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International Petroleum News and Technology / www.ogjonline.com

Applied Geophysics

Subsea gas-liquid separation helps boost production
Field tests prove NRU to upgrade low-btu gas
North Sea trials verify subsea grout curing

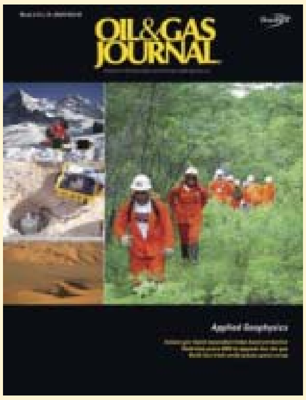
OIL&GAS JOURNAL
Oct. 26, 2009
Volume 107.40

Applied Geophysics

Regular Features

Cover

Cover images, clockwise from top left, show a technician testing a low frequency seismic recording station's environmental specifications in the Alps, an LF seismic survey crew on contract for Petroleo Brasileiro SA in northeastern Brazil, and dunes that dwarf an LF seismic survey camp in Libya, where the small crew and light equipment gathered 230 sq km of exploration data in fewer than 40 days. An interview with incoming Society of Exploration Geophysicists Pres. Stephen J. Hill, starting on p. 18, and an article on low frequency seismic applications on p. 33 make up OGJ's Applied Geophysics special report. Photos courtesy of Spectraseis.



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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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OGJ Newsletter

Oct. 26, 2009

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General Interest — *Quick Takes*

ExxonMobil ordered to pay in MTBE case

A US District Court in Manhattan found ExxonMobil Corp. liable for contaminating New York City's ground water with methyl tertiary butyl ether (MTBE) and awarded the city $104.7 million in damages, New York City officials said.

On Oct. 19, the New York City's Law Department said a jury awarded the compensatory damages after an 11-week trial in a product-liability case. The city sued ExxonMobil for the costs of removing MTBE from drinking water wells in southeast Queens.

The case was tried before Judge Shira Scheindlin of the US District Court for the Southern District of New York. The trial focused on six water wells.

A spokesman for ExxonMobil downstream issued a statement saying the company was disappointed with the decision, and it will consider all its legal options.

"As we've maintained throughout, our service stations were not the source of the MTBE contamination" at the six wells, ExxonMobil said. "We do not believe we should be required to compensate the City of New York for someone else's contamination."

Several other large oil companies previously settled claims from New York City against them for a total of $15 million.

APPEA issues update on Montara oil leak

Australia's oil and gas industry expects soon to stop an oil leak from Montara field in the Timor Sea off Western Australia, said the Australian Petroleum Production & Exploration Association.

APPEA Chief Executive Belinda Robinson, in an Oct. 19 statement, called the sealing of the leaking well at Montara "an extremely difficult and complex operation." She said, "A team of international and Australian experts are drilling a relief well down through 2.6 km of the seabed and then seeking to intersect a leaking 25-cm section of steel casing."

The drilling team's next attempt to intercept and stop the leaking well was scheduled for Oct. 22. The leak started on Aug. 21. Thailand's PTTEP owns and operates the Montara platform complex.

Seadrill Ltd. said its West Atlas jack up drilling rig is working under a PTTEP contract. An oil leak developed on a well adjacent to where the West Atlas worked, Seadrill said, adding that all West Atlas personnel were evacuated (OGJ, Sept. 7, 2009, Newsletter).

"The operation is being undertaken by Australia's best drilling experts from across the industry," Robinson said. "Once the leaking well is intercepted, heavy mud will be pumped from the West Triton drilling platform down into the relief well, displacing the oil, gas, and water and stopping the flow."

Once the leak has been stopped and a 24-hr safety period has passed, a team will reboard the wellhead platform, and the West Atlas rig to further secure the well by inserting two plugs into the previously leaking wellbore.

This second operation to plug the well is expected to take about another week to complete, Robinson said.

Gazprom signs gas deal with Azerbaijan

OAO Gazprom will import 500 million cu m of Azerbaijani gas starting in January 2010 under a contract signed with State Oil Co. of Azerbaijan Republic (SOCAR).

"The contract doesn't limit the maximum purchase volume. The gas price will be defined under a price formula," said Gazprom. Gas volumes may increase, it added, and signified a long term partnership with Azerbaijan.

Alexey Miller, chairman of the Gazprom's management committee, recently led a delegation to Azerbaijan. Miller said, "Gazprom owns the world's largest contract portfolio for gas supply to the domestic and foreign markets as well as an advanced and flexible gas transmission system; Russia and Azerbaijan have a common border and have already been connected by the unified infrastructure."

Azerbaijan holds up to 1.5 trillion cu m of proved natural gas reserves, including the Shah Deniz field in the Azerbaijani sector of the Caspian Sea with recoverable reserves of more than 1.3 trillion cu m of gas.

Turkmenistan appoints energy minister

Turkmenistan's President Gurbangulu Berdymukhamedov, following his dismissal of several key officials, appointed Oraznur Nurmiradov as Minister of Oil and Gas, Industry, and Mineral Resources.

Nurmiradov's appointment followed a decision by the Turkmen president to fire several top energy officials, denouncing their "irresponsible approach" to their jobs.

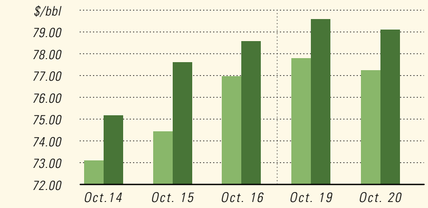
Officials dismissed in the industry shake-up include Mineral Resources Minister Annaguly Deryayev; the head of state gas company Turkmengaz, Dovlet Mommayev; and the state oil company chairman, Orazdurdy Khadzhimuradov.

At a meeting with heads of oil and gas companies, Berdymukhamedov criticized the "poor construction quality" of Turkmenistan's energy installations, delays in providing gas to towns and villages, and the absence of "needed measures to increase oil production."

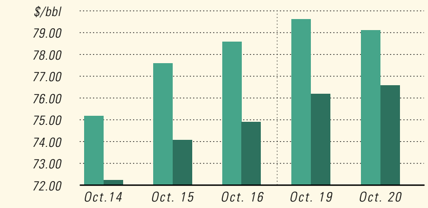
A mining engineer and hydrogeologist from Turkmen Polytechnic Institute, Nurmiradov formerly worked as an engineer, senior engineer, and researcher at the Turkmen research and design branch of the All-Union Scientific Research Institute and the Turkmen Research and Design Institute.

Industry Scoreboard

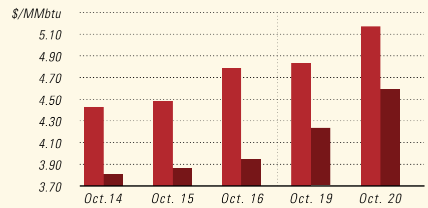
IPE BRENT / NYMEX LIGHT SWEET CRUDE



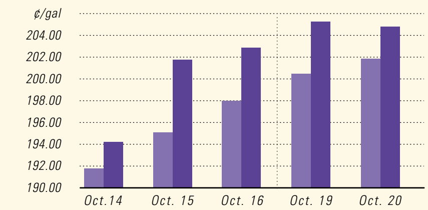
WTI CUSHING / BRENT SPOT



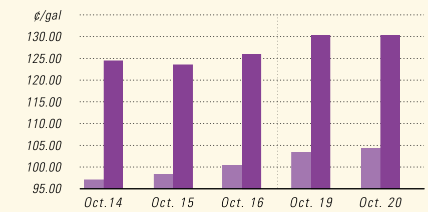
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



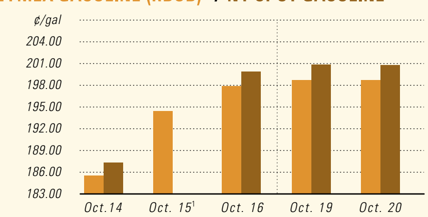
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

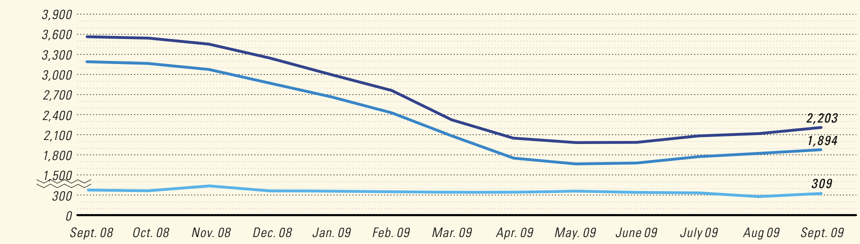
US INDUSTRY SCOREBOARD — 10/26

Latest week 10/9	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,110	8,648	5.3	9,030	9,002	0.3
Distillate	3,449	3,866	-10.8	3,600	3,952	-8.9
Jet fuel	1,410	1,461	-3.5	1,414	1,575	-10.2
Residual	466	542	-14.0	542	621	-12.7
Other products	4,329	3,853	12.4	4,138	4,418	-6.3
TOTAL DEMAND	18,764	18,370	2.1	18,724	19,568	-4.3
Supply, 1,000 b/d						
Crude production	5,353	4,141	29.3	5,244	4,954	5.9
NGL production[2]	2,129	1,860	14.5	2,002	2,112	-5.2
Crude imports	9,289	8,915	4.2	9,229	9,756	-5.4
Product imports	2,681	3,115	-13.9	2,783	3,148	-11.6
Other supply[3]	1,605	1,670	-3.9	1,682	1,558	8.0
TOTAL SUPPLY	21,057	19,701	6.9	20,940	21,528	-2.7
Refining, 1,000 b/d						
Crude runs to stills	14,502	13,212	9.8	14,502	14,683	-1.2
Input to crude stills	14,857	13,749	8.1	14,857	15,038	-1.2
% utilization	84.2	78.0	—	84.2	85.4	—

Latest week 10/9	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	337,760	337,426	334	308,198	29,562	9.6
Motor gasoline	209,159	214,389	–5,230	193,788	15,371	7.9
Distillate	170,672	171,756	–1,084	122,148	48,524	39.7
Jet fuel–kerosine	45,336	45,733	–397	36,258	9,078	25.0
Residual	35,071	35,269	–198	38,706	–3,635	–9.4
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.3	22.9	1.7	23.7	–1.7	
Motor gasoline	23.0	23.7	–3.0	22.1	4.1	
Distillate	49.5	50.5	–2.0	31.4	57.6	
Propane	70.2	70.3	–0.1	77.2	–9.1	
Futures prices[5] **10/16**			Change		Change	%
Light sweet crude ($/bbl)	75.74	70.86	4.88	86.22	–10.48	–12.2
Natural gas, $/MMbtu	4.63	4.90	–0.27	6.74	–2.11	–31.3

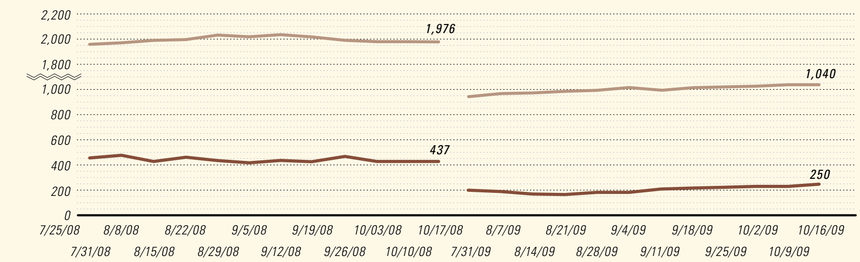
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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In 1993-96, he was a researcher at the Oil and Gas Institute of the Turkmen Oil and Gas Ministry. Since 1996, he has been researcher, senior researcher, and head of the Department of the Oil and Gas Institute of Turkmengaz. ✦

Exploration & Development — *Quick Takes*

Chevron group has Carnarvon basin gas find

A Chevron Australia group has made a gas discovery in the Carnarvon basin off Western Australia which is likely to boost reserves available to its Gorgon and Wheatstone LNG projects.

The group's successful Achilles-1 wildcat was drilled in permit WA-374-P immediately south of Io/Jansz field and west of Gorgon field.

The well, drilled by the Ensco 7500 semisubmersible rig, intersected 100 m of net gas pay in Triassic Mungaroo sandstone.

The well is part of a 10-well campaign being carried out by the group in Australia this year.

The Ensco rig has moved to the next location, also in WA-374-P, called Satyr-1.

Chevron has a 50% interest in the permit, which lies 160 km northwest of Onslow in the Greater Gorgon Area. ExxonMobil and Shell each have 25%.

OMV makes discovery west of the Shetlands

OMV AG made an oil and gas discovery with the Tornado exploration well, which reached a TVD of 2,743 m off the UK west of the Shetland Islands.

Well 204/13-1 penetrated hydrocarbons in the tertiary. OMV and its partners plan to drill a sidetrack to delineate the discovery.

Tornado lies 10 km northwest of the Suilven discovery and 30 km northwest of Schiehallion, Foinaven, and Loyal fields.

The well was drilled in 1,048 m of water by the Stena Carron drillship as a cost-sharing endeavor between production licenses P.1190 and P.1262.

Graham Stewart, chief executive of Faroe Petroleum, said, "The Tornado well is the second of a firm five-well Atlantic Margin exploration drilling program, which Faroe is undertaking over the coming months. The first well in the program, operated by DONG [Energy AS], made a significant discovery, the Glenlivet gas field, which is currently being appraised. We are scheduled to drill three further very high impact exploration wells, the Anne Marie oil prospect in the Faroes (operated by Eni), the Cardhu oil prospect in the UK (operated by BP) and the Lagavulin oil prospect in the UK (operated by Chevron)."

OMV has 35% interest in Tornado; Dana Petroleum PLC has 30%; DONG Energy has 20%; and Faroe Petroleum and Idemitsu E&P each have 7.5%.

Dana to buy stake in concession off Guinea

Dana Petroleum PLC is to gain a 23% interest in the Hyperdynamics concession off Guinea under an exclusive letter of intent (LOI) signed with Hyperdynamics Corp., Sugar Land, Tex.

The partners hope a binding agreement will be signed by yearend for the acreage, which covers 80,000 sq km. Hyperdynamics hopes to bring another partner into the concession.

"Dana has the option to negotiate for an additional interest of up to a further 27% (to give Dana a total of 50% interest) if Hyperdynamics does not sign a letter of intent with such a company by Nov. 30," said Dana.

In October, Hyperdynamics let a contract to TDI-Brooks International, Houston, for a comprehensive oil seep study (OGJ Online, Oct. 6, 2009).

Last month, Hyperdynamics agreed with Guinea's energy ministry to relinquish 64% of the current acreage by yearend and review the existing production sharing contract (PSC) by Apr. 1, 2010 (OGJ Online, Sept. 15, 2009).

It will spud its first well by 2011. The company has right of first refusal on any new concessions Guinea offers in the relinquished area if it matched terms offered by another party.

Subject to signing the final agreement by Dec. 31, Dana will pay Hyperdynamics $5 million that will go towards a $10 million 2D seismic survey scheduled to start by Oct. 31. Dana will pay Hyperdynamics another $15 million, in either cash or shares, on signature of the revised PSC.

The seismic dataset will be used to evaluate which parts of the concession to relinquish as mutually agreed by Dana and Hyperdynamics.

Eni reports 'world-class' gas find off Venezuela

Italy's Eni SPA said it has made a "world class" natural gas discovery after successfully drilling an exploration well in Perla field on the Cardon IV block in the Gulf of Venezuela.

Venezuela's President Hugo Chavez was quick to turn the discovery into political capital, saying that the find could help boost Venezuela to fourth place in the world in proven gas reserves within 4 years.

"Venezuela is growing more established as a global energy power," Chavez said on state television. Repsol YPF SA first announced the find a few weeks ago during a visit by Chavez to Spain, but Eni's statement confirmed the magnitude of the find.

"The results of the well exceeded predrill expectations, making Perla the largest gas discovery in Venezuela and, potentially, one of the world's largest natural gas discoveries in recent years," Eni said.

It said these results will be evaluated "with the objective of accelerating the definition of a work program to further define the discovery and establishing possible development scenarios."

Eni said, "The field has a reserve potential higher than the 6 tcf of gas previously estimated."

The Perla 1X well, drilled 50 km offshore, encountered a 240-m hydrocarbon column. During the production test, it produced high-quality gas with a capacity of 600,000 cu m/day and 500 b/d of condensate.

"Normalized gas production per well is expected to increase to over 1 million cu m/day," Eni said.

Cardon IV Block is licensed and operated by a joint operating

company Cardon IV SA, which is held equally by Eni and Repsol YPF. Venezuela's state-owned Petroleos de Venezuela SA owns a 35% back-in right in the development phase and, if exercised, Eni and Repsol YPF will each hold a 32.5% interest in the project. ✦

Drilling & Production — *Quick Takes*

Yuri Korchagin offshore installations completed

OAO Lukoil is closer to bringing its Yuri Korchagin oil field on stream in the Caspian Sea in December following installation of offshore facilities.

Offshore facilities have been installed at Lukoil's Yuri Korchagin oil field in the Caspian Sea. Production is expected to start in December. Photo from J. Ray McDermott SA.

This will be the first of Lukoil's North Caspian fields in the Russian sector of the Caspian Sea to be developed.

The company let the contract to J. Ray McDermott SA, which completed the installation within a month and a half: an ice-resistant fixed processing platform (LSP-1) and adjacent living quarters (LSP-2) joined together by a 243-ft bridge.

Oil from LSP-1 will be delivered to the marine transportation complex, which consists of a floating storage offloading system (FSO) and the 1,005-ton single-point mooring (SPM) substructure via a 36-mile, 12-in. pipeline.

"Additional work included engineering, procurement, fabrication, transportation, and installation of tie-in spools connecting LSP-1 and the SPM to the 36-mile subsea pipeline as well as hydrostatic leak testing and flushing of the entire pipeline system," said J. Ray McDermott.

The field lies in 11-13 m of water and holds proved, probable, and possible reserves of 570 million boe. It is 180 km from Astrakhan and 240 km from Makhachkala and will produce 2.3 million tons/year of oil and 1.2 billion cu m/year of gas.

Neptune Explorer drillship completes upgrade

Neptune Marine Oil & Gas, a subsidiary of Jasper Investments Ltd., completed a $340 million upgrade of its deepwater drillship, the Neptune Explorer.

Sembawang Shipyard in Singapore did the work. Sembawang Shipyard is a subsidiary of Sembcorp Marine Ltd.

After almost 36 months of upgrading and conversion, the Neptune Explorer now is a dynamically positioned deepwater drilling rig with a variable deckload of 7,220 tonnes.

It is equipped to work in 5,000 ft of water.

Shell lets contract for flowlines

Shell Nigeria Exploration & Production Co. Ltd. let a contract to Saipem SPA to carry out subsea development of Bonga Northwest field on OML 118 about 120 km off Nigeria.

Saipem will carry out engineering, procurement, fabrication, installation, and precommissioning services for 13 km of 10-12 in. production pipe-in-pipe flowlines and 4 km of 12-in. water injection flowlines as well as related production facilities. The $200 million contract also includes installation of 15 km of umbilicals.

Bonga Northwest is in 900-1,200 m of water and will be developed with 12 subsea wells tied back into the Bonga main infrastructure.

Marine activities will be carried out mainly by Saipem FDS and Saipem 3000 vessels during the second half of 2012 and the last quarter of 2013. ✦

Processing — *Quick Takes*

Petrobras, PDVSA resolve refinery terms

Brazil's Petroleo Brasileiro SA (Petrobras) said it has resolved all outstanding issues with Venezuela's Petroleos de Venezuela SA over development of the Abreu e Lima refinery planned for Suape, near Recife in northeastern Brazil.

Paulo Roberto Costa, Petrobras director for supply, said there were no more obstacles to construction of the refinery, and that there is no change in the proportion of investment required from either side, with Petrobras to supply 60% of the refinery's investment and PDVSA the remaining 40%.

However, PDVSA will have to pay Petrobras at least $400 million when it signs the final agreement for the Abreu e Lima refinery, according to a Petrobras spokesperson.

"This amount represents the obligations PDVSA has in this project calculated until December 2008. A consulting company is now reviewing all investments that both companies have to take responsibility for as from January 2009," the spokesperson told BNAmericas.

"We expect the revised amount to be paid by cash immediately after the agreement is signed," the spokesperson added.

Asked if Brazil's President Luis Inacio Lula da Silva would sign a definitive agreement with Venezuela's President Hugo Chavez on an upcoming state visit, Petrobras Pres. Jose Sergio Gabrielli said he didn't know. Lula was to visit Caracas on Oct. 17-18, according to Brazil's foreign ministry.

Meanwhile, Costa said there had been several obstacles holding up the refinery agreement, including the rising cost of the project, which has escalated to about $12 billion from a preliminary estimate of $4.06 billion.

Petrobras said the increased cost of the joint venture was normal for such projects because pricing always increases once more detailed plans are developed. Petrobras also said that $2 billion of the cost increase came from the appreciation of Brazil's currency.

Other areas of disagreement came over rights to purchase products from the refinery and Venezuela's desire for higher-than-market prices for the heavy crude it plans to supply to the refinery.

Qatar Fertilizer lets urea plant contract

Qatar Fertilizer Co. SAQ (Qafco) has let a lump sum turnkey contract to partners Saipem SPA and Hyundai Engineering & Construction Co. Ltd. for the Qafco 6 project, including a 3,850-tonne/day urea plant.

The deal is worth $610 million. The site is in the new Qafco industrial complex in Mesaieed, about 30 km south of Doha.

The engineering, procurement, and construction contract also covers associated utilities and offsite units at the fertilizer complex. It will be completed by the third quarter of 2012.

Saipem and Hundai are building two ammonia plants and a urea plant for Qafco in the Qafco 5 project. The Qafco 6 urea plant will use surplus ammonia from Qafco 5. ✦

Transportation — *Quick Takes*

China begins commissioning third LNG terminal

China's Shanghai LNG terminal received its first LNG cargo of 45,000 cu m aboard the 88,000-cu m Arctic Spirit LNG carrier from Bintulu, Malaysia, Oct. 11. A second cargo is slated for later this month.

China National Offshore Oil Corp. owns 45% of the 3-million tonne/year terminal with Shenergy Group (55%), the Shanghai government's power investment group. CNOOC last year signed a 25-year agreement to buy 2 million tpy from Qatargas Operating Co. Ltd. with supplies to start later this year from the 7.8-million tpy Qatargas 2 project. The terminal also has another 25-year supply contract with Malaysia for 3.03 million tpy.

