to contribute about 1 million to its total production by 2015.

Hayward said these new projects will more than offset the anticipated decline in currently producing fields. BP gained access last year to exploration and production assets in Iraq, Indonesia, Jordan, the US Gulf of Mexico, and Egypt.

He reaffirmed the company's commitment to research and development spending aimed at growing its low-carbon businesses, especially US onshore wind power, biofuels, solar power project as well as carbon capture and sequestration.

BP invested $1.3 billion in alternate energy in 2009 and a cumulative total of more than $4 billion since 2006.

Downstream plans

BP's refining and marketing expects to improve underlying profitability by over $2 billion within 3 years. Hayward believes refining operations can be profitable even in depressed conditions like those the industry faced in 2009.

The ongoing modernization of BP North America's refinery in Whiting, Ind., is expected to become operation in 2012, executives said. The 384,750-b/cd refinery is undergoing construc-

tion to increase its capacity to process Canadian heavy crude. The modernization is expected to cost $3.8 billion.

Hayward emphasized that safety remains a top priority for BP. A 2005 explosion killed 15 people and injured 170 others at the 446,500-b/cd Texas City, Tex., refinery. Since then the US Chemical Safety and Hazard Investigation Board issued a series of recommendations about process safety (OGJ, Sept. 8, 2008, p. 20).

Separate from the analyst presentation, BP also announced on Mar. 2 that it informed the southern African governments of Namibia, Malawi, Tanzania, Zambia, and Botswana of plans to sell its marketing businesses in these countries. This follows a strategic review by BP into its R&M businesses.

BP Africa's Chief Executive Sipho Maseko told governments and employees in South Africa and Mozambique that the company is staying in these two countries and will be investing there. ✦

Tullow eyeing higher oil production target in Uganda

Eric Watkins
Oil Diplomacy Editor

Uganda's oil production target could more than double to 350,000 b/d by 2018 from the current target of 150,000 b/d in 2013 if the right business plan is adopted, according to Tullow Oil PLC.

"When the oil basin is in full production, we are probably talking about 350,000 b/d," said Tullow Chief Executive Officer Aidan Heavey, adding that the firm plans to begin producing crude oil this year, with initial production of 1,000 b/d.

Heavey said output will rise to 10,000 b/d in 2011 and to 150,000 in 2013. The 150,000 bbl-target for 2013 is based on current proven reserves of 700 million boe. But there is upside in the basin as proved, probable, and possible reserves are estimated to total 1.5-2 billion boe.

Tullow owns 100% of Block 2 and is awaiting approval from the Ugandan government to purchase the remaining 50% stakes in Blocks 1 and 3A from Heritage Oil, giving it full ownership over the three blocks in Uganda's Albertine Rift basin.

Tullow is talking to Total SA and China National Offshore Oil Corp. (CNOOC) about selling them a 50% stake in the licenses and jointly managing development of the Lake Albert's oil resources. Tullow also expects the partner to help with the construction of a refinery and export pipeline.

"The investment is going to be huge. You are talking about multiple billions of dollars of investments. The only two companies that are currently in the final process are CNOOC and Total," Heavey said, adding, "It would be good if both were involved."

However, Tullow's proposed farm-in may deviate from that plan as the Ugandan government has asked the Irish firm to reduce the size of its proposed share from 50% to 33% in two of the blocks and to allow CNOOC and Total each to operate one block.

"In recognizing the need to avoid a monopoly, Tullow has presented their plan to partner with both Total and CNOOC," said Kalisa Kabagambe, the energy ministry's permanent secretary.

"However, government has asked Tullow to reconsider its proposal of operating two out of three exploration areas and instead let each partner operate an exploration area," Kabagambe said.

The Ugandan government is still considering the development plans presented by Total and CNOOC, after which a final decision will be made on Tullow's acquisition of the Heritage stake—probably by the end of March.

"The farming-in partners, CNOOC and Total, have been invited to present their plans for development of the oil sector to the government," Kabagambe said.

"The approval for the partners to join the licenses shall be made only upon confirmation that the partnership addresses the country's interests," Kabagambe said.

Kabagambe said Uganda required significant investment of $8 billion over the next 10 years to develop the oil and gas industry, and he also called for the creation of a national oil company.

"The government should form an oil company to increase national participation, especially in commercial aspects of the oil and gas sector," Kabagambe said. ✦

Norway launches new licensing round

Eric Watkins
Oil Diplomacy Editor

Norway, while warning of the potential for espionage directed against its oil and gas industry, has launched its 2010 oil and gas licensing round for predefined areas (APA).

"Good and regular access to acreage is necessary to secure further activity on the Norwegian Continental Shelf," said Norwegian Oil Minister Terje Riis-Johansen.

The 2010 APAs will offer 63 more predefined areas compared with the 2009 round: 43 in the Norwegian Sea and 20 in the Barents Sea. Sept. 15 is the deadline for application, and the new licenses are to be awarded late 2010 or early 2011.

Although a number of the blocks announced have seen earlier petroleum

activity, the announcement is said to represent a major extension of oil and gas operations in the Norwegian Arctic.

"With this [launch], I prepare the ground for new findings, new field development and new activity in the North," said Riis-Johansen, who earlier also announced that "I want to have more projects on the [NCS]."

PST's threat report

The round's launch coincided with an annual report by the Norwegian Police Security (PST) that foreign states' intelligence activity in Norway and against Norwegian interests will remain at a high level in 2010.

"PST anticipates that political decision-making processes related to the High North will be particularly susceptible to foreign intelligence activities," the report said, adding that "advanced technological environments in the Norwegian petroleum and energy sphere will be vulnerable targets."

"Currently the greatest intelligence activity registered by PST has been within the management of the oil and gas resources in the High North," said the PST report.

"The extraction of oil and gas resources in the north constantly requires technological innovation," it said, noting that several intelligence services focus on such technological environments to enable them to gain a competitive edge.

"Norwegian specialist communities are technologically far ahead in this field and must therefore expect undesired intelligence activities to be directed at their work," the report said.

Foreign states' intelligence activity will continue to be geared towards political decision makers, employees in bureaucracy, players in the business sector, journalists, and individuals working in research and development, the report said.

No specific foreign intelligence services or countries were named in the PST's threat report. ✦

Doing business together

If there is anything the oil and gas industry desperately needs, it is business. For that reason, British and Argentinean officials should stop touting their respective rights in the South Atlantic and think of doing business together out there.

Is the idea unthinkable? Certainly not, as shown in a recent announcement by Spanish-Argentine oil group Repsol-YPF SA that it plans to start drilling for oil in the Falklands basin by yearend.

According to a company spokesperson, Repsol YPF's drilling will take place within Argentine territorial waters and "far from the disputed waters" around the British-ruled Falkland Islands, which Argentina also claims.

"We're now in the phase of contracting the oil rig," said Repsol YPF's Chief Executive Officer Antonio Brufau, adding that the consortium will go ahead with its plans even though exploration in that area is not easy and the probability of success is very "low or limited."

Key point

The key point, though, is not the distance from the Falklands or even the chances of success, but the identity of Repsol YPF's partners: Brazil's Petroleo Brasileiro SA (Petrobras) and Pan American Energy, a joint venture of Petrobras and—guess who?—the UK's BP PLC.

Clearly, if a British firm and an Spanish-Argentinean firm can work together in exploration of the South Atlantic in the region of the Falkland Islands, then it should be possible for even greater cooperation between the two sides.

But that's not how the scenario is playing out, either in the UK or in Argentina. Indeed, the new Falklands dispute has revived tensions which exploded in 1982 when Argentinean troops staged a surprise landing on the islands to assert their claim to the territory.

The result of that landing, in case anyone needs a reminder, was a 74-day war between the two sides in which 649 Argentine and 255 British soldiers, sailors, and airmen died. Those figures are, or should be, enough to keep both sides talking.

60 billion bbl

So far, though, the only talking has been the kind that keeps the two sides apart. Argentine President Cristina Kirchner signed a decree ordering any ship passing through Argentine waters to request permission before going to the Falklands.

More recently, Kirchener's Foreign Minister, Jorge Taiana, pressed United Nations chief Ban Ki-moon to intervene in the dispute in order to prevent Britain from any further "unilateral acts."

But Britain's UN ambassador Mark Lyall Grant reaffirmed his country's rights in the area as "underpinned by the principle of self-determination as set out in the UN Charter."

Such remarks are bound to keep everyone talking with anyone who'll listen, and there are plenty of those. But such remarks are not going to achieve what is really necessary in the region: peaceful exploration for the oil and gas needed on world markets, estimated by the British Geological Society at 60 billion bbl.

Surely, there is plenty of business in those waters for both sides. ✦

Lehigh Park field seen as indicator of S. Florida offshore oil potential

Daniel J. Acquaviva
Omar Rodriguez
RMA GeoLogic Consultants Inc.
Fort Myers, Fla.

Olga I. Nedorub
University of South Florida
Tampa

Lehigh Park field in Lee County, southwest Florida, was discovered in 1974 by Exxon. Production is from the Lower Cretaceous (Aptian) age Sunniland formation in a combination structural-stratigraphic trap at an approximate depth of 11,500 ft.

Lehigh Park field is the northwesternmost of 14 oil fields discovered to date in the Sunniland trend. Cumulative production from this trend exceeds 100 million bbl of oil. Production through December 2008 at Lehigh Park is about 5.9 million bbl of oil from five wells, only one of which is still producing. The field's oil has an API gravity of about 28°, a low gas-oil ratio, and a moderately high sulfur content.

The world-class production from Campeche Sound should serve as encouragement for future exploration in the South Florida basin.

Lehigh Park field represents the approximate mean size of anticipated future onshore discoveries in the Sunniland Trend and thus can be used as model for risk evaluations for that play. From a sequence stratigraphic aspect, it represents deposition in a relatively shallow water patch reef environment during periods of more open circulation in a rimmed arid shelf setting.

This means that offshore portions of the basin, which have been not explored, may contain much larger hydrocarbon reservoirs formed in grainstone shoal and boundstone reef settings.

In addition to the Sunniland formation, which is commonly subdivided into four productive intervals, several other carbonate-evaporite cyclothems are present in deeper intervals in the basin.

The paucity of deep tests in the South Florida basin, combined with favorable petroleum source, reservoir, and trapping characteristics; as well as proximity to Mesozoic production in the Sonda de Campeche and northern Cuba provinces, make the South Florida basin an underexplored but attractive area for future petroleum exploration.

Introduction

The Sunniland formation is one of several carbonate-evaporite cyclothems present in the Lower Cretaceous of South Florida.

The Lower Cretaceous-age section in South Florida is typically about 3,500 ft thick, and the Sunniland formation is about 250 ft thick (Fig. 1). The formation was named after the initial field discovery in the trend, at Sunniland, in 1943, located about 24 miles southeast of Lehigh Park field, in Collier County (Fig. 2).

Sunniland field was discovered by Humble Oil (now Exxon). Exxon has been the dominant explorer in the trend. It also discovered West Felda field, the most productive (about 48 million bbl of oil) field in the trend, located 8 miles southeast of Lehigh Park.

Exploration methods initially used by Humble Oil included gravity and magnetics, structural mapping from shallow (usually about 1,200 ft deep) stratigraphic test holes, and seismic. Until relatively recently, seismic quality was rather poor in this area due to in-

SUMMARY OF FIELD DISCOVERY WELL Table 1

Location:	SW SE 22-44s-26e
Operator:	Exxon
Well name:	22-4 Consolidated Tomoka Land Co.
Elevation:	39′ KB
Completion date:	July 30, 1974
Total depth:	11,630′
Casing program:	20″ @ 244′, 13.375″ @ 1,360′, 9.625″ @ 3,593′, 7″ @ 11,630′
Perforated interval:	11,389-94′
Treatment:	None
Initial potential:	490 bo/d (28° API), 48 bw/d
Initial pressure:	Estimated 4,800 psia

terference from evaporite beds, present in the thick Eocene through Jurassic section and other stratigraphic features, including the high permeability zones in the Eocene age Oldsmar formation, commonly referred to as the "boulder zone."

As the number of exploratory wells in the trend increased, the importance of subsurface mapping has also increased.

Oil from the Sunniland formation fields typically has gravities in the mid to high 20° range, low gas-oil ratios, and moderately high sulfur content. It is trucked from the Lehigh Park tank battery to Port Everglades in Fort Lauderdale, from where it is transported by tanker, usually to refineries in the Texas Gulf Coast. Large volumes of hypersaline produced water are also common, requiring installation of water disposal wells.

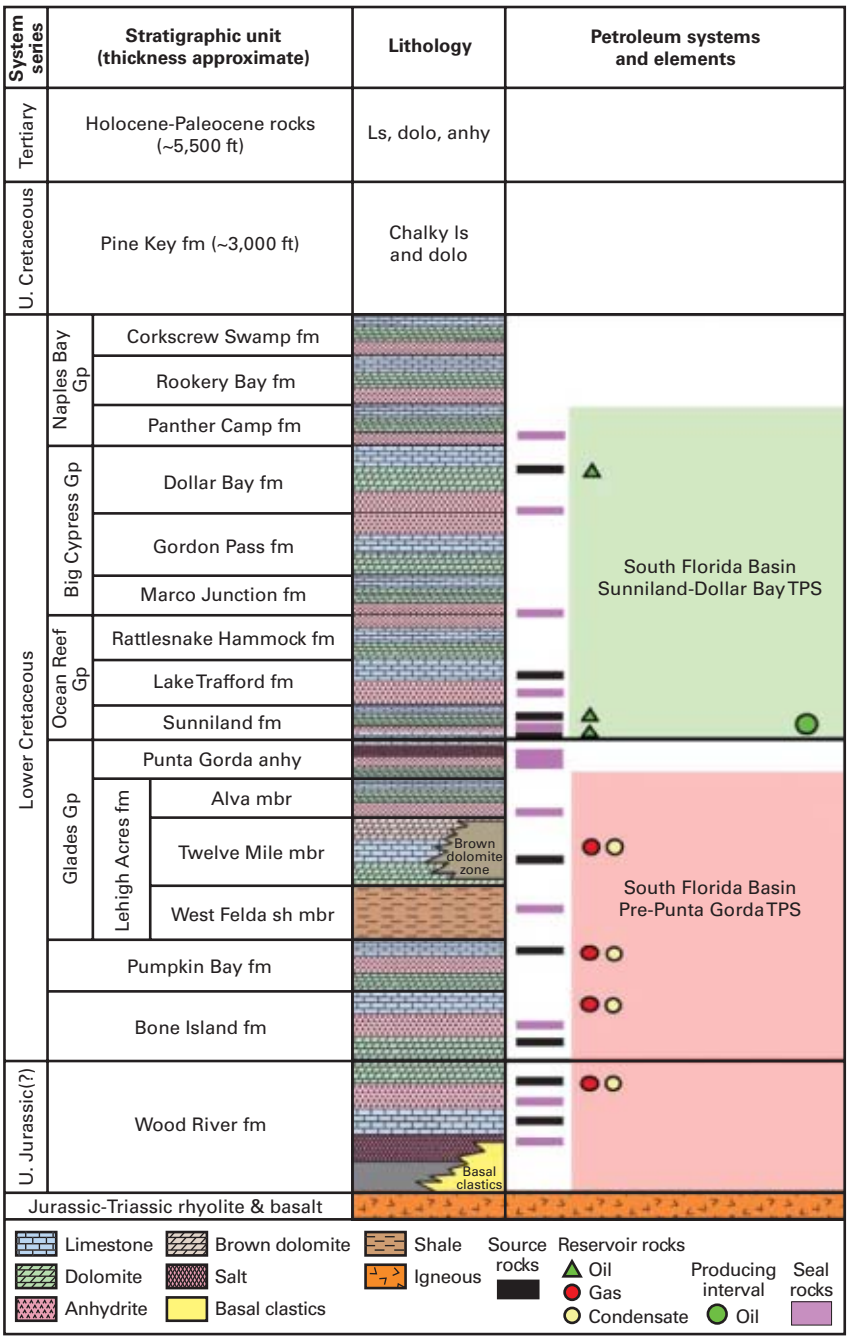
The Sunniland formation is a self-contained petroleum system with its own reservoir, source rock, and trap. The reservoir is provided by porous dolomitic limestones that were deposited in shallow water biohermal buildups. Primary depositional porosity is the dominant porosity type, with later enhancement by partial dolomitization.

The source rock is dark micritic, moderately organic-rich limestones in the lower part of the Sunniland formation. Thick anhydrite beds overlie (Lake Trafford anhydrite) and underlie (Punta Gorda anhydrite) the Sunniland formation.

Structural trapping of the hydrocarbons at Lehigh Park is due to four-way closure related to the breaking of a southeast plunging anticlinal nose by a small northeast trending, high-angle, normal fault[1] (Fig. 3).

SOUTH FLORIDA BASIN GENERALIZED STRATIGRAPHIC SECTION

Fig. 1



Source: Modified from Faulkner and Applegate, 1986, and Pollastro et al., 2001.

Field discovery

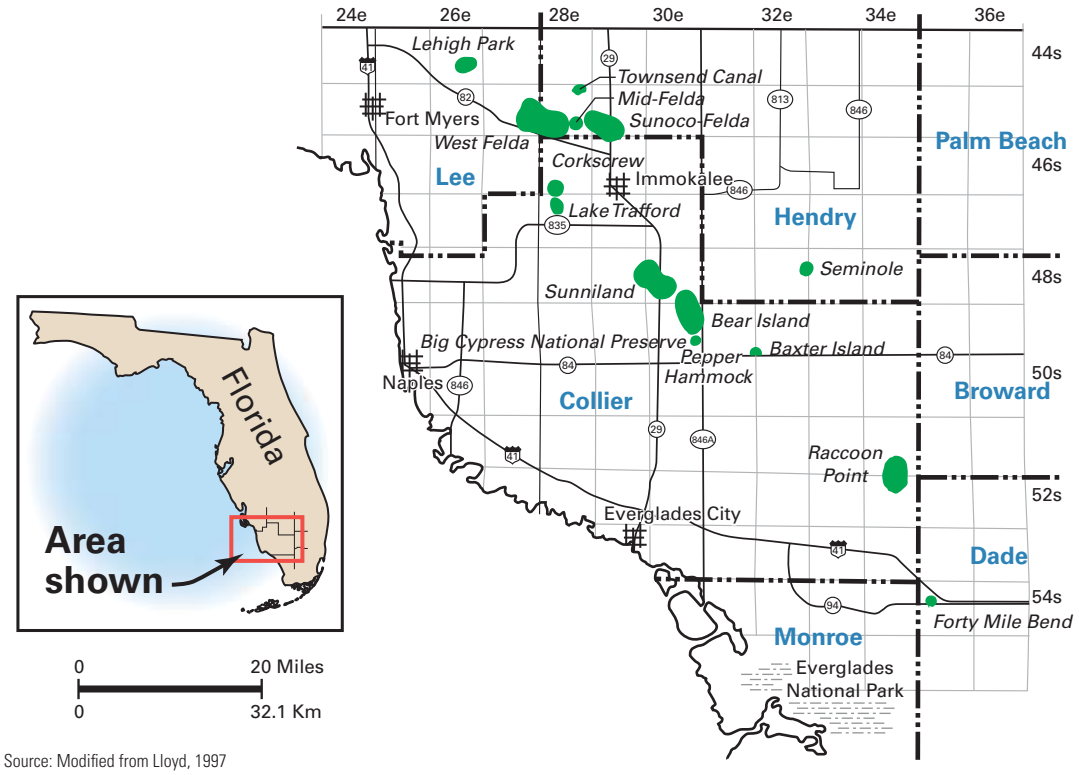
Because the Lehigh Park field area is only 8 miles from West Felda field, discovered in 1966, and updip from West Felda along the same plunging anticlinal nose, exploration in the Lehigh Park area was to be anticipated.

However, because one large land development company, the Lehigh Acres Development Corp., controlled most of the surface and mineral rights in the area, and most of the area had been planned for residential development, access for petroleum exploration was limited to lots platted for future church sites by that company or to the few parcels controlled by others.

Prior to completion of the Lehigh Park field discovery well in July 1974, only two petroleum test wells had been drilled in the area proximal to the field. One of these was a shallow (3,018 ft) test drilled in 1924 by Florida Exploration.

SUNNILAND TREND OIL FIELDS IN SOUTH FLORIDA

Fig. 2



Source: Modified from Lloyd, 1997

A summary of Exxon's discovery well is provided (Table 1).

In 1980 the discovery well was plugged back to 6,800 ft, sidetracked to the southeast, and recompleted as the 22-4A. All four of the field development wells were drilled as directional holes. The tank batteries for the field are located at the site of the discovery well, in a lightly populated sub-urban-rural area, south of the old Buckingham Army Air Force Base, a World War II era training facility.

SUMMARY OF GENERAL RESERVOIR AND FIELD DATA

Table 2

Trap type:	Combination structural-stratigraphic
Regional setting:	South Florida basin
Other formations with shows:	None
Oldest formation penetrated:	Punta Gorda anhydrite
Well:	Exxon 27-2 Consolidated Tomoka NE NW 27-44s-26e
Logging practice:	Laterolog, sonic and-or density-neutron
Completion practice:	Set 7" casing, perforate with 4 spf
Number of productive wells:	5
Number of dry holes:	6
Number of water disposal wells:	2 (1 active)
Number of pressure maintenance wells:	0
Major operators:	Originally Exxon, now Calumet Florida
Porosity:	Averages about 15% in the field
Permeability:	Between 150 and 1,650 md[1]
Average pay thickness:	About 15'
Productive area:	Approximately 1,145 acres
Oil column:	30'
Original oil-water contact:	–11,304' NGVD
Gas-oil ratio:	Approximately 100:1
Drive mechanism:	Water drive
Rw and-or salinity:	0.05 ohm sq m/m @ 75° F., avg. TDS = 250,000 mg/l.[2]
Bottomhole temperature:	Approximately 192° F.
Character of oil:	28° API, approximately 3.5% sulfur content[3]
Continuity of reservoir:	Relatively continuous of variable thickness in the field, discontinuous outside the field
Spacing:	160 acres
Cumulative production:	5,921,000 bbl of oil, 608 MMcf of gas, 47,115,000 bbl of water
Estimated ultimate primary recovery:	6.1 billion bbl of oil
Estimated original petroleum in place:	15 million bbl of oil equivalent
Estimated recovery factor:	40% or 349 bbl of oil/acre-ft

[1]From Core Laboratories, Report # 2107-9, May 5, 1974 for Well # 22-4. [2]From Pensacola Testing Laboratories, Report # 41366, July 2, 1975. [3]From Palacas et al., 1984.

Reservoir geology

The Sunniland formation was subdivided in this field study into four units, which with increasing depth, as shown on cross-section A-A' (Fig. 4), have been labeled as Zones A through D.

Porosity development is possible in each zone. Dense, low porosity, correlatable stratigraphic units provide vertical separation between these zones. Porosity is best developed in Zone B at Lehigh Park field; this is the producing interval in the field. A porosity isopach map for Zone B (Fig. 5) shows the extensive porosity buildup in the field area.

In a core study[2] of the Sunniland formation in Lehigh Park field, 11 carbonate and evaporite facies were described and attributed to five depositional environments. These are, in order of decreasing water depth, shallow water shelf, shoal water bioherm, restricted and open lagoon, tidal flat, and sabkha. The hydrocarbon-productive zone was determined to have been deposited in shoal water biohermal patch reef environments. These deposits are thought to have undergone early subaerial expo-

sure and diagenesis that preserved the initially high primary interparticle porosity and enhanced it with secondary moldic and vugular porosity.

Winston[3] described an idealized, repeatable set of cyclical lithofacies in the Sunniland formation of South Florida. These facies are, within a single cycle: anhydrite, microcrystalline dolomite with interbedded anhydrite, micritic limestone, chalky limestone, calcarenitic limestone, followed by a repeat of the previous lithofacies in reverse order, terminating in the anhydrite lithofacies.

Within the Sunniland at a particular location some of the end members of this idealized cyclothem may not be present. The calcarenitic limestone unit, corresponding to the shoal water biohermal depositional environment of Ferber and Lock,[2] provides the best potential for reservoir development.

The basal zone of the Sunniland is composed of dark grey micritic to argillaceous limestones. It is sometimes referred to as the "rubble zone." Total organic carbon contents range between 0.4% and 3.0% in this unit along the Sunniland productive trend.[4] The onset of oil generation probably began during the Late Paleocene or Eocene. Oil generation in this system continues to the present. The low geothermal gradient in South Florida is responsible for the relatively immature character of the Sunniland oil.

A summary of general reservoir and field data for Lehigh Park field is provided in Table 2.

Production history

Subsequent to the completion of the field discovery well in 1974, four additional producing wells were completed in Lehigh Park field.

These development wells were drilled in 1976 and 1977. A summary for the productive wells in the field is provided as Table 3. A graphical summary of historical production is provided as Fig. 6. The one well that remains on production is the 26-2 Consolidated-Tomoka. The other four former producers have been plugged and abandoned.

Field significance

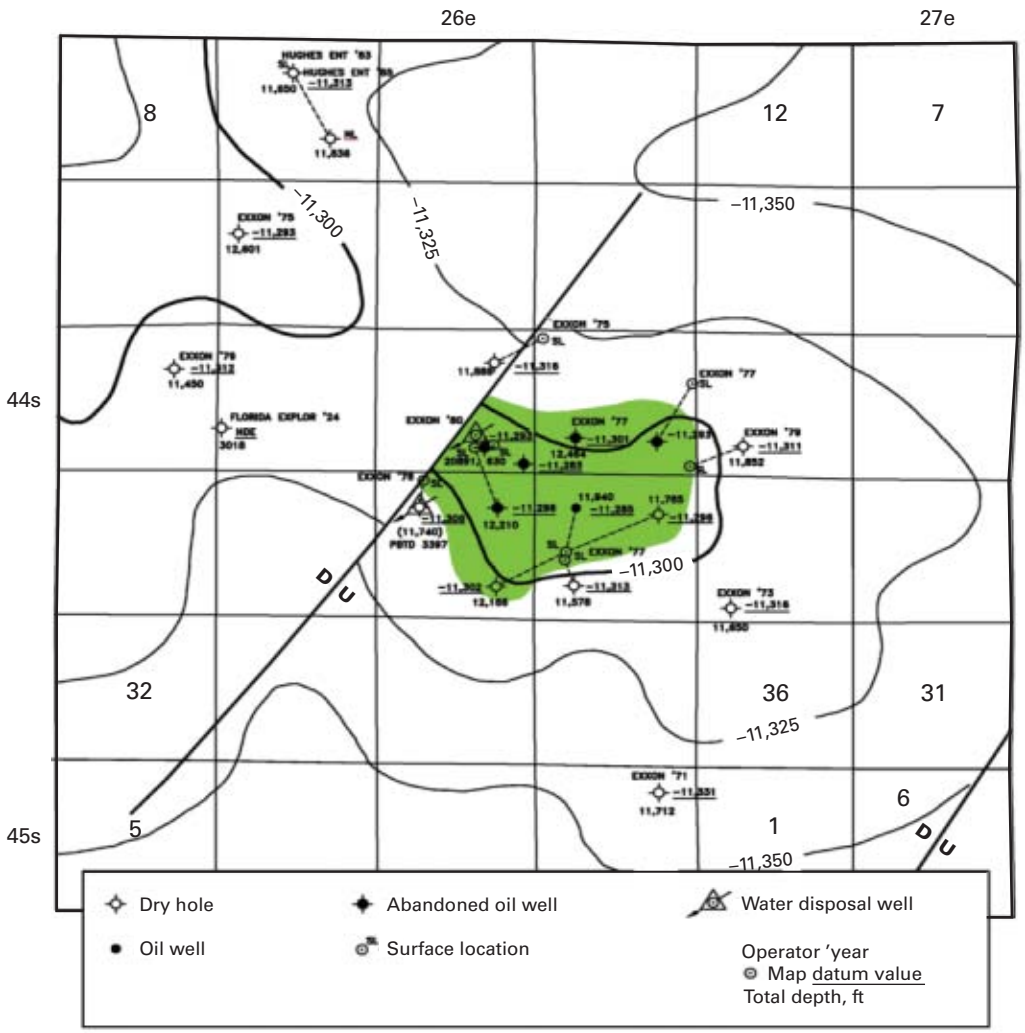
Lehigh Park field is the northwesternmost of 14 Lower Cretaceous-age Sunniland oil fields in the South Florida basin.

The Sunniland fields are combination structural-stratigraphic traps with porosity development occurring in bio-

SUBSURFACE STRUCTURE ON TOP OF SUNNILAND FORMATION

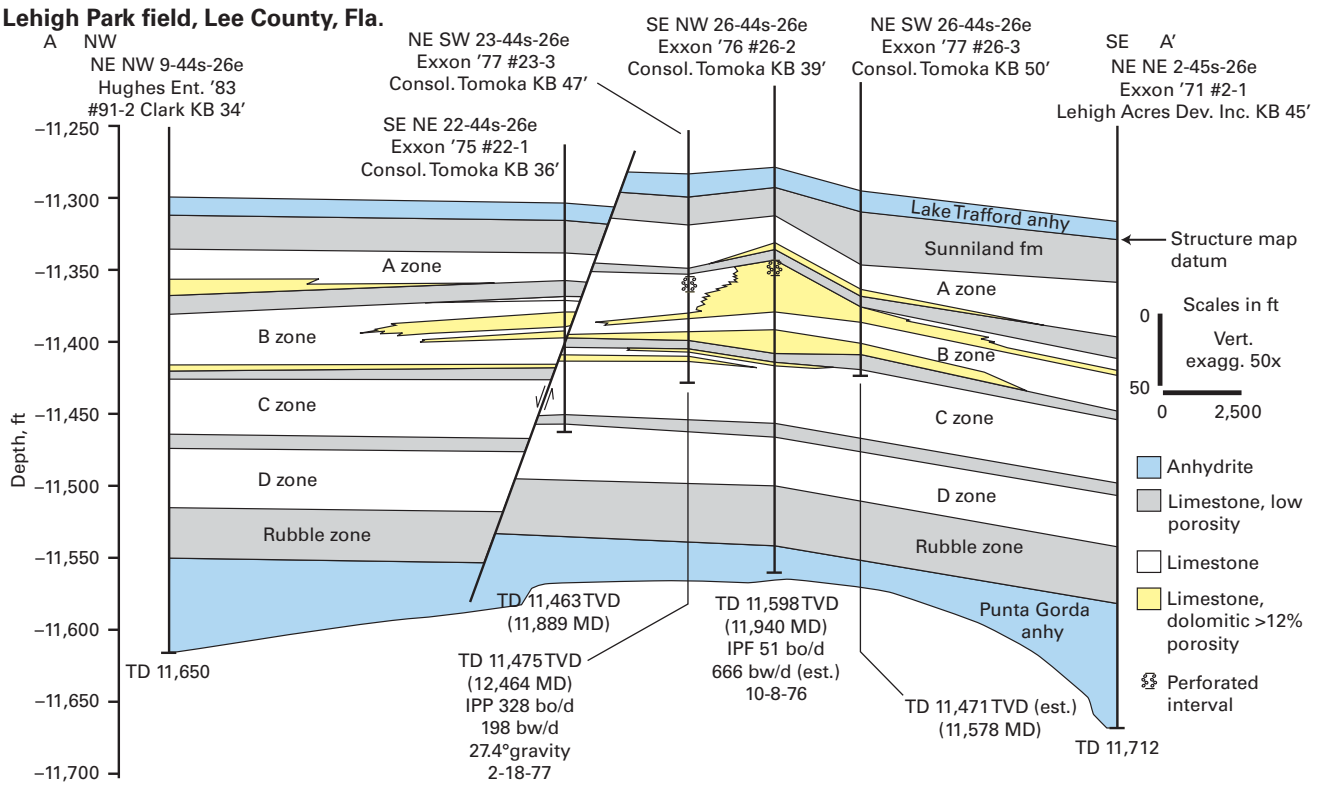
Fig. 3

Lehigh Park field, Lee County, Fla.



LEHIGH PARK FIELD CROSS SECTION

Fig. 4



PRODUCTION SUMMARY THROUGH DEC. 31, 2008

Table 3

Well No.	Initial potential	Date of first production	Last production	Cumulative production
22-4 (4A)	480 bo/d 48 bw/d	7/30/74	1985	439,035 bbl of oil 43,843 Mcf of gas 3,831,818 bbl of water
26-2	51 bo/d 660 bw/d	10/8/76	Producing	2,463,182 bbl of oil 265,602 Mcf of gas 25,036,992 bbl of water
27-1	236 bo/d 660 bw/d	3/10/76	1987	1,536,906 bbl of oil 155,678 Mcf of gas 7,351,468 bbl of water
23-3	328 bo/d 198 bw/d	2/18/77	1987	1,122,607 bbl of oil 113,610 Mcf of gas 7,427,562 bbl of water
23-4	121 bo/d 329 bw/d	9/14/77	1991	359,033 bbl of oil 29,568 Mcf of gas 3,466,921 bbl of water
Cumulative field production:				**5,920,763 bbl of oil 608,301 Mcf of gas 47,114,759 bbl of water**

hermal algal mounds formed on subtle seafloor highs related to faulting in the underlying basement.