Capacity at Shanghai is to be expanded to 6 million tpy at some as yet unannounced date. China has two other operating LNG terminals: the 6.2-million tpy Dapeng LNG terminal in southern Guangdong Province and the 2.6-million tpy Fujian terminal, which began operating earlier this year and is to be expanded to 5.2 million tpy (OGJ, June 1, 2009, p. 12).

Ban sought on Russian gas re-exports

Turkmenistan, now negotiating with Russia's OAO Gazprom, is seeking to ban the Russian firm from re-exporting the natural gas it purchases from the Central Asian nation.

"The new contracts will include a clause banning re-export of gas," said Turkmenistan's Deputy Premier Baimurad Khodzhmukhamedov at a conference in Ashgabat earlier this month.

Khodzhmukhamedov's statements came ahead of this week's meeting between Turkmenistan's President Kurbanguly Berdymukhamedov and Gazprom Chief Executive Officer Alexei Miller aimed at resuming Russia's import of Turkmen gas that were suspended in April after a pipeline blast.

Both sides have since said they expect gas supplies to resume before the end of October, but they are still negotiating the terms of an amended supply agreement.

Prior to the blast, Gazprom had been buying 50 billion cu m/year of Turkmen gas and re-exporting most of it to Ukraine, much to the chagrin of Ashgabat.

While Turkmenistan wants to include the re-export ban, Gazprom wants to reduce its purchases of Turkmen gas to 30 billion cu m/year and to establish a flexible pricing formula that will ensure prices are in line with the international gas market.

Yemen LNG yields first production

Into a world already oversupplied with LNG capacity, yet another production project has come online. Total has announced that the 6.7-million tonne/year (tpy) Yemen LNG plant produced its first LNG from the first of two planned trains. The second train remains under construction.

The announcement did not specify to which customer this first production was to be sent, saying only that the plant's first cargo is "scheduled in the coming weeks." Three gas sales agreements were signed in 2005 with Kogas, GDF-Suez, and Total Gas & Power Ltd.

The $4.5-billion project supplies gas from Block 18 in the Marib region of central Yemen through a 320-km (nearly 200 miles) pipeline to the LNG plant at the port of Balhaf on the country's southern coast of the Arabian Sea.

Counting this first train of Yemen LNG, this year has seen nearly 30 million tpy of new production capacity come on line.

Sakhalin added two trains of 4.8 million tpy each earlier in the year. Qatargas 2 started up its 7.8-million tpy Train 4 and hopes to start up the 7.8-million tpy Train 5 by yearend.

In Asia, debottlenecking at Malaysia Dua was to have added 1.5 million tpy at some point in the year. And Indonesia's 7.6-million tpy Tangguh formally began operations but has been plagued by outages and is currently shut down.

At last week's World Gas Conference in Buenos Aires, BP's Ton Hayward said the project would produce from both trains this week, declining to specify amounts or destinations.

Expected to start up very early in 2010 is Peru LNG's 4.4-million tpy plant.

Midsize Chinese LNG plant to supply locally

China's Ningxia Hanas Natural Gas Co. will employ Air Products' LNG process technology and equipment for a midsize LNG project in Yinchuan, China, according to an agreement with overall project manager Technip announced Oct. 15.

Air Products will supply single mixed-refrigerant process technology, engineering, design, and manufacturing of the heat exchanger equipment for liquefaction process sections in two 400,000-tonne/year trains. The process uses Air Products' proprietary wound-coil main cryogenic heat exchanger technology.

Yinchuan is the capital of northwest China's Ningxia Hui Autonomous Region. The Yinchuan LNG plant will be the largest of its kind in China, according to Air Proiducts' announcement, and will distribute LNG to markets in the region.

Target completion for the units is second-half 2011. ✦

C a l e n d a r

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

OIL&GAS JOURNAL *online*

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2009

OCTOBER

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PICT-Passive Inflow Control Technology Meeting, Copenhagen, +44 (0) 1483-598000, e-mail: Dawn.Dukes@otmnet.com, website: www.inflowcontrol.com. 27-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

North African Oil and Gas Summit, Tunis, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

Vietnam Saigon Oil and Gas Expo, Saigon, +49 40 30101 266, +49 40 30101 936 (fax), e-mail: industrial.pr@sgs.com. website: www.cpexhibition.com/vnoffshore. 29-31.

NOVEMBER

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 5.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO2symposium.com. 5-6.

Sulphur International Conference and Exhibition, Vancouver, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.sulphurconference.com. 8-11.

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. 8-13.

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

Multiphase User Roundtable-South America, Rio de Janeiro, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-sa.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Digital E&P Event, Houston, (646) 200-7444, (212) 885-2733 (fax), e-mail: cambrosio@wbresearch.com, website: www.digitaleandp.com. 9-11.

NPRA/API Operating Practices Symposium, Dallas, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 10.

Petroleum Association of Wyoming (PAW) Annual Oil & Gas Statewide Reclamation Conference, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: cheryl@pawyo.org, website: www.pawyo.org. 10.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 10-12.

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NPRA International Lubricants & Waxes Meeting, Houston, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 12-13.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

Latin America LPG Seminar, Miami, (713) 331-4000, (713) 236-8490 (fax), e-mail: ts@purvingertz.com, website: www.purvingertz.com. 16-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

Energise Your Future Forum, Paris, +33 0 1 47 96 91 68, e-mail: claude.leonard@bostik.com, website: www.energiseyourfuture.com. 18-20..

DECEMBER

Advanced Contract Risk Management Europe for Oil & Gas, Aberdeen, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.contractriskmanagement. MAC=11579.003EDIARY. 1-2.

Refining and Petrochemicals in Russia and the CIS Countries Annual Meeting, Amsterdam, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 1-3.

World LNG Summit, Barcelona, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), e-mail: info@thecwcgroup.com, website: www.thecwcgroup.com. 1-4.

European Drilling Engineering Association Expandables, Multilaterals and Technologies Meeting, Vienna, +44 (0) 1483-598000, e-mail: Dukes@otmnet.com, website: www.dea-europe.com. 3-4.

International Petroleum Technology Conference (IPTC), Doha, +971 4 390 3540, e-mail: iptc@iptcnet.org, website: www.iptcnet.org/2009. 7-9.

Nuclear Power International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.nuclearpowerinternational.com. 8.

Power-Gen International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.power-gen.com. 8-10.

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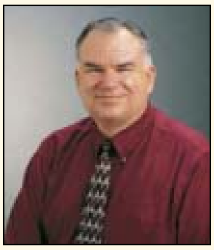


Alan Petzet
Chief Editor-Exploration

Publishing Oil & Gas Journal magazine and web site has always been a challenging and rewarding task for the small group of people whose names you see on the masthead.

The group of editors, reporters, and correspondents has been minimal compared with the magnitude of the task, but that fraternity depends on a much larger cadre of individuals: our sources in the industry.

With mergers, acquisitions, bankruptcies, new startups, oil and gas price fluctuations, technology development, and so on, just keeping up with sources is a time-consuming job.

Yet a relatively small number of folks in the industry make unusually selfless and long-lasting efforts to keep in touch with OGJ and help us understand the trends, technologies, economics, and other complexities that make up the industry we cover.

At some point we began referring to those folks as "Friends of the Journal." The late Edward F. Durkee was one of those friends.

The exploration life

OGJ doesn't publish obituaries, but Durkee's business partner Selmer Pederson wrote a memorial to him in the October 2009 issue of the American Association of Petroleum Geologists Bulletin.

The memorial was updated with information provided by Durkee's daughter, Debora, and Dr. Tom Haskell of New Zealand.

Durkee wasn't president of a major oil company or an emir or sheikh or sultan, just a geologist who knew geology and economics and the exploration business inside-out.

He was engaged at one time or another in exploration on nearly every continent except Antarctica, and at the same time he was often working prospects of his own in the US.

He was involved in oil and gas exploration since graduating from the University of Wyoming in 1952.

The man

Durkee was born in 1928 in Midwest, Wyo., son of an oil rig builder, roustabout, and pumper in Salt Creek and Lance Creek oil fields.

Besides his geology shingle, he had a masters in paleontology. Durkee had a good grasp of geophysics, and in his last decade he made considerable efforts—mainly with the aid of Al Gallagher of Denver—toward understanding and integrating surface geochemical exploration methods for which Durkee earlier expressed skepticism.

Durkee participated in a Papua New Guinea promotional effort that was reported, Pederson wrote, to have been "the most successful World Bank project of its type to that time, with new exploration investment amounting to $500 million and resulting in several significant discoveries in subsequent years."

Pederson continued: "He traveled the world visiting national oil company offices, negotiating with same, and had friends on all the continents. He was a gentleman and a scholar and became a close friend with all the international petroleum people he had the pleasure of meeting and discussing their petroleum potential in the world economic market."

Durkee and OGJ

No one here now can remember how long Durkee maintained contact with OGJ editors. He lived most of his later life in Manila, where he opened a consulting office in 1994, and was involved in exploration throughout Southeast Asia.

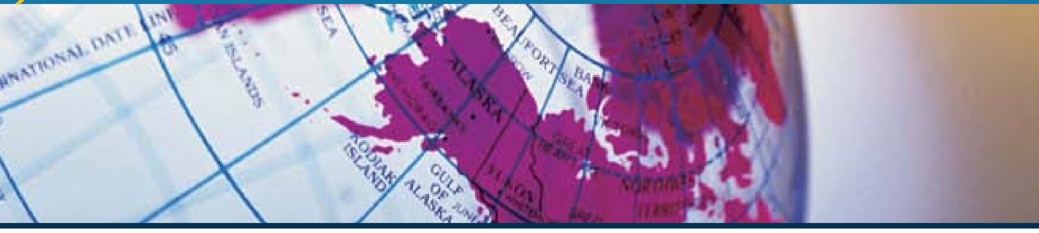
His written contributions go back at least to 1985, when he cowrote an exploration article on the Papuan basin. We also published his articles on Turkey, Myanmar, and several on the Philippines.

In the Myanmar piece, Durkee described a primitive, integrated oil industry with exploration, drilling, oil production, transportation, refining, marketing, and distribution (OGJ, Oct. 20, 1997, p. 63). He came upon the thriving operation, which has no connection with Myanmar's national oil company, on a trek into the remote Chindwin basin 150 miles northwest of Mandalay.

Durkee was a prolific writer, and OGJ wasn't his only publisher. In the early 1980s he contributed chapters to the former World Energy Developments issue of the AAPG Bulletin, in which a series of detailed articles described exploration and development activity in the world's basins for the previous year.

An OGJ editor could encounter Durkee in the Intercontinental Hotel in Vienna or in downtown Perth or trudging the streets of Salt Lake City at 6:30 a.m. after a doctor told him he must "walk or die." He staved off the end until June 1, 2009.

As Pederson pointed out, Durkee "participated in international activities to the fullest and to the last moment, vis-a-vis his latest article in OGJ, May 25, 2009, titled 'Smallest Philippine block has shallow gas, deep reef potential,'" with coauthor Jhana Hale of Manila. ✦



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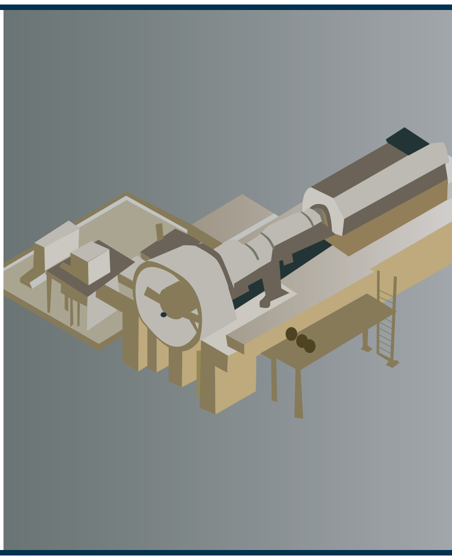
- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.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



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Editorial

US refining under threat

The threat to US refining from misguided climate-change legislation has become chillingly clear. Indeed, the clarification elicits a question: Why would the US, as a matter of policy, swap a large chunk of domestic refining capacity for trivial cuts in emissions of greenhouse gases?

The American Petroleum Institute has released the full report of a study by EnSys Energy, Lexington, Mass., on the effects on refining of climate-change legislation passed in June by the US House. The bill, whose sponsors are Henry Waxman (D-Calif.) and Ed Markey (D-Mass.), would cap emissions and create tradable emission allowances.

API, which commissioned the study, in August published a summary warning that enactment of the Waxman-Markey bill would cut US refinery throughput by as much as 4.4 million b/d by 2030 (OGJ, Sept. 7, p. 26). New details illuminate the nature and extent of the hazard.

The study

The study applies an EnSys model of the global refining industry to three forecasts by the US Energy Information Administration: a baseline from EIA's annual energy outlook, adjusted for federal stimulus spending, and two projections from an analysis of the Waxman-Markey bill. Unlike EIA's, EnSys's analysis accommodates the increased cost of allowances for direct US refining emissions and accounts for interaction between US and non-US refining.

Waxman-Markey makes refiners responsible for emissions by their facilities as well as those associated with use of their products. Under it, the refining industry would have to make 43% of all required cuts yet receive only 2.25% of allocated emission allowances. Refiners thus would be heavy allowance buyers.

Allowance costs, therefore, are crucial. The lower-cost projection by EIA puts the values at \$22/tonne of carbon dioxide-equivalent (CO_2e) in 2015 and \$65/tonne in 2030 (2007 dollars). The higher cost scenario, assuming no international offsets and limited technical development and nuclear growth, estimates allowance costs at \$65/tonne of CO_2e in 2015 and \$190/tonne in 2030. Under the lower-cost assumptions, EIA sees a lowering in US oil consumption from the baseline of 250,000 b/d by 2020 and 900,000 b/d by 2030. The higher allowance costs raise consumption cuts to 330,000 b/d by 2015 and 1.65 million b/d by 2030.

In the EnSys model, cost increases hurt the ability of US refiners to compete in this shrunken market. While falling in the US, the study says, throughput would be rising elsewhere—by 900,000-3.3 million b/d in 2030, necessitating US product import gains of 14-19%.

For refiners, Waxman-Markey's biggest effect would be on variable operating costs. Allowance costs for direct refinery emissions, net of free allowances, would average 50¢-\$1.20/bbl in 2015 and \$2.70-7.20/bbl by 2030. The higher figure in the 2030 range is nearly three times the operating cost EnSys considers typical. "These increases would be a prime driver of the reductions in US refineries' ability to compete, in their projected reduced throughputs, and the offsetting increases in non-US refinery throughputs and investments," the study says. Annual US refinery investment under Waxman-Markey would fall below 2030 baseline assumptions by as much as \$89.7 billion.

With oil demand sluggish and biofuels displacing nearly 1.5 million b/d of oil supply in 2030, refinery capacity utilization will be under strain in any case. Waxman-Markey, according to the study, could push utilization to as low as 67-68% in 2015 and 63% by 2030. Using 85% as the rate below which refineries are assumed to be unprofitable, the study says 1.5 million b/d of US refining capacity is at risk of closure through 2020 under baseline assumptions. Under Waxman-Markey, the at-risk number in 2030 would be nearly 3 million b/d in the lower-cost scenario and 4-5 million b/d under higher cost assumptions.

Emission effects

Because non-US refining would compensate for US capacity losses beyond consumption declines, emission cuts would be minor. While Waxman-Markey would lower US refinery emissions by 20-41% in 2030, net global reductions in refinery emissions would be only 3%, the study says.

For this relatively small payoff, Waxman-Markey would sacrifice a large piece of the US refining industry—and the jobs, incomes, and security that come with it. It's a deplorable deal. ✦

CONSTRUCTION PROJECT Data To Count On!

Our worldwide construction surveys are updated regularly

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

Worldwide Construction Surveys

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

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

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

Production Projects Worldwide

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

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Four types of vessels are tracked – Jack-up Rigs, Semi-submersibles, Drillships, and Tender Assist Vessels. Include – Rig Name, Owner, Design, Shipyard, and Country, Delivery Date, Cost in $ millions.

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POINT OF VIEW

Science is touchstone for new SEG president

Bob Tippee
Editor

The new president of the Society of Exploration Geophysicists tends to address geophysical progress in terms that go beyond practicalities such as identifying targets for oil and gas drilling.

For Stephen J. Hill, the touchstone is science.

The perspective well suits a PhD physicist who sandwiched 25 years with a major oil company between stints as a college professor and now consults.

Here, for example, is how Hill assesses time-lapse seismic, also called 4D, in which sequential 3D surveys over a target reservoir monitor subsurface changes during production of oil and gas: "The introduction of time-lapse has been a huge plus for us as a science," Hill says, pointing out that time-lapse surveys embody "repeatable experiments," the essence of science.

Typically, improvement in the precision of those experiments has enhanced what scientists learn from them. Geophysicists at first used time-lapse surveys to monitor the movement of fluid boundaries through a reservoir as production progressed. They did so by tracking changes in acoustic impedance, a measure of the resistance of a subsurface layer to sound travel.

An early challenge was to ensure consistency of survey parameters, mainly source and receiver locations. Because the aim was to monitor changes in a specific set of survey measurements, other conditions had to be constant. The experiment, in other words, had to be repeatable, a requirement complicated by the marine environment in which most time-lapse surveys were and still are conducted.

Since the early days of time-lapse work, Hill points out, increasingly precise survey geometry and other factors of repeatability have given rise to new information about the subsurface. Geophysicists now assess changes not only in boundaries between reservoir fluids but also, because production changes reservoir volumes, movement in rocks surrounding the reservoir.

"So we've learned some things about rock physics as a result of time-lapse that make us better scientists," Hill says.

He uses the same framework to judge the application of geophysical methods to an emerging technological frontier: subsurface sequestration of carbon dioxide as a way to mitigate climate change.

"It's going to be interesting to see where that technology goes in the future," he says. "But it's going to be good for science because we're going to learn stuff."

Blending disciplines

In fact, the blending of geoscientific and engineering practices needed to develop CO_2 sequestration technology fits another Hill observation: "Advances in science will occur at the interface of what we previously thought of as separate disciplines."

He offers examples from both science in general and geophysics in particular.

Many years ago nuclear physics joined astrophysics to help explain the distribution of elements in the universe. Similarly, nuclear physics expanded into medicine to produce advances in health care. And in modern geophysical work, solid-state detectors are replacing mechanical geophones in land surveys, the result of a combination of electrical engineering with physics.

Similar mergers of geophysics with other disciplines have fostered geophysical progress in the past: with electrical engineering in the 1960s and 1970s to bring geophysical methods into the digital world, for example; with physics to integrate the wave equation into seismic processing and interpretation; and with computer science to supply the computational power and visualization essential to modern geophysical work.

It will happen again, Hill says, adding a warning: "My crystal ball only works in a time reverse mode. Unfortunately, I do not have a good guess as to which outside expertise is to come in the next 10 years."

"Advances in science will occur at the interface of what we previously thought of as separate disciplines."
—Stephen J. Hill, consultant

'Dream algorithms'

Hill's own specialties are seismic processing and imaging. In those areas, the burgeoning power of computers enables geophysicist to apply what Hill says were just "dream algorithms" years ago.

A resulting benefit is the ability to describe propagation of the full sound wave through the subsurface with a mathematical expression known as the wave equation. The ability greatly improves migration, a processing step that moves indications of reflection points to their proper positions on seismic displays.

Previously, migration relied to varying degrees on ray-tracing, a computationally less intense technique that Hill describes as "pretty good in a constant-velocity world." Because of subsurface irregularities, sound travel seldom follows constant-velocity assumptions. A more-complete solution to the wave equation than is available with ray-tracing more accurately represents wave behavior and thus greatly enhances geophysical interpretation.

Wave-equation migration is especially important in areas of "strong velocity discontinuities," such as around subsurface bodies of salt, Hill notes.

Improvement of migration algorithms also has helped seismic processors suppress multiples, which appear in seismic displays as reflections but really represent energy reflected more than once before detection by receivers. Multiples can be especially troublesome in earth volumes of complex sound velocity, such as those intruded by salt.

Geophysicists have long known that the migration algorithms that assumed all energy followed a ray path rather than a spreading wave front provided "just an approximation of what nature does," Hill says. "We in fact had the algorithms 20 years ago, but we did not have the computer power to implement them."

Seismic attributes

Hill, who becomes SEG's president at the group's annual convention this week, points to interpretation of seismic attributes as an area of great promise but one "still very much in its infancy."

Attributes can be basic signal parameters such as frequency, amplitude, or phase—or any other measurable qualities within a volume of seismic data that enable interpreters to compare traces with one another, looking for patterns and discontinuities. Traces are the lines on seismic records on which wiggles indicate sound reflections.

Hill says he didn't fully appreciate attribute interpretation until he edited a book on the subject by Satinder Chopra of Arcis Corp., Calgary, and Kurt Marfurt of the University of Oklahoma. "What's the common problem that they're trying to address with this?" he asked himself, eventually deciding it was "the challenge that we have as human beings in visualizing things in 3D."

In the 3D world, he explains, "we look at things in 2D surfaces." Seismic attributes "collapse the information that's in a 3D slab [of the subsurface] down to just 2D data."

Hill considers seismic attributes "an extremely creative front of activity" and says, "I think that quest will continue full bore."

In line with his view about how science advances, he adds: "Seismic attribute analysis is a technology that really stands at the juncture of seismic processing and seismic interpretation."

Another area of promise, in Hill's view, is reservoir characterization through the acquisition and interpretation of shear-wave (S-wave) data. With S-waves, particle movement caused by

Career highlights

Employment

Stephen J. Hill worked on the faculty of the Michigan State University Astronomy Department during 1971-78, earning the MSU Teacher-Scholar Award for public service, teaching, and programming work in telescope automation. During 1978-2003 he worked for Conoco, where at different times he managed the seismic processing function, served as an interpreter of Oklahoma and Gulf of Mexico seismic data, consulted on technology at the company's international and North American headquarters, and taught internal seismic processing and seismic analysis courses. More recently he has been a consultant, based in Boulder, Colo., and professor at the Colorado School of Mines.

Education

Hill holds a bachelor's degree in physics from Iowa State University and earned a doctorate in physics and astrophysics through the Joint Institute for Laboratory Astrophysics at the University of Colorado.

Affiliations

He has chaired several SEG committees and served as Geophysical Developments Series Editor and member of the Seismic Interpretation Pitfalls Subcommittee. At the Geophysical Society of Tulsa he was president, past-president, editor, editor-elect, and education chair.

a sound pulse is perpendicular to the direction of sound travel. Most seismic work is conducted with compressional waves (P-waves), in which particle movement is parallel with sound movement.

Because P-waves and S-waves behave differently in the subsurface, they provide "two independent observations which hopefully you can play off against one another," Hill says.

At the Colorado School of Mines, where he has been a professor, the independently sponsored, graduate-level Reservoir Characterization Project is using S-waves for time-lapse investigations.

By comparing P-waves with S-waves, Hill says, "hopefully, you can unravel the intrinsic stiffness of the rock vs. what's in the pores." While geophysicists have been experimenting with S-waves for a number of years, he adds, "It seems to be a technology that's always just around the corner."

A possible reason: "It's an extra cost item on the menue."

Need for geophysicists

Asked about the employment prospects for geophysicists, especially in view of diminished industry activity and steady gains in computer power, Hill offers a mixed answer.

Handling increasing amounts of data, seismic processing centers must build much larger velocity models than they did in the past. The task requires heavy interpretation, which requires people. But companies stressing high-cost wells, such as those in deep water, may need fewer prospects to absorb drilling budgets—and therefore fewer geophysicists to handle the interpretation, Hill says.

Offsetting that trend in marine work, however, is the heavy emphasis on gas drilling onshore, most of which is based on geophysical data.

"When we think of interpretation work and the SEG, one thinks first of the petroleum industry," Hill adds. "That's not the only place that's employing geoscientists and geophysicists."

Environmental work and archaeology also use geophysical methods, he says, and neither area is sensitive to the price of oil.

Science progresses in nonpetroleum realms, too—usually in unpredictable ways.

"Everything I've read about great physicists says that they were led by their intuition and not by their math," Hill says. "Of course, they had to have their math, too." ✦

Salazar announces oil shale lease round, addenda inquiry

Nick Snow
Washington Editor

US Interior Secretary Ken Salazar announced a second round of federal oil shale leases on Oct. 20 with substantially different terms than the first round. He also said he will ask his department's inspector general to investigate favorable addenda offered to holders of existing leases 5 days before the end of the previous administration.

"If we are to succeed in unlocking oil shale's great potential, we must first answer fundamental questions about water use, power use, and environmental and social impacts of commercial development," Salazar said at a press conference. "With this new round of [research, development, and demonstration] leases, we hope to move closer to responsibly and sustainably developing our oil shale resources." An estimated 800 billion bbl of shale oil is believed to exist on federal land in Colorado, Utah, and Wyoming.

Applicants will have 60 days after

publication of the lease sale's notice in the Federal Register to submit nominations of up to 160 acres each to the US Bureau of Land Management. Salazar said that an interdisciplinary team of BLM professionals and representatives from Colorado, Utah, and Wyoming (as appropriate) and the Defense and Energy departments will evaluate the nominations.

Like the first round, the latest leases will be 160 acres each. They will run for 10 years. And nominations will be evaluated according to their potential to advance technologies, their economic viability, and their environmental impacts.

But they also will have a smaller preference right area (480 acres instead of 4,960 acres), a higher application fee ($6,500 instead of $2,000), and additional questions concerning water use, energy use, water quality impacts, socioeconomic impacts, and other factors.

Many questions

Salazar said many oil shale development questions still need to be answered. "How much water would be required for commercial oil shale development and where it would come from is obviously important in Colorado and Utah, which are arid states with limited water supplies and where commercial oil shale development would have major impacts on agriculture and other uses?" he observed.

BLM and the Department of the Interior also will consider whether technologies being developed can become commercial, how much electricity will be needed to pry the kerogen from the rock, and what impacts commercial oil shale development would have on nearby communities, water, wildlife, and climate, Salazar said.

"These are central questions to which answers are needed before we plunge forward in the full-scale endorsement of any commercial oil shale development," he said. "That's why it is so essential for us in our reform agenda as we look to developing a comprehensive energy plan, that we have honest straightforward answers to these central questions."

New oil shale leases also will contain diligence milestones that were not a part of the first round in 2007, Salazar said. These will include submitting a development plan within the first 9 months. Once BLM approves that plan, lessees will be required to obtain state and local permits within 18 months and deploy infrastructure within 24 months, as well as submit quarterly progress reports.

If an RD&D lease's conversion to commercial status is approved, a minimum of 10,000 b/d of commercial production would be required, and the royalty rate would be determined by either the secretary or new regulations. Salazar said that the changes reflect specific parts of a broader reform effort which are aimed directly at the nation's oil shale resource.

Addenda inquiry

The secretary also said he will ask Mary L. Kendall, DOI's acting inspector general, to invest a set of lease addenda that the administration of President George W. Bush entered into with holders of the six existing oil shale RD&D leases on Jan. 15—just 5 days before its tenure ended.

BLM issued these Colorado and Utah leases in January 2007. On Jan. 15 of this year, it granted the leaseholders the right, at the time of conversion to commercial development, to elect to have their leases governed by a set of favorable conditions and low royalty rates, including an initial royalty rate of 5% which Salazar considered premature.

"There are serious questions about whether those lease addenda in fact are legal or whether or not they should be rescinded. I have decided that before taking final action on those lease addenda that it's important for me as secretary of Interior to get to the facts about the circumstances surrounding the issuance of those lease addenda," he said.

Salazar withdrew the Bush administration's proposal to expand offerings in a second oil shale leasing round on Feb. 25 because he said that it made the parcels four times the size of the earlier leases and locked in low royalty rates and a premature regulatory framework. "I said then and I still will say today that I think there is a question about how those royalty rates could actually be set when these very important fundamental questions have not yet been answered," he told reporters on Oct. 20.

Responding to his announcement, the American Petroleum Institute said in a statement that it considered Salazar's decision to proceed with a second oil shale leasing round a positive step. It also expressed concern over some of the new terms, particularly the 87% reduction in total commercial lease size.

"Slashing the size of the potential commercial lease diminishes the incentives for investment and ignores the enormous up-front costs and risks undertaken to develop these technologically complex resources," API said. ✦

Shale finds muddle Arctic development timing

Alan Petzet
Chief Editor-Exploration

The timing of oil and natural gas development in the Arctic, estimated to hold 22% of the world's undiscovered conventional oil and gas resources, has grown less predictable with massive discoveries of gas in the world's shales.

The potentially vast shale gas resource adds uncertainty to the timing of Arctic development, already daunting due to the gas-prone nature of the Arctic resource, extreme Arctic risk and expense, unresolved sovereignty claims, and environmental protection safeguards.

These are among the conclusions of a study released by the US Energy Information Administration of the 6% of the earth's surface above the Arctic Circle that falls in eight countries: Canada, Denmark (Greenland), Finland, Iceland, Norway, Russia, Sweden, and the US.

The prospect of recovering 5,000 to 16,000 tcf of shale gas in more accessible geologic provinces could defer Arctic development generally, although growing European gas demand may be a strong incentive for Russian Arctic gas development, EIA concluded.

Large Arctic discoveries began at Tazovskoye in Russia in 1962 and at Prudhoe Bay in the US in 1967.

EIA tallied 61 large oil and gas discoveries above the Arctic Circle in four countries, 43 of them in Russia. Fifteen of the 61 were found in the 1970s-80s and are undeveloped due to the expense. Thirteen of the 15 are in North America.

The US Geological Survey released mean estimates in 2008 of an Arctic undiscovered resource of 90 billion bbl of oil, 44 billion bbl of natural gas liquids, and 1,670 tcf of gas, 84% of it offshore (OGJ, Aug. 4, 2008, p. 17). That study of 25 geologic provinces left eight other provinces unassessed as being too minor.

The three largest Arctic provinces account for 65% of the total resource, and the top 10 for 93%. The high concentration might reflect that little if any exploration has occurred in the low-estimate provinces. The Arctic resource mix is judged to be 78% gas and NGL.

The estimates embody considerable uncertainty, even for the two assessment units in the province judged to hold the largest Arctic resource, the West Siberian basin.

Eurasia has 63% of the Arctic resource base and North America 36%, and the Eurasian base is 88% gas and gas liquids while the North American side has 65% of undiscovered Arctic oil. Three North American provinces have 54% of the Arctic's total undiscovered oil resource: Arctic Alaska, the Amerasia basin just north of Canada, and the East Greenland Rift.

Even without the shale gas proliferation, the Arctic presents imposing development hurdles.

Denmark, Canada, Norway, Russia, and the US have overlapping economic sovereignty claims in Arctic waters. Some claims stem from a 1982 United Nations convention that permits countries to claim as much as 350 nautical miles beyond the point where sea depth exceeds 8,200 ft of water, EIA pointed out.

Duplicate claims exist, for example, between Denmark and Russia in the Arctic Ocean, Norway and Russia in the Barents Sea, and Canada and the US in the Beaufort Sea.

Development impediments include harsh weather, poor soil conditions, no summer access, facilities damage and supply hindrance from ice, long supply lines, and higher worker inducements.

One study found Alaska North Slope onshore development costs to be 1.5-2 times as expensive as a similar project in Texas, but costs and risks can be significantly greater due to long lead times, lack of infrastructure, supply chain delays, weather, and court challenges.

This suggests "that only the world's largest oil companies, mostly likely as partners in joint venture projects, have the financial, technical, and managerial strength" to tackle the Arctic, EIA said. ✦

MMS conditionally approves Shell's Beaufort Sea leases

Nick Snow
Washington Editor

The US Minerals Management Service approved Shell Offshore Inc.'s exploration plan for two Beaufort Sea leases with stringent conditions, the US Department of the Interior agency said on Oct. 19. Environmental groups immediately protested the action.

MMS said Shell obtained the two leases during US Outer Continental Shelf Lease Sales 195 and 202 in 2005 and 2007, which were part of the 2002-07 5-year leasing program. They were not affected by the recent federal court decision which sent the 2007-12 program back to MMS for additional analysis under Section 18 of the OCS Lands Act, MMS said.

It said that Shell plans initial activity on the leases during the July-October open water drilling season. Operations would be conducted using the M/V Frontier Discoverer, a modern drillship retrofitted and ice reinforced for operations in arctic OCS waters, it said.

Shell also plans to take a midseason break beginning Aug. 25, 2010, and remove the vessel from the area to accommodate subsistence bowhead whaling by the Alaska Native villages of Kaktovik and Nuiqsut, MMS added. Activity may resume following the hunts and run through Oct. 31, depending on ice and weather, it said.

The company's exploration plan also will have to be consistent with Alaska's Coastal Zone Management Plan before drilling can commence, according to MMS. It also will need to obtain drilling permits from MMS, and meet US Environmental Protection Agency air and water quality rules and Marine Mammal Protection Act requirements of the US Fish and Wildlife Service and National Marine Fisheries Service, MMS said.

Shell's plan is limited to the far western area of Camden Bay, including the use of one drillship with one tending ice management vessel, it indicated.

Groups protest

Eight environmental organizations, including the Sierra Club and Earthjustice, protested the decision. "Once again, MMS approved a drilling plan without a full analysis of the potential consequences," said David Dickson, the Alaska Wilderness League's Western Arctic & Oceans program director.

The plan would involve use of a drillship "and an armada of support vessels and an armada of support vessels and aircraft, [which] would generate industrial noise in the water while emitting tons of pollutants into the air and thousands of barrels of waste into the water," the groups said in a joint statement.

The risk of an oil spill in the area's waters is high, yet there is no technology and very little capacity to clean a spill up in icy Arctic conditions, they added.

"The reality of offshore oil drilling is that accidents will happen, and when oil spills in Arctic ice, there is no cleaning it up," said Chuck Clusen, the Natural Resources Defense Council's national parks and Alaska projects director.

"A blow-out like the one that recently despoiled waters off the coast of Australia would leave oil in the waters off the coast of the Arctic National Wildlife Refuge for decades, killing whales, seals, fish, and birds, and turning irreplaceable spawning and feeding grounds into an ecological wasteland," he declared. ✦

Study estimates added costs of US energy production

Nick Snow
Washington Editor

US energy production and consumption cost an estimated $120 billion, primarily from motor vehicle and electric power plant emissions, beyond market prices in 2005, the National Research Council said in a study.

Such added costs were significantly lower from power plants using natural gas instead of coal, but "remarkably similar among various fuels and technologies" for transportation fuels, the congressionally mandated report said.

The examination attempted to look past market prices for oil, gas, coal, and other energy sources and their transportation and power generation fuels and at human health costs from air pollution, according to the council, which is part of the National Academy of Sciences.

It said its estimates do not include damages from climate change, harm to ecosystems, effects of some air pollutants such as mercury, and risks to national security, which the report examined but did not monetize.

The council said the committee writing the report focused on monetizing damage from major air pollutants (sulfur dioxide, nitrogen oxides, ozone, and particulate matter) on human health, grain crops and timber yields, buildings, and recreation. When possible, it estimated both what the damages were in 2005 (the latest year for which data were available) and what they are likely to be in 2030, assuming current policies continue and new policies already slated for implementation are put in place.

Coal vs. gas costs

The report estimated total annual external costs in 2005 from 406 coal-fired power plants producing 95% of the nation's coal-generated electricity were $62 billion, or about 3.2¢/kw-hr, which could drop to 1.7¢/kw-hr in 2030. Its sample of 498 gas-fired power plants representing 71% of the nation's gas-generated electricity produced an estimate of $740 million of total non-climate damages in 2005, or an average 0.16¢/kw-hr which could fall to 0.11¢/kw-hr in 2030.

Estimated power generation climate damage costs from gas were half that of coal, ranging from 0.05¢ to 5¢/kw-hr, it added.

Noting transportation accounts for nearly 30% of total US energy demand and currently relies almost exclusively on oil, the report estimated motor vehicles produced $56 billion in domestic health and other non-climate costs in 2005. It said the committee evaluated costs from exploration and production to refining and end-use. "In most cases, operating the vehicle accounted for less than one-third of the quantifiable non-climate damages," it said.

Costs per vehicle mile traveled were similar among various combinations of fuels and technologies (in a 1.2-1.7¢/mile range), and the report recommended caution in interpreting small differences. "Nonclimate-related damages for corn grain ethanol were similar to or slightly worse than gasoline, because of the energy needed to produce the corn and convert it to fuel," it said. "In contrast, ethanol made from herbaceous plants or corn stover, which [is] not yet commercially available, had lower damages than most other options."

It said for both 2005 and 2030, vehicles using gasoline made from oil extracted from tar sands and those using diesel derived from the Fischer-Tropsch process (which converts coal, methane, or biomass to liquid fuel) had the highest life-cycle greenhouse gas emissions. Vehicles using ethanol made from corn stover or herbaceous feedstock such as switchgrass had some of the lowest greenhouse gas emissions, as did those powered by compressed natural gas, it added.

The report said fully implementing federal rules on diesel fuel emissions, which require 2007 model year or newer vehicles to use an ultra low-sulfur formulation, is expected to substantially decrease non-climate damage costs from diesel by 2030. The committee considered this an indication of how regulatory actions can significantly affect energy-related damages. Major initiatives to lower other emissions further, improve energy efficiency, or shift to a cleaner mix of energy sources could reduce other damages as well, it said. ✦

Amended commodities reform bill clears House FS panel

Nick Snow
Washington Editor

The US House Financial Services Committee approved a bill on Oct. 15 that would regulate over-the-counter trades in commodity markets for some—but not all—participants. Energy producers and consumers using commodity hedges to control prices apparently would be exempt.

The exemption was part of a manager's amendment offered by the committee's chairman, Barney Frank (D-Mass.), which clarifies that the bill's marginal requirements would allow use of noncash collateral for commodity hedges. Independent producers have said that this is essential so they can continue using their reserves instead of cash. Airlines and other commercial fuel customers also support an exemption.

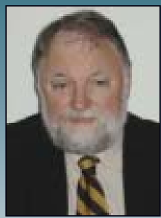
The administration of US President Barack Obama indicated earlier in the week that it could support an exemption for such commercial commodities traders after initially opposing it. Top officials at the US Commodity Futures Trading Commission and the US Securities and Exchange Commission, which would be jointly responsible for enforcing any new OTC commodities regulations, apparently remain uncomfortable with it.

One committee member said the provision is a step in the right direction

Watching Government

Nick Snow, Washington Editor

Blog at www.ogjonline.com



The categorical exclusion target

A 2005 National Energy Policy Act (NEPACT) provision designed to facilitate onshore drilling permit processing remains a target of advocates for far-reaching US oil and gas leasing reforms.

NEPACT's Section 390 authorizes the US Bureau of Land Management's use of categorical exclusions (CXs) to streamline environmental analysis of onshore drilling permit applications in certain instances. Congressional and other critics charge that it has been used to bypass the National Environmental Policy Act (NEPA).

They point to a Sept. 15 Government Accountability Office report that found BLM's use of the provision "has frequently been out of compliance with both the law and BLM's guidance."

It noted violations that included approving more than one well under a single decision document, approving projects inconsistent with the law's criteria, and drilling a new well after time frames had elapsed.

GAO also found cases, in 85% of the BLM field offices it studied, where officials did not follow guidance, most often by failing to adequately justify a CX's use.

Lack of guidance

It blamed a lack of clear guidance and oversight for the violations. "While many of these are technical in nature, others are more significant and may have thwarted NEPA's twin aims of ensuring that BLM and the public are fully informed of the environmental consequences," GAO said.

The report's release as the House Natural Resources Committee began hearings on chairman Nick J. Rahall's (D-W.Va.) bill to dramatically reform federal minerals management policies also produced a response from one western state's governor.

"On one hand, we heard that the land use plans should not be detailed because the details would be worked out in the project-level analysis. With the passage of these categorical exclusions, we were told that the project-level analysis would not be done in favor of using categorical exclusions, relying on the land use plan level analysis they told us we didn't need in the first place," Dave Freudenthal of Wyoming said on Sept 17.

'Not discretionary'

But the Independent Petroleum Association of Mountain States said on Oct. 1 that GAO's report also cites instances where BLM officials should have used CXs, but didn't.

"CXs are not discretionary. GAO found many examples where BLM failed to use them, highlighting their cautious and overly conservative use," said Kathleen Sgamma, IPAMS government affairs director. "We would be very interested in seeing the data on cases where CXs were not used, even when all criteria were met."

GAO's report actually provides reasonable recommendations for BLM to exercise CX oversight, Sgamma added.

"In fact, it details mostly administrative errors, not major violations of the law. Careful analysis of the report sample shows just a 6.7% rate of errors resulting in a violation. That number can be brought close to zero if BLM implements GAO's oversight recommendations," she said. ✦

because it addresses a lot of end-users' concerns. "Still, the language still is unclear in that regulators can still require them to meet the cash requirement," observed Scott Garrett (R-NJ). The committee adopted Frank's amendment by voice vote.

The bill, HR 3795, passed by 43 to 26 votes, largely along party lines. It is aimed primarily at swaps, which are contracts that call for an exchange of cash between two counterparties based on an underlying rate, index, credit event, or the performance of an asset, according to information provided by the committee's majority staff.

Major participants

Trades between dealers and major market participants would have to be cleared on regulated exchanges or electronic trading platform if the measure becomes law. The bill defined a major market participant as a person or entity that maintains a substantial net position in swaps, exclusive of hedging for commercial risk, or which has a position creating such significant exposure to others that it requires monitoring.

Regulatory authority would be split between CFTC, which has jurisdiction over swaps, and SEC, which regulates securities-based swaps. The US Treasury would have authority to issue final rules if CFTC and SEC were unable to decide on a joint approach within 180 days. The two commissions would have to jointly approve subsequent interpretations of rules.

Frank said leaders from his committee will try to help resolve such questions later in meetings with the House Agriculture Committee, which plans to consider its own commodities reform bill on Oct. 21. Its chairman, Collin C. Peterson (D-Minn.), introduced a discussion draft on Oct. 9 that addressed OTC clearing, trading, capital and margin requirements, and position limits. The draft attempted to build on HR 997, an OTC regulatory bill which the committee passed earlier this year.

"We have been working throughout with the Agriculture Committee, which has jurisdiction over the CFTC. There are some issues which can't be resolved by one committee, particularly when they are jurisdictional in nature. We will deal with them later," said Frank. US Senate committees also are preparing commodities reform measures.

Positions had changed heading into the markup, Frank conceded. Paraphrasing Otto von Bismarck, chancellor of the German Empire during the late 19th century, the chairman said: "Watching sausage being made, and watching legislation being made, isn't always attractive. There clearly has been a lot of give-and-take here. People who have been trying to fix the position of any one member at any given time have been mistaken because everyone has tried to work with an open mind."

Other responses

Republicans on the committee remained critical. Spencer T. Bachus (Ala.), the ranking minority member, conceded following the vote that his three proposed amendments became part of the final bill. They would extend the implementation period of the legislation from 180 days to 270 days after enactment, provide SEC and CFTC with exemptive authority similar to current law; and perhaps most importantly, to prevent taxpayer funded bailouts of clearinghouses. All were adopted by voice vote.

But the bill still increases government regulation, Bachus continued. "One of the lessons from the crisis is that we need smarter regulation, not more regulation. We need to close the gaps in regulation, not add layer upon layer on existing legislation," he said.

"The new system of complex regulation will place American businesses and the economy at a disadvantage," Bachus said. "The committee has heard from companies that use derivatives to manage risk that the Democrats' legislation will drive up costs for the whole economy and could lead to capital restraints for users of derivatives. That is why Republicans offered amendments to ensure the legislation is workable and less disruptive to the economy. Unfortunately, in the end, overregulation trumped sound policy."

CFTC Chairman Gary G. Gensler said following the vote that the House FS committee's action "represents historic progress toward comprehensive regulatory reform of the over-the-counter derivatives marketplace," adding, "The committee's bill is a significant step toward lowering risk and promoting transparency."

Gensler said, "I look forward to building on this committee's hard work with Chairman Frank, Chairman Peterson, and others in the House and Senate to complete legislation that covers the entire marketplace without exception and to ensure that regulators have appropriate authorities to protect the public." ✦

House subcommittee passes chemical security bill

Nick Snow
Washington Editor

A US House subcommittee passed chemical security legislation Oct. 14 that critics said would change federal regulations that have not been fully implemented.

The Energy and Commerce Committee's Energy and Environment Subcommittee approved HR 2868, the Chemical Security Anti-Terrorism Act of 2009, by 18 to 10 votes and referred it to the full committee. The bill would amend the 2002 Homeland Security Act by adding a title regulating security practices at US chemical facilities, including refineries and petrochemical plants.

If it becomes law, the measure would give the secretary of the US Department of Homeland Security (DHS) authority to designate a chemical as a "substance of concern" and set limits on how much of such substances could be used, stored, processed, manufactured, or distributed at a regulated installation. Risk-based regulated tiers would be assigned for each covered site, which would be notified within 60 days of its designation or any change in it.

The DHS secretary also would have to develop regulations establishing risk-based and performance-based standards, protocols, and procedures for mandatory security vulnerability assessments (SVAs) and site security plans (SSPs) and set deadlines by tier for completing both. The secretary would approve or disapprove SVAs and SSPs within 180 days of their submission. Covered plants would have to review and resubmit SVAs and SSPs at least every 5 years.