Available Bouguer gravity data indicate the trend could continue farther to the northwest toward the northwest boundary of the basin, which is the Sarasota arch. Exploration has been sparse in that area, likely due to higher population and urban-suburban development.

The possibility of subparallel Sunniland trends downdip and to the southwest is likely.[5] The area immediately southwest of the trend has generally been characterized as basinal anhydrite facies[6] but more likely represents a salina environment during sea level lowstands in the context of current carbonate sequence stratigraphic models.[7] Exploration has been very sparse in the deeper basin area, which is mainly offshore.

In its year 2000 assessment of the onshore and state waters (i.e., to 12 miles offshore) portion of the South Florida basin,[5] the US Geological Survey calculated a mean of 25 undiscovered fields in the Sunniland Trend with mean field size of 5 million bbl of oil. Thus, Lehigh Park field is significant from the aspect that it would be a typical analog for future discoveries in the onshore portion of the trend.

The USGS[5] recognized two petroleum systems in the South Florida basin—an oil-prone Dollar Bay/Sunniland system and an underlying gas-prone system below the Punta Gorda anyhydrite. Numerous oil shows have been reported in the Dollar Bay formation,

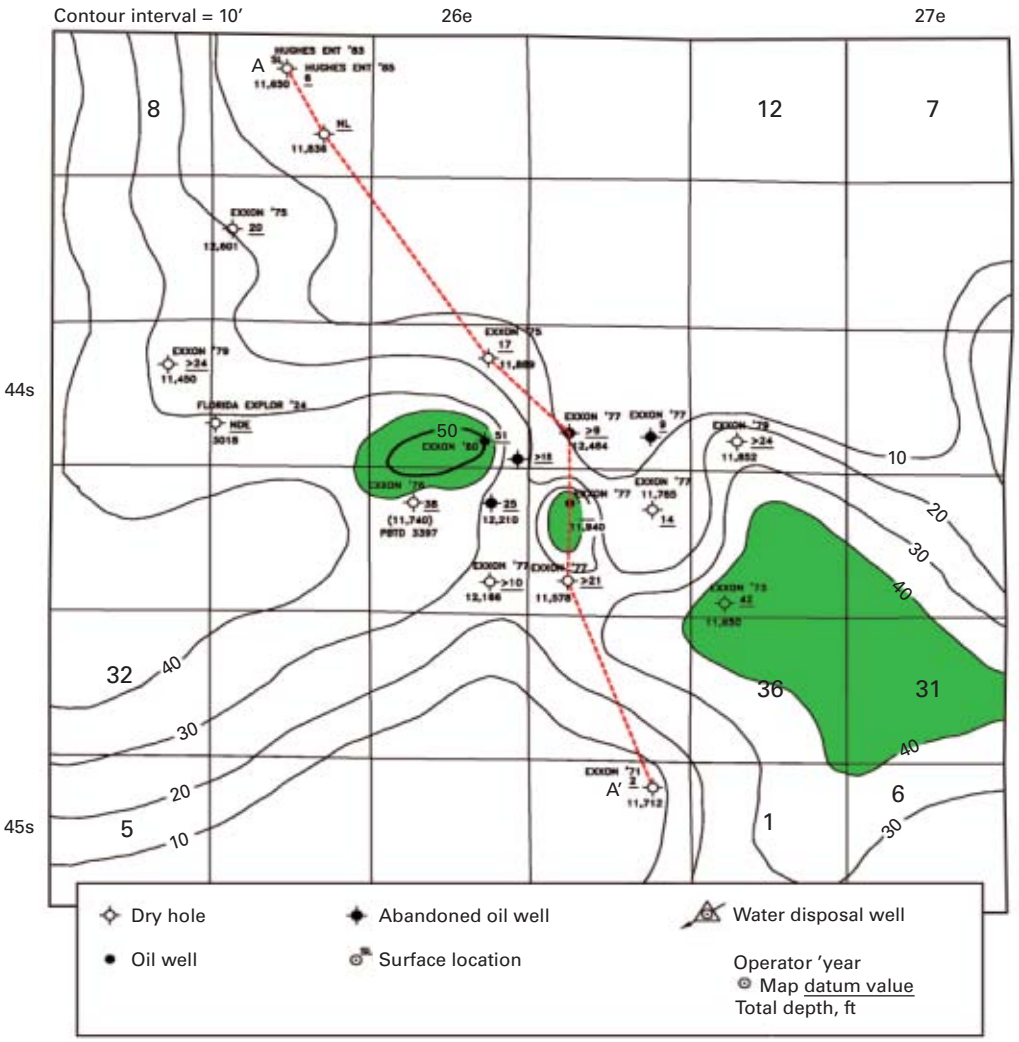
which is generally about 2,000 ft shallower than the Sunniland but is so far unproductive.[8]

Potential reservoirs in the deeper system include the Twelve Mile member of the Lower Cretaceous (Aptian) age Lehigh Acres formation, Pumpkin Bay formation (Barremian-Aptian), and Bone Island formation (Berriasian-Barremian), and the Upper Jurassic (Tithonian) Wood River formation. All of these potential reservoirs are carbonates with the exception of some sand units in the Wood River. Potential source rocks are present in all of these formations.[4] Oil or gas shows have been reported in each of these formations at various locations in the South Florida basin.

SUNNILAND FORMATION ZONE B, NET FEET OF POROSITY GREATER THAN 12% ISOPACH

Fig. 5

Lehigh Park field, Lee County, Fla.



The method typically utilized to date to evaluate the potential of deeper (i.e., pre-Punta Gorda anhydrite) reservoirs in the South Florida basin has been to drill one deep test in each Sunniland field. The number of such penetrations, when combined with deep wildcat tests, is extremely small for a basin as large as the South Florida basin.

The rationale for drilling the deep tests in the Sunniland fields may not be valid in that it assumes that similar trapping mechanisms would be present in the deeper section. A total of approximately 26 pre-Punta Gorda tests (21 onshore and 5 offshore) have been drilled in the South Florida basin. The basin has an area of about 80,000 sq miles (Fig. 7).

Prior to the opening of the Gulf of Mexico in the Paleocene, the South Florida basin was most closely related geographically to the Sonda de Campeche of the Mexican Gulf Coast. Paleogeographic setting and depositional environments during the Late Jurassic and Early Cretaceous were very similar for these two areas during the formation of the proto Gulf of Mexico.

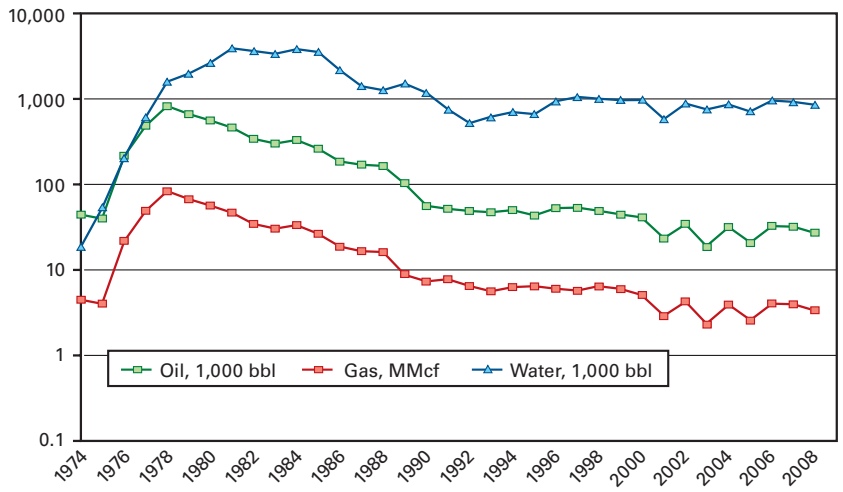
Although the Sonda de Campeche petroleum province has undergone a distinct and significantly different postburial, structural, and diagenetic geologic history[9] since the opening of the gulf, the original rock type and age of the reservoir and source rocks are similar. Therefore, the world-class production from the Sonda de Campeche should serve as encouragement for future exploration in the South Florida basin.

To date, the USGS has not assessed the petroleum potential of the offshore (i.e., federal waters) of the South Florida basin.

In its 2000 assessment of the onshore and state waters portion of the

LEHIGH PARK FIELD ANNUAL PRODUCTION

Fig. 6



basin, the USGS noted that oil expulsion rates in the Sunniland formation should be higher in the offshore portion of the basin than in the onshore portion due to deeper burial and entrance into the oil window earlier. Sequence stratigraphic models also indicate that much larger hydrocarbon accumulations could be present in the offshore portions of the basin, potentially up to giant field size.

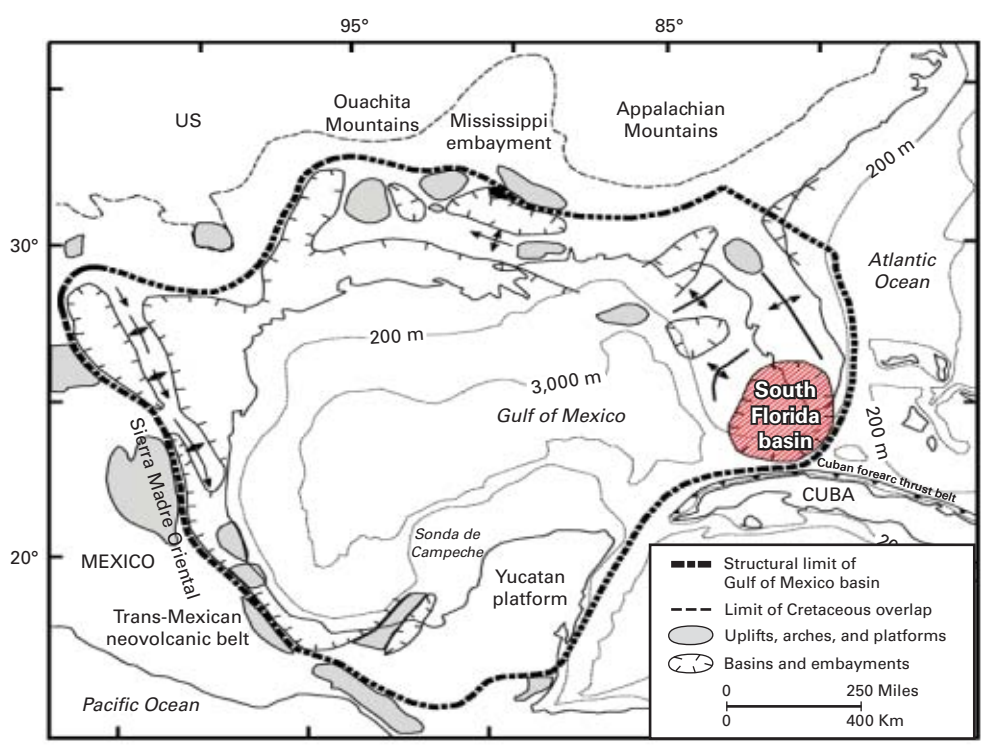
The presence of more significant structural features and related hydrocarbon traps is also likely in the offshore portion of the basin due to closer proximity to structural elements related to the evolution of the Gulf of Mexico.

A recent inventory[10] of world petroleum reserves and historical production concluded that 56% of all petroleum discovered to date has been from carbonate reservoirs, and of that 64% has been in traps that have anhydrite seals.

Thus, the offshore portion of the South Florida basin, which contains the distal depositional settings of a rimmed arid carbonate shelf during the Mesozoic, is one of the few areas in the US that remains essentially untested. It has been under a federal drilling moratorium since 1982 (currently scheduled to expire in 2022) but potentially could be a location for prolific domestic hydrocarbon production, with fields that could compare to those of the Sonda de Campeche. ✦

GULF OF MEXICO GENERALIZED STRUCTURE SHOWING SOUTH FLORIDA BASIN

Fig. 7



Source: Modified from Mello and Karner, 1996.

References

1. Acquaviva, D.J., and Nedorub, O.I., "Petroleum geology of the Lehigh Park field and its implications for future exploration in the South Florida basin" abs., in Geological Society of America Abstracts with Programs, Vol. 40, No. 6, 2008, GSA/GCAGS Joint Annual Meeting, 2008, p. 482.

2. Ferber, R.J., and Lock, B.E., "Depositional environments of Sunniland formation and diagenetic characteristics of productive facies, Lehigh Park field, Florida," abs., AAPG Bull., Vol. 69, No. 9, 1985, pp. 1420-21.

3. Winston, G.O., "Oil occurrence and Lower Cretaceous carbonate-evaporite cyclothems in South Florida," AAPG Geologic

Notes, Vol. 56, No. 1, 1972, pp. 158-160.

4. Palacas, J.G., Anders, D.E., and King, J.D., "South Florida Basin—prime example of carbonate source rocks of petroleum," AAPG Studies in Geology 18, "Petroleum Geochemistry and Source Rock Potential of Carbonate Rocks," 1984, pp. 71-97.

5. Pollastro, R.M., Schenk, C.J., and Charpentier, R.R., "Assessment of Undiscovered Oil and Gas in the Onshore and State Waters Portion of the South Florida Basin, Florida, USGS Province 50," USGS Digital Data Series 69-A, 2001, 70 pp.

6. Winston, G.O., "Regional structure, stratigraphy, and oil possibilities of the South Florida Basin," in GCAGS Transactions, Vol. 21, 1971, pp. 15-29.

7. Handford, R.C., and Loucks, R.G., "Carbonate depositional sequences and system tracts—responses of carbonate platforms to relative sea level changes," in Loucks, R.G., and Sarg, J.F., eds., "Carbonate Sequence Stratigraphy, Recent Developments and Applications," AAPG Memoir 57, 1993, pp. 3-41.

8. Winston, G.O., "The Dollar Bay Formation, of Lower Cretaceous (Fredericksburg) Age in South Florida: Its Stratigraphy and Implications," Florida Bureau of Geology Special Pub. 15, 1971, 99 pp.

9. Mitra, S., Figueroa, G.C., Garcia, J.H., and Alvardo, A.M., "Three-dimensional structural model of the Cantarell and Sihil structures, Campeche Bay, Mexico," AAPG Bull., Vol. 89, No. 1, 2005, pp. 1-26.

10. Kendall, C.G., Weber, L.J., and Alsharhan, A.S., "The common association of giant oil fields with evaporates: linked by both pull apart and collision of continents, climate, basin position, and sea level" abs., in 2009 AAPG annual convention abstracts, 2009, p. 113.

Bibliography

Lloyd, J.M., 1997, 1994, and 1995 Florida Petroleum Production and Exploration, Florida Geological Survey Information Circular No. 11, Tallahassee, Fla., 62 pp.

Faulkner, B.M., and Applegate, A.V., "Hydrocarbon exploration evaluation of the Pulley Ridge area, offshore South Florida Basin," in "Transactions-Gulf Coast Association of Geological Societies," Vol. 36, 1986, pp. 83-95.

The authors

Daniel J. Acquaviva (dacquaviva@sachemresources.com) has 30 years' petroleum exploration and development experience in the US Gulf Coast, Rocky Mountains, and Midcontinent. He has worked for Texaco, Supron Energy, and Sachem Resources. He has an MS degree in geology from the University of Kentucky.

Omar Rodriguez (orodriguez@rma-geologic.com) has 14 years' geoscience experience in onshore and offshore Cuba, the Gulf of Mexico, and the Caribbean region. He has worked for CUPET, Repsol-YPF, and RMA GeoLogic Consultants. He has a BS degree in geology from the University of Pinar del Rio, Cuba.

Olga I. Nedorub (nedorub@mail.ru) is completing an undergraduate degree in geology at the University of South Florida and plans to obtain a master's degree in geophysics. She has worked for PT&C Inc. and RMA GeoLogic Consultants. She attended Taganrog Science University, Rostov, Russia.

California

Venoco Inc., Denver, plans to drill at least five vertical Monterey shale exploratory wells and shoot 3D seismic over parts of its acreage in California in 2010.

The company spent minimally for onshore Monterey shale work in 2009 and accelerated leasing in the second half of 2009. It expects to aggressively add acreage this year.

The 2010 Monterey onshore budget is $26 million, but the company may hike that later in the year. The first half program is focused on science, but "we expect to begin testing various completion techniques that have been successful in unconventional reservoirs in other parts of the country," Venoco said.

Utah

Two companies encountered oil in four Jurassic zones and ran production casing to 1,100 ft to test an indicated discovery in Grand County, Utah, in the northern Paradox basin.

Tidewater Oil & Gas Co. LLC, Denver, and Forest Gate Energy Inc., Montreal, drilled the Tidewater-State well, in 3-22s-19e, 20 miles west of Cisco Dome field, to a TD of 3,050 ft to Triassic Wingate sandstone (OGJ Online, Jan. 25, 2010).

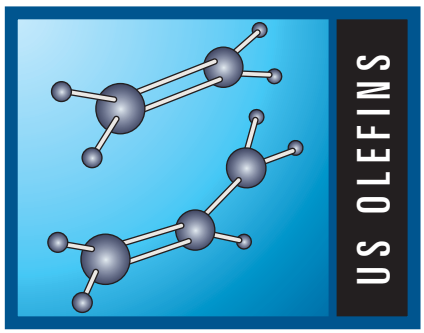
Forest Gate reported the following results from a third party evaluation of the well on its Crescent Junction property:

- 40 ft of potential oil pay at 390-430 ft with 28% porosity and a calculated 37% water saturation in the Brushy Basin member of the Morrison formation.
- 50 ft of potential oil pay at 770-820 ft with 20% porosity and 39% water saturation in the Lower Salt Wash member of Morrison.
- 10 ft of potential oil pay at 830-840 ft with 20% porosity and a calculated 37% water saturation in the Lower Salt Wash.
- 30 ft of potential oil pay at 870-900 ft with 20% porosity and a calculated 50% water saturation in the Lower Salt Wash.

The Brushy Basin and Lower Salt Wash have produced oil for many years at Cisco Dome field, Forest Gate noted. The well also yielded important data to help target the Wingate at future wells, the company said.

Forest Gate holds varying interests in 121,000 gross acres and 31,335 net acres in Utah and has an option to acquire a 50% interest in a further 135,505 gross acres and 37,264 net acres in the state.

OGJ FOCUS



US olefins production rebounds amid global economic recovery

Dan Lippe
Petral Worldwide Inc.
Houston

Second-half 2009 saw sustained recovery for the US petrochemical industry, even as broader economies continued to experience credit crises and economic recession. Although plants' operating rates were less than 90% and profit margins for ethylene producers remained under pressure, the economic landscape for the petrochemical industry proved to be much better than most analysts expected during first-quarter 2009.

US refineries operated at higher rates in third-quarter 2009 than in third-quarter 2008, but operating rates in fourth-quarter 2009 fell lower than in fourth-quarter 2008. Despite the year-to-year decline in operating rates in the fourth quarter, merchant sales of refinery-grade propylene were higher in both third and fourth quarters 2009 than in 2008.

Although the petrochemical industry welcomed the rebound in demand for ethylene and propylene, the economic recovery also brought higher costs. Ethylene producers managed to keep pace with rising costs, but profit margins were very thin for those plants that continued to use light naphthas.

SECOND-HALF 2009

US ETHYLENE FEED SLATE

Table 1

2009	Ethane	Propane	n-Butane	Naphthas, gas oils
	1,000 b/d			
April	877.0	288.2	30.9	367.3
May	905.5	265.6	29.3	289.0
June	854.9	285.9	41.6	268.4
July	853.0	329.6	38.1	281.5
August	852.3	317.3	35.8	323.3
September	853.5	295.3	48.8	344.3
October	890.7	292.6	45.4	268.1
November	916.5	324.3	32.4	342.7
December	892.0	283.6	4.5	382.9

Source: Petral Monthly Olefin Feedslate Survey

Feed slate trends

Ethylene industry's demand for fresh feed averaged 1.50 million b/d in second-quarter 2009 and increased to 1.52 million b/d in third-quarter 2009. Ethylene demand for fresh feed in second and third quarters 2009 was 190,000-200,000 b/d higher (about 15%) than in first-quarter 2009, but feedstock demand remained 130,000 b/d lower than the average for first-half 2008.

Demand in fourth-quarter 2009 averaged 1.56 million b/d. After the strong rebound in the second quarter, ethylene demand for feedstocks was nearly flat during second-half 2009.

Demand for LPG feedstocks (ethane, propane, and normal butane) averaged 1.21 million b/d in third-quarter 2009 and 1.23 million b/d in fourth quarter. LPG feeds accounted for 79% of total fresh feed in third and fourth quarters 2009 vs. 72% of fresh feed in first-quarter 2009. The LPG share of total fresh feed for 2005-07 averaged 70%.

Two factors pushed the LPG feed share to nearly 80%. First, all ethylene producers had strong economic incentives to maximize the use of ethane, and ethane availability was sufficient to support higher demand over a sustained period. Second, operating rates for LPG crackers jumped to 95% of capacity, while multifeed crackers operated at 75% of capacity during third and fourth quarters 2009.

Table 1 summarizes trends in olefin plant fresh feed.

As economies in North America began to recover in third-quarter 2009,

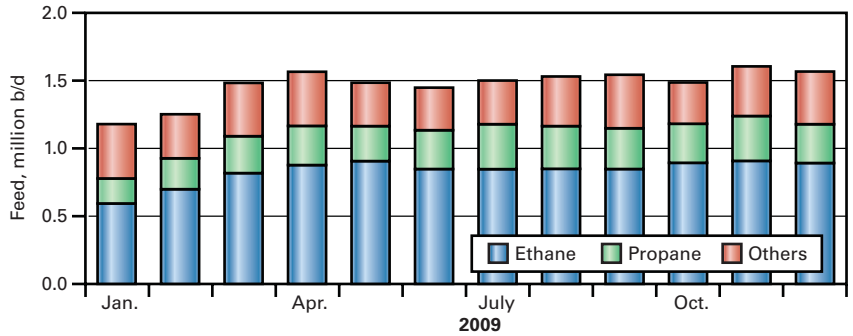
ethylene producers responded to the increased demand for ethylene by increasing production to 86-88% of capacity in fourth-quarter 2009. Unless the economies in North America slip back into recession during first-half of 2010, the industry's operating rate is likely to average 88-92%.

Total demand for fresh feedstocks will average 1.55-1.65 million b/d during first and second quarters 2010. Total demand for LPG feedstocks will average 1.25-1.30 million b/d during first and second quarters 2010.

Fig. 1 shows historic trends in ethylene feed slates.

US ETHYLENE PLANT FEED SLATE

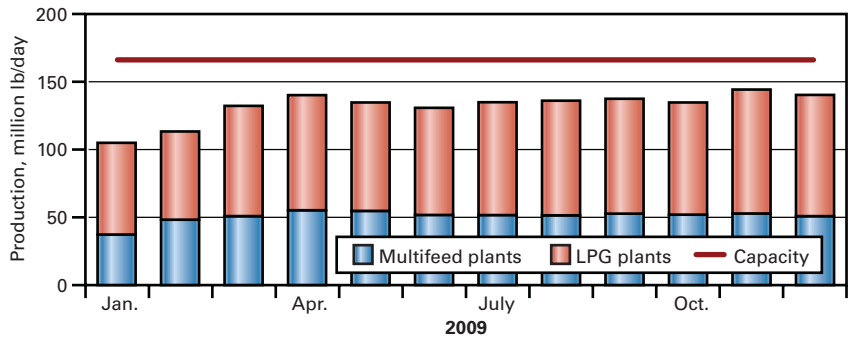
Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

US ETHYLENE PRODUCTION

Fig. 2



Source: Petral Monthly Olefin Plant Feedslate Survey

US ethylene production

Ethylene production from fresh feed totaled 13.1 billion lb in third-quarter 2009 and increased to 13.6 billion lb in fourth-quarter 2009. Ethylene production from steam crackers during third-quarter 2009 was 295 million lb higher than in second-quarter 2009. Production in fourth-quarter 2009 was 944 million lb higher than in third-quarter 2009.

Production from LPG plants totaled 4.88 billion lb in third and fourth quarters 2009 and was about 40 million lb less than in second-quarter 2009. Production from multifeed crackers totaled 7.69 billion lb in third-quarter 2009 and increased to 8.0 billion lb in fourth-quarter 2009.

Production from multifeed crackers during third-quarter 2009 was 289 million lb more than during second-quarter 2009, and production in fourth-quarter 2009 was 313 million lb more than during third-quarter 2009.

Table 2 summarizes trends in ethylene production.

Operating rates for LPG crackers averaged 93% of nameplate capacity (based on capacity of 21.6 billion lb/year) during third and fourth quarters 2009 vs. 95% in second-quarter 2009 and 80% in first-quarter 2009.

Multifeed crackers operated at 79% of nameplate capacity (based on capacity of 39.2 billion lb/year) during third-quarter 2008 and increased operating rates to 82% during fourth-quarter 2009 vs. 77% in second quarter and 67% in first-quarter 2009. Operating rates for the industry overall averaged 84% in third-quarter 2009 and improved to 86% during fourth-quarter 2009.

Fig. 2 shows trends in ethylene production.

ETHYLENE FROM US STEAM CRACKERS

Table 2

2009	LPG crackers	Multifeed crackers	Total
	Production, billion lb		
April	1.65	2.57	4.22
May	1.70	2.49	4.19
June	1.59	2.35	3.94
July	1.64	2.53	4.18
August	1.63	2.62	4.25
September	1.61	2.54	4.15
October	1.65	2.55	4.20
November	1.64	2.72	4.35
December	1.60	2.74	4.34

Source: Petral Monthly Ethylene Feedslate Survey

PROPYLENE FROM US STEAM CRACKERS

Table 3

2009	LPG feeds	Naphthas, gas oil feeds	Production (est.)
	Production, million lb		
April	354.1	434.7	788.8
May	345.6	357.5	703.1
June	363.0	313.8	676.8
July	410.3	344.8	755.1
August	396.0	394.2	790.2
September	379.1	404.5	783.5
October	386.7	324.4	711.0
November	390.4	392.0	782.4
December	369.2	405.0	774.2

Source: Petral Monthly Propylene Supply Analysis

US propylene production

Industry operating rates improved steadily during second, third, and fourth quarters 2009 and US ethylene production in fourth-quarter 2009 was up 22.5% from production in first-quarter 2009. Propylene from steam crackers, however, lagged the rebound in industry operating rates due to the continued increase in ethane demand.

Coproduct propylene supply totaled 2.33 billion lb in third-quarter 2009 and was 7.4% higher than in second-quarter 2009. Despite the improvement in ethylene plants' operating rates, however, coproduct propylene supply declined to 2.27 billion lb in fourth-quarter 2009 or 3.4% lower than in third-quarter 2009.

Coproduct propylene supply during third-quarter 2009 was almost 240 million lb lower than year-earlier volumes, but production in fourth-quarter 2009 was only 80 million lb lower than in 2008.

Propylene production from LPG feeds totaled 1.19 billion lb in third-quarter 2009 but declined to 1.15 billion lb in fourth-quarter 2009. Production from LPG feeds in third-quarter 2009 was about 120 million lb less than in third-quarter 2008. In fourth-quarter 2009, coproduct propylene supply from LPG feeds was 350 million lb more than in fourth-quarter 2008.

Propylene production from naphthas, condensates, and gas oils totaled 1.14 billion lb in third-quarter 2009 and was 115 million lb lower than during third-quarter 2008. Coproduct yields of propylene from heavy feeds declined to 1.12 billion lb in fourth-quarter 2008, or almost 430 million lb lower than in fourth-quarter 2009.

The year-to-year decline in coproduct propylene was primarily due to the increase in ethane's share of the industry feed slate. In third-quarter 2009, ethane accounted for 56% of total fresh feed vs. 48% in third-quarter 2008. Ethane's share of fresh feed increased to 58% in fourth-quarter 2009 vs. 49% in fourth-quarter 2008.

Table 3 summarizes trends in coproduct propylene supply.

Refinery supply

Refinery propylene sales into the merchant market are a function of fluid catalytic cracking unit feed rates, FCCU operating severity, and economic incentives to sell propylene rather than use it as alkylate feed. Normally, FCCU feed rates increase to their seasonal peaks during second and third quarters. Furthermore, refineries typically operate FCC units at high severity during second and third quarters. Propylene yields from FCC units are higher when those units operate at high severity.

US REFINERY MERCHANT PROPYLENE

Table 4

2009	Texas	Louisiana	Other areas	Total
	Sales, million lb			
April	482.4	459.1	193.4	1,134.9
May	530.6	471.3	204.3	1,206.3
June	501.1	437.9	264.0	1,203.0
July	550.5	432.9	276.3	1,259.8
August	538.7	460.3	255.6	1,254.6
September	509.1	486.6	283.8	1,279.5
October	454.7	451.4	297.8	1,203.9
November	493.8	418.0	273.0	1,184.7

Source: EIA Petroleum Supply Monthly

FCCU operating rates tracked the typical seasonal trend during second, third, and fourth quarters 2009. The US Energy Information Administration reported FCCU feed increased by 79,000 b/d and averaged 5.22 million b/d in third-quarter 2009. FCCU feed rates in third-quarter 2009 were also 429,000 b/d higher than in third-quarter 2008—consistent with the quiet 2009 hurricane season vs. the extensive downtime that occurred after September 2008 due to hurricanes Gustav and Ike.

Based on EIA's statistics for October and November and Petral's estimates for December, FCCU feed rates declined by about 300,000-325,000 b/d in fourth-quarter 2009 and averaged 4.87 million b/d. The decline in FCCU feed from third-quarter average was consistent with the overall decline in refinery operating rates. Feed rates in fourth-quarter 2009 were also about 40,000 b/d lower than in fourth-quarter 2008.

Refinery-grade propylene production increased to 3.79 billion lb in third-quarter 2009 and averaged 41.3 million lb/day (Table 4). Merchant sales from refineries were 525 million lb more than in third-quarter 2008 and were 250 million lb more than in second-quarter 2009.

Refinery-grade propylene production declined by more than 200 million lb in fourth-quarter 2009 and totaled 3.58 billion lb, or about 39 million lb/day. Merchant sales, however, were almost 270 million lb more than in fourth-quarter 2008.

US propylene supply totaled 6.12 billion lb in third-quarter 2009 and was 410 million lb higher than in second-quarter 2009 and 289 million lb higher than in third-quarter 2008. Total US supply declined by about 300 million lb in fourth-quarter 2009 and totaled only 5.83 billion lb. Total fourth-quarter production was 191 million lb more than year-earlier volumes.

Fig. 3 shows trends in coproduct and refinery merchant propylene.

Ethylene production costs

Ethane and propane accounted for about 81% of total ethylene production in third-quarter 2009. Production costs for ethylene in the Houston Ship Channel (based on full spot prices for all coproducts) based on purity-ethane feeds averaged about 22¢/lb in third quarter.

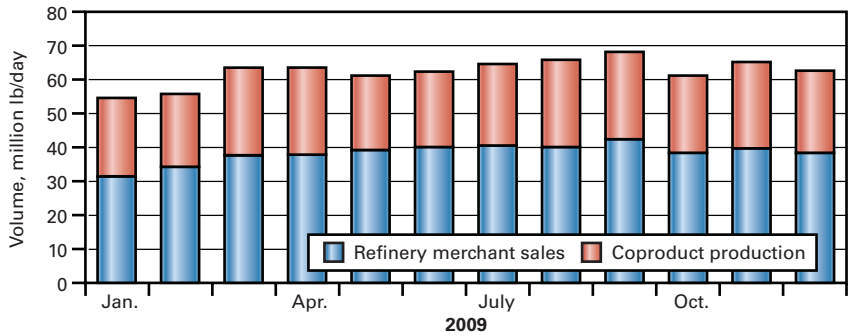
Production costs based on ethane increased by less than 1¢/lb in third-quarter 2009 and provided ethylene producers with incentives of 4-7¢/lb to switch from heavier feeds. Production costs for purity propane averaged about 23¢/lb. Propane also provided ethylene producers with incentives of 3-6¢/lb to switch from heavy feeds.

Feedstock prices, coproduct values, and ethylene plant yields determine ethylene production costs. Petral maintains direct contact with the olefin industry and tracks historic trends in spot prices for ethylene and propylene. We use a variety of sources to track trends in feedstock prices.

Some ethylene plants have the necessary process units to convert all coproducts to purity streams. Some do not have, however, the capability to upgrade mixed or crude streams of various coproducts and sell some or all their coproducts at discounted prices. We evaluate ethylene production costs in this article based on all coproducts valued at spot prices.