The bill also would establish an Office of Chemical Security, and require covered plants to establish security background checks for employees and others with access to the plant's restricted areas.

'Making a mistake'

The measure drew fire from the full committee's ranking minority member. "I think we're making a mistake. I think we're making significant changes to a chemical facility security program that's not even been fully implemented yet," said Rep. Joe Barton (R-Tex.) as markup of the bill began before the vote. "I think we should wait until it is implemented before we decide to change it."

Chemical security applies to a broad swath of the US economy, from hospitals to farms to factories as well as chemical plants, Barton said, adding, "We should at least identify and understand the problem we are trying to fix before we rush head-long into legislation. We seem to be approaching this from the perspective of crafting a solution in search of a problem."

In a statement following the vote, National Petrochemical & Refiners Association Pres. Charles T. Drevna also noted that current federal chemical facility antiterrorism standards still are in the process of being implemented and should at least have the opportunity to take effect before changes are made.

NPRA also believes mandating an "inherently safer technology" (IST) program for facilities in the two highest tiers, as the legislation proposes, is unnecessary, he added. "IST is an engineering philosophy, not a technique, nor is it a panacea for security. Forced chemical switching under an IST mandate will not necessarily result in safer operations, and in fact, may result in increased risks to facilities, their employees, the public, and the environment," Drevna said.

Increased regulatory and financial burdens under an IST mandate would likely cause many petrochemical and refining businesses to consider simply moving their operations overseas, he warned. "Unfortunately, this bill appears to be nothing more than an attempt to further a partisan environmental agenda in the name of security," he said. ✦

Russia's Gazprom planning earlier start at Sakhalin-3's Kirinsky field

Eric Watkins
Oil Diplomacy Editor

Russia's state-owned OAO Gazprom plans to start production at the Sakhalin-3 project's Kirinsky field in 2011 or 2012, 2-3 years ahead of schedule, according to a senior company executive.

"I think that at the end of 2011-12 we could already start production at the Kirinsky field," said Alexander Mandel, head of OOO Gazprom Dobycha Shelf, the Gazprom subsidiary that oversees offshore projects.

"It had been planned that development of Kirinsky will start in 2014," Mandel said of the field, which is a part of the Sakhalin-3 offshore project whose gas reserves are estimated at 75.4 billion cu m.

Mandel said the decision to speed up the launch of the Kirinsky field development would depend on demand for gas in the region and Gazprom plans to launch the Sakhalin-Khabarovsk-Vladivostok gas pipeline.

According to analyst IHS Global Insight, "The change of plans at Kirinsky follows the signing last week of a framework gas supply agreement between Gazprom and China's CNPC."

IHS Global Insight also said the speed-up at Kirinsky followed another reported agreement in principle on gas prices between Russia and China, which could see Gazprom deliver up to 70 billion cu m/year of gas to China in the next decade.

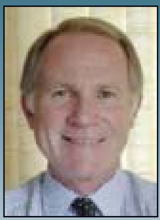
"Accelerating the development of the Kirinsky field could provide Gazprom with volumes needed for the Khabarovsk-Vladivostok pipeline and put more pressure on ExxonMobil [Corp.] regarding gas production from Sakalin-1," the analyst added.

Meanwhile, stepping up pressure on potential Asia-Pacific buyers, Gazprom Deputy Chairman Alexander Medvedev told Japan's Nikkei Business Daily the state-owned natural gas monopoly will likely partner with Mitsui & Co. and Mitsubishi Corp. on the Sakhalin-3 project.

When asked about the chances of Japanese companies taking part in the Sakhalin-3 project, Medvedev reminded the paper that Gazprom already has contracts with Royal Dutch Shell PLC, Mitsui, and Mitsubishi, which hold stakes in the Sakhalin-2 project.

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



Whodunit in Georgia?

As if the oil and gas industry didn't already have enough problems on its hands, bombers struck a train in Georgia this week and reawakened memories of the conflict that occurred there just over a year ago.

"According to preliminary information, TNT was used in the explosion," said Georgian Railway spokeswoman Irma Stepnadze, who confirmed no one was injured in the blast, which damaged 100 m of track and overturned 16 tanker cars.

The explosion took place on the rail line between Senaki and Georgia's Black Sea port of Poti, a major center of oil exports. Stepnadze said repair work was under way, but it was unclear when traffic on the line would resume.

The cause of the explosion was completely clear to officials in Georgia, now considered by the US and Europe as an important segment of a key oil and gas transport corridor from the Caspian to western markets.

No accident

The Oct. 21 blast appeared to be "an act of sabotage" and not an accident, according to Shota Utiashvili, a spokesman for Georgia's interior ministry, whose words echoed those of other Georgia officials.

More worrying, the blast is the third in a series apparently targeting the railway network in the country's western region near the Russian-backed separatist Abkhazia province.

"The recent increase in the frequency of explosions on the Georgian railroads is sign of deteriorating security in Georgia," said analyst IHS Global Insight, which said the attacks are especially painful for Georgia since its rail network is essential for transporting oil.

"Georgia owes much of its foreign direct investments to the fact that it has become a vital oil and gas transport corridor," said IHS Global Insight, which added that attacks have also been staged against the Baku-Tblisi-Ceyhan oil pipeline.

Maximum damage

"It is clear from the repeated attacks to essential infrastructure that the instigators of these acts are interested in causing maximum economic damage to the country rather than human casualties," IHS Global Insight said.

According to the analyst, the Georgian government has yet to present evidence to support the allegation that the Abkhazians from the breakaway region in the northwestern part of the country, close to Senaki, are responsible for the attacks.

However, the analyst had no hesitation in saying that "to retain its important role as a transport hub Georgia needs to step up security measures on essential transport routes in order to guarantee the safe passage of vital oil and gas exports through its territory."

True enough, so far as it goes. But such a conclusion does not go far enough for it overlooks the fact that oil passing through Georgia comes from states to the East and is heading toward states to the West. In a word, more countries than Georgia have a stake in trans-Caucasian transport security.

It's everybody's problem. ✦

"Those contracts stipulate that Gazprom give priority to the three firms once it obtains the development rights to the project and decides to seek cooperation with foreign businesses," he said.

Regarding disagreements over where to send output from Sakhalin-1, Medvedev said the Russian government, under its industrial development plans for the Far East and eastern Siberia, has clearly stated natural gas from the Sakhalin-1 project will be supplied to the domestic market.

"Sakhalin-1 shareholders are calling for the output to be exported to China, but we cannot agree with such a move," he said, referring to ExxonMobil, Itochu Corp., and Marubeni Corp. "We will likely consider exporting LNG to China and South Korea from other gas fields in eastern Siberia," he said.

When asked about the disruption of gas supplies from Russia to Europe early this year, Medvedev said it was caused by a domestic political conflict in Ukraine and that there should be no concern for markets in Asia Pacific.

"We can promise that we will be able to fulfill our gas supply contracts for the Asia-Pacific region. We only have economic motives. We have never intended and will never intend to use gas supplies as a political tool," he said. ✦

Holly to buy, integrate Sinclair refinery in Tulsa

Holly Corp. has entered a definitive agreement to purchase Sinclair Oil Corp.'s 75,000-b/d refinery in Tulsa and will integrate the facility with its 85,000-b/d refinery 2 miles away.

Holly bought the other Tulsa refinery in June from Sunoco Inc. (OGJ, Apr. 20, 2009, Newsletter).

Operation of the refineries as a fully integrated complex will lower total crude capacity to about 125,000 b/d, according to Holly Chairman and Chief Executive Officer Matt Clifton, who

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said the reduction will cut investment requirements.

"We will save approximately $110 million of previously required regulatory capital costs versus our initial $150 million estimate," Clifton said. "We also expect the integrated facility will reduce expected capital expenditures for forthcoming reduced benzene in gasoline requirements from approximately $30 million for the Holly facility alone to approximately $15 million for the integrated complex."

Holly will pay $54.5 million in cash and $74 million in common stock for the refinery and about 2.3 million bbl of storage. It also will purchase the refinery's inventory of about 500,000 bbl at market value at the time of closing.

Holly will agree at closing to provide as much as 50,000 b/d of gasoline and diesel fuel to Sinclair's Midwest marketing network.

Holly Energy Partners, a midstream master limited partnership of which Holly Corp. owns 41%, will buy an additional 1.4 million of storage at Sinclair's Tulsa refinery as well as various loading racks and related facilities.

Holly expects to enter into a long-term agreement with the partnership for storage, loading, and delivery services.

The refineries

The company said Sinclair has invested more than $300 million in the past 5 years to enable the Tulsa refinery to meet low-sulfur gasoline standards and to produce 100% ultralow-sulfur diesel. Holly expects to invest $16 million to finish emission-reduction projects in progress.

Integration will allow Holly to charge gas oil from its existing Tulsa refinery to the fluid catalytic cracking unit at the refinery it's buying from Sinclair to produce gasoline and diesel. The company will use a desulfurizer at the Sinclair refinery for diesel from its existing refinery.

Holly expects about half the diesel from the combined facility to meet ultralow-sulfur standards. It plans to invest $10 million over the next 2 years to expand the Sinclair refinery's desulfurization capacity in a project that will raise the complex's yield of ultralow-sulfur diesel to 100%.

Holly also expects to invest $30 million to add sulfur recovery capacity and to expand the flare gas recovery system at its existing Tulsa refinery.

Clifton said crude capacity of the integrated refinery could be expanded "through relatively modest capital expenditures if future market conditions and economics warrant."

According to Oil & Gas Journal's 2008 Worldwide Refining Survey, capacity of the Sinclair refinery's fluid catalytic cracking unit is 16,200 b/cd. Other capacities include 10,800 b/cd of catalytic reforming, 2,700 b/cd of sulfuric acid alkylation, and 5,400 b/cd of pentane-hexane isomerization.

The refinery Holly purchased from Sunoco has processing capacities of 8,500 b/cd of delayed coking, 17,500 b/cd of catalytic reforming, and 24,000 b/cd of catalytic hydrotreating. It also has 8,500 b/cd of lubes capacity. Holly, Dallas, also operates a 100,000-b/sd refinery in Artesia, NM, and a 31,000-b/sd refinery in Woods Cross, Utah.

Sinclair operates two refineries in Wyoming, one near Rawlins with crude capacity listed in OGJ's survey at 66,000 b/cd and the other at Casper, 22,500 b/cd. ✦

Hearings on Senate's climate change bill to begin soon

Nick Snow
Washington Editor

The US Senate Environment and Public Works Committee will begin 3 days of hearings on Oct. 27 on the global climate-change bill that its chairwoman, Barbara Boxer (D-Calif.), and John F. Kerry (D-Mass.) introduced Sept. 30.

"Members of the committee and their staffs, along with the committee's staff, have been working day and night since the bill was introduced, and we have made great progress," she told reporters at a briefing. "Draft provisions of the chairman's mark have been sent to the Environmental Protection Agency for analysis. We expect that to be completed in time for the hearings."

Boxer said the hearings will begin with testimony from US Energy Secretary Steven Chu, Interior Secretary Ken Salazar, Transportation Secretary Ray LaHood, Environmental Protection Agency Administrator Lisa P. Jackson, and Federal Energy Regulatory Commission Chairman Jon Wellinghoff.

Witnesses for the two other hearings will be announced shortly, she said. "We will schedule a full committee markup as soon as possible after the hearings," she said.

Boxer's announcement came a day before the Senate Energy and Natural Resources Committee's second hearing on potential costs of a carbon cap-and-trade program, a component of both S. 1733, the Boxer-Kerry bill, and HR 2454, the measure cosponsored by Reps. Henry A. Waxman (D-Calif.) and Edward J. Markey (D-Mass.), which the House approved by seven votes on June 26.

'Radical transformation'

"As the Senate continues to consider ways to deal with the global environmental problem of climate change, much of the discussion centers around the overall costs and benefits of such a program," committee chairman Jeff Bingaman (D-NM) said Oct. 14 as he opened the hearing. "Addressing the issue of climate change will require a radical transformation of our energy sector, so this committee will continue to take a great interest in this topic in the months ahead."

The committee's ranking minority member, Lisa Murkowski (R-Alas.), said it will be important to make certain climate change legislation does not endanger a domestic economic recovery. "The proposals before us will affect not only climate change, but every facet of our economy for decades to come," she maintained. "It's incredibly difficult to conduct a sensitive and comprehensive analysis of climate change bills, but it's equally important to know how those bills might work and what they may cost."

Four federal analysts testified at the hearing: Douglas W. Elmendorf, director of the Congressional Budget Office; Richard G. Newell, US Energy Information Administration administrator; Reid P. Harvey, a branch chief within the EPA's climate economics division; and Larry Parker, of the Congressional Research Service.

Addressing climate change could entail substantial costs domestically since the US accounts for roughly 20% of total global carbon dioxide emissions, Elmendorf said in his written testimony. "Achieving such reductions would probably involve transforming the US economy from one that runs on CO_2-emitting fossil fuels to one that increasingly relies on nuclear and renewable fuels, accomplishing substantial improvements in energy efficiency, or implementing the large-scale capture and storage of CO_2 emissions," he said.

Climate legislation also would permanently shift production and employment away from industries which produce carbon-based energy and energy-intensive goods and toward alternative energy sources, goods, and services, Elmendorf said. "While those shifts occurred, total employment would probably be reduced a little compared with what it would have been without a comparably stringent policy to reduce carbon emissions because labor markets would most likely not adjust as quickly as would the composition of demand for different outputs," he indicated.

Aspects of HR 2454

Other witnesses discussed studies of HR 2454 since its passage. Newell said EIA found carbon capture and storage and other key technologies for reducing emissions face a variety of technical challenges and, in some cases, additional questions regarding their widespread deployment.

"EIA's results also suggest that the free allocation of allowances to electricity and natural gas distributors significantly lowers direct impacts on consumer electricity and natural gas prices prior to 2025, when it starts to be phased out," he continued. "While this result may serve goals related to regional and overall fairness of the program, the overall efficiency of the cap-and-trade program is reduced to the extent that the price signal that would encourage cost-effective changes by consumers in their use of electricity and natural gas is delayed."

Harvey said in his written testimony that EPA's analysis of HR 2454 and related Senate bills indicates cumulative reductions over several decades affect overall costs more than a particular year's cap level. "Because HR 2454 allows emissions allowances to be banked over time, its 2050 cap (an 83% reduction from 2005 levels by 2050) drives overall behavior and encourages banking in the early years of the cap-and-trade program," he observed.

"In other words, just changing the 2020 cap alone does not have a significant effect on total costs if all else stays the same. Costs will be lower the sooner we start acting, but a national commitment to meeting these long-run emission targets is key," Harvey said.

Parker said the ultimate costs of HR 2454 would be determined by the economic response to the bill's technical challenges, that the distribution of allowance value (either through free allocations or auction revenue) would determine who bears much of the program's costs, and that the availability of offsets, especially international allowances, will be significant.

"The interplay between nuclear power, renewables, natural gas, and coal-fired capacity with carbon capture and storage among the cases emphasizes the need for a low-carbon source of electric generating capacity in the mid-to-long term," he continued. "A considerable amount of low-carbon generation will have to be built under HR 2454 to meet the reduction requirement." ✦

NGSA: Economic recovery biggest variable in winter fuel outlook

Nick Snow
Washington Editor

The strength and pace of an economic recovery could be the single biggest variable in natural gas demand this winter heating season, the Natural Gas Supply Association said as it issued its annual forecast.

"This winter, we expect the state of the economy to potentially be the dominant factor affecting natural gas demand," said NGSA Chairman Patrick J. Kuntz, who also is vice-president of natural gas and crude oil sales at Marathon Oil Corp. in Houston.

"Winter weather remains important, but the strength and pace of any economic recovery could be even more significant this year," Kuntz said.

The National Oceanic and Atmospheric Administration has predicted near-normal to slightly warmer-than-normal winter temperatures in the coming months, he said. NGSA expects neutral pressure on gas prices based on record storage, overall flat demand, and production, which has remained relatively steady despite dramatically reduced drilling activity, Kuntz said.

NGSA anticipates that any economic recovery in the US in the next few months will be fragile, Kuntz told reporters at a briefing. "Unemployment is the looming question mark. Compared to last winter, however, we expect the economy to exert modest upward pressure on gas demand," he said.

Demand outlook

Citing data supplied by Energy Ventures Analysis Inc., NGSA said it expects US gas demand to reach 75.2 bcfd this winter, slightly less than the 75.6 bcfd that was reached a year ago. It anticipates that demand will decline by 0.5%, compared with the 1.7% drop during the 2008-09 winter heating season, while annual electric power generation additions will total 6.8 Gw compared with 7.3 Gw a year earlier.

The forecast anticipates that industrial gas demand will increase slightly, residential and commercial demand will be flat year-to-year, and power demand will decrease slightly. "We saw levels of about 2 bcfd of gas substituting for coal this past winter so it's still significant," Kuntz said.

"A relatively mild summer in some parts of the country, combined with production which remained steady, has led to record storage," Kuntz said. "It's going to be an overhang, putting downward pressure on the markets this winter." NGSA expects storage heading into the heating season to reach 3,822 bcf, compared with 3,412 bcf a year earlier. New storage capacity could reach 123 bcf this winter, up from 82 bcf in the 2008-09 heating season, its forecast said.

Kuntz said US gas producers have responded to reduced demand by curtailing their drilling substantially. NGSA's latest forecast calls for annual well completions to fall to 18,800 this winter from 30,591 in 2008-09, and the averaging US rig count to drop to 786 from 1,535. It expects US gas production to average 55.7 bcfd this winter, up slightly from 55 bcfd a year ago, however.

Shale gas impact

"In spite of lower rig counts and fewer wells being drilled, shale gas activity has kept production relatively steady," Kuntz explained. "Horizontal drilling is helping recover resources which were ignored 10 years ago. We're seeing a fairly wide variation in forecasts for production this winter. Everyone is trying to get their arms around what's going on in shale plays relative to well completions and rig counts."

Access is less of an issue than it has been in previous years, he conceded. "It has slipped a notch or two as part of the message, but it's still an issue. I don't want to consciously take away from this country the ability to find resources, either offshore or onshore. State regulations are increasingly important," he said.

Growing shale gas production could revolutionize the domestic industry since it is geographically diverse and could make the country less reliant on Gulf Coast and Gulf of Mexico supplies, which are vulnerable to hurricanes, Kuntz said. "We don't know if and when a pricing environment can affect shale gas production. I have to believe it can't be ignored. But the long-term prospects for shale gas development are good," he said. ✦

CERI sees US economic gains from Canadian oil sands

Nick Snow
Washington Editor

Canadian oil sands development represents a potential economic boon that could lead to more than 342,000 new US jobs, concluded a Canadian Energy Research Institute study commissioned by the American Petroleum Institute.

The study, "Canada's Oil Sands and Economic Impact on the USA," said more Canadian oil sands production could stimulate economic activity in both countries.

As oil sands production and investment in Canada rises, demand for US goods and services would add an estimated $34 billion to US gross domestic product in 2015 and $42.2 billion in 2025, the study said.

CERI's study also projected new US jobs would be created as a result of the oil sands development, with the heaviest growth during 2011-15 when 342,000 positions would be added, including 43,700 in finance, insurance, real estate, and rental and leasing; 29,000 in food; 21,900 in administrative and support, waste management, and remediation; and 21,700 in professional, scientific, and technical.

"Oil sands reserves play an increasingly important role in the economic development of Alberta, Canada and the United States," CERI said. "What is often not clearly understood is that the large investment in the oil sands industry contributes to increased economic activity in the rest of North America by stimulating demand for goods and services across a wide range of industries."

On Oct. 16, API Pres. Jack Gerard said, "Not only is greater oil sands production crucial for US energy security, it also supports thousands of American jobs and is a major contributor to our nation's economic growth."

CERI based its assumptions on oil sands output rising from about 1.4 million b/d to 4 million b/d in 2025. It estimated annual capital investment and operating costs needed to achieve this output (about $25 billion in new investment and $7 billion in operating costs in 2015) and then projected the economic impact to Canada and the US.

"The economic benefits of oil sands development and production do not fall to one industry but are broadly shared across many industrial sectors," it said, citing steel products in particular. ✦

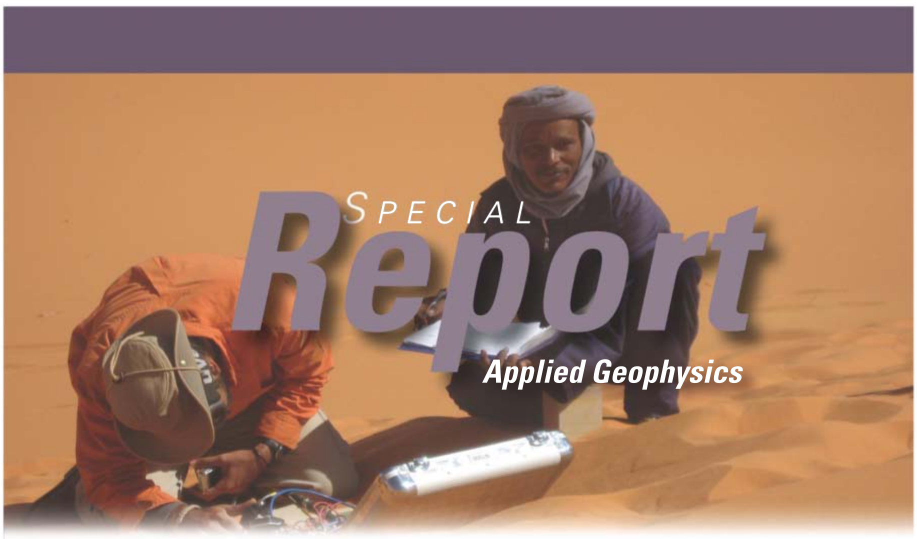
Low frequency seismic has numerous E&D applications

Andrew Poon
Spectraseis
Houston

Economic uncertainty, volatile oil and gas prices, and frozen capital markets, combined with growing reservoir complexity, are having a significant effect on oil and gas exploration and development, causing a renewed focus on managing risk and reducing costs.

Restricted access to locations, environmental sensitivities, high drilling costs, and problematic production options are all driving the demand for new technologies that increase the probability of success in discovering, delineating, and developing oil and gas reservoirs. At the same time, companies must effectively reduce costs through efficient project execution.

One such technology that addresses this industry need is low frequency (LF) seismic, the spectral analysis of the natural seismic wavefield of the earth between 0.1 and 10 Hz. The methodology uses very sensitive broadband seismometers—not the standard 3C geophones—to directly acquire the earth's low frequency (<10 Hz) seismic background data (Fig. 1). Each instrument station includes a portable, ultrasensitive three-component broadband seismometer, battery pack, a GPS unit, and a hand-held controller.