PROPYLENE PRODUCTION, SALES

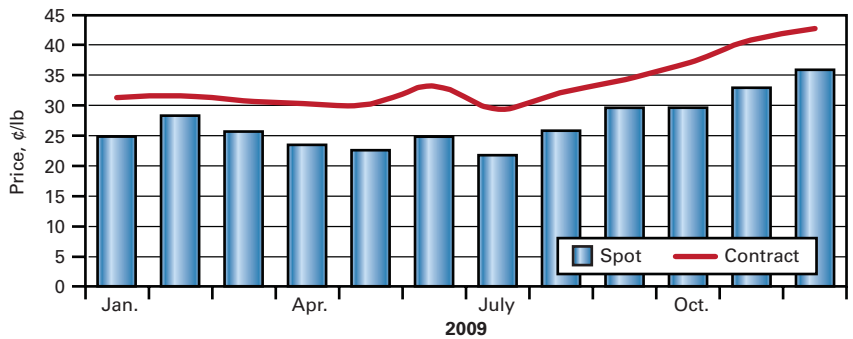
Fig. 3



Source: Petral Monthly Coproduct Supply Analysis

ETHYLENE PRICES

Fig. 4



Source: Petral market research

In fourth-quarter 2009, production costs based on purity ethane jumped to an average of 29-30¢/lb and reached 32¢/lb in December 2009. Producers that could increase their use of ethane had incentives of 3-8¢/lb to switch from heavy feeds.

Production costs based on purity propane jumped to 33¢/lb in fourth quarter. Although costs based on propane remained higher than for purity ethane, ethylene producers had incentives of 4¢/lb to switch from light naphthas.

Average production costs for natural gasoline during third-quarter 2009 averaged 28-29¢/lb and were 7¢/lb higher than ethane and 5-6¢/lb higher than for propane. In fourth-quarter 2009, ethylene production costs based on natural gasoline jumped to 38¢/lb and were nearly 9¢/lb higher than for ethane and 5¢/lb higher than for propane.

Table 5 summarizes trends in ethylene production costs.

ETHYLENE COSTS, HOUSTON SHIP CHANNEL

Table 5

2009	Purity ethane	Purity propane	Normal butane	Light naphthas	Industry composite
	Variable, direct fixed cash costs, ¢/lb				
April	18.9	22.4	21.7	30.9	23.0
May	20.6	22.3	20.5	32.0	23.9
June	24.1	27.0	25.4	37.1	28.1
July	20.6	20.8	19.1	28.3	23.4
August	22.1	23.2	19.9	30.0	24.1
September	22.2	24.2	21.0	26.8	23.8
October	25.5	29.6	28.0	35.8	29.2
November	30.8	31.7	31.6	38.6	33.0
December	31.8	37.7	36.0	39.5	35.7

Source: Petral Consulting Co. production cost analysis

Ethylene pricing, margins

Contract prices for ethylene increased by 0.75¢/lb in third-quarter 2009 and averaged 32¢/lb. The contract benchmark prices in second-quarter 2009 had reached a high of 33.3¢/lb in June, but buyers were successful in negotiating a reduction of almost 4¢/lb in July. Rising production costs, however, especially for heavy feeds, supported increases in August and September. The benchmark price increased to 34.3¢/lb in September.

Benchmark prices rose steadily during fourth-quarter 2009 and averaged 40.3¢/lb, or 8.3¢/lb higher than the average for third-quarter 2009. The benchmark for December 2009 settled at 42.8¢/lb.

Spot ethylene prices increased by 2.1¢/lb in third quarter and averaged 25.9¢/lb. Spot prices dipped to 21.9¢/lb in July 2009 but jumped to 29.8¢/lb in September. In July, spot ethylene prices were 7.6¢/lb less than the contract benchmark. By September, the discount for spot ethylene narrowed to 4.5¢/lb.

During fourth-quarter 2009, spot ethylene prices averaged 32.9¢/lb and were 7.0¢/lb higher than the average for third-quarter 2009.

Margins based on the contract

ETHYLENE PROFIT MARGIN

Fig. 5

Source: Petral analysis

benchmark prices were stronger for all feedstocks in third-quarter 2009. Margins based on purity-ethane production costs averaged 10.4¢/lb vs. 10.0¢/lb in second-quarter 2009. Margins based on propane averaged 9.3¢/lb and were 2¢/lb higher than in second-quarter 2009.

Ethylene producers were also happy to see positive margins for natural gasoline and light naphthas. Profit margins for natural gasoline feeds averaged 3.6¢/lb in third-quarter 2009 vs. a loss of 2.1¢/lb in second-quarter 2009.

As the demand for petrochemicals continued to improve during fourth-quarter 2009, margins for ethane improved and averaged 10.9¢/lb. Margins for propane and natural gasoline weakened. Margins based on propane narrowed to 7.2¢/lb and margins based on natural gasoline narrowed to 2.3¢/lb.

Profit margins based on the contract benchmark are almost always stronger than margins based on spot ethylene prices. Profit margins based on spot ethylene prices and production costs for purity ethane ranged 3-4¢/lb during third and fourth quarters 2009. Profit margins for purity propane averaged 3.1¢/lb in third-quarter 2009, but margins broke even in fourth-quarter 2009.

Finally, production based on spot ethylene prices and costs based on natural gasoline generated losses of 2.5¢/lb in third-quarter 2009 and 5.0¢/lb in fourth-quarter 2009. The persistent weakness in profit margins based on spot ethylene prices indicates that the economic environment has a lot of room for improvement in 2010.

Fig. 4 shows historic trends in ethylene prices (spot prices and net transaction prices); Fig. 5 shows profit margins based on contract ethylene prices and composite production costs.

Prices for all grades of propylene move in tandem with each other, and differentials between grades are generally constant within a narrow range. We highlight trends in refinery-grade prices and discuss differentials between polymer and refinery-grade propylene. The premium for polymer-grade propylene covers operating costs and profit margins for the various merchant propane-polypropylene splitters in Texas and Louisiana.

Refinery, polymer grade C_3=

Spot prices for refinery-grade propylene increased by almost 16¢/lb during third-quarter 2009 and averaged 49.9¢/lb. The premium for refinery-grade-propylene prices vs. unleaded regular gasoline prices was 16¢/lb in third-quarter 2009 vs. 2.5¢/lb in second-quarter 2009.

In fourth-quarter 2009, spot prices for refinery-grade propylene ranged from a low of 40¢/lb in October to a high of 46.6¢/lb in December. For the quarter overall, however, spot prices were nearly unchanged and averaged 44.2¢/lb. Spot refinery-grade propylene prices averaged 13.2¢/lb premium to conventional unleaded regular gasoline for fourth-quarter 2009, or nearly 3¢/lb less than in third-quarter 2009.

The contract benchmark for polymer-grade propylene increased by 14.2¢/lb in third quarter and averaged 47.7¢/lb. The contract benchmark premium vs. spot refinery-grade propylene was 2.8¢/lb in third-quarter 2009 vs. 4.4¢/lb in second-quarter 2009. The contract benchmark increased to 50.2¢/lb average for fourth-quarter 2009 and the premium vs. refinery-grade propylene averaged 6.0¢/lb.

Mid-2010 outlook

OPEC responded to the collapse in crude oil prices during second-half 2008 with a series of agreements to reduce production. In accord with these agreements, crude oil production from Organization of Petroleum Exporting Countries' members declined by 2.96 million b/d July 2008 through March 2009.

Even though OPEC achieved only 85-90% compliance with its final agreement, production curtailments were sufficient to tighten the global crude oil supply/demand balance and to spark a sustained price rally after February 2009.

Although OPEC gradually increased production during second and third quarters 2009, production rose in tandem with recovery in demand, and WTI cash prices reached $80/bbl in mid-October 2009. The seasonal decline in refinery crude runs and the seasonal squeeze on refinery profit margins were strong bearish influences and WTI prices slipped to $70-72/bbl by mid December.

WTI prices staged a strong but relatively brief rally from mid-December through early January and reached $82/bbl before bearish seasonal pressures once again pushed prices lower. During most of January, crude oil prices were under substantial bearish pressure.

Seasonal supply/demand influences will swing from bearish to bullish during the second and third quarters 2010, and WTI prices will likely increase to $84-88/bbl in second quarter and $92-98/bbl in third-quarter 2010.

The projected rally in crude oil and refined products prices will carry prices for ethylene feedstocks and coproducts higher during second and third quarters 2010.

During fourth-quarter 2009, ethylene production costs (full cash costs) increased for all major feedstocks (ethane, propane, and light naphthas). Purity ethane consistently yielded the lowest ethylene production cost, averaging 29¢/lb for fourth-quarter 2009. Light naphthas consistently yielded the highest production cost, averaging 38¢/lb for fourth-quarter 2009.

Ethylene production costs will likely average 40-46¢/lb during second-quarter 2010 and 45-55¢/lb in third-quarter 2010. Spot ethylene prices will average 45-50¢/lb during second-quarter 2010 and 50-55¢/lb during third-quarter 2010. Profit margins will average 5-7¢/lb for purity ethane and 3-5¢/lb for purity propane. ✦

The author

Daniel L. Lippe (danlippe@petral.com) is president of Petral-Worldwide Inc., Houston. He founded Petral Consulting Co. in 1988 and cofounded Petral Worldwide in 1993. He has expertise in economic analysis of a broad spectrum of petroleum products including crude oil and refined products, natural gas, natural gas liquids, other ethylene feedstocks, and primary petrochemicals. Lippe began his professional career in 1974 with Diamond Shamrock Chemical Co., moved into professional consulting in 1979, and has served petroleum, midstream, and petrochemical industry clients since that time. He holds a BS (1974) in chemical engineering from Texas A&M University and an MBA (1981) from Houston Baptist University. He is an active member of the Gas Processors Association, serving on the NGL Market Information Committee and currently serving as vice-chairman of the committee.

Competitive pressures changing Asian petchems

Liutong Zhang
Praveen Kumar
Facts Global Energy
Singapore

OGJ FOCUS

Massive growth in Chinese and Middle East petrochemical capacities and prospects of intense competition for Asian markets from Middle East producers are prompting profound change in Asia's petrochemical industry. Growth in Asian capacity could support naphtha pricing, while competition from the Middle East will put pressure on margins and naphtha prices.

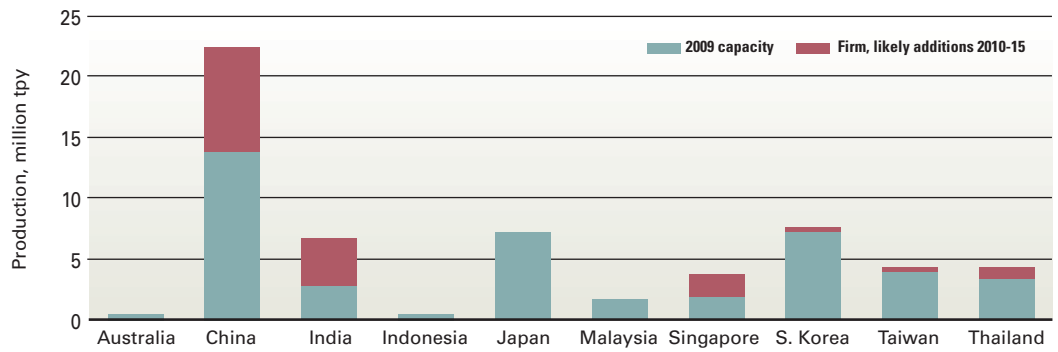
It is possible that low-cost exports from the Middle East may force some ethylene plants in Asia to close (especially in Japan). Consuming countries may retaliate, however, by imposing tariffs and dumping regulations to protect their industries.

Asian petrochemicals are witnessing rapid and fundamental changes with the:

- Emergence of China as the largest petrochemical producer in Asia.
- Rise in Middle East production capacity based on cheap natural gas.
- Huge potential Chinese demand for basic chemicals as the country's economy grows.
- Advent of KG-D6 gas in India that will free up naphtha for use in petrochemical production as well as for exports from the region.

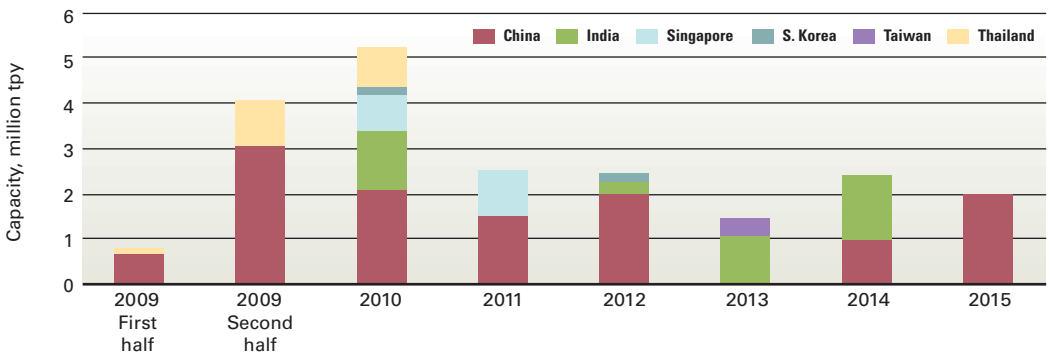
Asia-Pacific: ethylene capacity

Fig. 1



Asia-Pacific: ethylene additions

Fig. 2



Asia's ethylene industry

Already an important player in the global ethylene market, Asia is adding capacity rapidly. With about 43.8 million tonnes/year of ethylene capacity in place at yearend 2009, Asia will add a further 16 million tpy by yearend 2015. In second-half 2009 alone, the region added 4.1 mil-

lion tpy of ethylene capacity, and Facts Global Energy expects it to add another 5.4 million tpy of ethylene capacity this year.

Figs. 1 and 2 show that about 50% of capacity addition from start of 2009 to yearend 2015 occurs in second-half 2009 and in 2010. These peaks in the capacity additions are mainly due to China and India.

China will be responsible for 54% of the new capacity 2010-15. In 2005, China surpassed Japan to rank second globally in ethylene production capacity. It is currently behind the US by a whopping 25 million tpy, but this gap is narrowing rapidly.

China had 13.9 million tpy of ethylene capacity in place at yearend 2009. Of the 8.7 million tpy capacity the country will add through 2015, 42% will be achieved in the next 2 years. By yearend 2015, China will have more capacity than Japan, South Korea, and Taiwan combined.

Recently, the Sinopec/ExxonMobil/Saudi Aramco joint venture began to produce from its 800,000-tpy ethylene plant at Fujian (OGJ Online, Nov. 11, 2009). Meanwhile, in early November, the Sinopec/SABIC Tianjin joint venture started trial runs at its 1-million-tpy ethylene plant.

PetroChina has also started trial runs at its 1-million-tpy Dushanzi ethylene plant. The construction of PetroChina's Qinzhou and Sinopec'c Zhenhai ethylene plants, both 1 million tpy each, are complete and ready to commence trial runs soon.

At present, China's demand for ethylene equivalent far exceeds its supply. It produced slightly more than 10 million tonnes of ethylene equivalent in 2008, while import needs stood at 12 million tonnes. For 2009, its ethylene-equivalent demand increased by around 25%, thanks to the 4 trillion Yuan ($586 billion) stimulus plan and other policies to boost domestic consumption.

The increase in basic petrochemicals demand in 2009 was largely met by imports. Table 1 indicates that the Chinese net imports of polyethylene in 2009 increased by a staggering 67% year-over-year. In the longer term, strong economic growth promises robust demand but no repeat of the staggering growth seen in 2009.

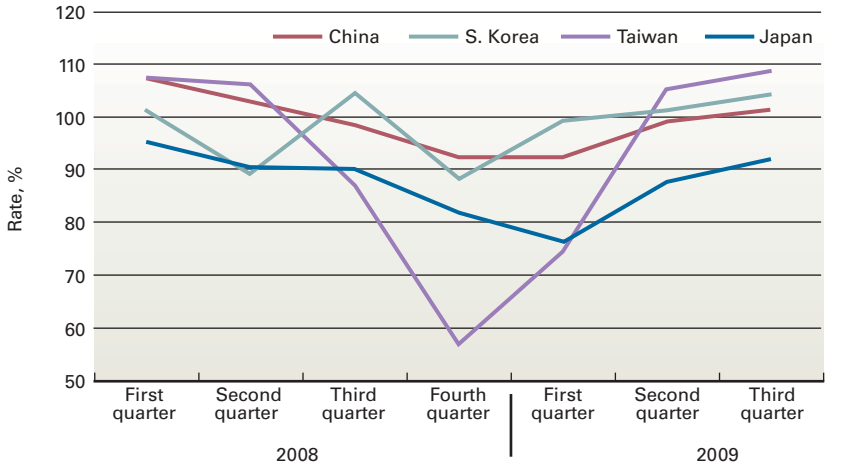
High import requirements by the Chinese have benefited Korean, Taiwanese, and Japanese firms since early 2009. The Chinese demand surge came at the right time for firms in these countries as the market nose dived in October 2008 (Fig. 3).

Aside from China, India will add 4 million tpy of ethylene capacity by 2015. The key projects in the near-term are:

- Haldia Petrochemicals Ltd., which plans to expand ethylene production capacity to 670,000 tpy from 523,000 tpy at its plant in West Bengal by first-half 2010. "Project Supermax," as the expansion has been dubbed, will result in an increase in ethylene production capacity by about 30%.
- Reliance Industries Ltd. will complete debottlenecking its ethylene cracker at its Hazira plant to 1.0 million tpy from 840,000 tpy in second-quarter 2010. This started in 2006 and is being executed in stages.
- Indian Oil Corp. will commission

EAST ASIAN ETHYLENE PLANT UTILIZATION

Fig. 3



CHINA'S ETHYLENE DERIVATIVE IMPORTS (NET)

Table 1

	PE	PVC	EG	Styrene monomer
	1,000 tpy			
2007	4,473	551	4,800	3,101
2008	4,411	481	5,187	2,809
2009	7,383	1,680	5,821	3,638
Growth 2008-09, %	67	249	12	30

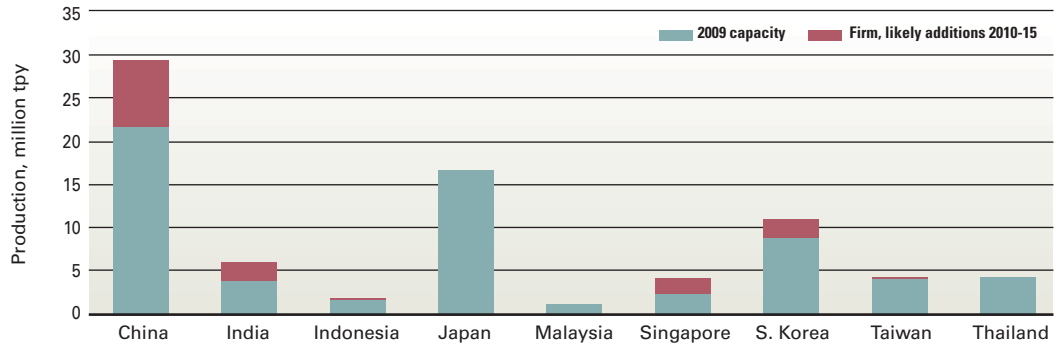
ADDED CHINESE ETHYLENE CAPACITY, JULY 2009-JUNE 2010

Table 2

Site	Company	Year	Qtr.	Ethylene, 1,000 tpy	Note
Fujian	Sinopec/EOM/SA	09	04	800	Commercial production started in Nov. 2009.
Liaoning	Huajin (local)	09	04	300	Trial production started in Sept. 2009.
Dushanzi	PetroChina	09	04	1,000	Trial production started in Sept. 2009.
Tianjin	Sinopec/SABIC	09	04	1,000	Trial production started in Oct. 2009.
Qinzhou	Petrochina	10	01	1,000	Mechanical construction almost completed.
Zhenhai	Sinopec	10	01	1,000	Mechanical construction almost completed.

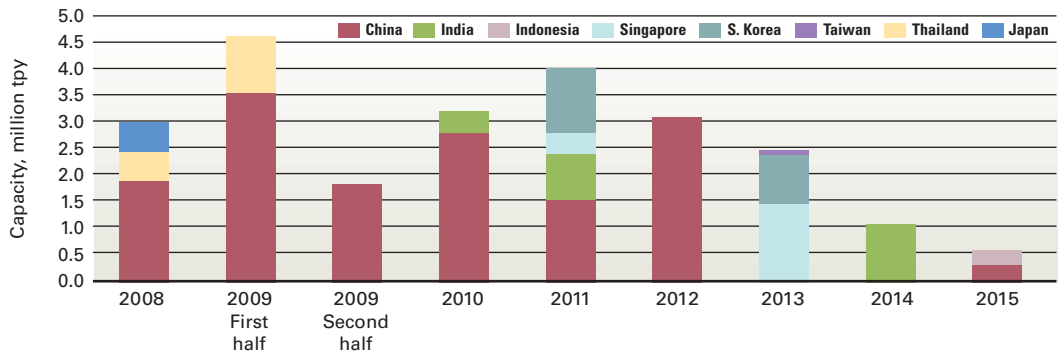
ASIA-PACIFIC: AROMATICS CAPACITY

Fig. 4



ASIA-PACIFIC: AROMATICS ADDITIONS

Fig. 5



ADDED MIDEAST ETHYLENE CAPACITY, JULY 2009-JUNE 2010

Table 3

Country	Company	Location	Year	Qtr.	Ethylene capacity, 1,000 tpy	Note
Saudi Arabia	Petro Rabigh	Rabigh	09	2	1,300	Commissioned and running.
Saudi Arabia	Yansab	Yanbu	09	3	1,300	Commissioned and running.
Kuwait	Equate 2	Shuaiba	09	4	850	Commenced production.
Saudi Arabia	Sharq	Al Jubail	10	1	1,300	Might get delayed to second quarter
Iran	NPC No. 5, Morvarid PC	Assaluyeh	10	1	540	Unit commissioned; start-up expected soon.
Qatar	Ras Laffan Olefins	Ras Laffan	10	1	1,300	On schedule.

its naphtha cracker unit at its refinery in Panipat, Haryana. This will produce 857,000 tpy of ethylene and is expected to be commissioned by third-quarter 2010.

In the longer-term key projects include:

• RIL plans to integrate its new 580,000-b/d refinery with a petrochemical complex. The proposed ethylene production capacity is 1.4 million tpy. The cracker will come on stream by 2014. The petrochemical plant will not run on naphtha but use refinery offgases and LPG.

• ONGC PetroAddition Ltd., a joint venture of India's state-owned upstream major ONGC (26%), GSPC (5%), and a few financial institutions, is setting up a petrochemical complex at Dahej in Gujarat state. This will consist of a cracker unit with an ethylene production capacity of 1.1 million tpy that will run on dual feed. The complex should be completed by third-quarter, 2013 but with large cost over runs.

India is not boosting its ethylene capacity as fast as China, and the government expects a shortfall of 5 million tpy of ethylene by 2012.

Will success continue?

FGE believes that the near-term large capacity additions in the Middle East and China will sharply affect the market.

By September 2010 ethylene capacity in China and the Middle East will increase by 5.1 million tpy and 6.5 million tpy, respectively (Tables 2 and 3). Long-term prospects for East Asian petrochemical players look bright. This will entirely depend, however, on the pace at which economies grow and especially the robustness of Chinese demand.

Asian aromatics

Asian aromatics (benzene, toluene, and xylene) production capacity is growing more slowly than its ethylene counterpart (Figs. 4 and 5). FGE expects the Asian aromatics production capacity to increase by about 26% by 2016 with China alone accounting for 59% of those additions.

Two large Chinese aromatics plants

came on line in 2009:

1. Locally owned Fujia Dahua Petrochemicals started commercial production from its 1.1-million-tpy aromatics plant (300,000 tpy benzene and 800,000 tpy xylene).

2. Along with its 240,000-b/d Huizhou refinery, CNOOC started its 1.56 million tpy aromatics plant (360,000 tpy benzene, 200,000 tpy toluene, and 1 million tpy paraxylene). More aromatics plants are to come on line in China in the next few years.

With Jurong Aromatics Corp. and the ExxonMobil expansions, Singapore will nearly double its aromatics capacity. In South Korea the Hyundai/Cepsa and S-Oil developments will add to the country's aromatics capacity.

KuoKuang Petrochemical Technology Co. (KPTC), Taiwan, plans to add a 1.45-million-tpy aromatics plant to the planned refinery to create a refinery and petrochemical complex. This greenfield project is to be completed by 2017.

These projects will target growing markets such as China.

Japan has added 580,000 tpy of aromatics capacity (410,000 tpy paraxylene and 170,000 tpy benzene production capacity) through the Kashima condensate splitter-based project. Japan also started trial operation of the 34,000-b/d Mizushima condensate splitter in August 2009.

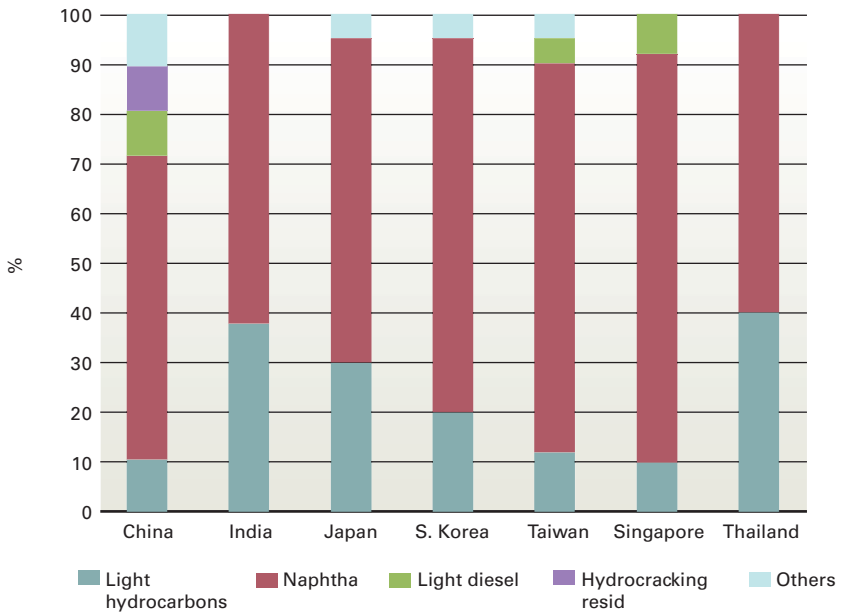
Unlike in some other Asia Pacific countries, projects in Japan specifically target integration with refineries. Japan has adopted this rationale in order to offset declining fuel demand.

India's current aromatics production capacity stands at a little more than 3.6 million tpy with plans to add another 2.6 million tpy of capacity by 2015. The government is aware that healthy growth in the population combined with rising robust demand for textiles, plastics, vehicles, and other consumer goods will help drive growth in India.

Therefore, its petrochemical policies focus on supporting demand and capacity growth. The government has allowed 100% foreign direct investment in petrochemical projects and established several petroleum, chemicals, and petrochemical investment regions and special economic zones to promote investments and make India a petrochemical hub.

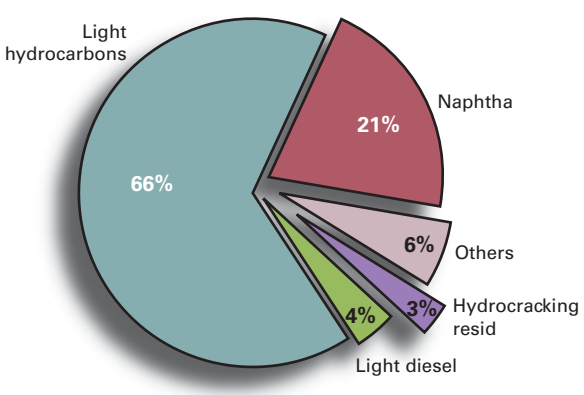
ETHYLENE PLANT FEEDSTOCK FLEXIBILITY

Fig. 6



ASIAN ETHYLENE PLANT FEEDSTOCKS

Fig. 7



Asian naphtha demand

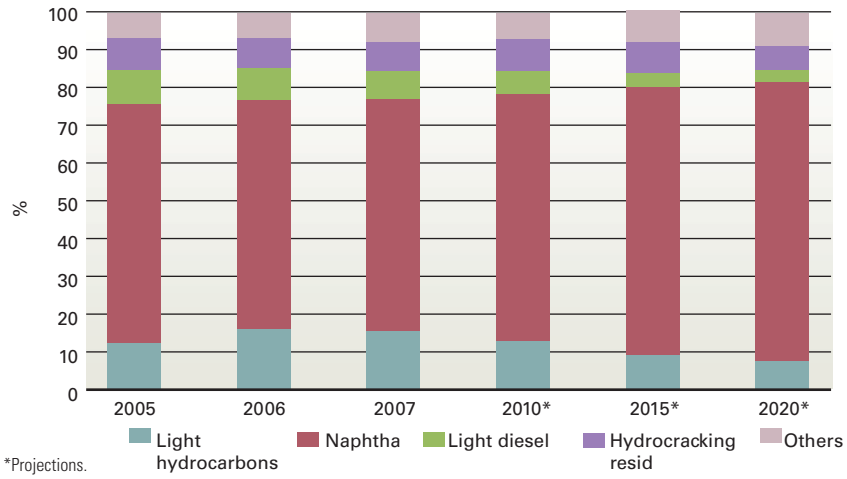
Most ethylene plants in Asia are naphtha based (Figs. 6 and 7). Therefore, changes in the petrochemical sector will affect naphtha demand. Most of the new Chinese ethylene plants will be naphtha based (Fig. 8).

FGE expects naphtha's share as an ethylene feedstock to rise to 71% from 61%. This takes into account China's intention to maximize use of chemical feed from existing refineries rather than naphtha imports, thus allowing other heavier oil products to be used as petrochemical feedstock. In the next decade, as the planned ethylene plants come on line, there is no doubt that the Chinese demand will drive the Asia Pacific naphtha demand (Figs. 9 and 10).

Asian naphtha consumption 1995-2008 exhibited growth of 112%. The dominant use of naphtha in Asia is as a petrochemical feedstock. Paraffinic naphtha is used mostly for olefins

CHINA ETHYLENE FEEDSTOCK

Fig. 8



*Projections.

and heavy (N+A) naphtha for aromatics production.

After 25 continuous years of growth, Asian naphtha consumption fell (–1.4%) in 2008, the result of the dramatic slowdown of the petrochemical sector in fourth-quarter 2008 associated with the global financial crisis.

The petrochemical sector bounced back strongly in 2009, especially in second quarter. The naphtha crackers in South Korea as well as Formosa Petrochemical Corp.'s crackers in Taiwan were running full in second-quarter 2009. This turnaround can be attributed to:

- Ethylene capacity that came on line in first-half 2009 being much lower than initially expected.
- The slow start and ramp up of new ethylene plants in the Middle East.
- China's stimulus package that lifted polymer demand in China.

In the future, naphtha will remain the primary feedstock for Asian petrochemical plants. With massive capacities coming on stream within the next year in China and the Middle East, however, FGE expects that Taiwan's, South Korea's, and Japan's crackers will be forced to run at a lower rate in the near term.

Based on these observations, FGE forecasts little change in naphtha demand in 2010 year-over-year. During 2011-15, however, FGE expects Asia-Pacific naphtha demand to pick up and average 4.6%/year, with China leading the way.

Country focus

In 2008, South Korea overtook Japan as the largest naphtha consumer in Asia. With development of the petrochemical sector in South Korea, its naphtha consumption climbed steeply but is now leveling off.

Its total naphtha demand in 2008 was 844,000 b/d and will increase in 2009 to 871,000 b/d. In 2010, however, FGE anticipates a drop in demand of around 5% to 825,000 b/d. For 2011-15, FGE expects South Korea's naphtha demand to grow at a 2.9%/year, to reach 954,000 b/d in 2015.

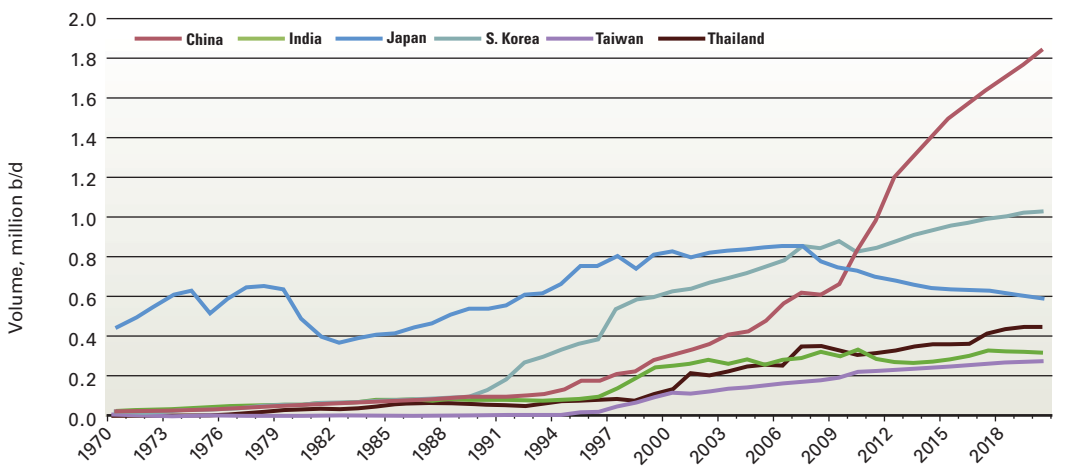
Japan is a large but declining consumer. Its naphtha demand in 2008 was 779,000 b/d, down by 8.3% from 2007. Japan's naphtha demand will decline at 2.8%/year 2008-15.

As with so much else, China will drive naphtha demand in Asia-Pacific. In 2008, its naphtha demand was 605,000 b/d, and it was a net exporter at 17,000 b/d. In 2009, estimated Chinese naphtha demand increased by 10%, to 665,000 b/d, and the country became a net importer. Between January-September 2009, China's net naphtha imports totaled about 40,000 b/d.

China's naphtha demand will grow at 14%/year 2009-15 and will overtake South Korea to become Asia's largest naphtha consumer by yearend 2011. China's net imports will rise to 240,000 b/d from 18,000 b/d by yearend 2012, rising further to 370,000 b/d by yearend 2015.

MAJOR ASIA-PACIFIC NAPHTHA CONSUMERS

Fig. 9



Taiwan's naphtha consumption pattern has been similar to South Korea's from 2001, but the growth rate was less pronounced. Taiwanese demand is also leveling off.

In 2008, Taiwanese naphtha demand was 350,000 b/d. In 2009, its estimated demand decreased by 5% and will drop by 8% in 2010. For 2011-15, naphtha demand will grow at 4%/year.

India is not a large naphtha consumer (317,000 b/d in 2008) nor does the country import large quantities (125,000 b/d). But it is a key player in the region because of its exports. In 2008, India exported 188,000 b/d of naphtha.

The country is also unique because naphtha is used as a swing fuel by the country's power and fertilizer producers to run their units when natural gas is unavailable and LNG is expensive. This is changing with the arrival of RIL's KG-D6 gas (OGJ Online, May 5, 2009), which is mainly directed to the power sector. India will thus emerge as a key exporter of naphtha.

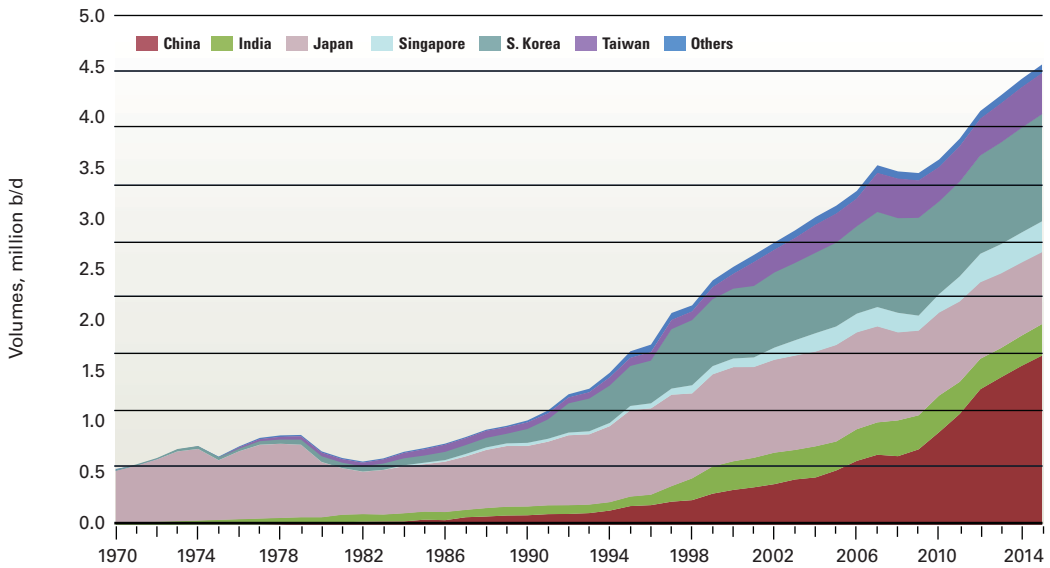
FGE expects India's naphtha demand to decline at 1.8%/year 2008-15 largely due to substitution by gas in power and fertilizer sectors. During this period, India's exports will rise at 7.6%/year, reaching 314,000 b/d, and imports will drop to 45,000 b/d by 2015. A drop in demand coupled with a rise in naphtha production due to increasing refining capacity drives this trend.

Overall, naphtha imports into Asia-Pacific will increase to around 1.05 million b/d in 2012 and 1.3 million b/d in 2015 from 995,000 b/d in 2008. China will be the front-runner.

China, Japan, South Korea, and Taiwan, due to their dependence on naphtha, will remain exposed to the market volatilities associated with this product. In order to protect themselves from high naphtha prices, Japan, South Korea, and Taiwan have tried to revamp their naphtha crackers to achieve greater flexibility to use more LPG as feedstock. ✦

ASIA-PACIFIC NAPHTHA DEMAND

Fig. 10



The authors

Liutong Zhang (L.Zhang@FGEnergy.com) is a senior analyst, East Asia Information and Analysis Group in the Singapore office of Facts Global Energy. Before joining FGE, Liutong worked briefly as a market and strategy analyst with Standard Chartered. At FGE, he covers the downstream Asia-Pacific oil and gas sector, focusing on Taiwan and China. In addition, Liutong conducts in-depth research and analysis on the refining and petrochemical sectors. Liutong holds a bachelor's in chemical engineering with First Class honors from the National University of Singapore.

Praveen Kumar (P.Kumar@FGEnergy.com) is a senior consultant and head of the South Asia Oil and Gas Team for Facts Global Energy, Singapore. Before joining FGE, he worked briefly as a consulting engineer specializing in modeling. At FGE, Praveen has participated in projects dealing with refinery investment, LNG sourcing, strategic planning, market feasibility studies, storage, and product quality. His research focuses mainly on the downstream oil and gas industry pertaining to the Indian subcontinent that includes demand forecasting and pricing projections as well as in-depth refinery analysis. Praveen completed his PhD and MSc (2007) from Queen Mary, University of London and a bachelor's in chemical engineering from the Institute of Chemical Technology, Mumbai (formerly known as UDCT). He is a member of the Society of Chemical Industry and the Institute of Materials, Minerals and Mining.

Europe pursues Baltic transit debottlenecking

Vlad Popovici
Toronto

The Baltic Sea region's role on Europe's energy map will grow in the near future. The Baltic accounts for more than 15% of global cargo transportation.[1]

But it is also a fragile environment. It is a shallow (average depth 50 m compared with 1,300 m for the Black Sea and 1,500 m for the Mediterranean) and almost closed body of water; only 3% of its water is exchanged each year with the neighboring North Sea.[2]

Faced with the growing use of the sea as a transit route and accompanying logistical difficulties, the EU has adopted a more coherent strategic approach for the region than it did for the similar transportation bottleneck in the Black Sea region. This article examines the recent evolution of oil and gas shipment in the Baltic region before discussing measures currently being considered by the EU to implement critical gas infrastructure projects proposed by the Baltic Energy Market Interconnection Plan among other initiatives.

Pursuing these initiatives is especially important during periods of economic crisis or slowdown when it's easier to put projects on hold, despite their long-term strategic importance. The EU should develop a regional energy dialogue with the main oil and gas supplier in the Baltic Sea region, the Russian Federation, by including it in the implementation of its Baltic Sea regional strategy. A regional EU-Russia energy dialogue forum would allow the parties better to address future developments in regional oil and gas transportation.

BALTIC PIPELINE SYSTEM (BTS) Fig. 1

Energy trends

The opening by the Russian Federation of new oil export markets around the world and the diversion of some of the oil previously exported through the Druzhba system to the Baltic port of Primorsk increased oil traffic in the Gulf of Finland—the eastern part of the Baltic Sea—by 400% between 1995 and 2005.[2] In 2007, 170 million tonnes of oil moved through the Baltic Sea compared with 80 million tonnes in 2000.[1]

In 2001 Transneft completed the Baltic Pipeline System (BTS), aimed at exporting oil directly from the Russian Baltic port of Primorsk instead of transiting and reexporting it through other countries such as Belarus, Lithuania, or Latvia. The BTS pipeline reached its 65-million tonne/year (tpy) design capacity in 2006.

Oil tanker transit pressure in the Baltic Sea will only increase in the near future, given the June 2009 beginning of construction of the 50-75 million tpy Baltic Pipeline System 2 (BTS 2).[1] The pipeline will transport oil to the Baltic export terminal in Ust-Luga and to the Kirishi refinery (Fig. 1). When BTS 2 reaches design capacity in September 2013 it could increase Baltic Sea oil transit to 200-220 million tpy.

Another project, supported mainly by Ukraine and Poland, would expand the Odessa-Brody pipeline through Plock to the Baltic port of Gdansk, Poland, to bring oil from the Black Sea. This project, if successful, could add

NORD STREAM ROUTE

another 10-20 million tpy to Baltic Sea oil tanker transit.

The European Union already considers the Baltic Sea an oil transportation chokepoint similar to more famous bottlenecks such as the Strait of Hormuz, the Suez Canal, or the Strait of Malacca. The busy oil tanker transit creates environmental risks for the region, the Baltic already suffering 120 ship accidents in 2007.[2]

The Baltic Sea is poised also to become a major natural gas transit region. Nord Stream, a double 1,220-km gas pipeline, will be the first major natural gas pipeline to cross the Baltic Sea and bring Russian gas to the Germany and other European markets.

The first line, with a capacity of 27.5 billion cu m/year is planned for completion in 2011, while the second pipeline, double capacity to 55 billion cu m/year would become operational in 2012 (Fig. 2).

Other international gas pipeline projects crossing the Baltic Sea are in different stages of planning, including the BalticPipe (Denmark to Poland) and Baltic Connector (Finland-Estonia) pipelines, and no less than five LNG terminals in Finland, Estonia, Latvia, Lithuania, and Poland.[3]

The amount of coordination and cooperation needed during the planning of the first phase of the Nord Stream project due to its political, legal and, environmental complexity highlights the problems faced by future similar pipeline projects in the region. A recent European Union study stated that eventual LNG shipping in the Baltic Sea remains legally uncertain. The study also concluded LNG shipping in the Baltic Sea would increase bottlenecks for an already busy shipping region.[4]

The natural gas consumption of most Baltic countries—with the notable exception of Sweden, which wants to move away from all fossil fuels—has increased and is forecast to continue to growing, especially given the EU's strong policy agenda promoting the use of natural gas as a relatively less polluting fossil fuel than oil or coal. Natural gas consumption in Poland, as an example, is forecast to increase to around 20-22 billion cu m/year in 2030 from current levels around 13-15 billion cu m/year.[5]

The EU has also strongly supported liberalization and opening of national gas markets to create EU-wide energy markets instead. Its policy efforts, however, are less advanced in the oil market and oil transportation. The historical development of their oil and gas transportation networks has kept Finland, Estonia, Latvia, and Lithuania essentially isolated from the wider EU oil and gas transportation systems,[2] limiting liberalization and creating supply and price risks.

EU strategy

As early as the 1990s, the EU moved to address some of its infrastructural shortcomings through regional initiatives and action plans, as well as

PROPOSED OIL, GAS PIPELINE PROJECTS; BALTIC SEA REGION

Name	Route	Capacity	Length, km	Main proponents, shareholders	Comments
Oil					
Baltic Pipeline System 2 (BTS-2)	Unecha-Ust Luga, Russia	50-70 million tonnes/year	1,170	Transneft	Under construction.
Sarmatia Pipeline (Odessa-Brody extension)	Brody, Ukraine-Plock-Gdansk, Poland	10-20 million tonnes/year	800	Sarmatia International Pipeline Co.	Planned. Would bring oil from Black Sea to Baltic Sea.
Gas					
Nord Stream	Vyborg, Russia-Greifswald, Germany	55 billion cu m/year	1,220, two parallel pipelines	Nord Stream AG	First line to be built 2010-11, second 2011-12.
Skanled	Norway-Sweden-Denmark	>7 billion cu m/year	—	Managed by Gassco with multiple other shareholders	Project suspended April 2009. Norwegian gas to Baltic Sea region.
Baltic Gas Interconnector	Rostock, Germany-Avedore, Denmark-Trelleborg, Sweden	3 billion cu m/year	200	Multiple German, Danish, and Swedish companies	Feasibility study completed, but project on hold.
Amber PolLit	Plonsk, Poland-Budzisko, Lithuanian border	>3 billion cu m/year	330	Gaz-System, Lietuvos Dujos	Onshore pipeline. Open season in 2009 did not attract sufficient interest to move forward.
Baltic Connector	Paldiski, Estonia-Helsinki, Finland	>2 billion cu m/year	100	Gasum Oy	Connect Finnish gas market to EU markets.
Amber Pipeline	Russia-Germany via Estonia, Latvia, Lithuania, and Poland	—	—	System operators in transit countries	Project on hold due to lack of interest in light of Nord Stream.
Germany-Poland interconnection	Sulecin-Brzozowiec	0.63 billion cu m/year	—	EWE AG, EWE Polska	—
Baltic Pipe	Avedore, Denmark-Ploty, Poland	3 billion cu m/year, expandable to 6	320	Gaz-System, Energinet.dk	Project on hold.

through three internal energy market legislative packages. These early initiatives included Baltic 21, a regional process for creating sustainable development in the region through cooperation among different stakeholder categories; Basrec—the Baltic Sea Region Energy Cooperation; and Baltrel, the Baltic Ring Electricity Cooperation Committee.[6] Each sought a regional gas market, the diversification of gas supply sources, and common measures of supply security.

The first energy market legislative package, the Gas Directive of 1998, asked EU countries to partially open gas markets to competition by allowing large users to choose their suppliers in an effort to avoid any discrimination by national gas monopolies.

The second Gas Directive in 2003 required each country to create a transmission system operator (TSO) in charge of operating, maintaining, and developing the national gas transmission pipeline network. By July 2007 all gas customers were able to choose their gas supplier.

The third legislative package, the Internal Energy Market package, approved in 2009, contains a directive on the common internal market for natural gas and regulation of conditions for access to the natural gas transmission networks,[7] pushing liberalization of the national gas markets further toward the creation of an EU-wide market.

The European Council invited the EU Commission in 2007 to present an EU strategy for the Baltic Sea region, approved in June 2009, marking the first time the EU has adopted this type of strategic approach. One of the main action plans of the new regional strategy is the Baltic Energy Market Interconnection Plan.[3] This plan focuses on both the power and gas sectors, its main objectives for the gas sector being to support projects connecting the Baltic energy markets to EU markets, increase the security of supply, and diversify supply sources.

Specific objectives for gas infrastructure development are:

- Ending the energy isolation and decrease dependence on a single external gas supplier of Finland, Estonia, Latvia, Lithuania, and Poland.
- Defining and strengthening Poland's role as an energy bridge to the other countries. Supply to Poland from Germany, Denmark, or LNG is necessary to move it further to eastern Baltic Sea nations.
- Assessing LNG's potential for diversifying supply sources in the Baltic Sea region.
- Compensating for the decline in the Danish gas reserves and providing new gas sources to Denmark and Poland, through new infrastructure projects in the West Baltic Sea region.[3]

The Ramboll report, delivered in preparation for the EU Strategy for the Baltic Sea Region meetings, identified several missing links in the regional gas infrastructure, including the following:

- Finland to another EU member state. With plans for establishing a gas network in Sweden halted, however, the only short-term solution seems to be a connection to Estonia such as the Baltic Connector.
- Estonia, Latvia, or Lithuania to one

of the member states already interconnected to the other EU markets, Poland or Germany.

- Norway to Denmark or Norway to Sweden, diversifying gas supply with Norwegian imports.
- Denmark to Poland.
- Germany to Sweden.[8]

The solutions proposed include new pipelines (see table), a number of which were put on hold due to the effects of the global economic crisis on gas demand and potential financing. Skanled, for instance, which would have brought Norwegian gas to the Baltic was suspended in April 2009.

Proposed solutions also included increased capacity through existing pipeline interconnections; reversed flow in the existing pipelines, such as Yamal-Europe and LNG terminal in the Baltic Sea; and new gas storage projects, especially in Latvia, Lithuania, Poland, and Germany.

The European Union is also assessing measures for creating a more coherent policy framework to address present and future oil transportation problems. The Oil Infrastructures report[1] recommends the EU develop an oil dimension to its energy policy instruments (currently including only electricity and gas) so it can better coordinate development of an EU-wide oil infrastructure and better manage future oil bottlenecks such as the Baltic Sea region.

The report also recommends including oil infrastructure projects in the Trans-European Networks-Energy program, providing selected projects with political support and financing. Another recommendation is to develop a more coherent EU-wide dialogue with the major oil suppliers, including Russia. ✦

References

1. Commission of the European Communities, "Oil Infrastructures—An assessment of the existing and planned oil infrastructures within and towards the EU," Commission Staff Working Document accompanying the Green Paper—Towards a secure, sustainable and competitive European energy network, 2008.
2. Commission of the European Communities, "Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and Committee of the Regions concerning the European Union Strategy for the Baltic Sea Region," COM(2009) 248 final, 2009.
3. Commission of the European Communities, "Baltic Energy Market Interconnection Plan—final report of the HLG," EU Energy Directorate, 2009.
4. Clingendael International Energy Programme (CIEP), "The Geopolitics of EU Gas Supply: The role of LNG in the EU gas markets, Part IIA/DMV," The Hague, 2008.
5. Upstream Online, "Poland pushes ahead with shale plans," Jan. 27, 2010.
6. Baltic Development Forum, Energianalyse a/s, "Energy Perspectives of the Baltic Sea Region—Interim Report," 2009.
7. Havris, C., "Competition and Regulation in the EU Energy Market," Romanian Journal of European Affairs, Vol. 9, No. 4, 2009.
8. Ramboll, "Future Development of the Energy Gas Market in the Baltic Sea Region—Final Report," prepared for EU Commission DG TREN C1, June 2009.

The author

Vlad Popovici (VPopovici@BrederoShaw.com) is marketing manager at a major Canadian energy services company with global business coverage. He currently manages multiple economic and strategic assessments of pipeline projects worldwide. Popovici holds an MBA (2005) from McGill University in Montreal and has been publishing technical articles and economic analyses since 1996.

Equipment/Software/Literature

New tool sizes, detects corrosion features in pipelines

The GEMINI system is a new range of combo tools that provide caliper, metal loss, and mapping information in a single tool.

The tool uses an active speed control with a gas bypass capability to run in high-speed gas pipelines to obtain corrosion and deformation information without restricting gas flow or line speed. It allows pipeline operators to accurately size and detect corrosion features using triaxial sensor technology.

In addition to sizing and detecting corrosion features, the design of the tool sensors effectively detects cracks in dents and other mechanical damage, including wrinkles, gouging, and metal loss within dents.

The tool also sizes and detects dents in the pipeline.

Source: **BJ Services Co.,** Box 4442, Houston, TX 77210-4442.

Services/Suppliers

Transocean Ltd.,

Zug, Switzerland, has named Steven L. Newman CEO. He succeeds Robert L. Long, who is retiring. Newman is a candidate for the Transocean board. He previously served as president and COO since May 2008. Prior to that, Newman was executive vice-president of performance; EVP and COO; senior vice-president of human resources, information process solutions, and treasury; and vice-president of performance and technology. He also has served in international field and operations management positions, including project engineer, rig manager, division manager, region marketing manager, region operations manager, and region manager.

Newman

Transocean is the world's largest offshore drilling contractor and a leading provider of drilling management services worldwide.

John Zink Co. LLC,

Tulsa, has named Jim Goodman president. He replaced Steve Pirnat, who left the company in 2009. Previously, Goodman was COO since 2002. He joined the company in 1990. Prior to that, Goodman worked for a number of companies supplying process equipment to the petroleum and petrochemical industries. He has a bachelor's in mechanical engineering from the University of Oklahoma.

John Zink, a unit of Koch Chemical Technology Group, provides advanced combustion systems and related technologies worldwide.

Enerji Ltd.,

Perth, has appointed Samantha Tough nonexecutive director. Previously, she was project director for the Pilbara power project in Western Australia, in consultation to the Western Australian government to deliver a cooperative framework for government and industry to meet the expanding power requirements in the Pilbara region. She also has served as director of strategy at Hardman Resources; general manager, North West Shelf, Woodside Energy; and deputy CEO at Plexus International Ltd.

Enerji develops microgeneration power projects that generate and sell power onsite from low-grade waste heat from processing plants, transmission pipeline compression stations, fossil fuel power plants, and other industrial facilities.

GulfMark Offshore Inc.,

Houston, has completed its reorganization through merger with its former parent of the same name ("Old GulfMark"). The company changed its name from "New GulfMark Offshore Inc.," and Old GulfMark common shares were converted into GulfMark Class A common stock. The reorganization was intended to help preserve the company's status as a US citizen under the Jones Act by imposing certain ownership and transfer restrictions on the Class A common stock. The company's assets, liabilities, and executive leadership remain unchanged.

GulfMark provides marine transportation services to the energy industry through a fleet of offshore support vessels serving every major offshore market in the world.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	2-19 2010	2-12 2010	2-19 2010	2-12 2010	2-19 2010	2-12 2010	*2-20 2009
	1,000 b/d						
Total motor gasoline	689	1,160	20	8	709	1,168	826
Mo. gas. blending comp.	493	881	20	8	513	889	685
Distillate	391	630	0	0	391	630	477
Residual	357	402	16	174	373	576	464
Jet fuel-kerosine	47	63	17	46	64	109	23
Propane-propylene	79	312	15	8	94	320	154
Other	109	(354)	99	56	208	(298)	75
Total products	**2,165**	**3,094**	**187**	**300**	**2,352**	**3,394**	**2,704**
Total crude	**7,542**	**7,253**	**1,006**	**1,089**	**8,548**	**8,342**	**8,793**
Total imports	**9,707**	**10,347**	**1,193**	**1,389**	**10,900**	**11,736**	**11,497**

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

Purvin & Gertz LNG netbacks—Feb. 26, 2010

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.53	5.56	6.68	5.45	5.98	6.60
Everett	4.67	2.51	4.30	2.59	3.05	4.96
Isle of Grain	3.83	1.43	3.10	1.33	1.99	3.15
Lake Charles	2.49	0.56	2.24	0.73	0.96	3.14
Sodegaura	5.72	8.11	5.97	7.80	7.06	5.03
Zeebrugge	6.54	4.64	6.08	4.59	5.30	6.12

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	13,101	62,079	44,124	9,832	61,693	13,476	2,805
PADD 2	81,313	56,648	27,877	8,368	31,840	1,257	12,282
PADD 3	177,901	74,249	44,425	13,789	43,855	18,866	14,012
PADD 4	15,449	6,179	1,996	500	3,388	199	[1]918
PADD 5	46,739	32,910	28,416	10,187	12,479	4,053	—
Feb. 19, 2010	**334,503**	**232,065**	**146,838**	**42,676**	**153,255**	**37,851**	**30,017**
Feb. 12, 2010	**331,418**	**230,445**	**144,740**	**42,374**	**156,192**	**39,431**	**32,588**
Feb. 20, 2009[2]	**350,630**	**218,664**	**125,195**	**40,957**	**140,752**	**36,320**	**40,012**

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

Refinery report—Feb. 19, 2010

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,151	1,139	2,212	66	356	61	48
PADD 2	3,362	3,339	1,995	194	920	40	249
PADD 3	6,698	6,572	2,469	593	1,604	306	650
PADD 4	486	492	309	24	152	4	[1]51
PADD 5	2,410	2,230	1,443	399	401	131	—
Feb. 19, 2010	**14,107**	**13,772**	**8,428**	**1,276**	**3,433**	**542**	**998**
Feb. 12, 2010	**13,993**	**13,590**	**8,807**	**1,219**	**3,413**	**579**	**1,069**
Feb. 20, 2009[2]	**14,497**	**14,143**	**8,765**	**1,296**	**4,147**	**519**	**1,077**
	17,688 Operable capacity		**79.8% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*2-26-10	*2-27-09	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	86.46	50.68	35.78	70.6
Brent crude	76.25	42.70	33.55	78.6
Crack spread	10.21	7.98	2.23	27.9
FUTURES MARKET PRICES				
One month				
Product value	86.55	50.38	36.17	71.8
Light sweet crude	79.37	42.18	37.19	88.2
Crack spread	7.18	8.20	–1.02	–12.5
Six month				
Product value	90.16	54.47	35.69	65.5
Light sweet crude	81.14	48.74	32.40	66.5
Crack spread	9.03	5.73	3.29	57.5

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

OGJ GASOLINE PRICES

	Price ex tax 2-24-10	Pump price* 2-24-10	Pump price 2-25-09
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	226.3	257.7	193.7
Baltimore	221.8	263.7	191.7
Boston	217.8	259.7	189.8
Buffalo	211.9	275.1	195.7
Miami	221.9	274.8	192.8
Newark	224.7	257.6	184.7
New York	210.0	273.2	182.0
Norfolk	217.4	255.1	184.7
Philadelphia	217.9	268.6	198.8
Pittsburgh	216.5	267.2	208.7
Wash., DC	227.3	269.2	207.9
PAD I avg	219.4	265.6	193.7
Chicago	236.4	291.5	209.2
Cleveland	235.1	281.5	192.2
Des Moines	216.1	256.5	184.2
Detroit	231.9	283.5	191.2
Indianapolis	224.4	274.5	190.2
Kansas City	215.8	251.5	178.2
Louisville	223.6	264.5	187.1
Memphis	214.1	253.9	176.2
Milwaukee	221.2	272.5	188.2
Minn.-St. Paul	210.9	256.5	182.2
Oklahoma City	196.1	231.5	167.1
Omaha	209.8	255.5	178.2
St. Louis	207.8	243.5	175.2
Tulsa	194.1	229.5	170.2
Wichita	198.1	241.5	174.2
PAD II avg	215.7	259.2	182.9
Albuquerque	214.3	251.5	185.1
Birmingham	211.2	250.5	183.1
Dallas-Fort Worth	206.1	244.5	180.2
Houston	208.1	246.5	176.1
Little Rock	202.3	242.5	187.6
New Orleans	212.2	250.6	183.6
San Antonio	216.1	254.5	182.0
PAD III avg	210.1	248.7	182.5
Cheyenne	220.0	252.4	173.2
Denver	235.0	275.4	186.7
Salt Lake City	214.5	257.4	188.2
PAD IV avg	223.2	261.7	182.7
Los Angeles	224.7	290.5	214.8
Phoenix	234.2	271.6	199.3
Portland	240.2	283.6	224.3
San Diego	225.8	291.6	230.3
San Francisco	227.8	293.6	235.3
Seattle	230.7	286.6	224.2
PAD V avg	230.5	286.2	221.4
Week's avg.	**218.4**	**263.2**	**191.1**
Feb. avg.	**219.9**	**264.7**	**189.6**
Jan. avg.	**224.9**	**269.7**	**177.1**
2010 to date	**222.9**	**267.7**	—
2009 to date	**137.7**	**183.3**	—

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

REFINED PRODUCT PRICES

	2-19-10 ¢/gal		2-19-10 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	208.65	New York Harbor	205.82
Gulf Coast	207.15	Gulf Coast	203.57
Los Angeles	203.65	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	201.41	ARA	203.21
Singapore	209.05	Singapore	199.76
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	207.65	New York Harbor	169.36
Gulf Coast	207.40	Gulf Coast	176.26
Los Angeles	209.65	Los Angeles	175.26
		ARA	171.54
		Singapore	175.92

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

BAKER HUGHES RIG COUNT

	2-26-10	2-27-09
Alabama	4	2
Alaska	11	11
Arkansas	42	50
California	26	24
Land	25	23
Offshore	1	1
Colorado	48	62
Florida	1	0
Illinois	2	1
Indiana	0	1
Kansas	17	16
Kentucky	8	11
Louisiana	209	144
N. Land	137	71
S. Inland waters	14	5
S. Land	18	23
Offshore	40	45
Maryland	0	0
Michigan	0	0
Mississippi	11	12
Montana	7	3
Nebraska	2	0
New Mexico	59	39
New York	1	3
North Dakota	84	58
Ohio	7	8
Oklahoma	111	120
Pennsylvania	67	25
South Dakota	0	0
Texas	565	538
Offshore	4	5
Inland waters	0	0
Dist. 1	22	10
Dist. 2	20	18
Dist. 3	39	46
Dist. 4	50	46
Dist. 5	77	115
Dist. 6	76	94
Dist. 7B	7	16
Dist. 7C	55	39
Dist. 8	113	64
Dist. 8A	24	19
Dist. 9	35	20
Dist. 10	43	46
Utah	24	26
West Virginia	24	25
Wyoming	37	49
Others—HI-1; NV-4; TN-1	6	15
Total US	**1,373**	**1,243**
Total Canada	**576**	**394**
Grand total	**1,949**	**1,637**
US Oil rigs	456	260
US Gas rigs	905	970
Total US offshore	46	52
Total US cum. avg. YTD	**1,295**	**1,450**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	2-26-10 Percent footage*	Rig count	2-27-09 Percent footage*
0-2,500	115	6.9	46	—
2,501-5,000	51	64.7	66	49.2
5,001-7,500	128	23.4	173	51.5
7,501-10,000	253	6.3	261	20.2
10,001-12,500	288	7.9	247	3.0
12,501-15,000	220	1.3	240	2.8
15,001-17,500	175	—	134	0.4
17,501-20,000	76	—	73	—
20,001-over	49	—	41	—
Total	**1,355**	**8.3**	**1,281**	**6.6**
INLAND	13		16	
LAND	1,295		1,215	
OFFSHORE	47		50	

*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]2-26-10	[2]2-27-09
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	713	679
California	646	639
Colorado	67	65
Florida	5	2
Illinois	25	25
Kansas	114	111
Louisiana	1,456	1,352
Michigan	17	16
Mississippi	63	62
Montana	86	81
New Mexico	163	161
North Dakota	230	192
Oklahoma	185	178
Texas	1,442	1,374
Utah	67	66
Wyoming	148	142
All others	71	81
Total	**5,519**	**5,247**

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

US CRUDE PRICES

	2-26-10 $/bbl*
Alaska-North Slope 27°	70.46
South Louisiana Sweet	80.75
California-Midway Sunset 13°	72.20
Lost Hills 30°	80.15
Wyoming Sweet	70.66
East Texas Sweet	75.75
West Texas Sour 34°	71.25
West Texas Intermediate	76.25
Oklahoma Sweet	76.25
Texas Upper Gulf Coast	69.25
Michigan Sour	68.25
Kansas Common	75.00
North Dakota Sweet	69.50

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	2-19-10
United Kingdom-Brent 38°	73.75
Russia-Urals 32°	72.88
Saudi Light 34°	72.80
Dubai Fateh 32°	73.83
Algeria Saharan 44°	74.84
Nigeria-Bonny Light 37°	75.48
Indonesia-Minas 34°	77.08
Venezuela-Tia Juana Light 31°	74.69
Mexico-Isthmus 33°	74.58
OPEC basket	74.33
Total OPEC[2]	73.50
Total non-OPEC[2]	73.40
Total world[2]	73.46
US imports[3]	72.87

[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]

	2-19-10	2-12-10 bcf	2-19-09	Change, %
Producing region	607	673	725	**–16.3**
Consuming region east	935	1,030	886	**5.5**
Consuming region west	311	322	298	**4.4**
Total US	**1,853**	**2,025**	**1,909**	**–2.9**
	Nov. 09	**Nov. 08**	**Change, %**	
Total US[2]	**3,833**	**3,346**	**14.6**	