The LF data are analyzed to study small lateral variations. Empirical observations suggest that multiphase fluids in hydrocarbon reservoirs directly affect these small variations and generate energy anomalies in the earth's ambient seismic wavefield.

In this article, innovations in extracting attributes from low frequency (<10Hz) seismic wavefields are examined. Also, potential applications for frontier exploration as well as in mature field development are considered.

Citing recent case study examples, some of the challenges and developments in LF seismic will also be reviewed with regard to the quantitative integration of LF data with the reservoir's rock properties. Significant advances in processing and interpreting the LF data have been made using classical statistical analysis and predictive noise filtering.

Background

Low frequency, passive seismic data have been acquired at several locations around the world.

In one such case in 2007, an extensive survey was carried out above a tight gas reservoir and an adjacent exploration area in Mexico. Data from several hundred stations with three-component broadband seismometers, distributed over 200 sq km, were used for the analysis.

The hydrocarbon, reservoir-related attributes were calculated, mapped, and compared to the known gas intervals, showing good agreement between the LF attributes and the known hydrocarbon locations. The adjacent exploration area was then mapped for potential hydrocarbon locations.

Wells drilled after the survey confirmed the predicted, high hydrocarbon potential in the exploration area. It is assumed that hydrocarbon reservoirs are partially saturated, whereas the surrounding rocks are fully saturated. Real data observations are consistent with this conceptual model.

Broadband seismometers that acquire LF seismic data (Fig. 1).

Low frequency benefits

Low frequency (LF) seismic analysis produces attributes that describe the variation of the naturally occurring seismic wavefield below 10 Hz.

A growing number of surveys over different oil and gas fields throughout the world have established the presence of spectral anomalies in the earth's ambient seismic wavefield—microtremors—with a high degree of correlation to the location of hydrocarbon reservoirs.

Current hypotheses state that these anomalies may be directly related to the fluids inside the reservoir structure rather than to the reservoir structure itself. An analysis of the anomalies can therefore be used, together with other reservoir data prior to drilling, as an indicator for optimizing well placement during exploration, appraisal, development, and field extension, or reservoir management.

Spectraseis believes that a coherent explanation of the rock properties of the reservoir system can be developed using low frequency data, an uncommon measurement in traditional seismic surveys. Furthermore, it is expected that further analysis of reservoir data will explain the field observations that have been collected over the last decade around the world, linking reservoirs to low frequency seismic energy anomalies in the frequency domain.

The potential benefits to the oil and gas company from low frequency seismic are compelling. There is an increased probability of success in defining hydrocarbon zones prior to embarking on a drilling program, with fewer dry or nonproductive wells, lower drilling costs, and reduced exposure to health, safety, and environmental risk.

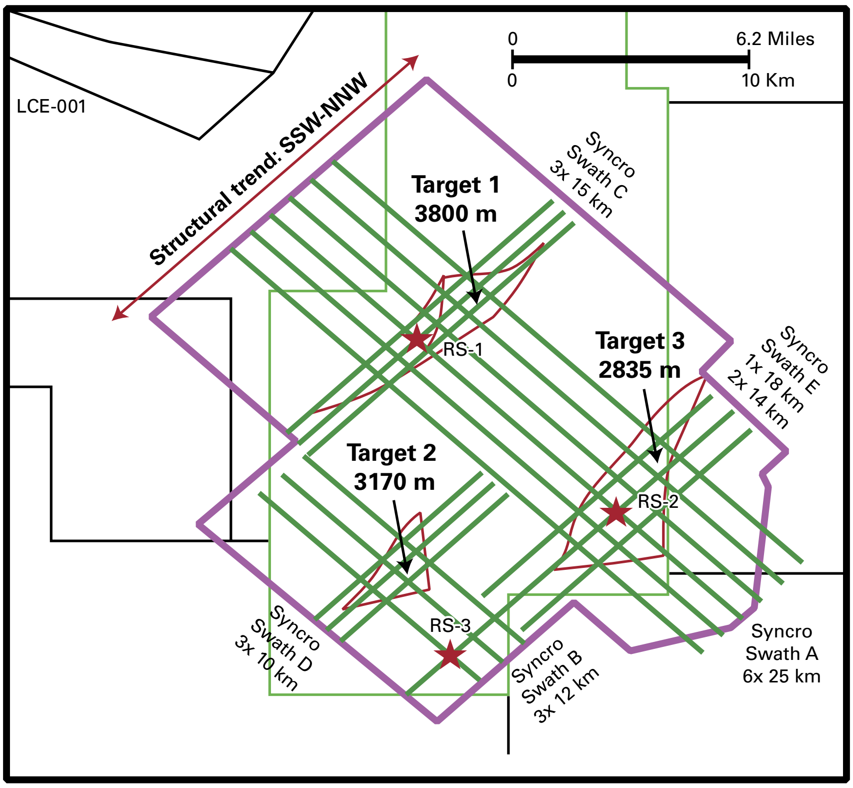
LF seismic also opens up opportunities that were previously considered "unexplorable." LF new technology developments allow the economic development and production of reserves that were thought to be uneconomic due to physical accessibility, field size, and-or geological complexity.

LF data provide information on the subsurface fluids in complex geological settings and can be economically acquired in relatively small areas that are uneconomic for traditional seismic and other surveys prior to drilling.

By integrating LF seismic results with other subsurface data, companies can better develop plays hampered by poor seismic imaging and target stratigraphic traps that can be difficult to map with traditional seismic alone. In this way, operators can segregate large areas according to high or low hydrocarbon potential, and manage their portfolios accordingly.

SURVEY DESIGN FOR PROSPECT-RANKING APPLICATION

Fig. 2



LF seismic also comes with a light environmental footprint with limited resource and HSE requirements. There is no need for external sources, such as explosives or vibrators, nor large infrastructure, such as cables and transportation.

Due to larger spacings between sensors and lighter equipment, smaller crews can be used to rapidly survey potential leads within a large concession. For example, LF seismic data can be acquired over 400 to 500 sq km in less than 20 days, with crews of less than 50 people in total. Such light equipment and limited manpower requirements can be equally valuable in remote and environmentally sensitive areas where costs and safety risks escalate rapidly.

HYDROCARBON AND NONHYDROCARBON AREAS

Fig. 3

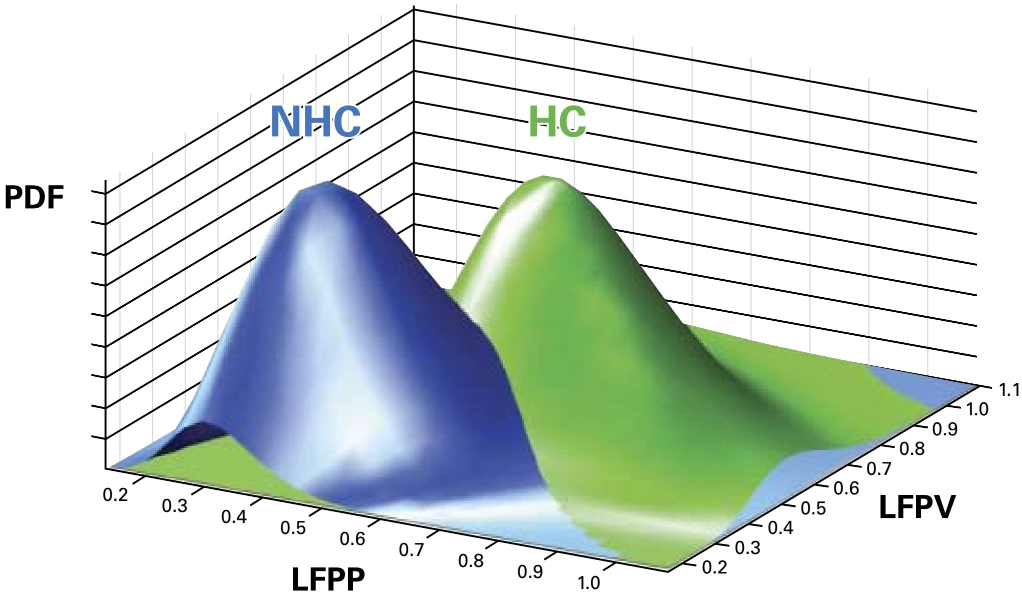


Fig. 2 shows a typical survey design for a prospect-ranking application. In this particular case, the layout covers 310 km, to be acquired with 40 sensors over 12 days.

In addition, the lower cost and logistical ease in acquiring LF seismic versus traditional seismic, can be particularly valuable for operators who are focusing on fields that are close to populated areas. California is one such example where many of the state's fields are too small for the major oil companies but with the extent of the residual reserves better defined might prove economic for independent oil companies prior to committing new investment.

Furthermore, some of the oil fields are unpredictable in terms of production and many of the state's fields are also close to towns, cities, and national parks: areas that would be unsuitable for traditional seismic techniques but where LF seismic is a viable option. Several other states have similar challenges.

LF developments

LF seismic technology, however, like any emerging technology, comes with its processing challenges.

For example, without strong sources like dynamite and Vibroseis units, can the relatively low signal-to-noise ratio from the passive acquisition of data overcome the natural and anthropogenic background noise?

The remainder of this article will examine how these challenges are being addressed by applying classical statistical methods and established noise filtering techniques. Techniques that will demonstrate how LF seismic is rapidly becoming a key technology in frontier exploration are reviewed.

Bayes methodology

Bayesian inference is a statistical inference in which evidence or observations are used to update or to infer the probability that a hypothesis may be true.

Based on the work of the British mathematician Thomas Bayes in the 18th century, Bayesian inference has applications in industrial quality control to discard faulty (vs. nonfaulty) products from a conveyor belt and is being used in both upstream and downstream oil and gas applications.

In LF seismic surveys, the Bayesian methodology captures basic empirical relationships between recorded LF seismic data and the subsurface properties, represented as statistical probability distributions, accounting for both uncertainty and variability (Fig. 3).

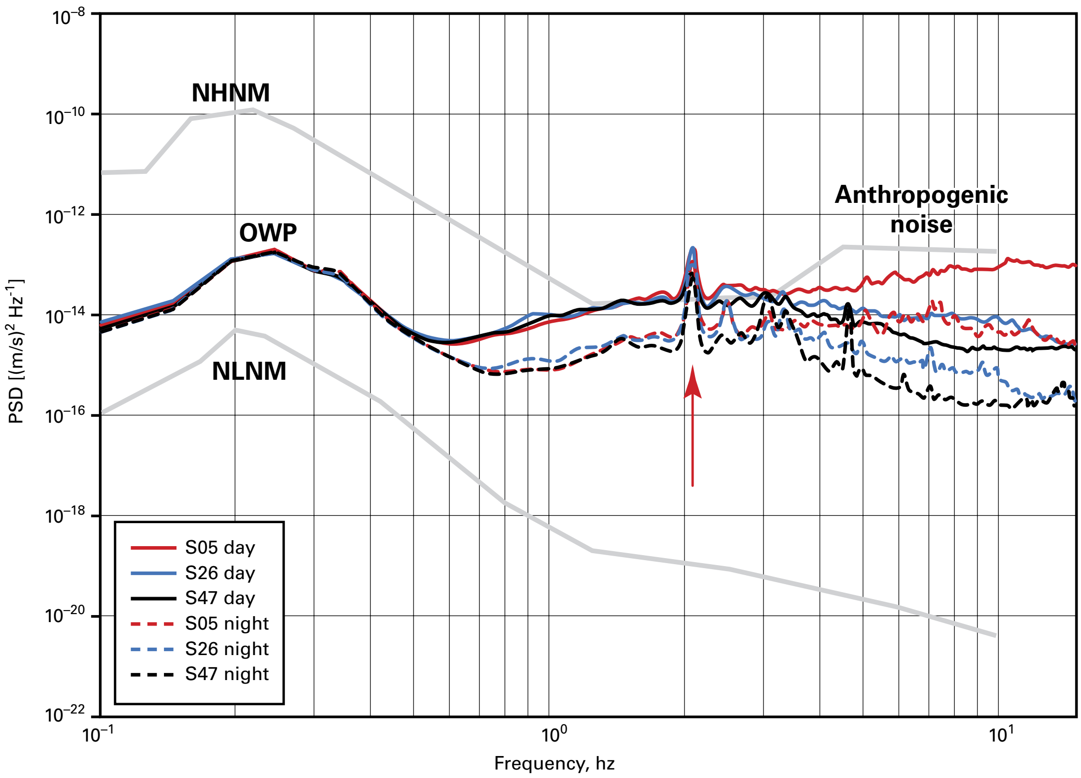
Hydrocarbon likelihood

As Fig. 3 demonstrates, an LF survey over a field in Texas was conducted to identify areas with increased prospectivity.

As a first step, a small set of receivers, representative for hydrocarbon (HC) and nonhydrocarbon (NHC) areas, is selected. The attributes of these sets are used to construct HC (green) and NHC (blue) Probability Density Functions (PDFs) over the two-dimensional space shown. In a Bayesian approach, receivers in new areas are

European survey's average noise spectra

Fig. 4



measured at the surface propagates in the form of surface waves. This "ground roll" noise is also present and can be a challenge for traditional or "actively acquired" seismic data.

Over the past 50 years, the seismic industry has developed various techniques to suppress the unwanted noise from surface waves. Lately, interest has emerged to use the ground roll as a signal source. The detrimental role of surface-generated noise in industry-type passive seismic surveys has been described recently[1 2] and highlights the need for advanced acquisition and processing methods for low frequency seismic data.

A recent case of an onshore project in continental Europe, demonstrates how these advanced acquisition and processing methods can be successfully applied. The survey took place around a small city. The layout of the survey consisted of two lines (a southern and northern line) with 25 stations, spaced 300 m apart, and a maximum line length of 7.5 km. Each station was equipped for continuous passive seismic recording with a buried three-component broadband seismometer, a digitizer, and a GPS unit. An oil reservoir was located approximately in the middle of both lines near the city center.

The LF survey was recorded in a 2-day period over a known oil field in the region as a test of concept for expanded exploration and development use. Careful identification and the re-

classified as HC or NHC by comparing their LF attributes with the constructed PDFs.

The Bayes method then compares new LF seismic observations to the basic statistical relationships and decides what subsurface property best fits the empirical observations. Due to the statistical uncertainty in the empirical models, this decision on what subsurface property is involved comes with a degree of confidence in the form of a probability of hydrocarbon content. The models can then be modified to be consistent with the recorded data. The validity of the resulting models is directly related to the quality and quantity of the LF seismic data acquired.

Key aspects of the Bayesian methodology include the fact that it accounts for the uncertainty of assumed models; uses actual empirical data as well as theoretical (synthetic) models; bases decisions on several subsurface properties while giving easy-to-interpret results; and has the ability to integrate new evidence into existing models (Bayesian learning). Well data, prior knowledge about the geology, and reservoir production data can also be readily integrated.

The process utilized information provided by the statistical distribution of the energy attribute, as opposed to simply the average value of the energy attribute. This generated the results in quantitative, hydrocarbon probability maps that are easier to interpret and more accurate than previously produced hydrocarbon potential maps based on a single (average) attribute value.

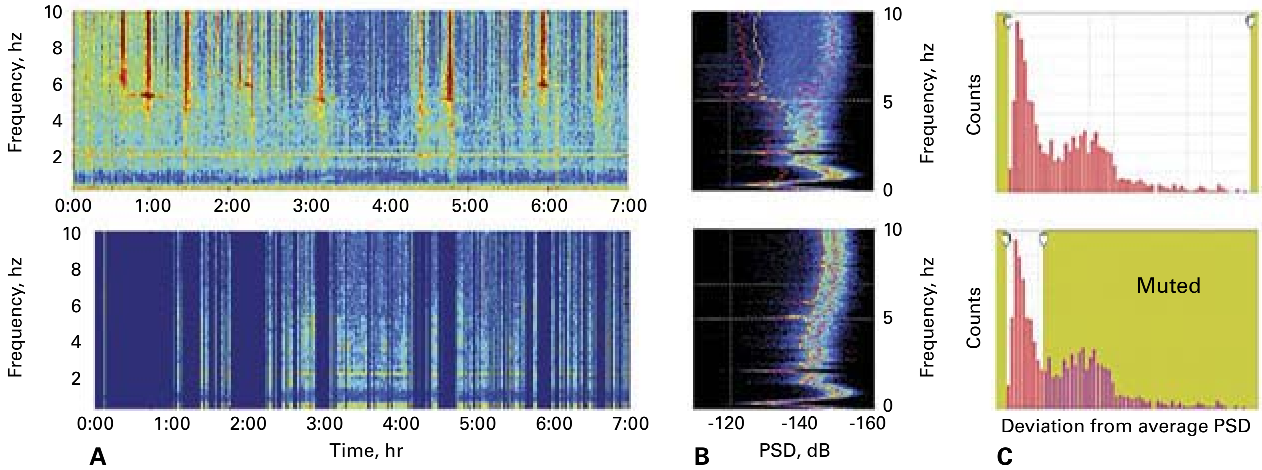
Capturing data, negating noise

One of the primary challenges in analyzing low frequency seismic data is the separation of wavefield components that contain information about the subsurface, from surface-generated noise traveling predominantly as surface waves.

Most of the seismic energy that is

REMOVING TRANSIENT CULTURAL NOISE IN EUROPEAN SURVEY

Fig. 5



moval of anthropogenic or man-made noise sources are necessary prerequisites for the analysis of LF seismic data, acquired passively at the surface.

In the context of anthropogenic noise contamination, the European survey presented a worst case scenario with various sources of noise criss-crossing the survey area. The northern line ran through an industrial quarter and crossed a much-used waterway, while the southern line ran across highways with high traffic volumes.

Fig. 4 shows the average daytime and nighttime noise spectra in the survey area in comparison to the New Global Noise Model. The arrow in Fig. 4 denotes machinery noise at 2.083 Hz.

Intensive data analysis was required to identify and separate various types of anthropogenic noise from the records in order to isolate the signals due to the uncontaminated seismic background wave field. For LF seismic signal analysis, anthropogenic noise can generally be categorized as two source types: (i) broadband transient signals, created by traffic, fauna, explosions, or falling objects, and (ii) stationary sources of narrow bandwidth, created by machinery, running water, or the structural resonances of buildings or bridges.

Transient noise was the most abundant in the European data and was filtered out by a statistical approach. Spectraseis calculated spectrograms using 40-sec time windows with a 20-sec overlap. Fig. 5 demonstrates the removal of transient cultural noise, and Fig. 5a shows the nighttime spectrogram of station 17 before (top) and after (bottom) the muting of transient noise.

For each spectrum representing a 40-sec period, the average power spectral density (PSD) was calculated over a specified frequency band. For each frequency band, the power spectral densities of all periods were then arranged in a histogram. In Fig. 5b, the spectral variance is dominated by transient noise. After data conditioning (bottom), the variance is reduced and the stationary background noise emerges as the lower end member of the spectral variance. Colors denote frequency of occurrence of the respective PSD level.

A bimodal distribution was observed in the histogram, with the higher mode attributed to time periods of transient noise contamination, and the lower mode representing the desired, uncontaminated background.

Transient noise was then removed by "muting" the data in all time periods above a fixed, threshold level in the histogram. For quality control, the spectral variance was examined over the selected time period (Fig. 5c). Fig. 5c is a histogram of average spectral levels between 0.1 and 10 Hz showing a bimodal distribution caused by transient noise contamination. Removing the higher mode of the distribution effectively mutes transients in the data (as compared with Fig. 5a).

An overall reduction in spectral variance was observed and convergence was obtained for the average to the lower level in the histogram, which represented the natural background level, plus stationary noise.

In addition, a frequency-domain despiking algorithm was developed that removes narrow-banded peaks created by stationary noise.

Two attributes were calculated from the clean, despiked data with transients removed. These attributes were used for the quantification of: (i) integration of the Power Spectral Density (PSD) spectrum of the vertical component, over a data driven frequency band, and (ii) integration of the spectral ratio of the vertical and horizontal components (called V/H). The V/H attribute is more robust with respect to transient noise contamination and was the attribute of choice for this survey due to the urban setting.

Spectraseis observed a statistically significant increase in the spectral ratio of V/H, between 1.5 and 3.5 Hz, over the reservoir. Because the lateral variation of attribute values in the anomalous region is larger than the standard deviation, it can be concluded that the observed anomaly is statistically significant. Furthermore, a check of the near surface statics revealed that the observed, anomalous V/H ratio could not be attributed to site effects or noise in the shallow subsurface. It was therefore concluded that observations made from the LF seismic data are in fact, an expression of the earth's modified, background seismic wavefield that is directly related to the fluids in the reservoir structure.

In this survey, careful identification and removal of anthropogenic noise sources from the LF seismic data were achieved.

Hiking exploration confidence

LF seismic technology remains a work in progress.

Spectraseis, in close collaboration with the Swiss Federal Institute of Technology (ETH Zurich), is spearheading the industry's biggest research program focused on the theory, methods, and applications of low frequency spectral analysis.

Through new innovations such as the introduction of Bayesian statistics, the ability to reduce man-made noise, developments in time reverse modeling (TRM) for depth imaging, and the capability to carry out surveys in environmentally sensitive locations, LF seismic is becoming a powerful and cost-effective derisking tool. LF seismic is today a tool with applications across the entire reservoir lifecycle, from exploration bid rounds, to exploration and delineation, through to prospect ranking and development.

Conventional oil and gas has become harder to find and produce economically, leading to an increase in exploration for, and development of unconventional reserves. Due to the geological complexity and expensive production methods typically found with unconventional reserve plays, the growth of independents, the number of "less giant" but potentially economic fields, and operators' relentless focus on reducing costs while managing risks, the emergence of LF seismic technology could not have been more timely.

Acknowledgments

Thanks to Spectraseis for permission to publish, and to Alex Goertz, Nima Riahi, Brice Bouffard, and Rob Habiger of Spectraseis for reviewing this article. Their comments and suggestions were invaluable, although the author accepts full responsibility for any remaining errors. Established in 2003 in partnership with leading European universities, Spectraseis is the principal technology and service provider in the fast-emerging field of low frequency seismic technology. Customers include Petrobras, StatoilHydro, Pemex, other majors and independent operators in the Middle East and North America. ✦

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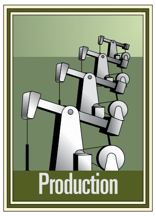
The author

Andrew Poon is business development director for Spectraseis. He has more than 30 years' experience in technical consulting, operations, project management, sales, marketing, and general management in the oil and gas industry. He started at Schlumberger as a wireline field engineer, receiving assignments in North America, Latin America, and the Middle East with progressive responsibilities in oilfield services, acquisitions and divestitures, economics, and business consulting. He was president of IndigoPool before joining ION as vice-president marketing. He joined Spectraseis in March 2009 where his primary responsibilities are to develop Spectraseis' business in North America. He has a BSc Hons. in physics from the University of the West Indies, an MSc in physics and electronics from Cardiff University, and an MBA from the University of New Orleans.