[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

	Dec. 2009	Nov. 2009	12 month average production 2009	12 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	Dec. 2009	Nov. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	533	592	599	609	–10	–1.7	105.3	135.8	1,425.06
Bolivia	40	40	40	40	—	–0.5	42.0	40.0	487.00
Brazil	1,999	1,986	1,950	1,813	138	7.6	29.0	31.0	356.00
Canada	2,670	2,720	2,581	2,595	–14	–0.5	478.2	416.6	5,132.90
Colombia	735	725	670	580	91	15.6	35.0	30.0	375.00
Ecuador	460	460	471	498	–27	–5.4	2.0	2.0	24.00
Mexico	2,593	2,553	2,602	2,799	–197	–7.0	213.0	210.0	2,566.38
Peru	114	114	107	82	25	31.1	10.0	10.5	121.50
Trinidad	106	103	107	113	–6	–5.0	127.4	123.2	1,391.52
United States	5,519	5,466	5,314	4,950	365	7.4	1,869.0	1,821.0	22,032.00
Venezuela[1]	2,190	2,200	2,163	2,352	–188	–8.0	70.0	68.0	830.00
Other Latin America	84	83	83	83	—	—	5.5	5.4	65.68
Western Hemisphere	**17,042**	**17,043**	**16,687**	**16,511**	**176**	**1.1**	**2,986.4**	**2,893.6**	**34,807.04**
Austria	17	18	18	17	1	6.7	5.0	4.9	56.10
Denmark	248	241	261	287	–26	–9.0	27.0	25.7	272.74
France	18	18	18	20	–1	–7.1	2.2	2.4	31.08
Germany	50	52	55	60	–5	–8.4	42.0	41.8	507.85
Italy	86	91	83	100	–17	–17.0	22.0	22.0	264.50
Netherlands	20	21	25	34	–8	–24.8	320.0	300.0	2,630.00
Norway	2,073	2,123	2,068	2,180	–112	–5.1	354.7	319.0	3,664.54
Turkey	48	49	46	41	5	11.7	—	—	—
United Kingdom	1,367	1,385	1,348	1,416	–68	–4.8	198.3	178.2	2,203.41
Other Western Europe	5	5	4	4	—	–0.6	2.1	1.6	13.59
Western Europe	**3,932**	**4,002**	**3,926**	**4,157**	**–231**	**–5.6**	**973.4**	**895.6**	**9,643.81**
Azerbaijan	1,100	1,100	1,046	895	150	16.8	70.0	60.0	515.00
Croatia	13	13	14	15	–1	–7.4	5.6	5.4	60.73
Hungary	14	14	14	14	–1	–4.2	7.4	7.1	85.28
Kazakhstan	1,500	1,600	1,348	1,208	140	11.6	110.0	100.0	1,210.00
Romania	90	90	90	93	–3	–2.7	19.0	18.0	222.00
Russia	10,110	10,120	9,917	9,748	169	1.7	1,800.0	1,700.0	18,200.00
Other FSU	400	400	433	408	25	6.1	450.0	450.0	4,150.00
Other Eastern Europe	42	43	43	48	–5	–9.7	18.9	18.8	225.43
Eastern Europe and FSU	**13,269**	**13,380**	**12,905**	**12,429**	**476**	**3.8**	**2,480.9**	**2,359.3**	**24,668.44**
Algeria[1]	1,250	1,240	1,240	1,373	–133	–9.7	245.0	235.0	2,940.00
Angola[1]	1,850	1,880	1,789	1,894	–105	–5.5	6.0	6.0	64.00
Cameroon	70	70	73	84	–11	–12.8	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	640	644	679	–35	–5.2	120.0	115.0	1,445.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.72
Gabon	240	240	229	235	–6	–2.5	0.3	0.3	3.65
Libya[1]	1,520	1,520	1,546	1,724	–178	–10.3	38.0	37.0	447.00
Nigeria[1]	2,010	1,980	1,825	1,944	–119	–6.1	100.0	95.0	1,071.00
Sudan	500	500	500	490	10	2.0	—	—	—
Tunisia	71	75	81	85	–4	–5.2	7.1	8.0	96.63
Other Africa	221	221	221	221	—	—	9.4	8.6	106.40
Africa	**8,958**	**8,951**	**8,734**	**9,314**	**–581**	**–6.2**	**525.8**	**505.0**	**6,174.40**
Bahrain	30	30	30	29	—	1.0	30.0	30.0	324.82
Iran[1]	3,720	3,700	3,734	3,907	–173	–4.4	285.0	275.0	3,415.00
Iraq[1]	2,400	2,370	2,399	2,424	–25	–1.0	25.0	20.0	248.00
Kuwait[1,2]	2,290	2,280	2,275	2,602	–327	–12.6	37.0	35.0	434.00
Oman	810	830	810	718	93	12.9	45.0	45.0	641.00
Qatar[1]	800	770	768	848	–80	–9.4	225.0	215.0	2,647.00
Saudi Arabia[1,2]	8,120	8,220	8,183	9,186	–1,003	–10.9	210.0	210.0	2,573.00
Syria	370	370	371	389	–18	–4.7	18.0	17.0	210.00
United Arab Emirates[1]	2,280	2,270	2,271	2,586	–315	–12.2	135.0	130.0	1,575.00
Yemen	280	280	276	306	–30	–9.7	—	—	—
Other Middle East	—	—	—	—	—	–13.3	8.0	7.4	108.35
Middle East	**21,100**	**21,120**	**21,118**	**22,995**	**–1,877**	**–8.2**	**1,018.0**	**984.4**	**12,176.17**
Australia	449	455	464	464	—	—	128.3	125.0	1,493.58
Brunei	180	170	154	161	–7	–4.3	38.0	35.0	419.36
China	3,793	3,823	3,768	3,803	–35	–0.9	260.0	277.6	2,998.36
India	697	670	665	677	–12	–1.8	136.6	126.2	1,295.93
Indonesia[1]	860	860	857	857	–1	–0.1	200.0	195.0	2,390.00
Japan	19	16	16	17	–1	–6.0	12.0	10.2	121.72
Malaysia	720	700	730	757	–27	–3.5	140.0	130.0	1,645.00
New Zealand	60	52	51	54	–4	–6.6	15.0	13.0	148.90
Pakistan	65	66	64	66	–3	–4.0	129.3	117.9	1,468.02
Papua New Guinea	35	35	37	41	–5	–11.1	1.0	0.9	11.50
Thailand	260	240	240	228	12	5.2	35.5	33.7	411.44
Vietnam	325	325	302	277	25	8.8	20.0	20.0	240.00
Other Asia-Pacific	47	49	48	41	7	17.7	94.5	91.5	1,117.00
Asia-Pacific	**7,510**	**7,461**	**7,394**	**7,443**	**–50**	**–0.7**	**1,210.1**	**1,176.1**	**13,760.81**
TOTAL WORLD	**71,810**	**71,958**	**70,763**	**72,850**	**–2,087**	**–2.9**	**9,194.6**	**8,813.9**	**101,230.66**
OPEC	28,890	28,890	28,665	32,194	–3,529	–11.0	1,378.0	1,328.0	18,368.00
North Sea	3,708	3,772	3,698	3,902	–204	–5.2	675.9	612.8	6,927.25

[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.

Marketplace

DEADLINE for MARKETPLACE ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to MARKETPLACE SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-832-9201, email: glendah@pennwell.com.

- *DISPLAY MARKETPLACE: $390 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 MARKETPLACE: $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 $60.00 No agency commission, no 2% cash discount. Centered/Bold heading, $12.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $85.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN MARKETPLACE SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR MARKETPLACE AD.*

EMPLOYMENT

Private Houston based brine production firm, an Equal Opportunity Employer, seeks drilling engineer. Qualified applicants will possess large bore drilling experience in Gulf Coast salt dome settings, along with experience in deformed and fractured carbonate and evaporite formations, (NY, PA and VA). Experience in solution mining a plus. Petroleum Engineering degree preferred and at least ten years direct experience in all aspects of drilling and workover operations. Please reply to petroleumclassifieds@pennwell.com with A2-22-10 in the subject line

Harvest Natural Resources, Inc. in Houston, TX seeks IM Systems Analyst. Qualified applicants will possess a Bachelor's degree in Computer Science or Information Systems or related engineering and at least five years experience in systems analysis or systems development. To apply, please email resume to resumes@harvestnr.com. Resume must include job code 1212010.

EQUIPMENT FOR SALE

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS:	**10 - 600 MMCFD**
AMINE PLANTS:	**60 - 5000 GPM**
SULFUR PLANTS:	**10 - 1200 TPD**
FRACTIONATION:	**1000 – 15,000 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

UNUSED 6,000 BPD
Crude Distillation Unit w/Utilities
Ready to ship in 2-4 weeks

For details call:
713-477-0201/ext.1609
VENTECH

Marketplace Ads Get Results!

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

REFRIGERATION PLANTS
5 and 12 MMSCFD, 1100, T. H. RUSSELL
4 and 7 MMSCFD, 1000, NATCO
8 MMSCFD, DARENCO, 1-3 MMSCFD PROCESS EQPT.
30 MMSCFD CHAPMAN
J.T. PLANTS
0.5 – 30 MMSCFD
DEHYDRATORS 8" – 36"
5 GPM AMINE
5,000 – 30,000 GALLON LPG TANKS
318-425-2533, 318-458-1874
regardres@aol.com

BUSINESS OPPORTUNITIES

WANTED:
Operated properties in Oklahoma (Kingfisher, Canadian, Grady and McClain Counties). Buyer is willing to pay a premium for the right package (non-operated or operated). For inquiries please call 262-248-1998 or fax 262-248-2027.

Have 300 Million Barrels of Oil
Shallow, recoverable, ready to go.
Need financial partner.
503-253-7400, Fax 503-253-8888
Email: diamonda@teleport.com

CONSULTANT

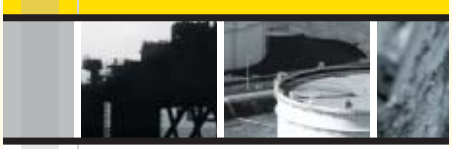
Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment-120 specialists upstream, downstream gas and biofuels.
Email: contato@expetro.com.br
Web: www.expetro.com.br-Rio de Janeiro, Brazil

LEASE

224 acre Goliad County, Texas, lease available to drill or rework. Production profitable. Great $$$$ area. 713-659-4463, BA.Explore@att.net.

Oil Gas Lease available on 480 acres in Divide County ND. Contact Bardal@verizon.net, 817-431-8104.

OIL&GAS JOURNAL
Site License



SOUND KNOWLEDGE.
SOUND BUSINESS DECISIONS.

An Oil & Gas Journal Site License gives your employees access to industry information they need to make tough business decisions.

For more information, contact:

Matt Dresher | *U.S. Site License Sales*
E : : mattd@pennwell.com
P : : (918)831-9539

Leo Wolfert | *International Site License Sales*
E : : leow@pennwell.com
P : : +44 1992 656 654

Marketplace

WANTED MINERALS

WANTED
Producing minerals,
Royalties & Overrides
1-150 million $
Contact
Charles Ferrell
FERRELLOIL CO., LLC
P.O. Box 1177
Okla. City, OK 73101-1177
(405) 606-8380
Fax (405) 606-8318
ferrelloil@cbsokc.com

Advertising Sales / Advertisers Index

Houston
U.S. Sales Manager, Marlene Breedlove; Tel: (713) 963-6293, E-mail: marleneb@pennwell.com. Regional Sales Manager, Mike Moss; Tel: (713) 963-6221, E-mail: mikem@pennwell.com. PennWell - Houston, 1455 West Loop South, Suite 400, Houston, TX 77027. Fax: (713) 963-6228

South/Southwest /Texas/Northwest / Midwest / Alaska
Marlene Breedlove, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com

Northeast / Texas/Southwest
Mike Moss, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6221, Fax: (713) 963-6228; E-mail: mikem@pennwell.com

Louisiana / Canada
Stan Terry, 1455 West Loop S. Ste. 400, Houston, TX 77027; Tel: (713) 963-6208, Fax: (713) 963-6228; E-mail: stant@pennwell.com

United Kingdom / Scandinavia / Denmark / The Netherlands
Roger Kingswell, 9 Tarragon Road, Maidstone, Kent, ME 16 OUR, United Kingdom; Tel. 44.1622.721.222; Fax: 44.1622.721.333; Email: rogerk@pennwell.com

France / Belgium / Spain / Portugal / Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33(0)1.3071.1119, Fax: 33(0)1.3071.1119; E-mail: danielb@pennwell.com

Germany / Austria / Northern / Switzerland / Eastern Europe / Russia / Former Soviet Union
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; www.sicking.de <http://www.sicking.de> Andreas Sicking

Japan
e.x.press sales division, ICS Convention Design Inc. 6F, Chiyoda Bldg., 1-5-18 Sarugakucho, Chiyoda-ku, Tokyo 101-8449, Japan, Tel: +81.3.3219.3641, Fax: 81.3.3219.3628; Kimie Takemura, Email: takemura-kimie@ics-inc.co.jp; Manami Konishi, E-mail: konishi-manami@ics-inc.co.jp; Masaki Mori, E-mail: masaki.mori@ics-inc.co.jp

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 #05-20, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel: 65 9616.8080, Fax: 65.6734.0655; E-mail: yfyee@singnet.com.sg

India
Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91.11.6283018/19, Fax: +91.11.6228 928; E-mail: rajan@interadsindia.com

Italy
Paolo Silvera, Viale Monza, 24 20127 MILANO Italy; Tel:+02.28.46 716; E-mail: info@silvera.it

Frac fluid fears show capacity for inconsistency

Controversy over hydraulic fracturing fluids and their possible effect on drinking water demonstrates the boundless human capacity for inconsistency.

Although chances are low that injected frac fluid will find its way down anyone's throat, fear persists in parts of the US about contamination of subsurface drinking water.

It persists despite the tens of thousands

The Editor's Perspective

by Bob Tippee, Editor

of frac jobs producers have performed over 60 years without fouling groundwater.

And it persists despite explanations about vertical separation between injection targets and freshwater aquifers, about mechanical controls that keep injectants from entering sensitive strata, and about regulations in place to ensure safe work.

A reason the fear persists is that people don't know what's in the small fraction of most frac fluid that isn't sand and water. The ingredients, in many cases, are commercial secrets.

Companies compete on the basis of the performance of the frac fluids they sell or use—how well they carry proppant, transmit pressure, and clean out fractures, for example. The companies don't want competitors to know what they put into the fluids to make them work as they do.

So an activity mysterious to people unfamiliar with it contains something unknown, which opponents of the activity spin into fear.

The fear is of tiny constituents of a fluid that probably never will come anywhere close to drinking water.

And it's enough to threaten with federal regulation an operation essential to development of gas shales—and thus of a potentially enormous supply of clean, secure energy.

Yet Americans deliberately drink an average of 3,296 oz/year each of a liquid the formula for which is a notorious secret.

They drink it knowing full well, if they read labels, that each ounce delivers 12 calories, 3.3 g of sugar, and virtually no nutrition. In other words, what people already know about this liquid should stir worry. And if reaction to frac fluid in the US Northeast followed a pattern for consummately reasonable behavior, what people don't know about this other liquid's "natural flavors" long ago would have inspired calls for federal regulation.

But people like how Coca-Cola tastes, so consistency doesn't matter.

(Online Feb. 26, 2010; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

US oil production climbs

Unlike most producers outside the Organization of Petroleum Exporting Countries, the US "put up remarkably strong oil production growth of 7.1% in 2009" after "a nearly nonstop decline" for the past 3 decades, said analysts in the Houston office of Raymond James & Associates Inc.

A production increase of some 320,000 b/d—"60% of the net growth or 41% of the gross, predecline growth"—came from "one-time items" such as post-hurricane recovery in the Gulf of Mexico and the first full year of production from Thunder Horse, the world's largest deepwater development. "The rest of the growth (which should be more sustainable) came from more structural and organic drivers, including strong growth in deep water, the Bakken [shale], and rising onshore natural gas liquids volumes. Since only the second category represents growth that can be sustained for more than a few years, we see low single-digit annualized growth in oil production as the most that the US can realistically achieve over the next 3 years," Raymond James analysts said.

US oil production may continue to grow on "a steady-state" basis for a few years. "But even under a very optimistic scenario it won't be anything close to the 7.1% growth rate of 2009. Low single-digit annualized growth is the most we can envision for the next 3-5 years. Our 'best guess' scenario is that production will grow around 200,000 b/d for the next 2 years and then flatten after that," said Raymond James analysts.

Raymond James currently projects 3.4% growth in 2010-12, followed by 1%/year declines thereafter. "While the US most likely won't go back to its steep historical declines anytime soon, it's unrealistic to expect future growth to be anything close to 2009 levels. As a result, the US shouldn't be a major factor (either positive or negative) for future changes in non-OPEC production, which means non-OPEC is still set to decline over time," the analysts said.

Earthquake impact

The massive 8.8-magnitude earthquake that rocked Chile Feb. 27, killing hundreds and triggering a tsunami, also forced the shutdown of the two largest of Chile's three refineries, accounting for more than 220,000 b/d of capacity.

That had little effect on energy markets when they opened Mar. 1. But the two refineries are the largest producers of diesel in Chile, which is the fourth-largest oil consumer in Latin America. Olivier Jakob at Petromatrix, Zug, Switzerland, said, "In the first half of 2008, Chile was instrumental in the support to the distillate cracks as it was sucking cargoes of gas oil to answer the power generation deficit generated by drought. If the refineries have suffered some damages in the earthquake, this could result in some incremental demand and could help the US Gulf [Coast] refineries to place unwanted cargoes of distillates. Developments and damage assessment in Chile will need to be monitored for their potential support to the distillate market."

The refineries apparently sustained greater damage than Chile's copper mines, which were further from the epicenter. Nonetheless, one fifth of its copper production was suspended. Chile is the world's largest producer of copper. Prices for that commodity rallied 5% to the highest levels in 5 weeks in futures markets Mar. 1.

Gas production declines

The Energy Information Administration reported a sequential decline in US natural gas production from the Lower 48 in December, down 500 MMcfd to 62.82 bcfd despite weather-related well freeze-offs that affected production. Wyoming and New Mexico declined by 200 MMcfd each while Texas reported a 100 MMcfd production decline. Louisiana reported only 0.9% month-on-month production growth, lowest since the beginning of last year.

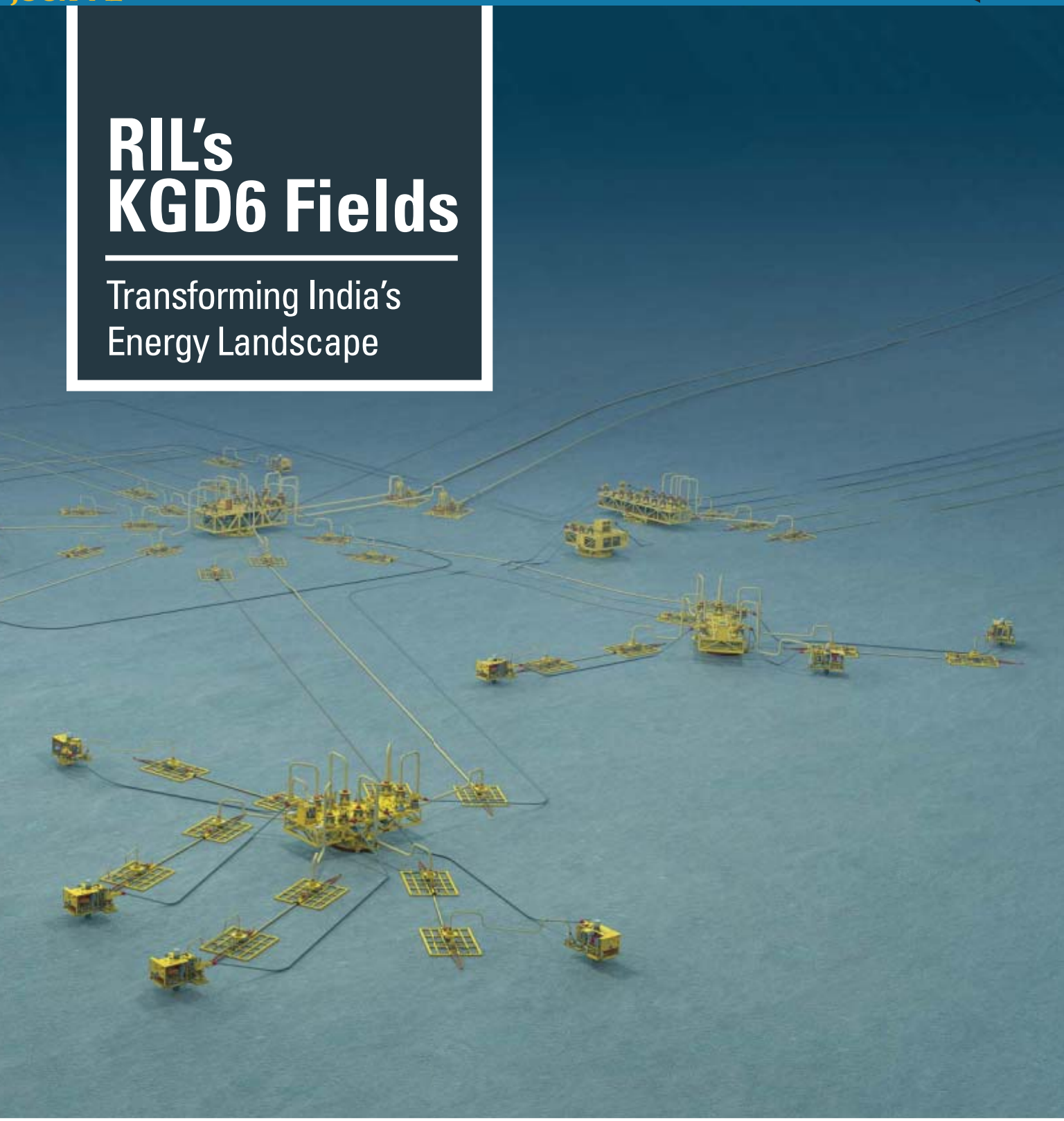
"Since peaking in February 2009, the US Lower 48 production was down only by approximately 760 MMcfd or nearly 1.2% by yearend 2009," said Pritchard Capital Partners LLC, New Orleans. "As we anticipated, the EIA data further indicated that natural gas supplies are holding firm. We believe that the EIA-reported supplies figures would continue to show resilience as more E&P firms probably brought drilled but uncompleted well inventory online to time the pricing support over winter," the analyst said.

Raymond James analysts, meanwhile, said, "The December supply datapoint is the cleanest we have had in the past couple of months." They see gas prices as "likely headed lower this year."

(Online Mar. 1, 2010; author's e-mail: samf@ogjonline.com)

RIL's KGD6 Fields

Transforming India's Energy Landscape



supplement to: OIL&GAS JOURNAL | OIL&GAS FINANCIAL JOURNAL | Offshore

Reliance Industries Limited

PennWell® Custom Publishing

VP, PennWell Custom Publishing,
Roy Markum
roym@pennwell.com

Managing Editor,
Gurdip Singh
gurdip@pacific.net.sg

Profile Writers,
Jerry Greenberg
jerrygreenberg@earthlink.net

Pramod Kulkarni
pramodk@aol.com

F. Jay Schempf
fschempf@sbcglobal.net

Presentation Editor/Designer,
Chad Wimmer
chadw@pennwell.com

Production Manager,
Dorothy Davis
dorothyd@pennwell.com
918.831.9537
fax: 918.831.9415

Circulation Manager,
Tommie Grigg
tommieg@pennwell.com
918.832.9207
fax: 918.831.9722

PennWell Petroleum Group
1455 West Loop South, Suite 400
Houston, TX 77027 U.S.A.
713.621.9720 • fax: 713.963.6285

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112
P.C. Lauinger, 1900–1988
Chairman, Frank T. Lauinger
President/CEO, Robert F. Biolchini

sponsored by:
Reliance Industries Limited

supplement to:
OIL&GAS JOURNAL
OIL&GAS FINANCIAL JOURNAL
Offshore

The commissioning of the KG-D6 project marks a proud new milestone in the journey of Reliance Industries Ltd. Bearing the names of the sacred rivers of Krishna and Godavari, and paying tribute to the inexhaustible inspiration of Dhirubhai Ambani, our Founder, the KG-D6 project is truly an infrastructural marvel on the eastern coast of India. It has propelled Reliance to a higher growth trajectory and transformed the energy landscape of India.

In the successful execution of this project in highly challenging frontiers, Reliance has created a new chapter in the annals of India's E&P sector. It has announced to the world that Reliance has arrived as a global energy player, even as it has opened new avenues in value creation. We are committed, and now poised, to make a material difference to the global energy industry, and to the energy security of India.

This book tells the story of how one of Reliance's dream projects moved from concept to commissioning. It also showcases the never-say-die spirit of our project teams who, working under the guidance of Mr. P.M.S. Prasad, have tirelessly executed this massive project, despite extreme hardships in the deep-sea environment and acute shortages in the global supply chain.

Mukesh Ambani
Chairman and Managing Director
Reliance Industries Limited

Contents

Introduction

Deepwater Fields Transform India's Energy Landscape:

Every once in a while there comes a game changer, sometimes through serendipity and sometimes through grit and resolve. Here is a project that showcases how grit, resolve and world class management can impact an entire nation's destiny.

The discovery and subsequent development of the deepwater oil and gas fields, in the KG-D6 Block off the Bay of Bengal in the east coast of India, have important ramifications for the country's energy security. And the discovery and development project has been executed by India's largest corporate house, Reliance Industries Ltd (RIL).

In fact, RIL is already producing natural gas from the Dhirubhai - 1 & 3 gas fields (D1&D3) since April 1, 2009, and light crude oil from the Dhirubhai 26 (D26) oil field, since September 17, 2008. Both projects have been commissioned in a record time –the D1 & D3 fields in about six and half years, and the D26 field in just a little over two years - from discovery.

Gas from these fields flows via a subsea architecture, through a Control and Riser Platform (CRP), to an Onshore Terminal (OT) located at Gadimoga on the east coast of India. Oil flows though a subsea system tied-back to a Floating, Production, Storage and Offloading (FPSO) vessel from where it is dispensed through shuttle tankers to local refineries.

These hydrocarbon finds by RIL are not only trendsetters in the exploration and production of oil and gas in India, but they also herald the renaissance of India's quest for energy self-sufficiency.

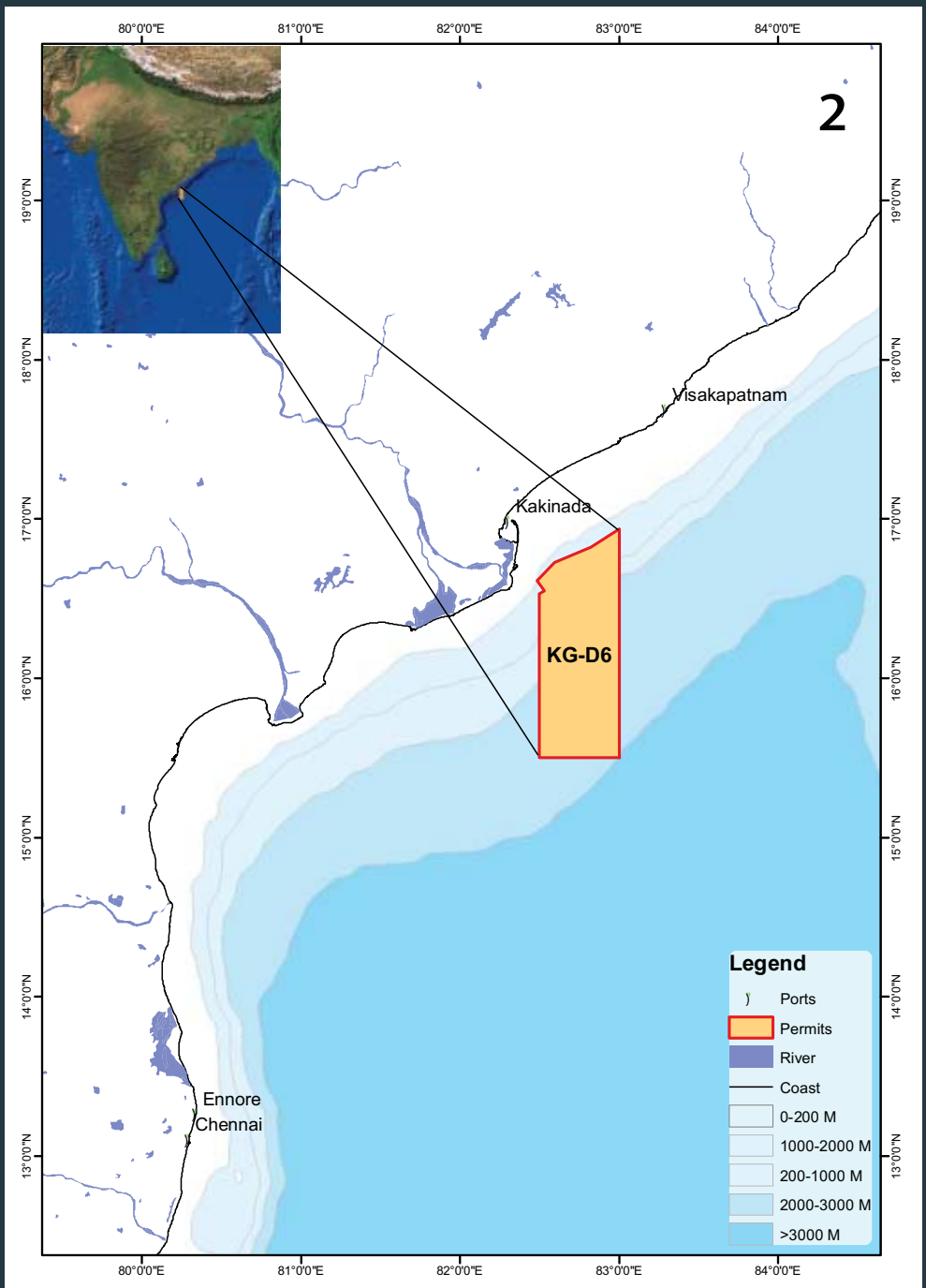
The Beginning

In 1999, the Government of India unveiled the New Exploration Licensing Policy (NELP) to attract large investments needed for the resurgence of E&P activity in India. Its origins lay in the compelling fundamentals that faced the sector.

Prior to the onset of NELP, primarily National Oil Companies had undertaken exploration campaigns, but only on land and in shallow waters close to the continental shelf. Consequently, barely 15 percent of India's sedimentary basins were well explored. With India's cumulative sedimentary basin acreage equivalent to almost four percent of the World's sedimentary basins, the question was: why was India's oil and gas production less than 1 percent of global production?

As one of the World's fastest growing economies importing nearly 40 percent of its energy requirement, which included more than 70 percent of its crude oil requirement, energy security had become a mission for the leaders of the country. Clearly, discovering indigenous resources of oil and gas had become a dire necessity. With India remaining under-explored, the realization had dawned that it would take massive scale risk capital to unlock the potential of India's sedimentary basins. It is then that the policy makers of the land sought to create a world class investment framework through NELP for enabling E&P operators worldwide to participate in the development of India's E&P sector. However, deep pessimism about hydrocarbon prospectivity in India's sedimentary basins, and the huge risk capital investment requirement meant that only those who truly believed in India's potential, and had the guts and gumption, participated in the NELP rounds of bidding.

Challenging conventional wisdom, RIL, hitherto known as India's leading petrochemical and petroleum refining company, took a plunge into exploration and production business in this backdrop - and that too in one of the most challenging frontiers of deepwater exploration and production. In the NELP-I round of bidding, Reliance Industries Limited (RIL) and its partner Niko Resources Limited (NECO) were awarded the block KG- DWN-98/3 (KG D6). RIL is the Operator with a 90 per cent participating interest in this block, with Niko holding the rest. The KG-D6 block is located in the Krishna Godavari (KG) basin off the east coast of India. The block covers an area of 7,645 sq. km. The proximal boundary of the block, in its northern part, is about 20-km southeast of Kakinada coast. The water depth in the block area ranges from 400-m in the north-northwest to more than 2,700-m in the south-southeast.



KG D6 Block Details

- Block No: KG -DWN -98/3
- Awarded under NELP -1 bidding, in year 2000
- Area: 7645 sq. km with Water depths -400 m to 2,700 m
- Located in Krishna Godavari Basin off the East Coast of India in Bay of Bengal
- First Discovery made in Year 2002
- No. of Exploratory / Appraisal wells drilled - 26
- 18 Gas Discoveries
- 1 Oil Discovery

In just two years as an Operator, RIL struck the largest gas find of 2002, in its very first venture in the deepwaters of the KG D6 block.

The KG basin is a known petroliferous basin and extends to both onshore and offshore areas. The onshore part covers an area of 28,000 sq. km. and the offshore part, including deep waters, covers an area of about 145,000 sq. km. After signing the production contract in 2000, Reliance embarked on an intensive exploration program.

What followed has redefined the history of the E&P sector in India.

In just two years as an operator, RIL struck the largest gas find of 2002, in its very first venture in the deepwater of the KG D6 block. This was a game changer on several counts. A discovery of this scale and size had been made in India after almost three decades - transformational from the standpoint of India's prospectivity perception, and thereby bolstering investments and activity in the Indian E&P sector. It also established a significant geological framework in the deepwater of the East Coast, confirming the presence of a biogenic gas channel-levee-complex petroleum system in the younger tertiary sequences.

In another six and half years, gas production from these fields, namely D1/D3, commenced in a record time in April, 2009, an achievement that normally takes anywhere between eight and ten years, per global averages. Operating in an area with no known infrastructure, one of the harshest operating environments in the world, and most importantly, with no prior availability of expertise, technology and services in this field, this is truly a remarkable achievement in constructing one of the world's largest Greenfield deepwater infrastructure.

Even as Reliance made several more gas discoveries within this block, and commenced the development of the D1/D3 gas fields, the company struck another milestone oil discovery, namely D26, in the deeper sediments of Mesozoic's in 2006. RIL developed this field in a little over two years, commissioning it in September 2008.

The Potential

Within nine years as an E&P Operator, RIL has become the largest gas producer in India, with current production at about 50 Million standard cubic metres per day. At peak, these fields can potentially produce 550,000 barrels of oil equivalent per day, which is equivalent to 40 per cent of India's current indigenous production. RIL's investment of about US$9 billion is by far the single largest investment by an Indian company in India's hydrocarbon sector, and has the potential to save the country more than US$10 billion a year in oil and gas imports for years to come. Of note is the fact that the D1/D3 fields cover just about 4.5 per cent area of the D6 Block, one of the 51 blocks within RIL's global E&P portfolio.

The Commitment

With several more discoveries in its repertoire, and with an acreage of over 325,000 sq km in 38 blocks in India, RIL's multi-billion dollar investment in deepwater hydrocarbon development indeed reflects the company's commitment to India's energy sector. "RIL remains committed to India's quest for energy self sufficiency, and we will do everything in our capacity to bolster India's hydrocarbon resource base," says Executive Director, RIL, Mr. PMS Prasad.

The Path Ahead

Commissioning of these fields has catapulted Reliance to an elite league of deepwater operators in the world. The intellectual capital and proven mega scale deepwater E&P project execution very favorably position RIL for its future ventures. These feats have obviously elated the entire top management of the Reliance Group. The dynamic Chairman & Managing Director of the Reliance Group, Mr. Mukesh D. Ambani, who is steering the company from strength to strength, strongly believes that the development of KG-D6 has put the company on the right path to manage high-risk upstream businesses.

"Reliance has always believed that what is good for India is good for us, and it gives us immense satisfaction to see that hydrocarbons from KG-D6 Block are flowing to meet the country's high energy demand," says Mr. Mukesh Ambani.

Against All Odds

By all standards, the development of the D1/D3 fields in the KG-D6 block has been one of the most challenging projects in the field of exploration and production of hydrocarbons, anywhere in the world. The daunting project was carried out in the hostile conditions of the East Coast of India, in the backdrop of a critical shortage of skilled manpower and extremely difficult business environment, even as the global oil and gas industry faced acute shortages of manpower, equipment, services and escalating costs.

"This was a discovery of great significance. It became global market talk, with skeptics wondering how a relatively unknown E&P company in India would exploit these reserves. It only made RIL even more determined to develop these fields, and in doing so raise the bar of performance," recalls Mr. PMS Prasad. "The country's huge energy appetite meant that we needed to develop the resources immediately. The Government of India, the relevant regulators and other authorities also facilitated with required approvals for accelerated development of the fields," adds Mr. Prasad.

A project of this magnitude and complexity defies conventional norms of E&P, especially when you have to build both capability and infrastructure from scratch. Besides, it was the first of its kind deepwater development in India, and we knew it was going to be a stupendous task, given the challenges and odds stacked against us.

The scale, magnitude, complexity, speed and span of execution positions this project in an elite league of mega deepwater projects. This project is testimony of the passion and commitment of our team that made it happen in a record time. In the process we believe we have built differentiating capability for executing Deepwater Projects. Truly building this mega greenfield deepwater oil and gas infrastructure is one I will cherish forever, especially so because of the sheer value it has created for our Nation.

This is indeed a tribute to the Vision of our founder Chairman Dhirubhai Ambani and the leadership of our Chairman Mukesh Ambani for his guidance and support at all times.

PMS Prasad
Executive Director
Reliance Industries Limited

Game Changing Discovery

With scant data available, RIL initiated an intensive 2D and 3D seismic program. This data, combined with regional geology and basin modeling, was used to develop the geological framework, and the concept of the petroleum system. Based on advanced 3D imaging and interpretation technologies, as well as Direct Hydrocarbon Indicator technologies, such as AVO and AVA (amplitude vs offset / amplitude vs angle), exploration experts at Reliance started mapping the prospects to commence its drilling program. In mid 2002, RIL embarked on its first drilling campaign. "Our emphasis was on integration of geological concepts and geo scientific technology through workflows that were benchmarked against the best in the industry" says Mr. IL Budhiraja RIL's President for Exploration

What followed is history. Reliance struck the world's largest gas discovery for that year. The well encountered almost 340-mts of gross pay comprising gas bearing sands. Data from the well was later integrated with the 3D seismic data, and what emerged was a biogenic channel-levee-complex gas reservoir in the Pliocene sequence.

After a series of discoveries in the shallow tertiary reservoirs, RIL also struck a new oil and gas discovery, D26, within the Mesozoic sequence in 2006. The field has been subsequently put on production in a record time of a little over two years.

"Our emphasis was on integration of geological concepts and geo scientific technology through workflows that were benchmarked against the best in the industry"

says Mr. IL Budhiraja RIL's President for Exploration

Challenges of a Giant Deepwater Gas field

The euphoria of the world's largest discovery had soon turned into a reality of numerous challenges, as it had come at a time when the global market was critically short of resources – be it manpower, material, fabrication yards, equipment, marine vessels or rigs. That the environment on the east coast of India is generally harsh, with strong winds, currents and cyclonic conditions, limiting the fair weather offshore construction window to about four months in a year, it made the project far more challenging.

In fact, the challenges were multifold, as RIL was a relatively new player in the E&P business. Apart from the supply chain pressures, the D1/D3 field itself posed numerous technical challenges during the concept and design stage of the project. As it was a complex reservoir with sinusoidal channels and a combination of thick and thin sands, RIL had to precisely map the location of the wells. It also had to factor in the risk of reservoir compaction and subsidence with future depletion due to unconsolidated sands within the younger tertiary sequences in its subsea facility design. As the seabed topography was relatively unknown, RIL also had to consider potential soil erosion and equipment corrosion issues, typical of offshore terrains, as well as Tsunami risks, prior to concept selection and design. To prevent the possibility of gas hydrate formation, RIL also factored in flow assurance issues within the concept studies in deepwater subsea systems. Adding to the woes was the development of the remote onshore site, which was not only prone to flooding and cyclones, but also lacked basic infrastructure. To top them all, RIL had set itself the ambitious target of implementing the project in just six years!

Investment Decision

While the Indian market was hungry for the new hydrocarbon resources, there were huge risks involved in implementing the project. A multibillion dollar capital expenditure in a completely unknown frontier for an operator with no prior experience was good enough to deter anyone from further investments. More so because it represented deep cash sink in the unknown. Any failure in execution could set the company back by decades. Obviously, it was not so for RIL, which had a rich history of entering and succeeding in uncharted territories, and as things turned out subsequently, here was another bastion to be won - against all odds. The final investment decision (FID) was prompt, as RIL mustered the necessary resources using its goodwill in the market.

Mega Deepwater Hydrocarbon Development

Understanding the Reservoir

A multi disciplinary team comprising geologists, geophysicists and petro-physicists worked closely to characterize the reservoirs. The D1/D3 reservoirs are a complex reservoir system of sandstone. It comprises two huge sinuous, stacked channel-levee systems of late Pliocene age. The main channel belts have a very thick column of highly porous and permeable gas saturated reservoir rocks. To characterize the reservoirs in this block, RIL carried out extensive 3-D seismic surveys over the entire D6 block, including high resolution "Q" marine 3D seismic surveys covering the fields. As a risk mitigation measure, RIL drilled two of the planned development wells ahead of schedule and cored 290-m of reservoir rocks. The 3D seismic data was inverted using Jason's™ Inversion Technology. The core data, a direct rock record, immensely improved the understanding of the reservoir rocks and their depositional processes and petrophysical characterization. Inversion and "Q" marine data improved the bed resolution, reservoir mapping and reservoir characterization further. All these measures increased the subsurface prediction accuracy significantly. The interpretation of the reservoir models were undertaken in virtual reality centers at RIL's E&P headquarters in Mumbai. These are state-of-the-art visualization centers using 3D immersive technology. Optimization of well locations to ensure maximum reservoir contact was greatly enhanced by these technology centers.

As an active member of the Stanford University's project on Deepwater Dispositional Systems, a global consortium of 20 Exploration and Production Companies, which includes the E&P majors, RIL also had access to the latest research and expertise that it utilized in reservoir characterization. "We drilled several wells in these fields. I am proud to say that in all these wells, there was a close match between predrilled prognosis and actual post-drilled results. The prediction accuracy was between 90 and 95 percent. Almost all the wells were better than the nearby exploratory wells in terms of net reservoir thickness and yields. This surprised many Industry experts. We have 118 different sand units in the 18 wells and all of them are now ready for production," shares a beaming Mr. Bhagaban Das, Head of Reservoir Characterization.

Facilities Concept Selection

RIL had set up a project team soon after the first discovery. The project team went in for concept studies, and subsequently FEED, at various offices of Aker Kvaerner in Norway and Singapore.

The team addressed site specific challenges such as flow assurance, reservoir compaction / subsidence, harsh environment and unknown seabed terrain at the concept selection stage itself. They also collected extensive field data and carried out technical studies in conjunction with the FEED study. Both concept and FEED were subsequently validated by reputed third party experts. Techno-economic feasibility of various options were analyzed before finalizing the concept, which was a typical "subsea to beach" approach. "The D1/D3 development concepts were benchmarked with the best in the industry," recalls Mr. S. C. Varma, RIL's President, Development.

"The D1/D3 development concepts were benchmarked with the best in the industry,"

recalls Mr. S. C. Varma, RIL's President, Development.

Design and selection of equipment and facilities were guided by:

- Safety in operations
- Maximization of reliability and availability
- Use of proven technology, as far as possible
- Simplicity in design and operation – with flexibility to integrate and scale up known and future discoveries
- Use of standard equipment/products
- The ease of construction and installation

Execution – Getting it Right the First Time

Safety - A Top Priority

In keeping with its corporate philosophy that safety overrides all production targets and that safe work practices in fact accelerate the project execution, RIL planned its project in line with world class safety processes to get it right the first time. The smooth execution not only amply justified the marginal expenses dedicated to safe project practices, but also set a new benchmark in safety for others to emulate.

Expanding the Talent Pool

In keeping with its ambitious timeline, RIL undertook an aggressive recruitment drive, as well as appointed consultants worldwide, to recruit the best available talent globally. "We adopted the strategy to go global, and appointed five international consultants to recruit the best experts available for the KG D6 project. It was very important for us to get the right people on board because RIL, as a young upstream company, was yet to build its international track record as a major player in the E&P space. Besides, nothing could be left to chance," says Mr. P. Sakthivel, Head of Human Resources. As advance planning was critical, RIL always kept the recruitment pace ahead of specific project requirements.

Back home, Reliance also recruited young engineers, and put them through a rigorous four-month express training program to make them project ready.

As a result, from a core group of less than 10 industry veterans, the RIL Petroleum E&P team has grown to be 1,350-strong over the last five years. The Projects & Development team alone has grown to 300, from 25 professionals in 2002.

Innovative Contracting Strategy

The contracting strategy had to take into account challenges associated with complex subsea architecture, an extremely aggressive timeline, highly overheated offshore markets and limited availability of major contractors. In order to understand the risks involved and to reduce the contract award cycle, RIL also studied various deepwater field developments (with subsea completion) executed around the world.

In view of stiff targets and availability of a fair weather window of about four months a year for offshore installation works, it was necessary to have a contracting strategy that would help maximize the chances of meeting the next-to-impossible deadlines. After considering various options in a niche market, RIL took a few path breaking decisions, such as booking manufacturing capacities in various vendor shops for critical long lead items / equipment through early engineering, and directly awarding contracts for long lead items like line

pipes, XMTs, valves, umbilicals, the control system and subsea structures. To complement these, RIL adopted a task-force approach for critical packages for both offshore and onshore, and awarded a single contract for offshore facilities installation, with the long lead items free issued by RIL, to minimize the interfaces. Similarly, it awarded single contracts for the CRP and the construction of the OT, while awarding separate equipment and services contracts for the drilling and completion works.

Well Construction - Large Bore High Delivery Deepwater Gas Wells

The need was for reliable and maximum productivity wells with minimal intervention throughout the life of the fields. Considering these are sinuous channel-levee-stacked reservoirs, the biggest challenge was placement of wells that will enable maximum reservoir contact and well bore integrity.

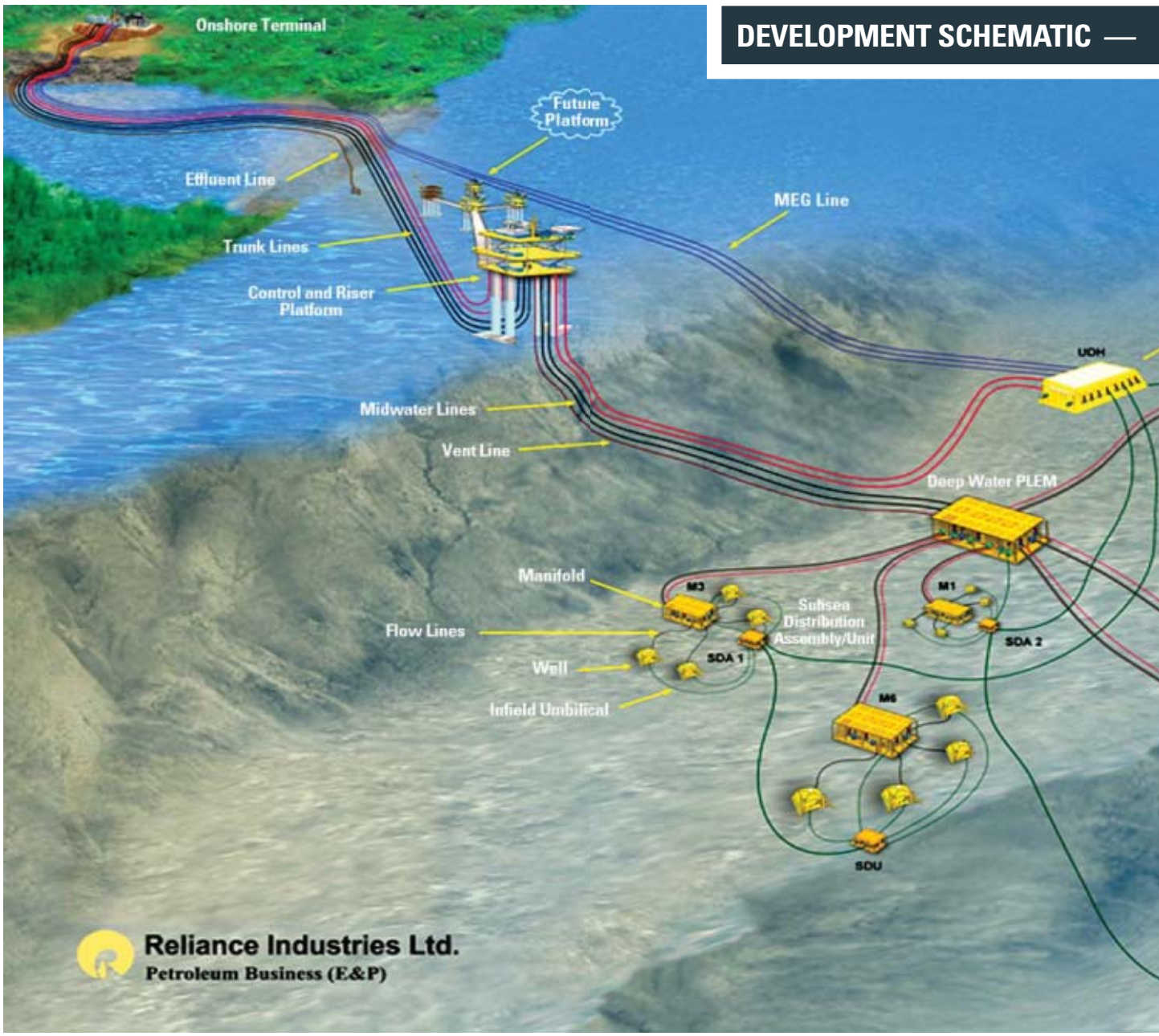
The team carried out design studies based on Finite Element Analysis Modeling to ensure well integrity throughout the well life with selected casing and completion designs. The target was to have high deliverability wells with big bore completions. Site inspection test programs and other measures helped with well designing, based on well life cycle to minimize intervention and to avoid costly rework or re-entering of wells in the deepwater. Additionally all wells are equipped with state-of-the-art instrumentation, such as gauges for reservoir surveillance and monitoring during production.

Three deepwater rigs were selected for development drilling and well completion. These were used to drill wells into highly unconsolidated sands, with completion ensuring effective sand control, following the best suited design that ensured that all the stacked pay zones contribute to the field life of at least 25 years. "As it is a very unconventional reservoir system, the situation demanded that we drill high angle wells. Ultimately, we drilled the wells at 50-52 degree angles. But we did not go there immediately, it happened gradually, using technology to improve and optimize production," recalls Mr. Bhagaban Das.

The entire drilling and completion operation was monitored in real time through a Real Time Operations Centre located at the Project Headquarters in Mumbai. Live feed from the rigs was continuously being analyzed to ensure that targets were achieved; both in terms of targeting the reservoir sands and well bore objectives.

Well Completion Philosophy:

- Flexibility in design to ensure higher production from wells - allowing 9 ⅝", as well as 7" completions
- Ensure effective and proven sand face completions with high quality gravel packing
- Use of proven components in design, and state-of-the-art equipment, tools and technologies used in deepwater gas developments around the world
- Minimized well intervention requirements
- Standardization of completion design and equipment for enhanced operational efficiency and flexibility
- Use of Temperature Array Sensor (TAS) System in selected wells, perhaps a first in reservoir temperature monitoring in the world. TAS is used to understand the reservoir during production.



Deepwater Subsea Facilities – A First in India:

Subsea Infrastructure

The subsea architecture comprises 18 production wells connected to six subsea manifolds, all of which are connected to a Deepwater Pipeline End Manifold (DWPLEM). Two 24-inch pipelines transport the well fluids from the DWPLEM to the CRP and three 24-inch shallow water pipelines transfer it from the CRP to the OT. The mammoth subsea facility weighs nearly 125,000 metric tons, comprising 350-km of pipelines, 150-km of umbilicals and 212 subsea tie-ins.

The Subsea operations are controlled and monitored from the Central Control Room (CCR) at the OT. Controlling and monitoring the subsea facilities are via a multiplexed electro-hydraulic control system comprising power and communication equipment, an Umbilical Distribution Hub

DHIRUBHAI-1 & DHIRUBHAI-3 GAS FIELDS

(UDH), subsea distribution assemblies (SDA), subsea distribution units (SDU), subsea control modules (SCM), X-mas tree mounted instrumentation and associated hydraulic and electrical flying leads.

The OT has the facility to pump Mono Ethylene Glycol (MEG) through six-inch diameter pipelines to the UDH and then through the infield umbilicals to well heads for continuous injection for hydrate prevention in the subsea pipeline system.

D1 D3 Subsea Architechture

18 Producing Wells

- 18 Subsea X'mas trees
- Six Subsea Manifolds (6 slots each)
- One Deepwater Pipe Line End Manifold (DW PLEM) (8 slots)
- One Umbilical Distribution Hub (UDH)
- 3 x Subsea Distribution Assembty (SDA)
- 14 x 8"/10" flowlines from wells to Manifolds
- 6 x 16"/18" Deepwater infield pipelines from Manifolds to DW PLEM
- 2 x 24" Gas trunk lines from DW PLEM to Control & Riser Platform (CRP)
- Manned CRP
- 3 x 24" Export pipelines from CRP to Onshore Terminal (OT)
- 3 x 6" MEG lines from OT to Umbilical Distribution Hub (UDH) for hydrate inhibition
- Subsea control system & umbilicals
- Block valve station at Land Fall Point

Subsea Control System - The Deepwater Nerve Centre

The D1/D3 Subsea Control System (SCS) is used for monitoring and control of gas production from 18 subsea wells located at water depth of 450 metres to 1150 metres. The SCS comprises topside control system equipment and subsea control modules installed on subsea control structures. The topside of the SCS is installed on the CRP and consists of the Master Control System (MCS), the Electrical Power Unit (EPU) and the Hydraulic Power Unit (HPU).

The MCS is integrated with the CRP/Onshore Terminal (OT) Distributed Control System (DCS) via a redundant OPC link. The communication between CRP and OT is via two separate redundant power and fibre optic umbilicals with the backup on the Microwave System. The microwave takes over the communication in case of failure of both the main umbilicals. This facilitates the remote monitoring and control of D1/D3 subsea facilities from the OT, which is approx 60-km from the field. The main subsea communications are provided using fiber optic backup on the communication-on-power between a CRP topside MCS and Subsea Control Module (SCM), via a composite services umbilical and appropriate subsea distribution units.

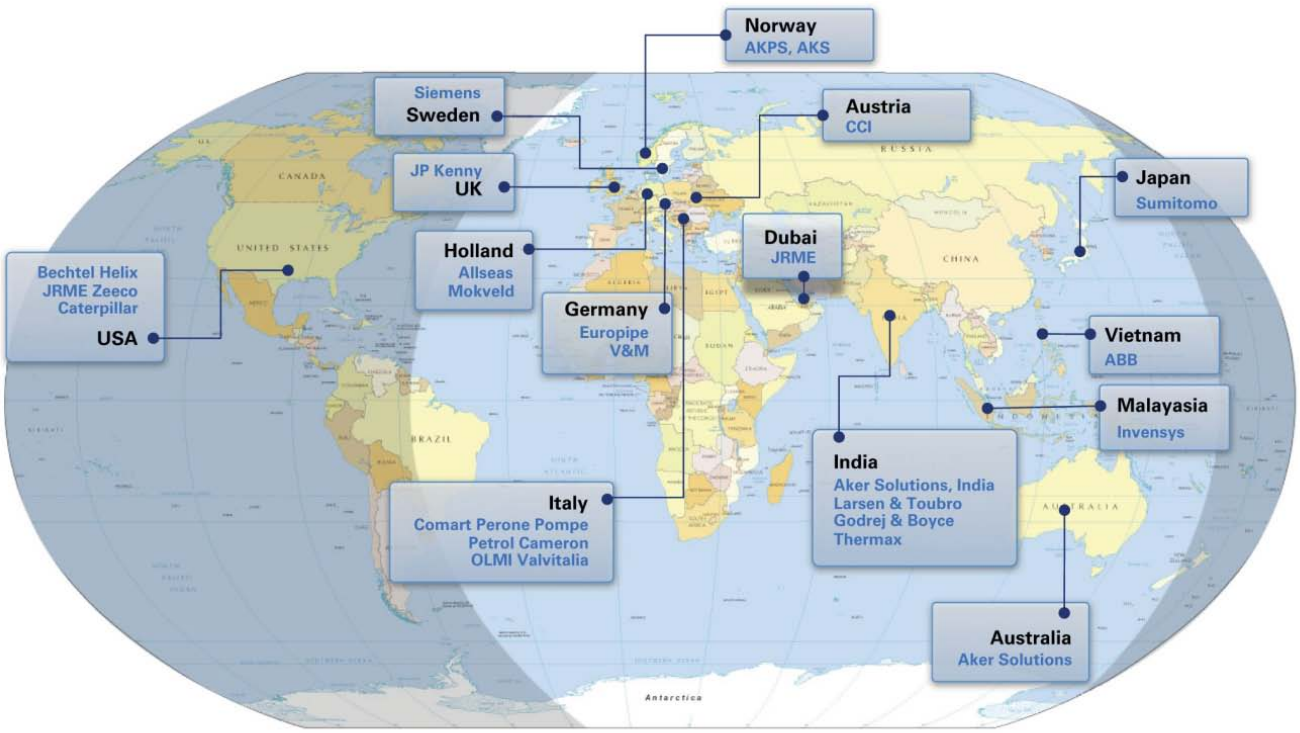
The entire communication up to the Subsea Distribution Unit (SDU) is on the high speed fibre optic backbone, with TCP/IP protocol. The Subsea Control System (SCS) is designed to provide flexibility, expandability and upgradeability throughout the life of the field, as well as for future expansions. The D1/D3 field has six subsea wells equipped with Down-hole Temperature Array Sensing (TAS) system for the reservoir and well monitoring.

Control and Riser Platform (CRP)

The Control and Riser Platform is the offshore hub of the KG D6 development. The CRP has a strategic role in managing the production from deepwater subsea network, as well as in controlling the future supply of natural gas from the D26 field. The CRP exports natural gas through three 24-inch pipelines to the OT. All gas from the KG D6 fields, including the gas from D26 field is gathered at the CRP and then exported to OT.

The CRP is continuously manned by 22 people. From a security standpoint, this platform is equipped with twin radars and night vision thermal cameras for continuous surveillance. Located in 98 metres of water depth, the CRP has six 24-inch risers and one 4.5-inch riser, with provisions for future expansion.

The topside of the CRP has four level decks comprising facilities and packages such as Living Quarters, the Heli-Deck, Deck Crane, Gas Import and Export Piping, Process Control System, Chemical Injection System, Fuel Gas System,



Nitrogen Generation System, Flare System, Emergency and Fire Protection System, as well as utilities, including Emergency Generator, Fire Water System and Survival System.

Project Execution and Management

Given the chosen contracting strategy and complexity, RIL had formed two independent project teams - one for offshore and another for onshore and adopted a fast-track approach of executing EPC activities in parallel. Attempting to compress the timeline by nearly 30 percent meant that it has to be a complex web of activities carried out at 20 international centres across the world, 24x7, keeping in mind the different time zones, with the nucleus of the entire activity at the company's headquarters at Mumbai, India. The complex project management needed an out of the box approach. As soon as the contracts were awarded, RIL created satellite office across the world, mobilized the workforce, and went headlong into project execution.

The complexity of the project also necessitated deploying engineering teams at engineering consultants' offices for a one-stop review of engineering documents, and for expediting the review cycle. The document submittal, review and approval process demanded swift exchange of various engineering documents and drawings. This was accomplished using a web based tool "eRoom" that helped the project engineering teams stationed at different locations globally to collaborate. Engineering reviews by DnV were also coordinated from respective engineering locations.

RIL had also located its procurement and expediting teams at consultants' offices for expe-

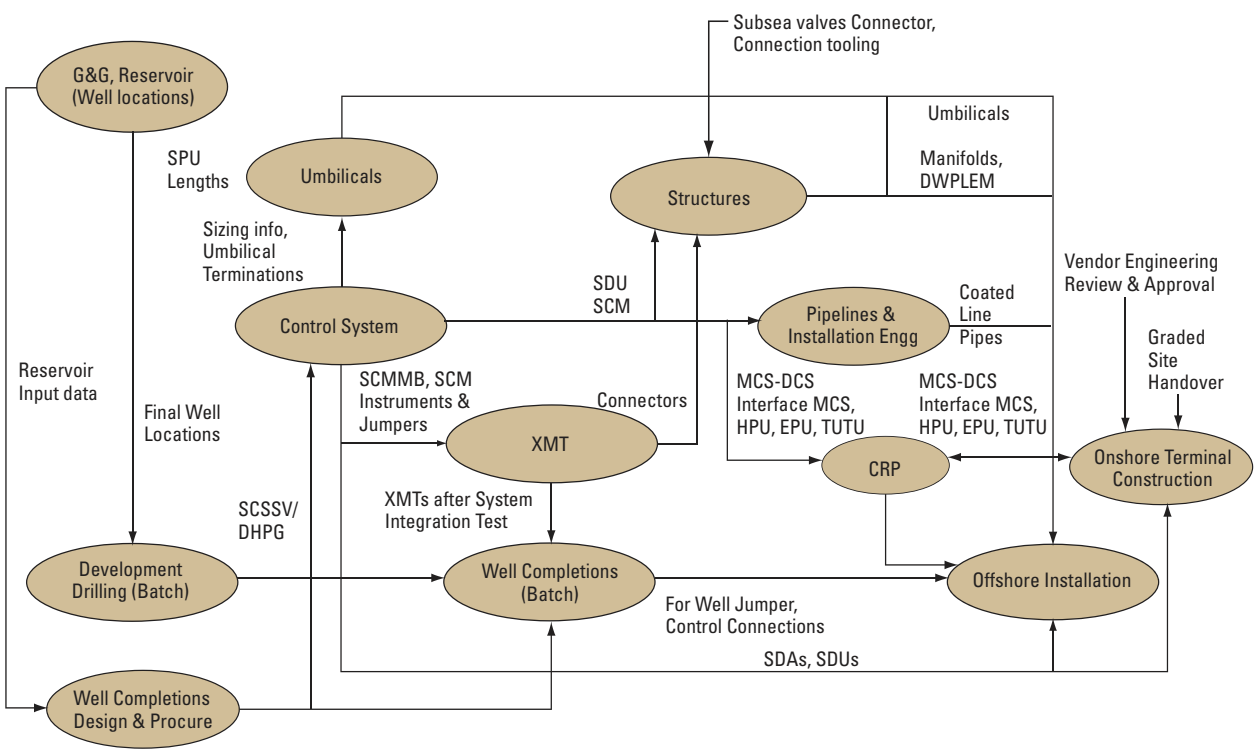
A multi-tiered project review system for close monitoring and control:

- Monthly progress reviews between RIL and major partners to address techno-commercial issues and find resolutions
- Steering committees formed with Project Sponsors drawn from RIL and Top Management representatives from various Project Partners to ensure continued alignment to Project objectives and goals.

diting ordering decisions for packages / equipment, and dedicated expeditors at vendor shops for expediting material / equipment deliveries. Dedicated construction management teams, including project planning engineers and quality inspectors, were deployed at fabrication sites to accelerate the fabrication activities.

Interface Management

Considering the huge challenges arising from the nature and number of contracts, RIL had formed an exclusive team for managing the interfaces. A dedicated lead engineer was nominated for dealing with interface issues for each work package.



Construction Management

As swells, currents and waves in the hostile east coast environment could threaten offshore work, the team had to take special care to choose appropriate installation vessels. A tight installation program restricted by a small fair-weather window and inadequacy of marine support infrastructure on the east coast necessitated that every piece of equipment had to be meticulously planned and selected."So when we were selecting the vessels and barges to work on that field, we had to ensure that there was enough inter-changeability. Our philosophy was simple; if something ever went wrong with one of them, the other should be able to substitute. Basically, we had to have a contingency plan at all times. So, we had to ensure sufficient flexibility while selecting the fleet of vessels and barges," recalls Mr. Naresh Narang, Project Manager, Offshore.

To ensure"zero-incident and zero-defect" field development activity, the team carried out an advanced assessment of port and berth availability to support offshore work. All vessels were inspected before they were mobilized in the water, and meticulous planning of vessel movement was carried out for simultaneous operations. An effective vessel tracking system was deployed to plan the simultaneous movement of 89 vessels and barges at the peak of the offshore work.

"The first and the last thing that made this complex project successful was the passion of the people. In spite of all the project management skills, the best contractors, the best equipment, and the best tools, you can never get a project of this complexity right without the passionate involvement of people. Finally, what made the difference was our passion to do this project, and we are proud of it. I feel it was a once-in-a-lifetime experience," says Mr. Narang.

Onshore Terminal – Amongst the Largest Gas Handling Terminals

As the Onshore Terminal site was remotely located, with no existing infrastructure, RIL had to work on building the infrastructure, as well as other enabling facilities at OT site, such as

"Finally, what made the difference was our passion to do this project, and we are proud of it. I feel it was a once-in-a-lifetime experience,"

says Mr. Narang, Project Manager, Offshore.

Construction Jetty

a dedicated construction jetty, a water supply pipeline network from a source 12-km away, a haul road from the land fall point to the OT site for transportation of Over Dimension Cargo (ODC), and widening of access roads from Kakinada city (30 Kms) to reach the OT site at Gadimoga. Also, as the 203-acre OT site was in a low lying area, and surrounded by creeks, it was prone to heavy floods during monsoons. Based on a mathematical model study, RIL engineers established the safe grade elevation of the OT site, and raised it by about 4.5-m, using approximately four million cubic metres of sand through hydraulic filling. Segmented piles, with mechanical connectors, were extensively used to support all equipment to avoid settlement. Each pile was driven to a depth of 50-m from finished grade level. A total of over 22,000 piles were driven to strengthen the site base for plant and civil construction. A workmen's colony was also set up near the OT for nearly 10000 workers. All essential, basic amenities were also provided.

Another challenge was sourcing and retention of skilled manpower in the remote site location, compounded by harsh environment. "We developed the entire infrastructure, including roads, water pipelines and workers' accommodation. Advance infrastructure planning and development was critical to the success of the OT, and we had

"We had to ensure that the large team working on the project felt motivated at all times,"

says Mr. Sudarsana Rao Kotaru, Project Manager, Onshore.

to ensure that the large team working on the project felt motivated at all times," says Mr. Sudarsana Rao Kotaru, Project Manager, Onshore. The OT facilities are designed to produce 80 MMSCMD of sales gas, with future scalability.

Mono Ethylene Glycol (MEG)

The OT has one of the world's largest MEG reclamation and regeneration system. Some 10,000 metric tons of MEG is stored at the terminal, from where 11cum/hr per hour is pumped into a 60-km pipeline to well-heads to inhibit hydrate formation in the gas flow, which comes up at a low five degree centigrade temperature. A reclamation system helps strip the rich MEG, as gas flows through pipelines into the plant, making it one of the single largest sites operating MEG facility in the deep water gas development business. The MEG reclamation units are now running with high production availability, setting a new benchmark in the industry.

Quality and Technical Assurance

The project also went through extensive quality assurance and quality control audits with the support of internationally renowned experts like Det Norske Veritas (DNV), Ward Associates and Shell Global Solutions. In all, there were four external and three internal audits over 18 months of brainstorming sessions.

The pipelines were put through Nitrogen Helium tests for leak tests and pressure points. More than 1,000 punch points were addressed within six months, eliminating risk factors. Fatigue tests were also carried out on installed infrastructure to ensure their ability to support the planned 25-year lifespan of the field. The entire development was put through stringent quality checks in compliance with the applicable standards, and organizational and project policies.

Third parties such as Det Norske Veritas carried out certification and verification of all works. DNV reviewed and verified engineering, fabrication and installation of all offshore facilities. DNV also carried out the HAZID and HAZOPs through the different stages of the project. Other independent surveyors included Lloyds Register and Moody's International.