Subsea gas-liquid separation helps boost production rates

Guntis Moritis
Production Editor

Subsea gas-liquid separation combined with pressure boosting allows the development of fields that have insufficient tubinghead flowing pressure for attaining adequate production rates to the host facility.

The last few years have seen installation or planned installation of a variety of subsea processing schemes. The projects differ in scope but all aim to allow or improve oil recovery from subsea completed wells. The projects have included gravity-based separation as well as other separation techniques.

FMC Technologies Inc. has been involved in several subsea processing projects including Tordis in the North Sea, Cascade-Chinook and Perdido in the Gulf of Mexico, BC-10 off Brazil, and Pazflor off Angola.

Chris Shaw, manager of field development and technical sales, subsea systems for FMC provided some information on the design of these systems.

Subsea processing benefits

Some benefits of subsea processing listed by Shaw were:

- Reducing back pressure on the reservoir, thereby increasing production rate, increasing time in production, and improving ultimate recovery.
- Extending plateau production.
- Enabling longer tiebacks for reservoirs with insufficient recoverable reserves to justify its own production platform.
- Improving recovery from deepwater reservoirs.
- Enabling exploitation of underpressured reservoirs and reservoirs with low permeability or poor fluid properties.
- Reducing capital expenditures, for instance subsea gas compression subsea costs less than building a structure in the case of the Ormen Lange development.
- Substituting processing for infill drilling because offshore drilling is expensive, risky, and requires the availability of a rig.

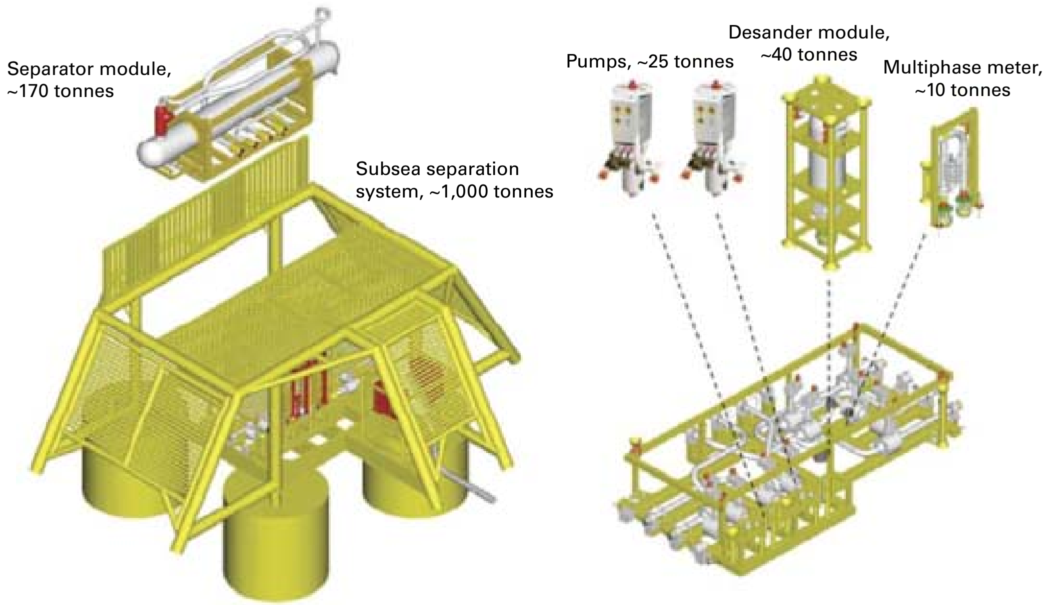
System design

Design of these systems requires extensive technology review and qualification per API RP 17N and must conform to API RP 17Q on system maintainability, Shaw said. The integrated components and subsystems also should have high system availability with component reliability capable of a minimum of 5-year mean-time between failure (MTBF) and with further development eventually a 7-year MTBF is hoped for, he added.

Shaw listed several benefits of gas-liquid separation and boosting compared with boosting only designs. One

TORDIS MODULAR SYSTEM

Fig. 1



Source: FMC Technologies

Pazflor

Fig. 2

Water depth: 2,700 ft

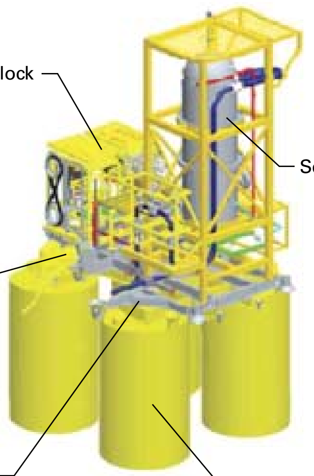
Step-out: 2.5 miles

Design pressure: 5,000 psi

Process capacity: 110,000 bo/d and 35 MMscfd

Gas tolerant pumps: Hybrid to 18% GVF

Gas: Free flows through two 6-in. flowlines



Source: FMC Technologies

Pump capabilities

Type	Maturity	Maximum inlet GVF,* %	Efficiency, %	Available shaft power, MW	Maximum pressure bar (psi)	Sand tolerance
Single phase centrifugal	Field proven Qualified	~10 ~10	65-75 65-75	2.6 2.5	190 (2,700) 250 (3,500)	Sand tested
Helico-axial	Field proven	~70	30-60	2.6	55 (600)	Sand tested
Hybrid (gas tolerant liquid pump)	Qualified	~40	50-70	2.6	120 (2,200)	Sand tested
Centrifugal split vane hybrid (ESP)	Field proven	~30	50-65	1.2	290 (4,000)	Sand tested
Twin-screw (positive displacement)	Installed and proven	~92	60-80	1.3	50 (600)	Critical for sizes about 300 µm

*GVF = gas volume fraction.
Source: FMC Technologies

Shaw countered these assertions by saying that separation is already part of a multiphase boosting-only solution as liquid is required to be separated for recycling.

• The gas line remains available for roundtrip pigging provided the manifold is properly designed to manage the gas to liquid transition. The gas line does not have to be insulated and operates under continuous hydrate inhibitor injection at low rates.

• Conditions at the production manifold where gas bubbles are large, temperatures are still hot and gas-liquid density differences are large greatly facilitate gas-liquid separation. Coupled to the lax gas and liquid outlet stream quality requirements makes separation readily achievable.

• Densitometers can control the pump speed thereby avoiding the need for distinct gas-liquid interface.

• Long skinny caissons can separate the gas and liquid, making the process suitable for deep water and high pressure.

• Gas-liquid separation lowers the back pressure on the wells to a greater degree than all other processing concepts.

• Gas-liquid separation allows gas-lift in the well because the flow-

of the main ones is that single-phase and hybrid pumps can operate with higher pressure rise than multiphase helico-axial and twin-screw pumps that have about a 600-psi differential pressure limit (table).

Other benefits Shaw said were:

• Single-phase and hybrid pumps have higher hydraulic efficiency than helico-axial pumps, with less power generation required for given hydraulic duty.

• Venting below the hydrate-formation pressure provides a means for managing hydrate formation in flowline jumpers and the liquid pipeline.

• Separation eliminates slugs or liquid surges, thereby decreasing the size of the needed separator on the host platform.

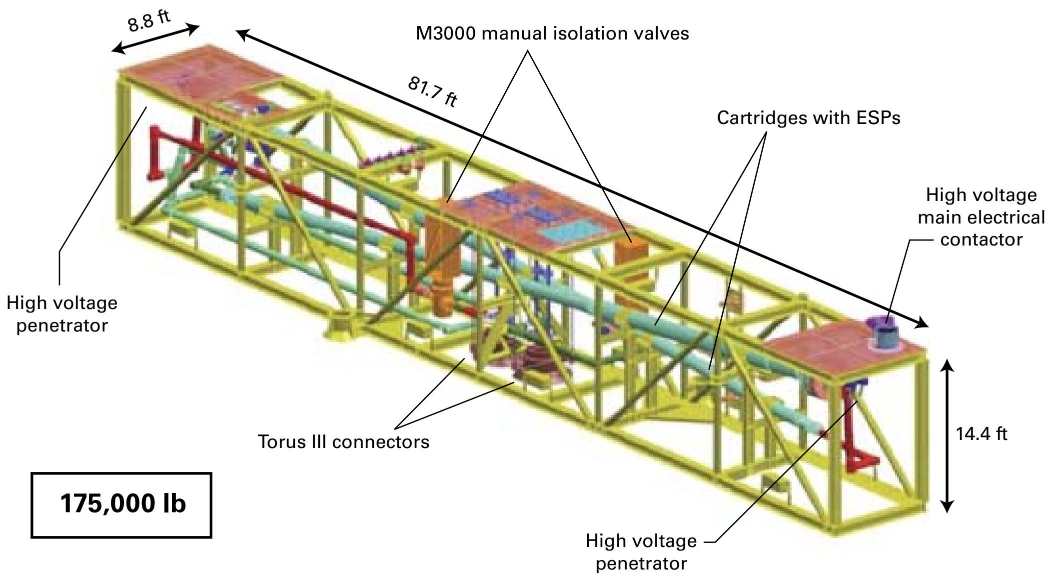
• Common concerns about subsea separation are that there is increased technical risk associated with the separator and there is an extra pipeline.

ing tubinghead pressure can be below the bubble-point. Gas-lift is not recommended with helico-axial pumps because the gas-volume fraction at inlet will exceed the 65% v/v, which is the pump's maximum operating design limit.

• A separator upstream of a pump will improve reliability especially when combined with a fast reacting control valve currently under qualification. This is due to the separator dampening the dynamic nature of typical multiphase flow.

CASCADE-CHINOOK PUMP CARTRIDGE

Fig. 3



Source: FMC Technologies

Tordis

One of the first subsea processing systems installed was the oil-water separation and reinjection system on StatoilHydro-operated Tordis field off Norway. The system with a 150,000-b/d liquid capacity was installed in 2007 in 650 ft of water.

Separating the water and reinjecting it reduced the need to increase water handling on the host facility as well as reduced the back pressure on the subsea completed wells. The system also separates and reinjects the produced sand with the water.

Shaw noted that Tordis was able to lower the back pressure on the production wells in this case by employing multiphase pumps in addition to removing the produced water.

The installed multiphase pumps have a 450-psi differential pressure rating (Fig. 1) while the injection pumps were capable of 1,450-psi differential.

Pazflor

The Total SA-operated Pazflor development in Block 17 off Angola will have three subsea vertical separators to separate gas from the liquids. The separators will be in 2,700-ft water depths (Fig. 2). Hybrid pumps will pump the liquids to an FPSO.

These will be the first gas-liquid gravity separation vessels installed subsea and the first hybrid-pump system with subsea barrier fluid control, according to FMC.

Each separator has a 3.5-m OD and 9.0 m height. Total expects production from the field to start in 2011.

Pazflor field will produce two different oils, Miocene and Oligocene. The Miocene reservoirs contain heavy 17-22° gravity, highly viscous oil and will have 18 producers and 17 water injectors.

The subsea separators are for the Miocene oil. The separation unit includes two hybrid liquid-boosting pumps on each of the three subsea production lines from the Miocene fields. Three flexible risers carry the liquids to a floating production, storage, and offloading (FPSO) vessel and six similar risers carry the gas to the FPSO.

The Oligocene reservoirs contain a light 35-38° oil that will be produced through a conventional loop linked to three manifolds and seven producing wells. The Oligocene reservoirs will also have five water injection and two gas injection wells.

Cascade-Chinook

First phase of the Petrobras Americas Inc.-operated Cascade-Chinook development will have horizontal electric submersible pumps (ESPs) to move liquids to the host FPSO, the first in the US portion of the Gulf of Mexico (Fig. 3).

Pumps are required despite the very high shut-in pressures because the reservoir has poor permeability and some decline in reservoir pressure is expected. In this case the pumps are required to ensure that the wells can achieve an economic rate and can extend plateau production.

Shaw noted that the wells have a high 12,000 psi shut-in pressure and ESPs are the only pumps available for that pressure. Another requirement not available from other pump systems is the pressure rise, rated at 3,200 psi with 15% gas.

The pumps will be in 8,800 ft of

Fig. 4

Perdido

Water depth: 8,200 ft

Step-out: 0 miles

Design pressure: 4,500 psi

Process capacity: Five gas-liquid separator direct vertical access caissons, 25,000 bo/d and 55 MMscfd

Gas tolerant pumps: ESP to 15% GVF, 25,000 bo/d pump systems, 1.2 Mw 2,200 psi differential

Gas: Free flows up top-tensioned riser annulus

Source: FMC Technologies

Fig. 5

BC-10

Water depth: 5,900 ft

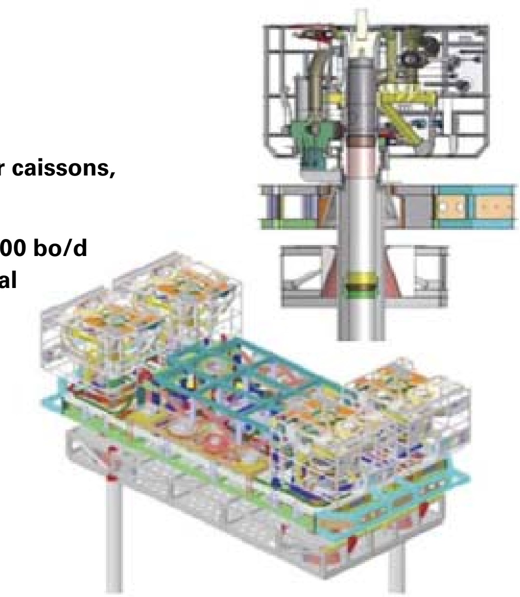
Step-out: 5 miles

Design pressure: 5,000 psi

Process capacity: Four gas-liquid separator caissons, 30,000 bo/d heavy oil and 3.5 MMscfd

Gas tolerant pumps: ESP to 15% GVF, 30,000 bo/d pump systems, 1.2 Mw 1,800 psi differential

Gas: Free flows through 6-in. flowlines



Source: FMC Technologies

water with production start-up planned for 2010.

Cascade-Chinook project will produce from deep discoveries in the Lower Tertiary trend of the Walker Ridge and Keathley Canyon areas of the gulf.

Perdido

Because of the water depth of 8,200 ft and its low pressure-low temperatures, the Perdido development in the Alaminos Canyon of the Gulf of Mexico requires pressure-boosting liquids at the seabed. Shell Exploration & Production Co. operates Perdido.

The boosting technology involves a 330 ft, 35-in. diameter caisson in the seabed that contains an 8-10 in., 1,500-hp ESP (Fig. 4).

The multiphase produced fluid flows into the caisson's inlet block, located just above the mud line, where the associated gas separates out and flows up the riser, while the liquid flows down and receives pressure boosting from the ESP.

Risers allow direct vertical access of the caissons from the Perdido regional host spar. Perdido will have five caissons for producing the three fields: Great White, Tobago, and Silvertip.

Production is expected to start in early 2010.

BC-10

Shell's Parques das Conchas project in BC10 of the Campos basin will have six (plus one spare) caissons for boosting production from the initial three fields: Abalone, Argonauta, and Ostra. Expected production through each ESP is 25,000-30,000 b/d.

The fields lie in 5,900 ft of water and are connected to a floating production and offloading (FPSO) vessel with flowlines and risers.

All four fields are low pressure and require boosting. Abalone and Ostra contain gas and require subsea separation. Argonauta has less gas and no need for caisson separation.

The Abalone appraisal well produced a 42° API light oil compared with the 16-24° oil from the other fields.

As with the Perdido, the project involves separating gas and liquids in 35-in. OD by 350-ft caissons with an ESP for pumping the liquid to the FPSO.

Production started in July 2009. ✦

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Field tests prove microscale NRU to upgrade low-btu gas

Field tests of a scalable, microscale, N_2-rejection unit have demonstrated the effectiveness of the portable and cost-effective NRU to upgrade low-pressure (<100 psig) and low-volume (≈ 100 Mcfd) low-btu gas to pipeline quality.

The NRU was designed, constructed, and tested[1] at Elmdale field (Chase County, Kan.) under a grant from the Stripper Well Consortium (SWC, Pennsylvania State University).

The project was a joint effort between the Kansas Geological Survey (University of Kansas) and the American Energies Corp., Wichita.

Low-btu gas

Pipeline specifications for natural gas in the US vary, but a heat content of 950 btu/cu ft is required for sale and transport. US reserves of natural gas are about 238 tcf.[2] "Subquality" gas may constitute as much as 17.5 tcf of reserves in the Midcontinent, 9 tcf in the Rocky Mountain region,[3] and 60 tcf in the US.[4]

Overall, 33% of the 1,253 gas analyses[5] recorded in Kansas in the last 50 years are low-btu (<950 btu/cu ft). Low-btu gas is more common in Permian and Upper Pennsylvanian reservoirs in Kansas, but it is found in reservoirs of all ages and lithologies.[5] In the Midcontinent, the presence of N_2[6,7] often results in natural gas being low-btu, while nationwide 17%[4] of known gas reserves are "subquality" due to N_2 contamination. Thus, N_2 is a major target for removal so that low-btu natural gas can be upgraded to pipeline quality.

Much of today's gas production is from large fields where low-btu gas can be processed in central upgrading facilities that use cryogenic separation,[8-11] conventional pressure swing adsorption,[12-15] or lean oil absorption

This shows the compact layout of the two-tower microscale NRU: gas scrubber (A), low-btu feed entering NRU (B), solenoid valves (red) controlling feed into tower (C), tower access port (D), instrument gas scrubber (E), adsorption/desorption towers (F), tower evacuation solenoid (red) valve (G), desorbed upgraded gas line (H), gas-fired engine (I), low-btu feed to engine (J), compressor (K), condensate removal (L), and surge tank (M; Fig. 1).

Unit operations: closeup of activated carbon granules (A), charging the towers with activated carbon (B), and leveling the carbon bed after charging towers (C; Fig. 2).

(Mehra process),[16] but such economy-of-scale is not feasible for smaller and often isolated fields.

A significant portion of N_2-induced low-btu gas is found in modest to small fields that are owned and operated by small independent producers.[4] At present, most of this low-btu gas is either shut-in behind pipe or simply abandoned because it cannot be burned locally or blended with readily available higher-btu gas.

Development of inexpensive N_2-rejection technology, designed for low-volume, low-pressure gas wells, can significantly increase the contribution of marginal low-btu gas to the nation's gas supply.

NRU process

Pressure swing adsorption is a proven commercial technique that is widely used in many industries to separate gases by use of an adsorbent bed. This bed selectively adsorbs one or more components from the feed gas under pressure while allowing other components to pass through unadsorbed. The adsorbed components are then recovered by reduction of pressure on the bed, and the reactivated bed reused for adsorption in the next cycle.

The demonstration NRU discussed here uses the process of vacuum swing adsorption,[17] a variation of PSA in which the bed is desorbed under subatmospheric pressure (i.e., vacuum). The NRU uses readily available and non-patented activated carbon (made from coconut husks) as an adsorbent bed to adsorb methane and heavier hydrocarbons under pressure while rejecting the entrained N_2 as a vent stream.

Adsorbent beds vary between PSA plants. Some, as the NRU discussed here, have fixed pore openings (as in activated carbon or molecular sieve), while others have custom-designed pore openings (as in molecular gate) to trap targeted gas molecules.

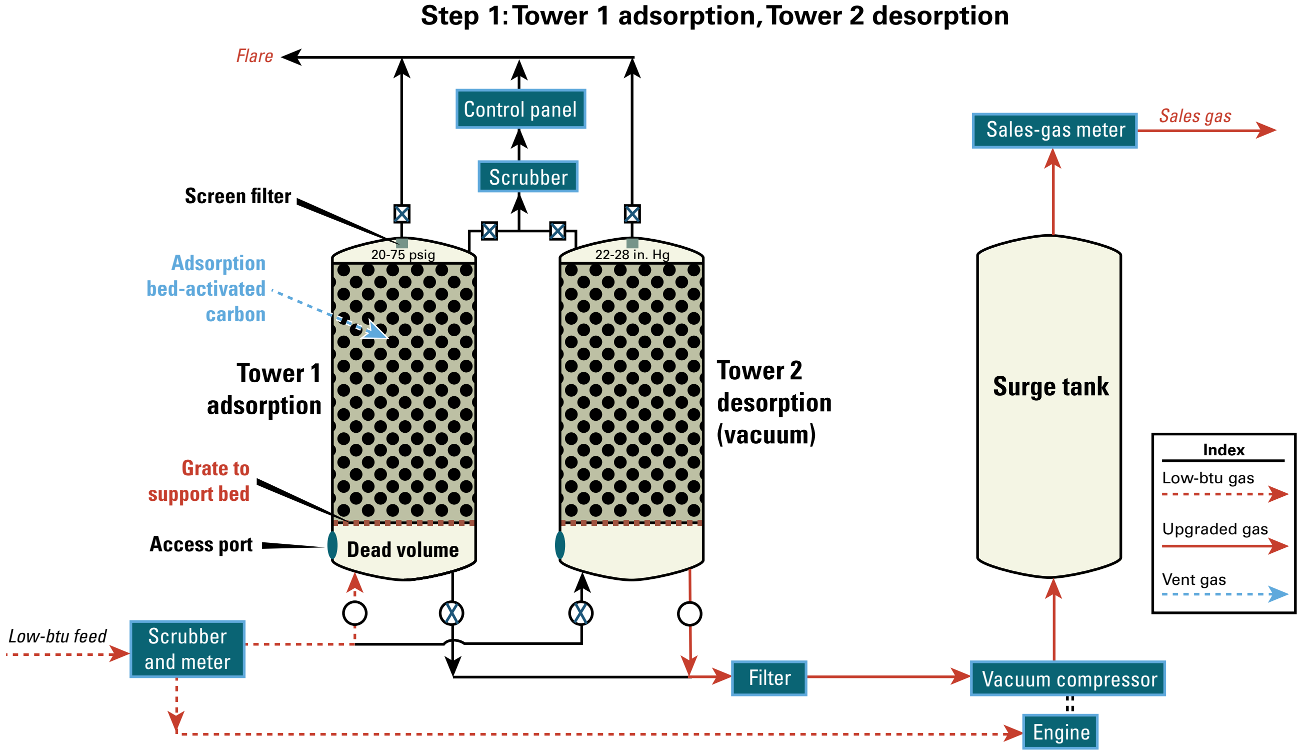
In general, PSA processes differ by the number of towers and the number of stages in each tower required to separate the feed hydrocarbons from the entrained N_2.