Extensive and intensive checks were done on all equipment, which included FAT, EFAT, SIT & SAT prior to installation. Multiple levels of inspection were undertaken by manufacturer's QC team, RIL QC team and Third party QC teams to ensure nothing was left to chance."We had stringent procedures and practices to ensure our quality spoke of the high grade of this project we had planned," says Mr. S. C. Varma, President, Development."We were aware that the industry has witnessed massive delays in projects due to equipment failure

"We had stringent procedures and practices to ensure our quality spoke of the high grade of this project we had planned,"

says Mr. S. C. Varma, President, Development.

post installation. As a preventive action, we put in stringent QA / QC measures to make it right the first time," he adds.

Commissioning - Flawless Start Up

Strategically, the O&M team was in place since inception. This enabled seamless understanding and validation of the entire field design and layout, and active participation in the project implementation phase. All key personnel were identified for each of the systems and sub systems and positioned well in advance. By design, they were actively involved in the installation phase to witness and take over the facilities through a detailed and approved hand-over / take–over (HOTO) process. "This helped in smooth commissioning and flawless start up of the KG D6 project," says Mr. P.K. Verma, who heads the D1 / D3 Operations. All teams involved from the planning to development stage were integrated while control room engineers underwent extensive training programs and made good use of the simulators to understand the production processes. "Multiple technical audits and stringent quality checks resulted in the desired gas quality being achieved within 30 minutes of arrival at the Onshore Terminal," adds Mr. Verma.

KG-D6 – Raising the Bar

It took 20000 professionals engaged 24x7 in 20 locations worldwide for a little over two years, 50 million man-hours of grueling effort and in excess of 125,000 metric tons of steel to build this mega Greenfield deepwater infrastructure.

"We believe we have set an industry benchmark for developing deepwater fields of this scale and complexity in 6-½ years, and for sure, the lessons learned in this mega-journey can be applied to all future deepwater projects,"
says Executive Director, RIL Mr. Prasad.

"We believe we have set an industry benchmark for developing deepwater fields of this scale and complexity in 6-½ years, and for sure, the lessons learnt in this mega-journey can be applied to all future deepwater projects,"
says Mr. Prasad, Executive Director, RIL.

Onshore Terminal Facilities

- Pressure Reduction Station and HIPPS
- Three 40 MMSCMD Slug Catchers/Inlet Gas Heater Trains
- Four 20 MMSCMD Gas Dehydration Trains
- Custody Transfer Metering
- Three 11m cu/hr MEG Reclamation and Regeneration Trains
- Condensate Handling Facility
- 45 MMSCMD High Pressure Flare.
  1.4 MMSCMD Low Pressure Flare
  A World Class State of the Art Control Centre to operate the subsea and on land gas facility at the Onshore Terminal

Utilities

- Air Compressiors for Plant and Instrumentation Air
- Water Storage Ponds for Raw and Fire Water
- Desalination plant
- 3 Gas Turbine Generators + Emergency Diesel Genrators for Power
- Three Hot Oil Heaters
- Effluent Treatment Plant

KG D6 Project Highlights

- World's largest Gas Discovery for the Year 2002
- Among the World's Largest and most complex Deepwater Gas production facility in the World
- Tie Back of 60 Km
- Transforming India's Energy Landscape
- Capacity of 550 000 boepd (barrels of oil equivalent per day)
- Equivalent of 40 % of India's current oil and gas production
- Has the potential to more than double the country's gas production
- Among the fastest Deepwater Field development projects
- Among the lowest F&D cost per boe for similar deepwater projects
- Global scale project management-simultaneous execution in 20 locations worldwide
- Among the largest Marine Construction spread
- Peak workforce of over 20,000 people
- Equipment weighing 125000 Metric Tons installed offshore
- 500 line kilometers of pipelines and umbilicals installed
- Flawless Commissioning

Community Development – Making a Difference

The project has also brought progress and prosperity to the residents of Gadimoga, a community of about 20,000 fishermen and their families living in nine villages in the midst of rivulets, creeks and backwaters along the East Coast of India. Nearly 1,000 of these residents are now employed to maintain the basic facilities at the Gadimoga Onshore Terminal. RIL is also assisting many others through community service programs."Our company believes in sustainable development," says Mr. P. K.Verma, Production Head, KGD6. "We have invested in education, health, sanitation and a potable water supply network,"he says.

For the start, RIL has already spent nearly Rupees 70 crores (US$14.5 million) on providing potable water to the Gadimoga Panchayat (Local Administration). All the nine villages are now receiving fresh water, purified through a"Slow Sand Filtration"system, on a daily basis from July 1, 2009. The water is brought through a 12-km pipeline from the Godavari River. Mr. Appana Babu, a 40-year old, welcomes the fresh water supply, saying it is a relief for the villagers, who usually had been traveling a long-distance to get drinking water. They are now getting 150-litre per day per family of piped water.

RIL has also upgraded the existing school facilities within the Gadimoga area. It has added new classrooms for the pupils, and provides uniform, shoes, bags and books to students attending these schools."We now have more class room space," says a 27-year old teacher, Ms. N. Shesharatnam who teaches 30 of the 2,200 students in the Gadimoga region."It is much neater and cleaner than before,"says Gopalapuram-resident Ms Shesharatnam who had to conduct crammed class in a small room during the monsoons.

On a broader scale, RIL has joined a novel education scheme"Protsaham"(Encouragement), which was launched by the East Godavari District Administration in 2008-2009. The renamed "Reliance Dhirubhai Ambani Protsaham"scheme provides sponsorships to support meritorious students in colleges and high institutions. The scheme will be supporting 200 best students in the current academic year, while 458 students benefited from it last year.

"Our company believes in sustainable development, We have invested in education, health, sanitation and a potable water supply network," says Mr. P. K. Verma, Production Head, KGD6.

D26 Development

The D26 field is located in approximately 1,200m to 1,400m of water depth in the northern area of the KG-D6 block, with its north boundary approximately 50-km southeast of Kakinada. It is an oil-gas-condensate reservoir in the upper Jurassic-lower Cretaceous fluvial-to-lacustrine sandstones, in a fault-bound structural trap.

Production from this field commenced on September 17, 2008 in a record time of about two and half years from discovery, creating history by the commissioning India's First Deepwater Oil and Gas Production facility.

Development Concept

Considering the location, the size of the field and technical feasibility for early production, RIL developed the field using an FPSO (Floating, Production, Storage and Offloading) based facility, with oil and gas processing, oil and condensate storage, offshore offloading and gas evacuation to the onshore terminal. INTEC, an independent consultant, also studied and validated the concept. Facilities have been planned for full development of the field, with seven wells using horizontal well technology, including multilaterals, as required to minimise the coning and to maximise reservoir contact.

These wells will be connected to the sub-sea manifold from where well fluid would flow to the FPSO through flexible risers. The well fluid will be processed at the FPSO. The stabilised oil and condensate will be stored and offloaded to an oil tanker and the dehydrated gas evacuated through a sub-sea pipeline from the FPSO to the OT via the CRP.

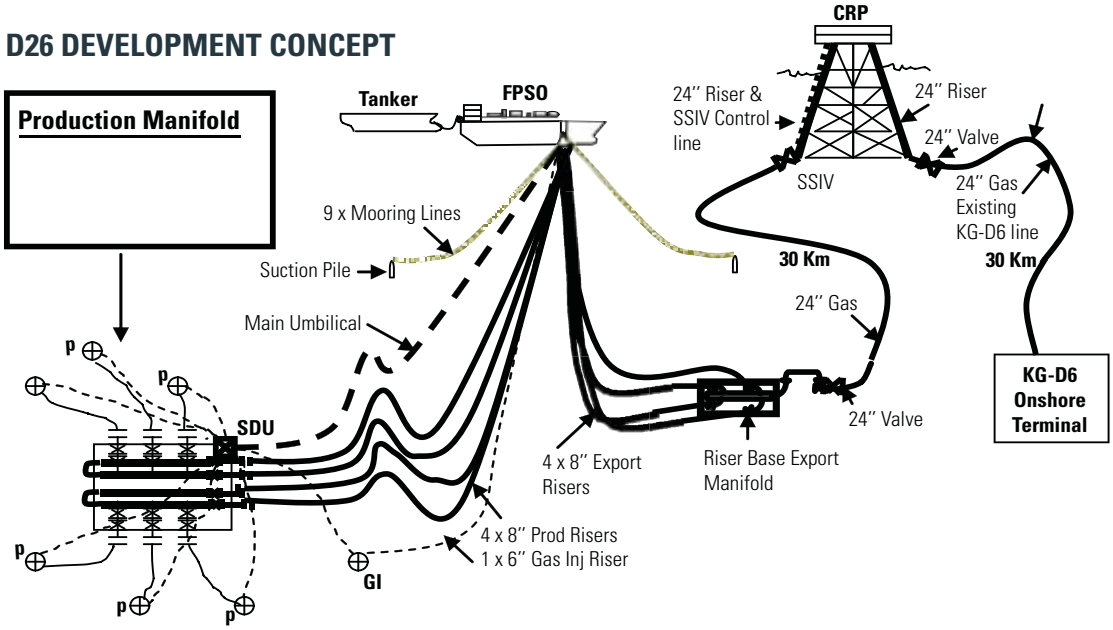
The development concept for the D26 field, as selected and validated by INTEC, is shown in the Figure.

"Since it was a good discovery of light crude oil, we decided to develop the reserves simultaneously," says Mr. PMS Prasad.

The FPSO is capable of processing up to 60,000 bopd of oil/condensate, along with 20,000 bopd of produced water and up to 315 mmscfd of gas. The crude oil storage capacity at the FPSO is about one mmbbls. The FPSO has a turret mooring system to position itself at the desired location for disconnection in extreme weather conditions, without causing any damage."Considering the volatile

"Considering the volatile seas in this part of the world, we found the FPSO-based concept the most apt for the development of the D26 field," says Mr. Padam Singh, Project Manager, D26 Field Development.

D26 DEVELOPMENT CONCEPT



seas in this part of the world, we found the FPSO-based concept the most apt for the development of the D26 field," says Mr. Padam Singh, Project Manager for the D26 Project.

Production from the sub-sea wells would reach the FPSO through four eight-inch flexible production risers. Exported gas will be transported through four eight-inch flexible risers up to an export riser base, and further through to a 24-inch export pipeline. The control signals, power and chemicals would be transmitted to Xmas trees, production and export gas manifold through a multi-path umbilical. Risers and the main umbilical will be connected to the FPSO through a turret and swivel that have a facility to disconnect as required. Oil would be offloaded from the FPSO to the oil tankers, which would be tandem moored to the FPSO. The gas will be exported to the OT through a 24-inch gas pipeline to be laid from the FPSO location in the D26 field to the CRP.

Project Execution

Engineering, design and fabrication of equipment and facilities for D26 field development took place at various locations. RIL leveraged several of its existing contracts in the D1/D3 development project with various vendors for implementation of the early production system. Aker Floating Production (AFP) was contracted for chartering the FPSO. The FPSO was built by conversion of the existing oil tanker, Polar Alaska. The work took place at an accelerated pace at the Jurong Shipyard in Singapore.

Given the tight schedule, RIL did engineering design in house, to be subsequently validated by Intec Engineering, Houston. Based on the selected concept and functional specifications with lump sum scope of work, including the supply, installation and commissioning of entire systems, hardware, and controls from the X'mas tree to FPSO production and product delivery system, tenders were called in the last quarter of 2006.

Aker Group of Companies was awarded the main contract in December 2006. It worked favorably, as Aker was already extensively involved in D1/D3 subsea architecture contracts, including supply of X'mas trees and umbilicals for the natural gas Subsea infrastructure. Besides, the Aker Floating Production was already in an advanced stage, converting a Very Large Crude Carrier, Polar Alaska, into an FPSO.

The FPSO, christened Dhirubhai-1 at Singapore's Jurong Shipyard, was anchored at the deepwater D6 field site on August 14, 2008, after the completion of subsea infrastructure by June 2, 2008. The hook-up started on August 15, 2008, linking the FPSO with the subsea infrastructure, including umbilicals and risers. The first well was opened on September 17, 2008, making deepwater hydrocarbon history in India.

Transocean and Reliance: Pioneering Deepwater Drilling

MUMBAI — Since 2002, Transocean and Reliance have advanced deepwater drilling in India, starting with the customer's first offshore discovery and more recently developing the next-generation of ultra-deepwater drillships.

While working on Reliance's Krishna Godavari (KG) field, the world's largest deepwater natural gas field, Transocean's drillships *Discoverer 534* helped Reliance set the pace for commissioning the field in record time and the *Deepwater Frontier* drilled India's first subsea completion wells. The campaign included an Indian deepwater drilling record and a string of discoveries. It came during a time of progress for both Transocean, including a strong fleet expansion, and for Reliance, which has added significant gas reserves in India.

"With such a wide range of progress in a relatively short period, Reliance and Transocean have gained valuable experience and forged a strong relationship," said Deepak Munganahalli, Managing Director of Transocean's India and Middle East Division. "We look forward to additional successes helping Reliance achieve its goals and further securing India's energy future."

Transocean's deepwater drillship *Discoverer 534* drilled a string of Block D-6 discoveries.

Overcoming Challenges

From the beginning, the *Discoverer 534* proved successful for Reliance, drilling the Dhirubhai discovery in 2002 and subsequent finds in Block KGD6. Success required overcoming challenges ranging from drilling operations in deepwater, including an Indian deepwater drilling record early on of 5,773 feet of water (1,760 meters), to strong surface currents and complex logistics.

At times, surface currents approaching 5 knots, the equivalent of about 60 knots of wind, pushed on the rig. In addition, 35-knot winds sometimes arose. Nevertheless, the rig's crews adapted to these challenging conditions using Transocean's safety and risk-management tools and training, the drillship's dynamic positioning system and close communications during all operations.

Risk-Management Leadership

To ensure success, Transocean and Reliance worked closely before, during and after drilling operations. The team developed the highest quality safety, environmental, risk-management, operational, logistical, materials-procurement and other management systems.

Both companies share the vision of an incident-free workplace in which everyone must return from work as safe as when they arrived. Supporting these efforts is Transocean's on-the-job training program, the most advanced in the offshore drilling sector.

Another contributing factor to the KG field success was Transocean's extensive knowledge of worldwide deepwater operations that includes 80 percent of all deepwater drilling records. This deep pool of expertise and experience proved useful during challenging Indian operations.

Working in India, Transocean's ultra-deepwater drillship *Deepwater Frontier* became the first floating rig to drill a well with concentric riser and managed pressure drilling.

Likewise, Transocean's offices in Mumbai and supply yards on the East and West Coasts of India have contributed by overcoming logistics challenges to provide expertise, supplies and parts.

Transocean personnel continue making offshore drilling history in India.

Toward New Frontiers

When the *Discoverer 534* arrived in India in 2002, it was the only rig in India capable of operating in water depths greater than 3,000 feet. Moving ahead, Reliance hired additional rigs for its exploration efforts in mid-water and deepwater. Transocean is pleased to be a partner with RIL in these efforts through long- term contracts on the drillships *Deepwater Frontier* (since 2006) and *Deepwater Expedition* (since 2008), still working in India today, and the semisubmersible rigs *Actinia* and *C. Kirk Rhein, Jr.* in recent years.

Also today, Transocean, Pacific Drilling and Reliance have introduced to India the latest generation of ultra-deepwater drillships, the *Dhirubhai Deepwater KG-1* and *Dhirubhai Deepwater KG-2*. With a variable deck-load of approximately 20,000 metric tons, these rigs can work in 10,000 to 12,000 feet of water and are outfitted to construct wells 35,000 feet deep.

Transocean and Reliance will also introduce the newbuild ultra-deepwater drillship *Discoverer India*, which will be capable of working in up to 10,000 feet of water and drilling wells 35,000 feet. Transocean's fifth enhanced Enterprise-class drillship, the Discoverer India is expected to mobilize from the shipyard to India in the fourth quarter of 2010.

In addition, offshore drilling technology pioneered by Transocean and Reliance in areas beside the KG basin includes the use of managed pressure drilling on the *Deepwater Frontier and the Actinia.*

"It's always great to be recognized for leadership in offshore drilling," said Munganahalli, "and it's especially meaningful when it's for work with a customer like Reliance, which has proven its leadership time and time again. The results of our relationship are special, and we are proud of everything our team has achieved."

Integrated Project Teams Achieve Fast-Track Conclusion at KG-D6

Aggressive development schedule challenge met by Reliance, Schlumberger

From the very start, Schlumberger has been involved in developing deepwater projects, contributing its marine seismic, data and consulting, reservoir evaluation and wireline, drilling and measurement, testing and other uniquely related technologies and services for the exploration, completion and production phases. Based upon RIL's unique needs for the KG-D6 development, Schlumberger has applied several new game-changing completion and production monitoring technologies.

The *Geco Eagle* acquired over 400 miles^2 of seismic data over the KG-D6 block.

Seismic to exploration well target selection calls for new geobody model

In 2001, RIL awarded the first 3D seismic survey on the KG-D6 block to Schlumberger's WesternGeco business unit, whose state-of-the-art vessel *Geco Eagle* acquired some 463 miles^2 of seismic data, which revealed several areas of interest for possible subsequent drilling. The processing of this initial survey identified a reservoir of interest among what was described as a very laminated and sinuous body of channel-fan complexes stacked together to a gross thickness of some 1,150 ft.

Reliance needed a new approach to capture the exact vertical extent of the channel-levee complex to delineate the reservoir and estimate volumetrics more accurately.

Reservoir modeling experts with Schlumberger Information Solutions (SIS) joined in a multidisciplinary team effort with RIL geologists, geophysicists and reservoir engineers in designing a new, more reliable geobody interpretation workflow program using SIS' Petrel* seismic-to-simulation software for representing reservoir features.

The advanced Petrel technology provided the team with a single, integrated platform from which to execute a complete workflow. Additionally, the software's ability to incorporate data from various other analyses allowed the SIS-RIL team to include a detailed thin-bed characterization and petrophysical analysis from core data in a new reservoir model.

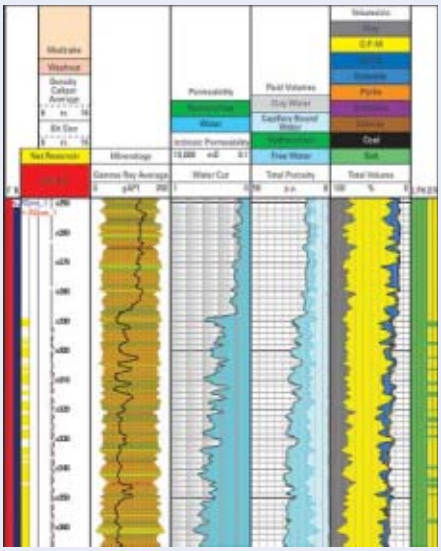
Using Petrel's geobody extraction tool allowed the team to complete the complex job in only about one-fifth of the time typically required by conventional aerial demarcation technology. Using Petrel markedly increased the effectiveness of the team's ability to model the reservoir and compute volumetric estimates.

Safe, efficient well LWD

From the beginning, RIL's main objectives at the Dhirubhai project were safe drilling and accurate formation evaluation. Operating in a region widely known for its extremely hostile weather conditions, including frequent tropical cyclones (typhoons) with winds of more than 100 mph, waves of up to 65 ft. (20 m) and subsea currents of more than 4 knots, the KG-D6 drilling posed challenges for even the three all ocean-rated, dynamically positioned drillships used for drilling and completions. What's more, once drilling began, Reliance faced challenges in acquiring log data in an area where wells had never before been drilled.

Anticipating a long line of similar challenges, the company took special care in choosing its project stakeholders. For the drilling and measurements (D&M) and wireline (REW) work, RIL again chose Schlumberger.

Once drilling began, Schlumberger and RIL collaborated in using drilling performance measurements made with LWD tools to enhance drilling performance and safety. Combining LWD data both in the field and in off-site planning centers allowed the drilling team to highlight formation attributes. It also helped them to identify crucial problem areas for which drilling engineers were able to take real-time corrective drilling measures, if necessary. Using real-time caliper data, for example, revealed hole shape and condition, thus making it easier to evaluate formations and to make appropriate completion decisions.



The EcoView* answer product assists in the analysis of the comprehensive data suite from the EcoScope service.

Schlumberger provided a full suite of LWD logs, including real-time caliper and the company's adnVISION* azimuthal density neutron service for real-time neutron porosity, formation bulk density and photoelectric factor data to characterize formation porosity and lithology while drilling, identifying and quantifying potential pay zones.

Particularly useful during LWD operations was the use of the EcoScope* multifunctional LWD service, which integrates a full suite of data formation evaluation in one compact single 26 ft. collar. Use of this service reduced the risk often associated with the multiple collars necessary for conventional triple combo logs in vertical well sections. In addition to resistivity, neutron porosity and azimuthal gamma ray and density, EcoScope provided while-drilling measurements of elemental capture spectroscopy and sigma.

The real-time data transited via a Schlumberger teleport, before reaching the RIL reservoir engineer's desktop.

InterAct carries well data globally

Additionally, the drilling team employed Schlumberger's InterACT* real-time monitoring and data delivery system to transmit well data from drilling locations to reservoir engineers' desktops at RIL's headquarters in Mumbai, as well as to those in the Schlumberger network of Operation Support Centers. These centers have experts who monitor drilling operations in real time, 24/7. Using a standard Web browser and intranet connections, InterACT helped to enhance the collaborative abilities of both well site and off-well site specialists in India and elsewhere around the world to leverage their decision making, enabling RIL to focus multiple, disparate and specialized resources on both individual wells and, subsequently, well clusters.

As identified by the LWD service, the formation of interest in KG-D6 is comprised of massive sands interspersed with a significant number of thin beds. So, the drilling team combined resistivity data from LWD with those recorded by Schlumberger's wireline-conveyed HRLA* high-resolution lateralog array tool in combination with the rugged PLATFORM EXPRESS* logging system.

New logging technology identifies additional reserves

In vertical wells with thick, homogeneous horizontal beds, standard resistivity logging tools like the AIT array induction imager tool deliver satisfactory data. In some KG-D6 wells, however, gas contained in laminated sand-shale sequences might have been overlooked due to the effects of anisotropy, where the thin beds all exhibit higher and/or lower resistivities, i.e. where conductivity in one direction – say, parallel to one layer – differs from that in another direction – say perpendicular to an adjacent layer. What's more, in such thin sand-shale turbidite sequences, many layers are thinner – in the millimeter range – than the vertical resolution of conventional wireline-conveyed induction logging tools, which have a minimum 1-ft (0.3-m) resolution, and even less than the 1.2-in. (3-cm) vertical resolution of typical porosity tools.

Certain HG-D6 wells were deviated to the extent that gravity decent wireline logging would not work. Pipe conveyed logging was chosen rather than LWD.

One such critical tool to deliver understanding of the laminated sections was the OBMI* oil-base micro-imager tool. This expanded the drilling team's understanding of the distribution of the thin beds and a more accurate sand count. In addition the vertical seismic imaging tool (VSI) enhanced the structural model and revealed rock property information that could be used for geomechanical study, enabling RIL to plan for the future production phase.

Engineer performs operational checks on the OBMI tool before a job.

Also included in the open-hole wireline logging tool combinations employed were the Rt Scanner* triaxial induction service, the Sonic Scanner*acoustic scanning platform and the PressureXpress* (XPT) reservoir pressure while logging tool selected because they were judged to deliver the required data in the most efficient manner.

For a deeper understanding of the true resistivity of the laminated pay sections, the Rt Scanner triaxial induction service, which measures formation resistivity both perpendicular and parallel to the direction of the laminated silt-sand layers (Rv and Rh, respectively) was utilized. (Note: The tool also provides

traditional AIT type measurements.) Taking measurements at multiple depths of investigation in three dimensions provided a true 3-D resistivity map. The enhanced hydrocarbon and water saturation estimates computed from these measurements resulted in a more accurate reservoir model and finer reserves estimates, particularly for the laminated, anisotropic formations.

Reservoir summation results derived by the Rt Scanner demonstrated that for the complete logged intervals, net pay thickness value was 1.35 times higher than that produced by the basic AIT tool. Additionally, the Rt Scanner-derived net pay hydrocarbon porosity thickness was 1.55 times larger than that of the corresponding AIT, which translated to a 700% additional net pay.

Single-pass sonic tool delivers quick formation evaluation

During drilling certain borehole sections exhibited radial plastic yielding caused by stress concentrations resulting in drilling-induced damages. Wireline formation pressure and sampling testing of such intervals resulted in lost seals or tight pre-tests. This increased the time to realize successful pressure and fluid samples at a cost proportional to expensive rig spread rates, far greater than the cost of the service itself.

To evaluate the formation alteration in subsequent, similar well intervals, RIL employed Schlumberger's Sonic Scanner tool to evaluate both far field and near field slowness. Unlike other sonic tools, which deliver mostly near wellbore data, the Sonic Scanner also is capable of measuring deep formation slowness at varying radial depths. The tool is equipped with 5 transmitters and 104 receivers, with a unique dipole source design that enables it to be fired in either pulse or "chirp" mode. Slowness identification using the Sonic Scanner aided the RIL-Schlumberger drilling team in denoting optimal pretest/sampling point selection, thereby saving considerably in nonproductive rig time. The tool also proved beneficial for evaluating radial acoustic behavior behind cemented casing intervals.

The Sonic Scanner tool provides the benefits of axial, azimuthal, and radial information for near-wellbore and far-field slowness information.

In comes the MDT

Once initial drilling was completed, RIL decided to conduct reservoir tests only in very promising zones and integrate other, lower-priority zones with an alternative method that would take less time and expense.

Working closely with Schlumberger Data and Consulting experts, RIL chose the MDT* modular formation dynamics tester, coupled with a dual packer, interval pressure transient testing tool – and integrating them into a single-well predictive model (SWPM) analysis to determine formation parameters and estimate well deliverability. InterACT real-time monitoring was used to transmit the test data to RIL engineers in Mumbai.

The interval pressure transient tests were conducted using the MDT's straddle packer system. The transient sequences consisted of single or multiple flow periods induced using a downhole pump, followed by periods of pressure buildup. The results were then used for the numerical single-well model to predict the commingled deliverability of several layers.

The success of single-well simulation and commingled approach allowed RIL to forecast absolute open flow potential (AOFP) for multiple zones. Well deliverability estimates were included using production tubular and choke information in the simulation model. According to RIL, this approach resulted in significant savings in rig time/cost by providing productivity estimates and AOFP without having to resort to conventional four-point deliverability tests.

In addition to the MDT sampling program, RIL also responded enthusiastically to the use in specific cases of

MDT packers are inflated to isolate a reservoir zone for fluid sampling and pressure measurements.

Schlumberger's PressureXpress reservoir pressure measurement tool for both lower and higher mobility sands of up to > 500 md/cp.

More drilling, seismic further expands KG-D6 play

After drilling and testing the initial wells, RIL chose WesternGeco to conduct a detailed, 3D seismic survey over the most promising areas covering some 1,120 miles^2 in the KG-D6 acreage.

The high quality of the data lead to a detailed seismic attribute interpretation; and 12 of 13 exploration wells hit the target structure and found commercial hydrocarbons.

Meanwhile, WesternGeco returned to the block for the third time, in this instance to acquire 875 miles^2 of 3D data, to cover the complete block concession with 3D data. This was done mainly to identify the presence of geological features similar to those in which discoveries already had been drilled, and to determine whether it was justifiable to declare the entire block as a discovery area.

In view of the resulting significantly higher hydrocarbon potential, coupled with a growing deficit in India's projected natural gas supply for the immediate future, RIL in 2006 obtained government approval to double its daily KG-D6 gas production and to enhance facilities for production, collection and handling of gas both offshore and onshore. A revised estimate of capital expenditures for the enhanced production profile rose to about US$5.2 billion.

Part of the new spending for development of Dhirubhai 1 and 3 included the need for special/advanced pro-

cessing and interpretation of already acquired seismic data, as well obtaining still more 3D data. For the latter, RIL decided to acquire high-resolution Q-Marine* point-receiver 3D data – the first time WesternGeco's Q-Marine technology would be used off India.

RIL called for Q-Marine data acquisition with pre-processing onboard, followed by integrated onshore processing and inversion of the acquired seismic data to address some of the uncertainties in the reservoir description, reserves estimation, and well target selection and placement.

WesternGeco mobilized the *Geco Topaz* for the job in 2007 to meet not only the demanding geophysical challenges of the development survey but also because the Q-Marine technology she deployed enhanced the ability to maneuver in and around a crowded field of drillships, jackup rigs and host of support and survey vessels. The steerable streamer technology made a significant impact with minimum lost time and safe passes, and, perhaps most importantly, coverage of the entire survey area with no gaps in data coverage.

Impressed with the completion of the 170 mile^2 survey ahead of time and meeting their objective for the KG-D6 gas fields, RIL then decided to extend the development survey to the 123-mile^2 MA oil field, which was promptly completed in a similar fashion.

Live well operations performed safely from a dynamically positioned vessel

For field development, RIL elected to drill and complete 18 strategically placed subsea production wells in the two KG-D6 gas fields and in the adjacent MA oil field, each well equipped with dual open hole gravel pack completions. Early production data would be used to delineate the reservoir and define connectivity and compartmentalization. Petrel was used to demarcate the geobodies.

The wells were batch drilled, with one drillship doing the lower completion and a second following behind for the upper completion. However, a major issue was how to conduct the live well operations safely from a dynamically positioned vessel with the added risk of severe monsoon weather conditions. The subsea landing string system incorporating SenTREE* 7 subsea test tree and SenTURIAN* electrohydraulic operating system provided the solution for efficient and safe access to the dynamic reservoir parameters. Schlumberger has been providing subsea landing string services for over 35 years, and the evolution continued on this project with the first application of SenTURIAN.

Schlumberger introduced the SenTURIAN subsea landing string electrohydraulic operating system on this project to deliver reliable subsea well control, with an emphasis on improved offshore operating efficiency. It is the world's first and only in-riser system design and certified in accordance with the International Electrotechnical Commission's IEC 61508 SIL 2 reliability specifications for safety-related systems. It features an innovative, modular system that is much simpler to operate and smaller than comparable systems, allowing rig-time savings of as much as 50% during handling under certain circumstances. The modularity of the system's design also makes it ideal for job-specific customization. It is designed to operate from dynamically positioned vessels in all subsea applications, including deepwater and HPHT wells, in waters as deep as 15,000 ft.

SenTURIAN subsea landing string electrohydraulic operating system

SenTURIAN is the first landing string system to use interchangeable mandrels and pressure-balanced accumulators. This allows both subsea control and accumulator modules to be combined in a single assembly, which is 50% shorter than other systems, while providing the tensile strength, pressure rating, and hydraulic output needed for the full range of water depths. The operating system has programmable emergency shutdown levels that can be configured to close all subsea test tree valves to shut in a well and unlatch the landing string in less than 15 seconds.

Reservoir illumination without intervention

Because of reservoir uncertainties with respect to zonal contribution and inter-well connectivity, RIL called for an advanced measurement system to be permanently installed along the sandface of six of their wells. This system would supply real-time temperature and pressure data as well as an array temperature profile to be used for flow-profiling, tracking depletion, identifying water breakthrough, and making other critical production and reservoir evaluations. This system would provide an extra dimension to the pressure interference testing traditionally used to map out connectivity, which was to be used in the remaining 12 wells drilled.

To deliver on this requirement, Schlumberger deployed its new WellWatcher Flux* digital sensor array system in the six designated wells with the goal of establishing a complete real-time communication chain from the sandface to the RIL offices in Mumbai.

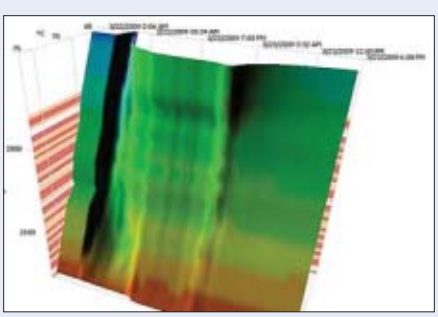
Integrated into the completion, the WellWatcher Flux system is designed to transmit data via a unique inductive coupler that links sensors on the gravel-pack to traditional permanent gauge hardware on the upper completion. The sensors are miniaturized, high-resolution, platinum resistance temperature devices located inside a small housing.

During manufacturing, according to RIL specifications, between 15 and 25 sensors were welded to a continuous control line to create a spoolable array for each well. The arrays were designed to be clamped along joints of each sandscreen as they were run in hole. Splicing and small depth adjustments could be made to each array during deployment if that proved necessary. The sensors measure the completion temperature which, in turn, is determined by the temperatures of both the incoming and wellbore fluids.

The inductive coupling, through wireless, allows transmission of power from the upper to the lower completion, as well as communication between the completion stages. Verification runs were made before running the upper completion to check integrity of the formation isolation valve, take a measurement of geothermal temperature and, most importantly, verify good communication across the inductive coupling. All six couplers worked flawlessly according to Reliance. Once the upper completion was landed, activation of the subsea tree penetrator brought the sandface data on line.