This NRU has two towers and uses three stages:

1. Adsorption under pressure.
2. Venting to 2 psig.

OPERATION'S FIRST STAGE*

Fig. 3



*Feed gas charges up the evacuated Tower 1 to set pressure (20-75 psi), depending on plant settings determined by feed-gas quality, while Tower 2 is evacuated to vacuum (22-28 in. Hg).

3. Desorption under vacuum.

Between the adsorption and desorption stages, many PSA systems employ the product (upgraded) gas to purge each tower of residual unadsorbed gas. Instead of this purge stage, which complicates plant controls and increases compression costs, the demonstration NRU vents the unadsorbed gas from each tower at the end of adsorption. The degree of separation[13] achieved in PSA process depends on feed-gas composition, charge and vent pressure, and system temperature.

The NRU was designed to have the following characteristics:

- Nonpatented processes and off-the-shelf equipment to minimize construction costs.
- Easily obtained adsorbent bed of inexpensive, non-patented activated carbon.
- Skid-mounted modular units that provide mobility and scalability.
- Small environmental footprint (≈ 400 sq ft).
- Few moving parts (outside engine and compressor) to minimize maintenance costs.
- Powered by solar panels and low-btu feed gas for operations at remote locations outside electric grid.

NRU layout

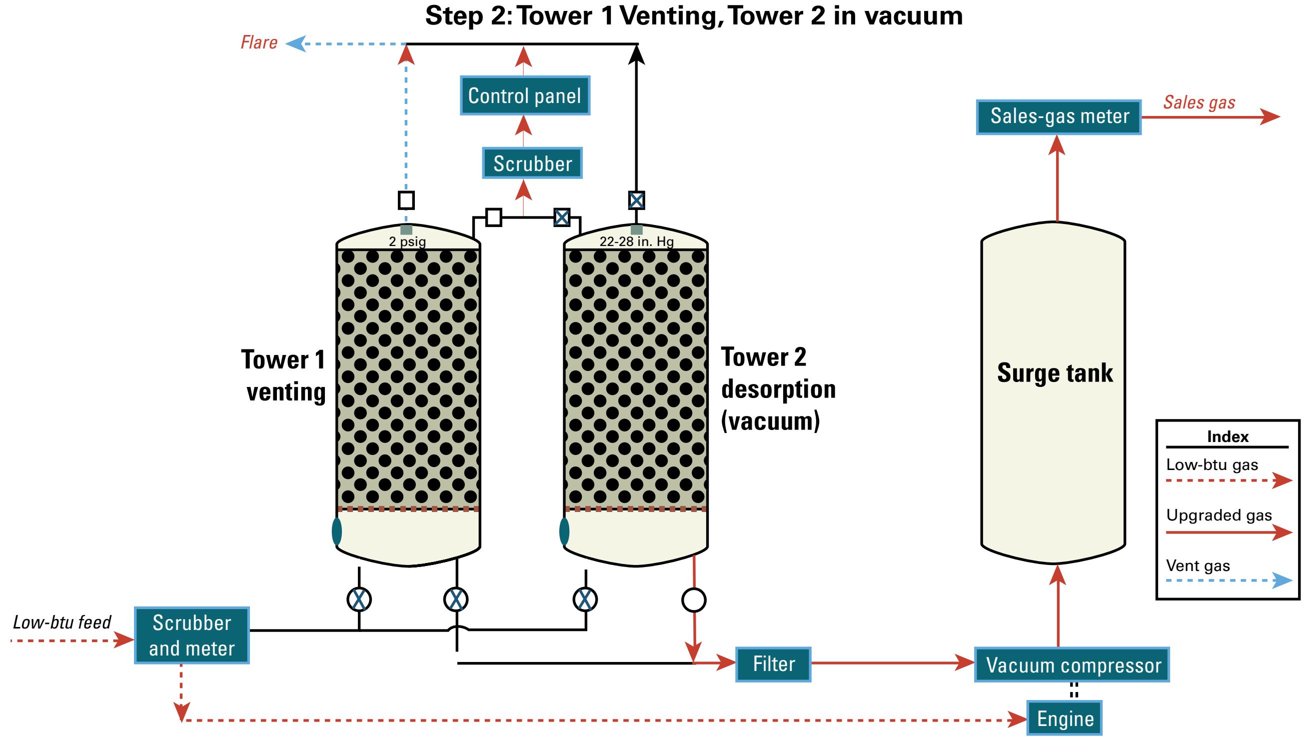
Fig. 1 shows the compact layout of the NRU.[18] Feed gas enters the plant through a 2-in. line, passes through a scrubber for removal of entrained moisture, and then passes through a flow meter into the adsorption/desorption towers. Each tower, made of carbon steel, has a 48-in. diameter, is 8 ft tall, and is designed to handle feed rates of around 100 Mcfd.

The modular design allows additional sets of towers to be added or removed to handle increases or decreases in feed volumes. Electronically controlled solenoid valves allow feed gas to flow into one tower for adsorption while isolating the other tower for desorption under vacuum. A small fraction of the N_2-rich vent (waste) gas is used as instrument gas to operate the pneumatics of the control panel.

Ports at the base of each tower provide access for removal of spent bed materials and tower cleanup. Off-the-shelf activated carbon made from coconut husks (Fig. 2a) was used to charge the towers (Figs. 2b and 2c). Each tower was charged with about 2,200 lb of this material, purchased in 1,100-lb bags at a cost of 7¢/lb.

A 6-cylinder, 50-hp VGG-330 engine (Fig. 1), operating on the low-btu feed gas, drives the compressor, designed for vacuum service, which pulls a vacuum on each tower during its desorption cycle. Desorbed methane flows through a 2-in. line to a gas scrubber and then to the compressor via a 3-in. line. N_2-rich vent gas from each tower travels to a flare tower by a 2-in. line. The compressed (upgraded) gas passes through a condensate-removal tower (Fig. 1) before flowing into a surge tank (5 ft diameter and

Operation's second stage* Fig. 4



*Tower 1 is vented to 2 psi after having been charged to set pressure, thus allowing removal of N_2-rich unadsorbed gas from tower. This venting results in some loss of CH_4 but also prevents the unadsorbed N_2 from ending up in surge tank during desorption process. Vent period is very short (less than 1 min for a plant this size) and Tower 2 remains under vacuum during this time.

25 ft long) where it mixes and attains uniform composition before being discharged to the nearby pipeline via a sales-gas meter.

Anticipating a maximum operating pressure of 75 psig, the NRU was successfully pressure tested at 105 psig to check for leaks. Thereafter, it was tested by pulling a vacuum of 26 in. mercury that was held over a 2-day test period.

Operational stages

1. Low-btu feed gas (broken red line, Fig. 3) is fed into the bottom of Tower 1, charging it to the requisite pressure that depends on the feed composition (i.e., N_2 and heavy hydrocarbon content) and btu requirements of the pipeline company.

Tower 2, in desorption mode, is evacuated from the bottom to vacuum (22-28 in. mercury) during this stage. The charging time for Tower 1 depends on the feed flow rate and pressure and tower fill-up volume.

During this charging period, hydrocarbons are preferentially adsorbed in the bed of activated carbon inside Tower 1. The free gas remaining in the space between the carbon particles and in the dead volume below the metal grate supporting the bed is rich in N_2.

2. The unadsorbed N_2-rich free gas in Tower 1 is vented to the atmosphere through the flare tower (broken blue line, Fig. 4) until the tower pressure reaches 2 psig. Tower 2 at this time is kept under vacuum. The length of the venting period is proportionate to the magnitude of the Tower 1 charge pressure.

3. Tower 1 is connected to the compressor from the bottom (red line, Fig. 5) and desorbed under vacuum, while the desorbed Tower 2 is connected (from bottom) to the low-btu feed stream (broken red line) for charging up to the same pressure as Tower 1 in Stage 1. Reduction of pressure in Tower 1 from 2 psig to vacuum (22-28 in. mercury) results in desorption of the adsorbed hydrocarbons (in Stage 1).

The hydrocarbon-rich desorbed gas leaving Tower 1 will be of pipeline quality (≥950 btu/cu ft) when the plant settings (i.e., charge-up pressure and vent pressure) are optimally set for the composition of the feed.

NRU performance

Feed gas (average: 715 btu/cu ft and $C_2H_{6+}/CH_{4++} \approx 7.9\%$) consisted of commingled production from several wells, some of which produced slugs of water along with gas. These conditions, along with valve adjustment at the upstream central manifold to maintain minimum flow rates and pressures, resulted in variation in feed-gas composition. It is not uncommon for the feed-gas composition to fluctuate under real-life operating conditions of marginal gas wells.

During initial testing, the feed gas averaged around 687 btu/cu ft. Under this condition, the plant was optimized to produce pipeline quality gas (>950 btu/cu ft) by charging the towers to 34

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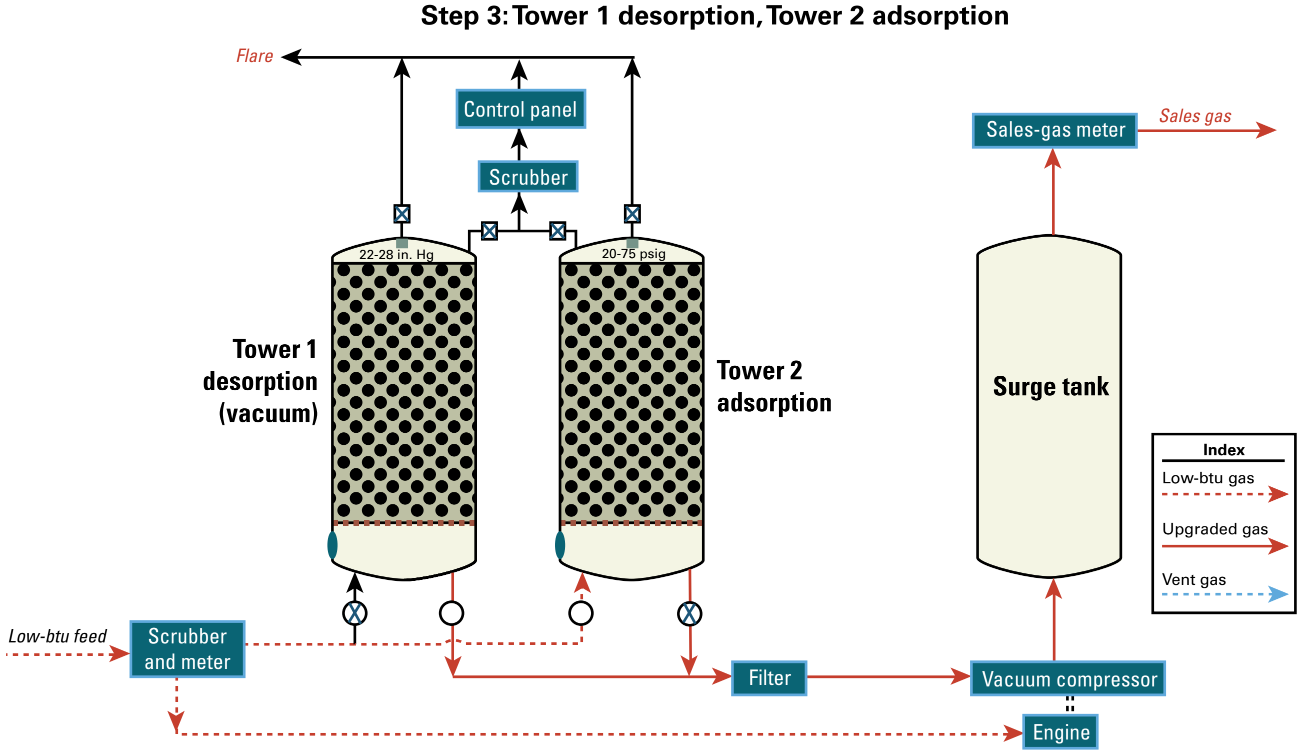
OPERATION'S THIRD STAGE* Fig. 5



*Tower 1 (after completion of the venting) is put under vacuum to recover hydrocarbons adsorbed in activated bed, while Tower 2 is connected to feed line for charging.

psig, then venting unadsorbed N_2-rich gas (from the top) to 2 psig, followed by vacuum desorption (25 in. mercury).

These settings (Table 1) resulted in a sales/feed ratio of 0.54 (i.e., 54% of the low-btu feed gas by volume was upgraded to pipeline quality). Thus a feed gas with 63% average hydrocarbon content (CH_{4+} % mole) was upgraded to a product stream containing around 84% hydrocarbon content resulting in 73.2% of hydrocarbon recovery and 75.7 % of btu recovery.

The btu recovery is calculated as the ratio of the product of total btu coming into the plant (i.e., feed volume times feed btu/cu ft) to that recovered in the sales stream (i.e., sales volume times sales btu/cu ft). Under these settings, the vented gas contained about 63.1% N_2 (% mole) resulting in an average N_2 rejection efficiency of 76.7%.

The sales/feed ratio critically determines the plant economics. Given similar feed compositions, higher sales/feed ratios result in greater recovery of the hydrocarbons and higher volumes of pipeline-quality gas for sale.

Given unchanging feed composition and bed adsorption characteristics, the sales/feed ratio depends on the differential between the tower charge pressure (34 psig, as stated earlier) and the vent pressure (2 psig), the dead volume within each tower, and volume of gas desorbed from the beds during the venting process.

Variation in feed composition imparted some uncertainty to optimization of plant settings. For example, the pressure differential between tower charge pressure and vent pressure was reduced to 20 psig and 2 psig, respectively, to increase the sales/feed ratio. By the time the plant could be operated under lower tower charge pressure, however, the feed-gas composition changed to an average of 743 btu/cu ft. The plant produced pipeline-quality gas (964 btu/cu ft) at a higher sales/feed ratio of 0.60 (Table 1).

It was difficult to determine, however, if the lower tower charge pressure resulted in slightly higher CH_4 recovery efficiencies (75.4%) and slightly lower N_2 stripping efficiency (72.6%), or if these were caused by improved feed-gas quality.

Later in the optimization process, the plant was connected to a different combination of wells resulting in a feed with poorer average heat content (622 btu/cu ft vs. 715 btu/cu ft). Also, the ratio of the heavy hydrocarbon fraction (C_2H_{6+}/CH_{4+}) decreasing to 3.8% from 7.9% necessitated higher tower charge pressures to produce pipeline-quality gas. The variation in feed btu content was less than 5% during this plant optimization study (Table 2).

When the plant was run with tower charge pressures of 15 and 30 psig and vent pressure of 2 psig (i.e., settings close to that necessary to upgrade feed averaging 715 btu/cu ft with a heavy hydrocarbon fraction ≈ 7.9%), the product gas was of subpipeline quality,

UPGRADING FEED TO PIPELINE QUALITY: TWO PLANT SETTINGS

Table 1

Avg. feed @ 715 btu/cu ft, $C_2H_{6+}/CH_{4+} \approx$ 7.9%

Feed, btu/cu ft	Tower charge pressure, psig	Vent pressure, psig	Average feed, CH_{4+}, %	Average sales, CH_{4+}, %	Sales/feed ratio	Efficiency CH_{4+}, recovery, %	Sales, btu/cu ft	Btu recovery, %	Efficiency nitrogen rejection, %	Vent gas nitrogen, %
687	34	2 (T[1])	63	84	0.54	73.2	[2]**953**	75.7	76.7	63.1
743	20	2 (T[1])	67	85	0.60	75.4	[2]**964**	77.4	72.6	59.2

[1]T—vent from top of tower. [2]Pipeline quality.

UPGRADING FEED TO PIPELINE QUALITY: MULTIPLE PLANT SETTINGS

Table 2

Avg. feed @ 622 btu/cu ft, $C_2H_{6+}/CH_{4+} \approx$ 3.8%

Feed, btu/cu ft	Tower charge pressure, psig	Vent pressure, psig	Average feed, CH_{4+}, %	Average sales, CH_{4+}, %	Sales/feed ratio	Efficiency CH_{4+}, recovery, %	Sales, btu/cu ft	Btu recovery, %	Efficiency nitrogen rejection, %	Vent gas nitrogen, %
619	15	2 (T[1])	59	78	0.64	84.9	831	86.0	65.7	75.4
622	30	2 (T[1])	59	82	0.49	68.9	881	69.9	78.9	63.9
621	70	13 (T[1])	59	86	0.45	66.0	920	67.0	84.6	63.4
618	66	9.5 (T[1])	59	84	0.49	72.7	923	73.8	83.6	68.4
607	66	4 (T&B[1])	58	88	0.42	64.2	940	65.3	87.9	64.4
633	69	3 (T&B[1])	60	89	0.39	58.3	[2]**958**	59.2	89.7	58.9
633	72	4 (T&B[1])	60	89	0.40	58.7	[2]**954**	59.6	89.2	58.9

[1]T—vent from top of tower; T&B—vent from top and bottom of the tower. [2]Pipeline quality.

i.e., 831 and 881 btu/cu ft, respectively. Raising the tower charge pressure to 70 and 66 psig, followed by venting to 13 and 9.5 psig, increased the heat content of the desorbed gas to around 920 btu/cu ft but also resulted in lower sales/feed ratios, i.e., 45% and 49%, respectively.

Higher tower charge pressures result in greater pressure differential during the vent process and therefore greater loss of hydrocarbons and lower sales/feed ratios.

In the current tower design (Fig. 6a), the grate supporting the adsorption bed was incorrectly designed to be located above the tower access hole resulting in 20 in. of dead volume at the bottom of each (8-ft) tower. This dead volume is not filled with any activated carbon, and N_2-rich low-btu gas (at 2 psig) occupies the dead volume at the end of the vent phase when venting is taking place solely from the tower top.

During the desorption stage, this low-btu gas in the dead volume entered the surge tank and lowered the btu of the product (sales) gas. To remediate the problem, attempts were made to see if simultaneous venting from both the top and bottom of the tower would help better vent the residual unadsorbed N_2-rich gas.

This replumbing met with some success; the product gas was of pipeline quality (at 958 btu/cu ft) when the tower charge pressure was set at 69 psig and vent pressure to 3 psig. This setting resulted in a sales/feed ratio of 0.39. The sales/feed ratio was improved slightly to 0.40 when the tower charge pressure was set to 72 psig and the vent pressure was set at 4 psig.

It is apparent from these results that this NRU can upgrade a feed gas with heat content as low as 633 btu/cu ft and a heavy hydrocarbon fraction around 3.8%. It is critical to note that both the heat content and the amount of heavy hydrocarbons in the feed stream dictate the optimum operational settings for the plant to attain pipeline-quality sales gas. Any deterioration in the quality of the feed will require towers to be charged to higher pressures resulting in higher pressure differentials during the venting process, in greater volumes of gas lost, and in lower sales/feed ratios.

Also, poor quality feed gas has lower amounts of hydrocarbons to recover and thus will naturally result in lower sales/feed ratios. With the poorer quality feed (at 633 btu/cu ft), the btu-recovery (Table 2) efficiency decreased to about 59% as compared with 75+% obtained with a superior feed whose heat content averaged 715 btu/cu ft.

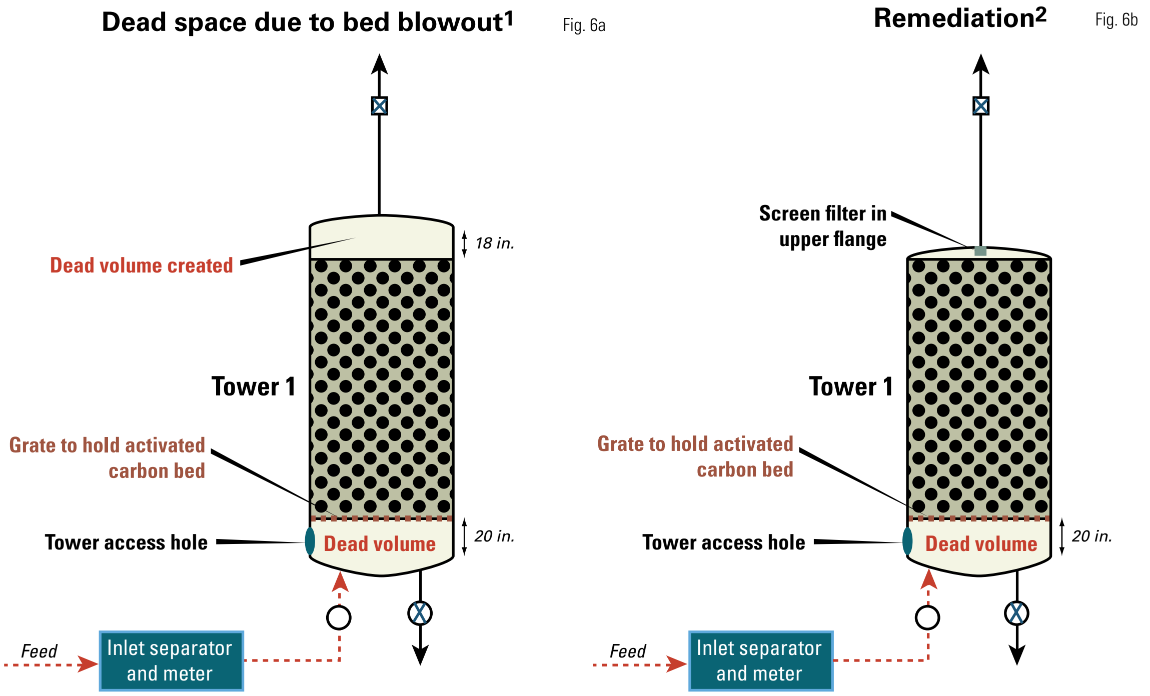
Plant controls

Only two parameters, the tower charge pressure and the vent pressure, are critical to optimizing the plant for upgrading a low-btu feed to pipeline quality. Different combinations of these two parameters must be tested to determine the settings for obtaining pipeline-quality product stream with minimum hydrocarbon loss in the vent stream.

A programmable logic controller pneumatically opens and closes the solenoid valves controlling the flow of gas into and out of the two towers. Charge and vent pressures (or times) are input to the PLC for continuous operation monitored by a once-a-day visit by the plant operator.

Bed blowout

Fig. 6



[1]Dead space created at top of tower due to bed blowout. Permanent dead space (≈20 in.) remains at base of 8-ft tower due to inadvertent design flaw.
[2]Tower topped with activated carbon and sealed in place by screen filter set in upper flange.