'Side Effects' deliver even more data

With the surface test equipment in place, the wells were cleaned up to avoid any excess completion fluid being passed into production facilities. The sandface data showed each zone cleaning up as gas displaced the completion fluid, generally progressing from the top of the well downward. But in many wells, the sandface data showed more than that. Several of the wells showed cross-flow before being put on line, with some flowing from bottom to top, others with zones flowing from top to bottom, and data indicated from which zone the flow crossed into the other.



THERMA modeling and analysis software derives flow profile information by combining WellWatcher Flux data with reservoir, fluid, well and completion properties. It also provides Flux data visualization, such as this example from well A9 where the image shows cold fluid ingress after opening formation isolation valve, heating as the well is brought online, slight cooling progressively from the top-down as the gas displaces completion fluid, a stable production temperature and finally cooling back to geothermal after the well is shut in.

The sandface and gauge data was transmitted to Mumbai for real-time visualization and analysis. Dedicated THERMA* visualization/interpretation software was used for 3D display of the sandface data.

The power of the THERMA software was demonstrated once the wells were put online for production. Analysis of the data from the first well equipped with WellWatcher Flux data demonstrated that gas was being produced across the extent of the sandface, with no significant skin damage from invaded completion fluid. A quantitative flow profile was also obtained.

As other wells were put onto production, however, the sandface data showed something even more interesting. The data indicated that the cross-flow was not just from one compartment to another, but, often from one well to another. RIL engineers complemented this information with traditional pressure interference testing and have been able to use the cross-flow information to update their geobody descriptions in Petrel, significantly increasing their understanding of the compartments and connectivity across the reservoir. This information will be used to plan the next phase of the production drainage.

Commitment to SE Asia

According to joint RIL-Schlumberger estimates, more than 10,000 offshore and 80,000 onshore worker hours were logged during the drilling and completion phase of the KG-D6 projects without lost-time or safety incidents.

Partly responsible for giving RIL-Schlumberger project teams the ability to conduct drilling and completion activity safely, on time and on budget with timely equipment arrival and utilization has been the construction in 2007 of a Schlumberger Deepwater Centre of Excellence at its land base in Kakinada, India, on the coast.

WellWatcher permanent monitoring systems integrate the most advanced permanent downhole gauges with surface data communication to allow remote monitoring of wells and reservoirs in real time.

Prominent features of the base include a 120-ft (36.6 m) subsea maintenance and storage tower and a 110-ft (33.5 m), 30-in. diameter test and assembly well.

There, subsea testing and completion tool strings were assembled, qualified and system-tested under realistic field conditions before being staged offshore. The Kakinada Centre serves RIL and in-country Schlumberger personnel as a training and technical support base for KG-D6 operations, as well as for similar deepwater operations for all other areas of Southeast Asia.

*Mark of Schlumberger

Schlumberger

Schlumberger Asia Services Ltd.
14th Floor, Tower C, Building No 10,
DLF Cyber City, Phase II,
Gurgaon - 122 002, India
Phone: +91 124 3355 667 • Fax: +91 124 3026 200
Email: marketingsupportINM@slb.com
Website: www.slb.com

No guts, no glory

In September 2006, Allseas was awarded the offshore installation contract for the Dhirubhai-1 & Dhirubhai-3 (D1 & D3) Gas development Project, off Kakinada on the East coast of India. It was the largest single order Allseas had received and the first contract from Reliance Industries Limited (RIL), a new player in the E&P industry and operator of the KG D6 Block. The contract included installation of subsea structures, pipelines, umbilicals and subsea tie-in connections.

Allseas' *Audacia* installing a PLEM

The D1 & D3 gas development project includes 18 wells in water depths ranging from 600 m to 1200 m, connected to a deepwater pipeline end manifold (DWPLEM) via cluster manifolds through pipelines and infield umbilicals. The gas from the DWPLEM passes through a shallow water control and riser platform (CRP) to the landfall point (LFP), situated 5 km from the onshore gas handling terminal.

Allseas engaged specialized sub-contractors and formed various project management teams at different sites all around world. The turn-around cycle was made swifter with RIL teams co-locating with Allseas' teams at multiple locations for dynamic review and decision making.

Offshore installation and pre-commissioning was carried out from August 2007 until August 2009. The inclement weather on India's east coast reduced an effective and fair weather window for offshore installation to four months (from mid December to mid April). A state of the art fleet of installation vessels was mobilized to the site. The main installation vessels Audacia, Lorelay, Tog Mor and Express were supported by more than 80 vessels and barges, working in a limited area of 350 sq. km. An effective vessel tracking system was utilized for meticulous planning of all vessel movements.

Allseas' fleet in the Indian Ocean - *Lorelay, Calamity Jane* and *Audacia*

The offshore facilities included installation of 350 km of pipeline, 150 km of umbilicals, 11 subsea structures (DWPLEM, manifolds, SDAs, UDH), 45 pipeline end terminations (PLETs), 29 anchor boxes and 56 jumpers. More than 200 subsea connections were executed.

On March 31, 2009, the loop test of two 24-inch gas trunklines from the DWPLEM to the onshore terminal was successfully completed in order to establish the baseline integrity. On April 1, 2009, the choke of the first well was opened.

With Allseas as one of the major contractors, many records were set, many milestones achieved and many benchmarks established. This challenging project would not have been successful without the extra effort every team member put in over the last three years and absolute support and commitment from the top management of Allseas and RIL.

Allseas Group S.A.
Route de Pra de Plan 18
Case Postale 411
1618 Châtel-Saint-Denis, Switzerland
Phone: +41 21 948 3500
Fax: +41 21 948 3599
Email: sales@allseas.com
Web site: www.allseas.com

Fast Track Deepwater Field Development Under Challenging Conditions

Limited initial knowledge of soil conditions. Absence of onshore logistical infrastructure. Hostile seas with an annual construction weather window of only four to five months. Severe supply chain constraints. Reads like a perfect recipe for project delays and troublesome operations, doesn't it? On the contrary, Aker Solutions, which clinched the two challenging deepwater contracts: KG D6 and MA D6 in the Bay of Bengal India, has helped Reliance Industries set the industry record for fast track development. From discovery to first gas, the KG Basin field development, also known as D1/D3 field, has been implemented in just 6.5 years, significantly ahead of the average nine-year span needed for projects of similar scale, whereas the MA D6 field, or known as D26 had successfully brought the first oil onshore in a record time of just under two and a half years.

Dhirubhai I FPSO is positioned over the MA D6 subsea production system. The suezmax tanker was converted to a Aker's Smart FPSO with a processing capacity of 9 million cubic meters of gas and 60,000 barrels of oil per day.

Integrated Turnkey Solution

For the D1/D3 gas field, Aker Solutions has provided the complete subsea production system with 19 subsea trees, six manifolds and associated systems, including 180 kilometers of steel tube umbilicals. For the D26 oil field, Aker Solutions has provided the subsea production system, flexible risers, and its first Smart FPSO solution with real-time onshore monitoring. Aker Solutions has also set up a service base in the town of Kakinada to provide life-of-field service support to both the D1/D3 and D26 fields.

Total Team Effort

"Never has such a complex deepwater project been delivered quicker," explained Dave Hutchinson, Aker Solutions' President for Subsea Asia Pacific, "The pace of the entire field development is a testament to the fast track approach Reliance has taken to this project, and their ability to make extremely fast decisions."

Project Director Oddvar Byrne described some of the ingredients in the successes of Aker Solutions. "We have a unique partnership with Reliance. Both sides have kept the same teams in place as much as possible from day one. Such relationships are important – never underestimate the value of continuity."

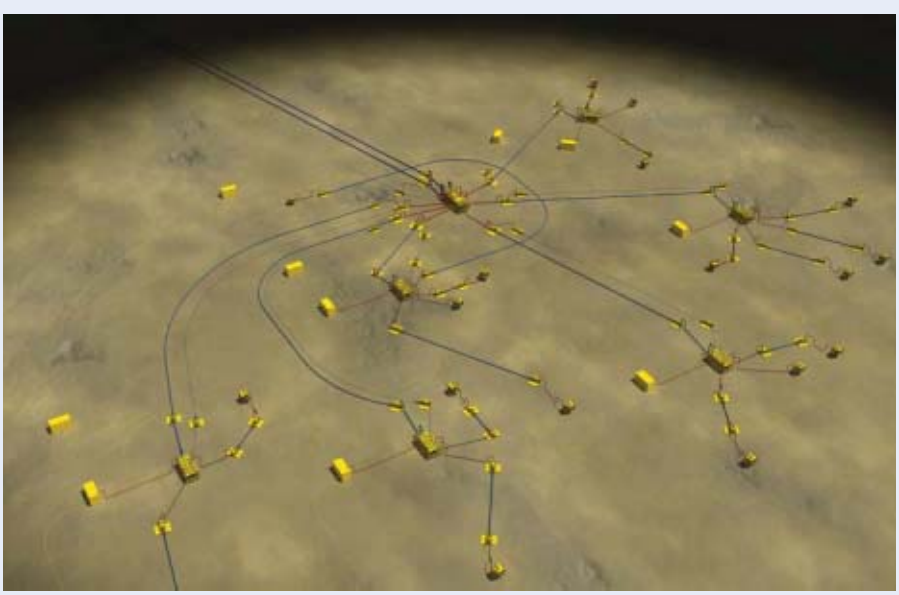
Subsea umiblicals were manufactured at Aker's Moss facility in Norway.

Global Engineering & Manufacturing

As a global provider of engineering and construction services, Aker Solutions called upon its resources in Norway, U.K. and Asia Pacific. The KG Basin projects have been managed out of Aker Solutions' headquarters in Oslo, Norway and the subsea equipment was manufactured at Tranby and Moss, Norway; Aberdeen, U.K.; and the high-tech manufacturing center in Port Klang, Malaysia.

Technology Challenges

As the Aker Solutions team learned more details about the virgin production area, several design and procurement changes had to be accommodated into the tight development schedule, including strong currents, an uneven seabed and low seabed water temperatures. For example, the production risers were initially designed for mild operating temperatures. Subsequently, stringent design temperature was imposed and Rilsan material was replaced by bi-layer PVDF material. Synthetic foam was added to the static section of the riser as well as the infield section. A Pliant-Wave® riser configuration was selected with 150 tons of distributed buoyancy per riser to accommodate the FPSO turret buoy in both connected and disconnected modes.



Reliance field subsea layout

Tight Weather Window

The D1/D3 and D26 fields are located in the Bay of Bengal, which is affected by the Monsoons from April to September and cyclones until late November. As a result, the offshore construction window typically ranges from December to April. The D26 field installation was managed over two phases. During 2008, Phase I covered first oil upon arrival of the FPSO and Phase II was performed in the following year for full production of the system.

Future Bay of Bengal Developments

In late December 2009, Reliance successfully achieved assessment of the design capacity of the KG D6 deepwater gas production facilities with a flow rate of 80 million standard cubic meters. "The Bay of Bengal is a fast-growing oil and gas region and we are well positioned to play a leading part in its development," said Mads Anderson, executive vice president, Aker Solutions.

Summarizing the project, Oddvar Bryne points out, "I don't think too many contractors can deliver what we have done all way through subsea installation to the operations side, from hardware delivery to management of all interfaces."

AkerSolutions

Aker Solutions

Regional HQ for Asia Pacific (Subsea)
Level 20, Menara HLA,No. 3, Jalan Kia Peng,
50450 Kuala Lumpur, Malaysia.
Tel: +603-2381 8388 Fax: +603 2164 4613

Reliance Employs Baker Hughes Products, Services for KG-D6 Development

Fast, yet safe operations plan calls for field-proven, new technologies

As a global market leader in the supply of equipment for the deepwater market sector, Baker Hughes was pleased to be chosen as one of the leading technology partners for Reliance Industries Ltd. (RIL) in development of the Dhirubhai 1 and 3 discoveries in India's Bay of Bengal. Baker Hughes took full advantage of the opportunity to deliver best-in-class products and services for one of the largest and most complex endeavors in Indian offshore petroleum history.

Supplying both its conventional tools and services and several of its latest technologies for drilling, formation evaluation, well completion and production, Baker Hughes has been an essential participant in bringing the first phases of the Dhirubhai gas and oil development to successful conclusion.

With the many challenges posed in the development of discoveries in water depths ranging between 2,297 to 5,577 ft (700 to 1,700m), including the delineation of producing reservoirs and placement of wells and production facilities in an area plagued by hostile weather, RIL was compelled to balance fast, but safe, drilling with highly accurate formation evaluation techniques. Due to its track record in deep water, Baker Hughes was chosen among RIL's key service partners for the project.

Leading-edge drilling, logging

In addition to specifying the use of industry-leading drill bits from Baker Hughes and optimum drilling and completion fluid systems, RIL contracted a significant number of the company's advanced directional drilling and formation services. These included the AutoTrak™ rotary steerable directional drilling system, high-performance drilling motors, integrated measurement-while-drilling / logging-while-drilling (MWD / LWD) drilling packages and high-pressure coring services.

RIL used Baker Hughes' people and services to precisely drill India's first deepwater multilateral wells, maintaining accurate TVD control, and to drill the deepest well in the project to a vertical depth of 20,210 ft (6,282m).

The technology deployed on this project for RIL included many of Baker Hughes' advanced LWD systems. The SoundTrak™ acoustic LWD service, which is integrated into the existing modular tool, delivers advanced acoustic information allowing for the accurate prediction of pore pressure and tie-in with the surface seismic. Also deployed for various applications were the OnTrak™ system, which is a compact integrated MWD-LWD platform providing resistivity, gamma ray and pressure readings very close to the bit, and the LithoTrak™ service, providing accurate borehole density and porosity readings in real time. In addition to the formation evaluation services, Baker Hughes deployed the CoPilot™ real-time drilling optimization service, which allows the drill crew to accurately understand downhole conditions, so surface parameters can be adjusted to optimize the drilling process.

Timely data, simple access

To tie field-specific data sets together for decision-making, Baker Hughes also provided its RigLink™ Web-based communications system to keep RIL engineers and geoscientists informed with real-time drilling data. The system made secure, current data from multiple rigsites available to RIL personnel both at the wellsite and at data centers on shore. Using RigLink's display and reporting package, RIL was able to streamline internal work processes, allowing both rig-based personnel and onshore experts to view critical data in real time. Additionally, RIL users could program RigLink to notify them whenever certain operations or drilling parameters were met.

Imaging through OBM

While Baker Hughes provided much of the drilling and MWD-LWD technology for the project, they also participated in logging and completing KG-D6 wells.

Among wireline services, RIL chose to apply the company's EARTH Imager™ resistivity imager. Using advanced electrical conductivity measurements for oil-based mud systems (OBM), the EARTH Imager service provides high-resolution image logs of a quality previously available only in water-based mud systems. These high-resolution images were crucial in the thinly bedded geologies seen in the wells.

Also vital to RIL's stated goal of fast yet safe drilling and completion operations, the company applied the Baker Hughes Reservoir Characterization Instrument™ (RCI) in a large number of wells. This system was crucial in supplying pressures and fluid samples from the wells. The RCI provides an efficient, cost-effective method for collecting quality formation fluid samples with minimal contamination and accurate formation pressures without need for a time-consuming drillstem test (DST).

Equalizing with inflow control

In the production and completions arena, Baker Hughes played a key role in development of the KG-D6 MA oil field.

The oil wells were completed using the EQUALIZER™ reservoir optimized completions system which, when combined with the EXCLUDER2000™ premium mesh screen technology, delivers superior sand control. Additionally, the system features a unique inflow-control device that helps to extend longevity of production in long, low drain-down, high flow rate horizontal wells by delaying water or gas coning.

In addition to the EQUALIZER system, Baker Hughes also provided liner hanger services and was a major provider of safety valves and service screens.

Baker Hughes
2929 Allen Parkway
Houston, Texas 77019
Phone: 713-439-8135
Fax: 713-439-8600
Email: Kathy.shirley@bakerhughes.com
Web site: www.bakerhughes.com

Bechtel Offshore's Project Management Consultant services results in smooth, fast field development

Bechtel Offshore, a market sector of Bechtel Oil, Gas and Chemicals (OGC), provided key Project Management Consultant (PMC) services to Reliance Industries' KG D6 D1/D3 and MA subsea oil field projects. The field was one of the oil and gas industry's fastest greenfield development projects ever, only 6 ½ years from discovery to production of the D6 field. Bechtel's services included support in design review, schedule integration, procurement and expediting, flow assurance analysis, supplier quality assurance, offshore installation supervision, precommissioning and start-up support.

Installation of the subsea facilities was accomplished in less than two years. The quick engineering, equipment deliveries and installation and commissioning took place during difficult sea conditions in a hostile offshore environment and challenging and hazardous subsea terrain.

The PMC team was organized to bring together Bechtel's experience, expertise and proven track record of its worldwide organization of over 40 offices and 390 active projects. Bechtel took the lead in a number of areas including HS&E, quality assurance, construction management, interface management, and assisting in the tendering of material purchase orders and contracts. At the project's peak, Bechtel had over 200 individuals working in the U.S., Europe, Middle East, India and Southeast Asia.

The deepwater pipeline end manifold (DWPLEM) being installed.

On-time delivery was accomplished from global suppliers who at times faced cultural challenges, working within different time zones, complex logistics and an overheated supplier market. Supplying components for the project truly was an international effort, with major suppliers providing equipment from the U.S., U.K., The Netherlands, Norway, Dubai, India, Japan, Germany, Italy, Thailand, Singapore, and Australia. Additionally, the subsea wellheads (valves, spools and fitting assemblies) and umbilicals were assembled in Norway. Subsea structures were assembled in Malaysia and the control systems were assembled in Scotland.

Bechtel oversaw fabrication, testing and system integration testing (SIT) of all jumpers onshore prior to offshore deployment.

In addition to the project management professionals, Bechtel supplied subject matter experts in subsea pipeline design, flow assurance, cathodic protection, welding and corrosion protection. The company managed the development of the production system simulator (PSS) which provided the magnitude of ramp-up rates to limit the liquid arrival at the slug catcher within its capacity for a flawless start-up.

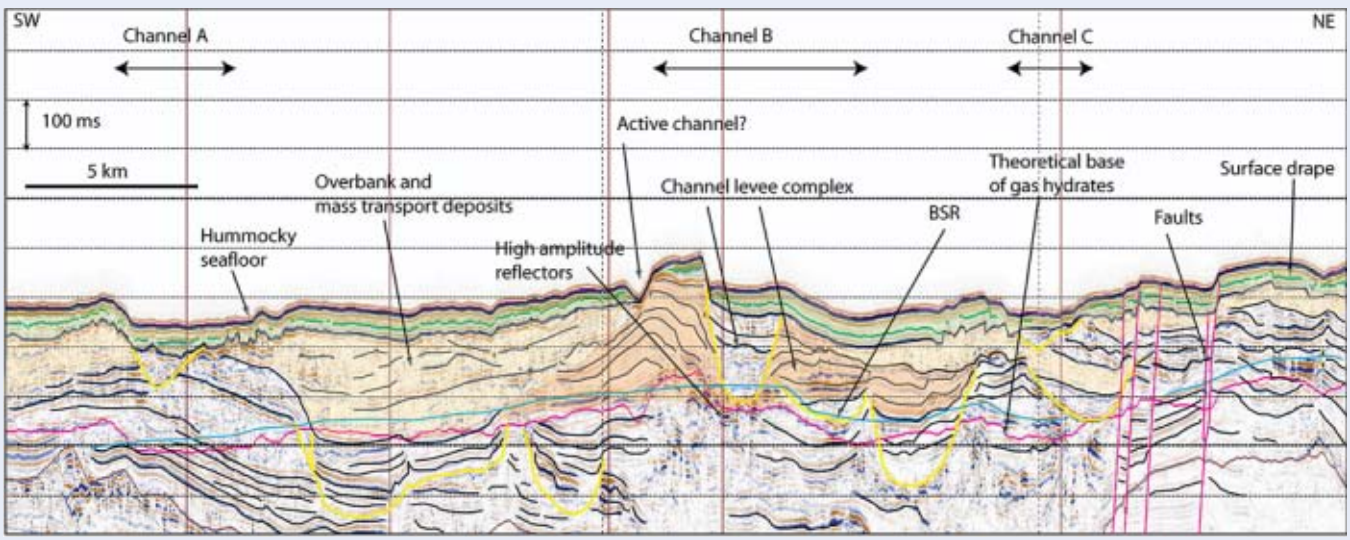
Bechtel provided support to manage and overcome two of the greatest challenges the project faced, namely logistics and weather. While the entire project was spread across 154 sq miles, most of the work was concentrated in smaller zones where pipelines and umbilicals cross and connect with well clusters on the seafloor. Bechtel and Reliance closely coordinated and monitored the various zones to manage access by the 89 large and small vessels used to install the equipment.

Bechtel's dedication to excellence in safety, engineering oversight, supplier quality management, interface management, and flow assurance amongst other PMC service assured that the project would start up free of consequences of slugging and the formation of hydrates that could be present due to the cold, deep waters in the field. Successful start-up of the wells attests to Bechtel's quality of work gained from the company's experience and expertise that began in the 1930s. Bechtel's offshore marine commitment and heritage spans signature projects such as the Hutton Field development in the North Sea, Cantarell Crude Oil Expansion in the Mexican Gulf of Mexico, Thailand Transmission Pipelines, MA/KG D6 project, and beyond.

Bechtel Corporation
3000 Post Oak Blvd.
Houston, Texas
77056 U.S.A
Phone: (713) 235-2000
Fax: (713) 960-9031
Web site: http://www.bechtel.com/

Geohazards and geoscience expertise

NGI (Norwegian Geotechnical Institute) was contracted by Reliance Industries Limited to undertake a regional geohazards study for their KG D6 Block development. Geologically, this area is characterized by rapid sedimentation from the many large river systems into the Indian Ocean and the Bay of Bengal. The study was undertaken to assess potential unstable conditions due to underwater sliding and other geohazards, to analyse the possibility of hazards to under water installations.



Seismic section KG D6, Ref. C. F. Forsberg, A. Solheim, T. Kvalstad, R. Vaidya, and S. Mohanty. 2007. Slope instability and mass transport deposits on the Godavari River delta, East Indian margin from a regional geological perspective. In: V. Lykousis, D. Sakellariou, and J. Locat, Submarine mass movements and their consequences. Publ. Springer, Dordrecht, The Netherlands. 19-27.

The study included review of available information on seabed topography, regional geology and soil conditions, supplemented by site specific geological and geotechnical investigations. The work resulted in alterations to pipeline routes in order to minimize geohazard risks such as underwater sliding. The safety and soundness of the planned development of the area was also confirmed.

Offshore geotechnical pioneers

NGI is a private foundation with offices and a laboratory in Oslo, a branch office in Trondheim, and an affiliated company in Houston. NGI works within the oil, gas and energy, building and construction, transportation, natural hazards and environment sectors.

NGI is a leading international center for research and consulting in the geosciences. The foundation develops optimum solutions, and offers expertise on the behavior of soil, rock and snow and their interaction with the natural and built environment.

NGI was awarded Centre of Excellence status in 2002 and leads the International Centre for Geohazards (ICG). NGI also received an award for "outstanding contributions in the field of offshore geotechnical engineering" from the International Society for Soil Mechanics and Geotechnical Engineering (ISSMGE).

The foundation has worldwide experience with development of offshore fields, including foundation solutions for fixed and floating platforms, subsea installations, pipelines/flowlines, site investigations, evaluation of pipeline routing, and geohazard evaluations.

NGI's capability with these topics is based on wide expertise within the geosciences and the vast experience of its personnel. The foundation utilizes a unique combination of marine geology, geophysics and geotechnical know-how.

NGI combines research and consulting activities

Achievements within geohazards R&D include:

- The understanding of seabed instability mechanisms;
- The modeling of mass flow and fluid and gas transport;
- The tools and methods for the assessment of material properties and design parameters;
- The quantification of uncertainties and frequency of geohazard events;
- The assessment of the consequences of offshore geohazards including earthquake response analysis.

The knowledge has enabled a rational assessment of geohazard risk and has provided valuable assistance for:

- Identification of geohazards;
- Production of geohazard maps and optimization of field layout to minimize hazard and risk;
- Evaluation of measures to reduce risk of damage to wells, field installations and the environment.

NGI
PO Box 3930 Ullevål Stadion
0806 OSLO, Norway
Phone: (+47) 22 02 30 00
Fax: (+47) 22 23 04 48
E-mail: ngi@ngi.no
Web site: www.ngi.no

Technip meets the challenges of fast track deepwater development in India

In early 2007, the Technip Group was awarded the contract for the supply of flexible risers and flowlines for the fast track development of Reliance Industries' MA D6 field. Additionally, the company was awarded a separate contract for the engineering, transportation, installation and pre-commissioning of the flexible risers and flowlines and the umbilicals free issued by the client. Several challenges were presented to Technip due to the fast track development. All were successfully met despite some formidable obstacles.

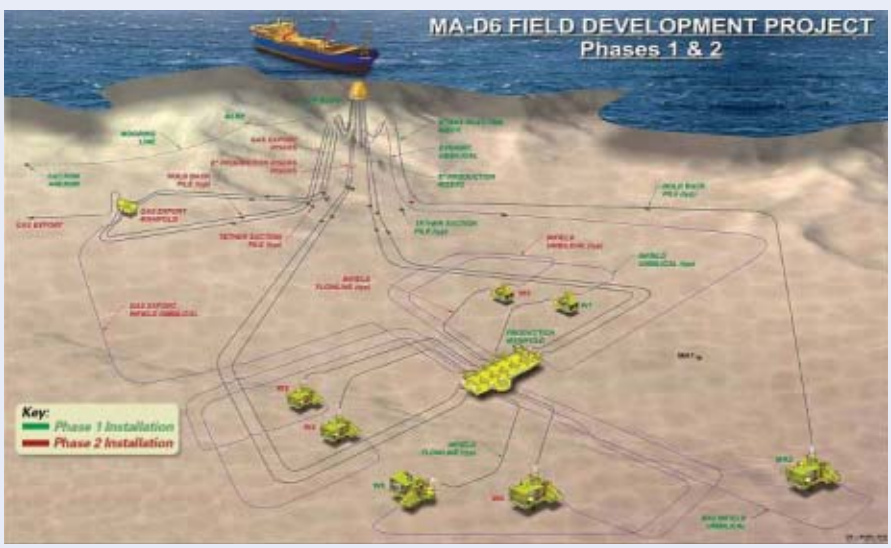
Among the project's challenges were:

- The first batch of 14 km flexible pipe had to be designed and manufactured in less than 12 months;
- Functional specifications during the initial phase of the project;
- Restricted turret buoy capacity that required a "wave" configuration for the risers with about 150 buoyancy modules per riser to limit their top tension;
- Design and fabrication of a state-of-the-art 60 ton subsea pulling winch installed on a submerged buoy and operated by divers in saturation at depths between 200-328 ft (60-100 m);
- Potentially strong ocean currents during riser installation and diving operations and limited weather window;
- A 42 ft (13 m) long dynamic umbilical bending stiffener assembly, the largest and heaviest assembly ever attached to a light umbilical.

Only 17 months elapsed between the contract award and the completion of the Phase 1 work scope by Technip. All of the typical preparatory phases of the project were conducted simultaneously rather than sequentially in order to integrate all of the technical data and specifications that were progressively made available to the project team.

While many of the technologies utilized in this project have been applied in other deepwater subsea developments, the MA D6 development was the first time that they were implemented in a single project that was executed in a fast track mode. The equipment included 10 risers in Pliant Wave® configuration; risers connected to an FPSO via a disconnectable turret buoy; limited available riser top tension; and high temperature flexible risers. All were successfully installed in water depths of more than 3,900 ft (1,200m).

Up to six vessels worked simultaneously on the MA D6 field during the company's activities. Technip's main construction vessel for the MA D6 installation project was the Deep Constructor, which was utilized for all of the lines and suction piles. The company also utilized its DSV Skandi Achiever for the saturation diving work, additional light construction work and surveys.



Technip supplied MA D6 field's flexible risers and flowlines. The company also was contracted for engineering, transportation, installation and pre-commissioning of the risers and flowline. The equipment included 10 risers in Pliant Wave configuration.

Technip's scope of work on the MA D6 Phases 1 and 2 included the fabrication and installation of 31 km of flexible risers and flow lines. The contract called for four 8-in. gas export risers, four 8-in. production risers, one 6-in. gas injection riser and six 6-in. production jumpers. Additionally, Technip installed the 170 ton gas export manifold and its130 ton suction anchor foundation as well as the single dynamic umbilical and eight infield umbilicals.

During Phase 1 riser connection operations, Technip pulled in and connected four risers to the disconnectable STP buoy in a water depth of approximately 500 ft (150m). During Phase 2, the company configured the heading control of the FPSO with two tugs and the direct pull in, connection and precommisioning of six risers. Total shutdown of the FPSO during the riser connection operation was less than four weeks.

The Skandi Achiever was also outfitted with laying winches as a backup to the Deep Constructor for installation of the flexible flowlines and jumpers. Additionally, Technip used two heavy lift vessels to transport ten flexible reels, the dynamic umbilical carousel, three static umbilical reels, the suction piles and all of the riser buoyancy modules from Europe. Total weight of this equipment was more than 5,000 tons.

Technip successfully completed this fast track deepwater project thanks to the experience and expertise of its fully integrated and dedicated project team.

Technip
92973 PARIS LA DEFENSE Cedex
+33 (0)1 47 78 21 21
email: press@technip.com
website: www.technip.com

Venkataramanan Associates designs state-of-the-art Operations Center

Poised to vault India into the league of economic superpowers, Krishna Godavari Dhirubhai 6 (KGD6) is at once a benchmark in the petroleum industry and an architectural landmark. For the main gas extraction and distribution point on the East coast of India, Architectural and Engineering firm **Venkataramanan Associates'** (VA) design brief described an integration of functionality and infrastructure with aesthetic appeal and local flavour.

The Onshore Terminal and Infrastructure Area, both comprising several operational sections, are linked visually and functionally by an overpass. Closest to the Infrastructure entrance, the Administration & Learning Block hosts the Business Center and offices for RIL's senior management and faculty. The block also comprises training and multi-purpose areas as well as a state-of-the-art auditorium. In keeping with RIL's ethos, the offices for senior management on the top floor are elegant and emphasize a flat organization.

The minimalist design of the building exteriors is exemplified in the simple lines and colonnade design of the Pipeline Control Center. Following the same design sense, the Operations office also takes full advantage of the intensity of the sun in the region. Lit by sunlight through the day, it is softened by lush landscape that surrounds the structure while a pebble court inside forms a relaxing break-out space in the midst of continually running operations.

The Food Court, inspired by RIL's logo, has the most unique design on campus. As the logo cradles a flame, the Food Court creates a space of comfort for the employees on campus. The Recreation Building close by comprises a badminton court, an auditorium and a gym apart from several other activity spaces, also for the employees. The structure's design serves to draw the eye towards the Accommodation Block as they together, create a sense of an urban space.

The design of the Accommodation Block, based on geomorphic patterns, takes the form of an opening triangle that signifies growth. With 32 studios, 16 plush suites, 5 VIP suites and an exclusive suite for senior management, the block is designed to accommodate short-stay visitors and care for every need of its residents. These luxurious rooms are complemented by a well-equipped gymnasium and indoor games facilities for recreation while lounges on every floor double as business and leisure areas.

The hub of all activity, the Control Center, is the most unique structure on campus. Designed without any fenestration, it can withstand virtually any form of stress including high levels of natural disaster. Placed in the geometric centre of the campus, the Control Center is the focal point of KGD6.

RIL's values are reflected in the master plan and design. The importance of the employee within the organization is visible, captured through images that line the corridors of the Control Centre. They feature concise captions and real situations on the rig and present glimpses of the experience of building KGD6. The design also extends to the smallest details including Braille markings in disabled friendly elevators, strobe lights in the alarm system and wheelchair ramps. To care for its employees and provide free medical facilities, the campus also houses a comprehensive hospital, the Occupational Health Center.

The campus is set among ample water bodies and landscaped expanses that are planted with over 100,000 trees and shrubs of local species to mitigate the area's harsh climate. The design also sought to create an environment of urbanity to enthuse employees and to give them a sense of pride in a place that is iconic. A project that has been realized close to VA's original architectural design, KGD6 was a challenge from foundation to finish.

Reliance Industries' main gas extracting and distribution operations center of the KGD6 development also includes administrative, training, residential, recreational and medical facilities.

The Onshore Terminal includes the Plant, main Control Center, Fire Station, Cafeteria, Laboratory and associated services. The Infrastructure Area includes the Pipeline Control Center, Administration and Learning Center, Core House, Occupational Health Center, Food Court, Departure Lounge, Operations Office, Pipe Shop, Warehouse and the Recreation and Accommodation buildings.

Venkataramanan associates
architecture + engineering + interiors

Venkataramanan Associates
10/2, O'Shaughnessy Road, Langford Gardens
Bangalore 560025, INDIA
Phone: +91 80 4030 3050
Email: va@vagroup.com
Web site: http://www.vagroup.com

Company Profile Index