The following guidelines will help optimize plant settings due to changes in feed-gas composition:

- If the feed btu and heavy hydrocarbon fraction increase, the towers may be charged to lower pressures to obtain pipeline-quality sales stream. Sales/feed ratios tend to improve with higher quality feed.
- If the feed btu and heavy hydrocarbon fraction decrease, the towers may be charged to higher pressures to upgrade to pipeline quality. Sales/feed ratios will decrease with poorer feed quality.
- With pipeline-quality product stream attained by adjustment of the charge pressure, the vent pressure may be fine tuned to optimize the sales/feed ratio.

Operational problems

During the initial testing period, the sales/feed ratio would suddenly decline despite minor variations in feed composition and unchanging operational settings after a few days of operation. Visual evidence of carbon particles being ejected from the vent tower during each vent phase confirmed that bed blowout was taking place.

This was caused by the absence of any filter in the upper flange connecting the tower to the vent line and by the pressure shock (release) of the venting process. With bed material being blown out, the dead volume increased at the top of each tower, resulting in performance degradation.

Opening the flange atop each tower allowed a visual check for bed blowout and revealed that each tower had lost about 18 in. of bed from the top of the column (Fig. 6a). This problem was solved after the towers were topped off with fresh activated carbon (Fig. 6b) and an appropriately sized screen filter was set below the upper flange.

It was also discovered that the bottleneck affecting the NRU sales (volume) throughput is primarily the time taken to desorb a tower from vent pressure (≈ 2 psig) to 22-25 in. mercury.

The tower evacuation time depends on the tower (or bed) volume and the compressor capacity and is normally longer than the tower charge-up time given sufficient pressure and rate in the feed line. Thus, the tower charging process often had to be slowed to make the charge time equal to the evacuation time for continuous operation.

One important lesson learned from this project is that a strong compressor, capable of evacuating the tower (volume) as quickly as possible, should be employed to reduce process cycle time and increase plant throughput.

Heavy HC adsorption

A mass balance of the heavy hydrocarbons (C_2H_{6+}) conducted on the feed and respective upgraded sales gas showed that about 98% of the heavy hydrocarbons entrained in the feed were recovered in the product stream. The bed of activated carbon was therefore efficient in capturing the incoming heavy hydrocarbons and the desorption process was equally effective in recovering the heavy hydrocarbons.

Methane was less efficiently captured—only 58-68% of methane in the feed gas was recovered, depending on gas composition. The vent stream was mostly made up of unadsorbed nitrogen and some methane, which limits the feasibility of capturing and upgrading the vent gas to pipeline quality.

Plant economics

The microscale NRU at Elmdale field was designed to handle around 100 Mcfd of low-btu feed gas. A local commercial upgrading plant offered AEC a 51% seller's percentage for low-volume sales less than 450 Mcfd (i.e., AEC gets paid for 51 Mcf of pipeline-quality gas for sale of every 100 Mcf of low-btu gas). Also, the sales contract carried a constraint that the feed could not have nitrogen content in excess of 28%, which, in effect, disqualified the feed from Elmdale field because its nitrogen content was >33%.

Additionally, AEC had to consider the cost of transporting the low-btu gas from the production wells to the commercial plant, provided that a nearby pipeline was available and its operator agreed to transport the low-btu gas. AEC estimated that the transportation would additionally cost about 13% of the volume of low-btu gas that it sold to the commercial upgrading plant. In summary, if AEC were to sell 100 Mcf of low-btu gas to the commercial plant, it would get paid for 38 Mcf of pipeline-quality gas after deduction of the upgrade and transportation costs.

In comparison, if AEC were to use the micro-NRU to treat its low-btu gas on site, it would save the transportation costs. Given the average sales/feed ratio achieved at the micro-NRU, if AEC were to process 100 Mcf of low-btu gas with average heat content of 622 btu/cu ft and 715 btu/cu ft at its own micro-NRU, it would get paid for about 39 and 57 Mcf of pipeline-quality gas, respectively. Thus, the micro-NRU offers competitive value to AEC, particularly for higher quality low-btu feed.

AEC built the NRU with off-the-shelf vessels, pipelines, control valves, engine, and compressor in its workshop with its own maintenance/service crew at a cost of $120,000 in 2008. This achievement highlights the simplicity of the plant design and should therefore provide confidence to other small operators to venture into building a microplant for their needs without relying on expensive expertise from consultants.

Based on average performance (sales/feed ratio), the payout time calculates to be 51 and 35 months, respectively, for feed gases averaging 622 and 715 btu/cu ft, assuming pipeline-quality gas to be priced at $2.00/Mcf and a feed volume of 100 Mcfd.

Lessons

- It is possible to upgrade low-btu gas with a heat content as low as 630 btu/cu ft and a heavy hydrocarbon fraction (C_2H_{6+}/CH_{4+}) of at least 3.8% to pipeline quality (>950 btu/cu ft) using a simple, cost-effective microscale NRU with an adsorption bed consisting of readily available nonpatented activated carbon made from coconut husks.
- Dead volume within each tower must be minimized relative to tower volume. Initial operation data indicate that greater bed mass (with minimum dead volume) results in larger volumes of adsorbed hydrocarbons and therefore better sales/feed ratio.
- The off-the-shelf bed of activated carbon is efficient in adsorbing heavy hydrocarbons (C_2H_{6+}) from the feed stream and desorbing it under vacuum. Methane removal is less efficient, so that dry-gas feed stock may be difficult to upgrade to pipeline quality.
- Despite the cost of the compressor being one of the major expenses in the building of the NRU, an effective compressor must be used to evacuate towers (to maximum vacuum) in the shortest time so that plant efficiency and throughput are not compromised.
- A constant feed chemistry and pressure require less operational supervision. Plant settings, i.e., tower charge pressure and vent pressure will require reoptimization if feed composition (btu, N_2 %, and C_2H_{6+}/CH_{4+} ratio) changes.
- Both nitrogen content and the fraction of heavy hydrocarbons in the feed control the optimum plant settings and determine its efficiency. Greater amounts of heavy hydrocarbons in feed result in higher sales/feed ratio and thus better plant economics.
- A micro-NRU may be a viable option if pipeline transport costs of the low-btu gas to commercial upgrading plants are significant.

Acknowledgments

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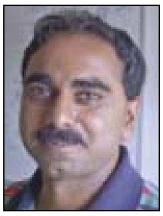

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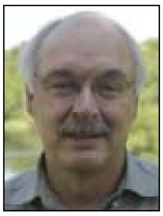

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North Sea trials verify subsea grout curing

Christopher E. Smith
Pipeline Editor

Full-scale tests of a subsea grout mixing and injection skid unit in the North Sea in June verified both the overall functionality of the injection system used for installing a Subsea Grouted Tee and the grout's ability to cure at seabed temperature and pressure.

SSGT technology mechanically connects an off-take fitting to an existing pressurized pipeline, providing an alternative method of hot-tapping into high and low-pressure pipelines without major welding.

Applying the technique to marginal satellite fields could help develop such prospects by dropping the cost of linking to export infrastructure. SSGT also offers a more efficient means of making emergency interventions.

Background

Subsea 7 began a Joint Industry Project in 2006 with UK engineering consultancy, Advantica (now GL Industrial Services UK Ltd.) to develop a grouted tee for subsea applications. The JIP sponsors (BP, Total, and ConocoPhillips) supported conversion of the technology for subsea use with the vision of taking it to ultradeep diverless applications.

Following completion of the JIP, Subsea 7 carried out further testing on the technology in test tanks and laboratories and conducted offshore trials in June 2009, mobilizing a grout mixing and injection skid, complete with test tee assemblies, on its Seven Pelican dive-support vessel. Divers conducted installation and hookup once the skid was deployed to the seabed.

Skid recovery followed grout injection into a test tee assembly and a 24-hr grout curing period. A successful grout quality test supported the technology's readiness state for subsea operations.

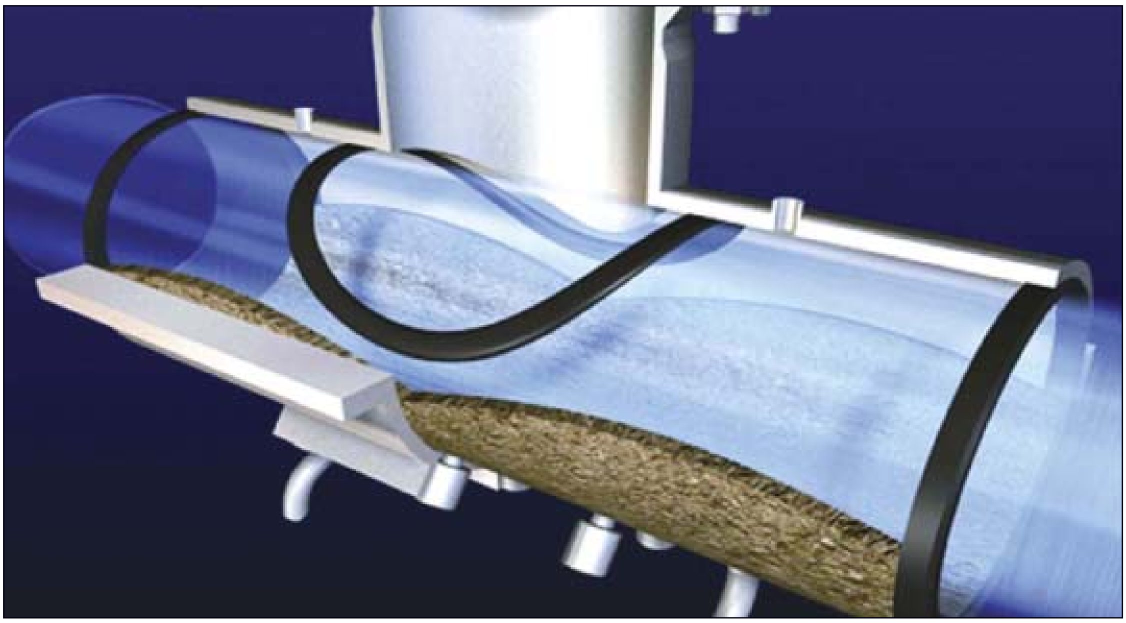
Advantages

Key advantages of this method of hot tapping include:

- The absence of hyperbaric welding or a hyperbaric welding habitat.
- Elimination of the need for specialist welder divers and prequalification.
- Shorter lead times (including potential off-the-shelf application in emergencies).
- No requirement for pressure reduction, allowing normal production throughout.
- Reduced expense.
- Potential future diverless application.

The accompanying table compares welded and SSGT options.

The potential exists to use SSGT for acute angle branch,



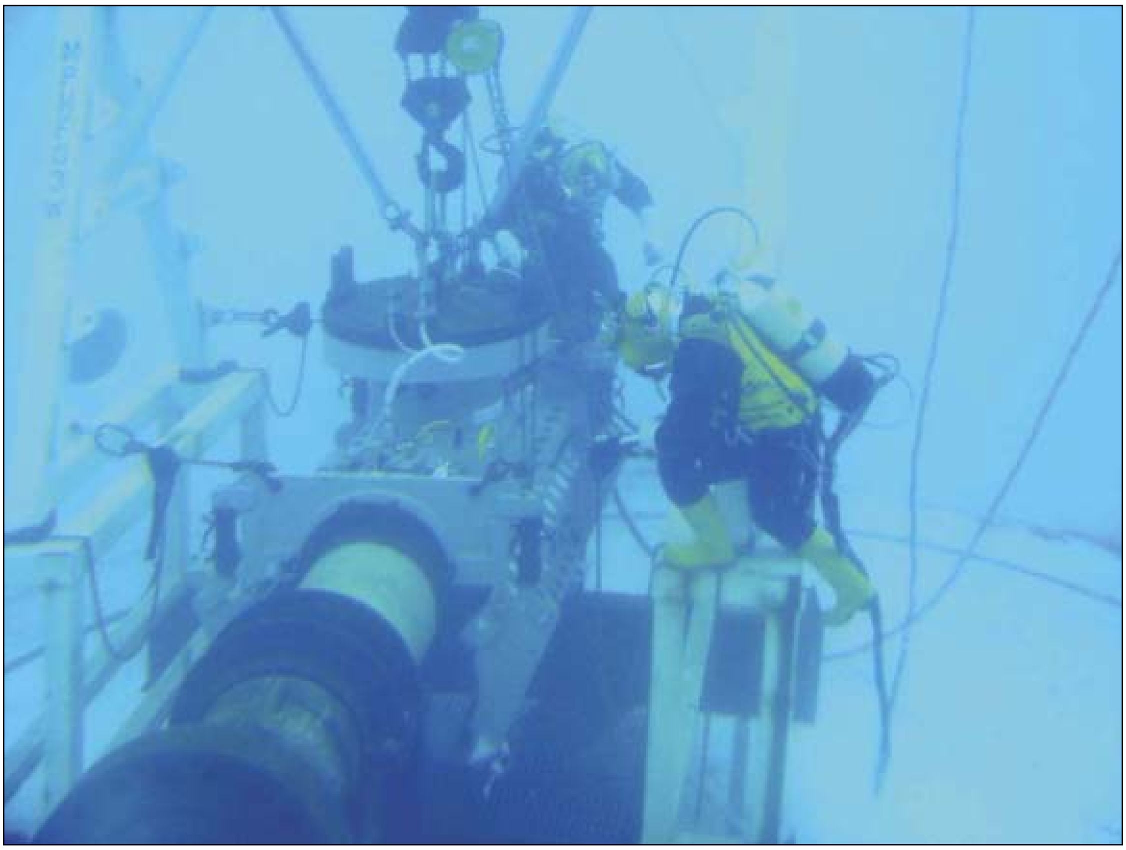
This cutaway of the Subsea Grouted Tee technology shows the seals between it and the main pipeline. The lower half of the tee, split into two parts, creates a door for application to the pipe. The tee is sized to create an annular gap into which the grout is injected (Fig. 1).

multiple branch, and K-type configured branch applications. Possible current applications include:

- Valve replacement.
- Pipe-branch connection.
- Repair bypass.
- Blockage removal, tooling introduction.

SSGT

SSGT consists of a tee using a top half-shell with a branch either welded or extruded onto the shell during fabrication. The tee-branch consists of a high-pressure double-block-and-bleed hydrogenated nitrile butadiene rubber seal energized through spreader plates activated when the tee is clamped in position around the pipeline (Fig. 1).



Divers install a 24-in. by 24-in. SSGT ANSI Class 900 prototype in a shallow-water test tank at Subsea 7's Greenwell base in Aberdeen (Fig. 2).

The lower half of the shell, split into two parts, creates a door arrangement operated hydraulically once the tee is positioned on the pipeline. The tee, deployed in an installation frame, is sized to produce an annular gap between tee and pipeline.

Drying the annular gap and injecting it with epoxy grout create the mechanical bond between pipeline and tee, allowing full transfer of load between the two.

Conversion of the land-based grouted tee to SSGT used a 24-in. stopple branch off a 24-in. pipeline, with an ANSI Class 900 flange connection for shallow-water diver operations (200-m maximum). Conversion involved three stages: design and qualification of SSGT, design and build of a subsea grout injection system, and hyperbaric testing. Divers and subsea equipment installed a 24-in. by 24-in. Class 900 stopple SSGT prototype in shallow-water test tanks (Fig. 2).

Hydraulic pistons and supporting high tensile strength bolts on horizontal flanges allowed the fitting to compress the primary saddle seal onto the main pipeline. O-ring sealing strips integrated into horizontal flanges on the doors and the branch half of the fitting provide a gas-tight environment in the annulus between the main pipe and fitting, allowing water in the annulus to be flushed by flowing nitrogen once the end seals are activated. These O-rings are temporary and only assist with drying and grout injection.

Once the fitting is wrapped around the main pipeline and temporary ends seals are installed, conventional hydraulic bolt-tensioning tools preload bolts on the horizontal flanges. Pressure testing the annulus to 20 psi establishes the seal as more than adequate to inject inert drying agents such as nitrogen. Flushing sea water and potential salt deposits in the annulus between the tee and the pipe with fresh water and then drying the annulus with dry nitrogen to a humidity of less than 20% is sufficient to achieve full structural

SSGT VS. WELDED FITTINGS

Activity	SSGT	Welded fittings
Prequalification exercise		
Preheat preparations	Not required	Required
NDT equipment sourcing	Not required	Required
Habitat modifications	Not required	Required
Welding-cooling equipment design	Not required	Required
Welding procedures, diver training	Not required	Required
Offshore operations		
Habitat installation-removal	Not required	Required
Welding equipment installation-removal	Not required	Required
Welding-NDT operations	Not required	Required

strength of the grout.

The subsea grout mixing and injection skid unit allows various preinjection testing stages to ensure skid settings match perfectly with ambient subsea conditions. The skid unit has two bladders, one containing resin and the other hardener, the main components of the grout. Each component is pumped independently and mixes at the built-in static mixer. The pumping process takes about 15 min, safely within the potting life of the grout.

After injection, the grout sets while preparation for hot-tap drilling commences. A full-pressure test on the branch precedes hot tap drilling once the grout has cured.

Field testing of a subsea grout-mixing and injection skid occurred in 113-m water depths at Total's Jura North Sea gas field in June 2009, using the Seven Pelican dive-support vessel (Fig. 3).

Test guidelines

Completion of the test tank trials helped define parameters for the field tests. Any coating would have to be removed before pipe-surface preparation. Concrete weight coating with reinforcing steel bar and anticorrosion coating must be removed to 500 mm either side of the tee to allow clearance for installation. Shot-blasting the pipe surface to SA2.5 with a profile of 30-70 µm allows for ideal grout injection and bonding of the grout.

Pneumatic (nitrogen) pressure testing of the interspace within the primary saddle seal reached 153 barg, with the main pipeline and branch at atmospheric pressure, without leakage. System tests went as high as 225 barg without leakage.

The grout injection rate on the 24-in. by 24-in. test measured roughly 5 l./min, with 70 l. required to fill the annulus. The grout curing process, commencing once the hardener and resin components are mixed, limits the injection window to 40 min at 4° C.[1]

Field test

Following the onshore qualifications program at the end of 2008, a subsea mixing and injection skid unit underwent full-scale grout injection trial in the North Sea June 27, 2009. Injection-skid deployment took place on the seabed near Total's Jura gas field at about 113-m water depth and a seabed temperature of 7° C. (Fig. 3).

The trial sought to verify overall functionality of the injection system and the grout's ability to cure at seabed temperature and pressure. Testing used two 16-in. OD pipe-in-pipe samples with one sleeve fabricated from clear acrylic to allow grout flow path assessment. The trial lasted almost 5 hr and test samples were left at seabed conditions for 24 hr to cure before the whole system was recovered to surface.

Grout flow path inside the test sleeves was similar to onshore qualification injection trials and the results of grout compressive strengths were within the expected parameters.

The deepest hot-tap work being performed by divers is at roughly 250 m. SSGT development is focused on 100% remotely operated applications for use in deep and ultradeep water environments.

SSGT principles can extend to pipelines up to 48-in. OD and cover a pipeline operating temperature range between 2° C. and 70° C.[1] ✦

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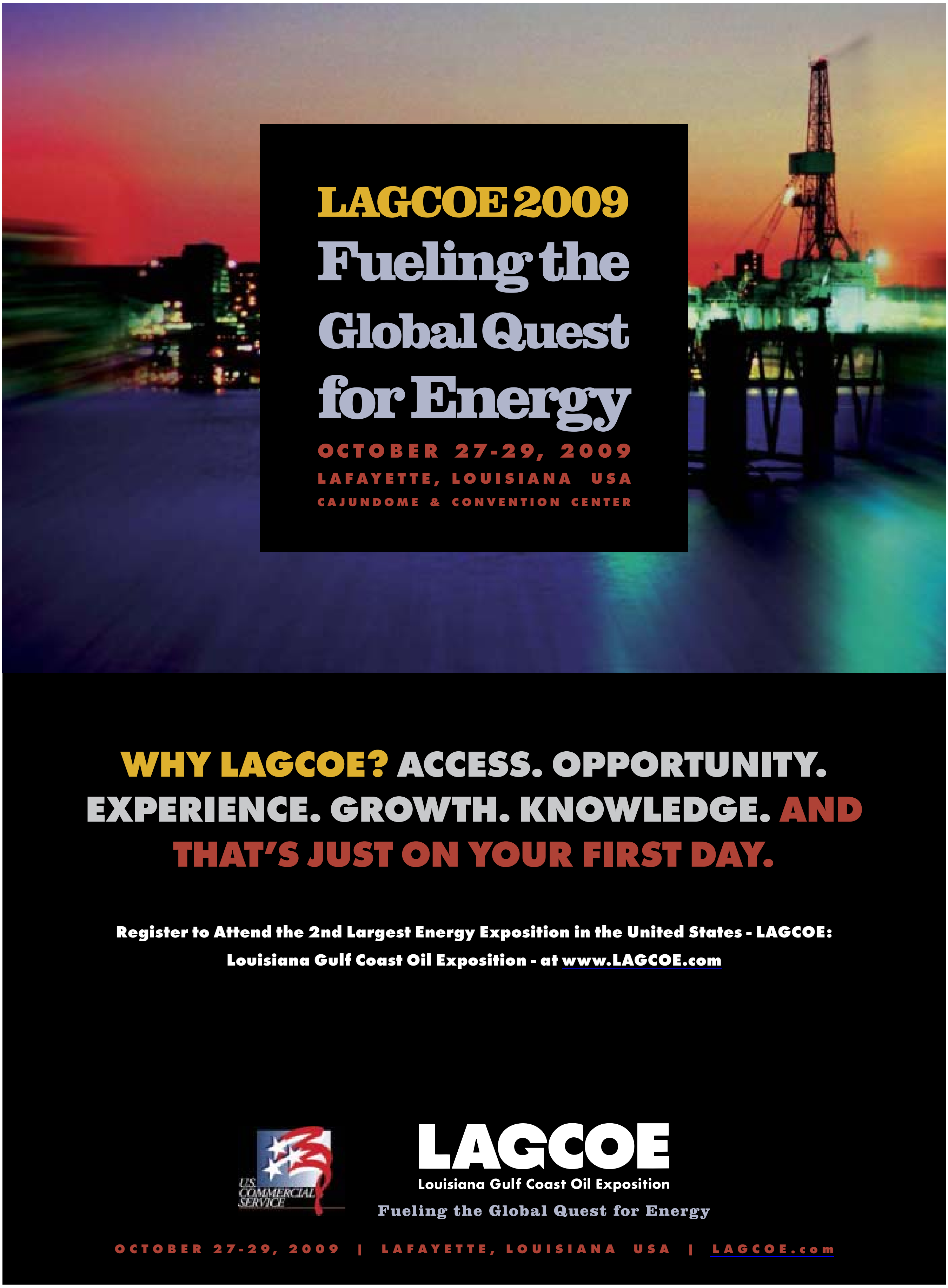
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Statistics

Imports of crude and products

	Districts 1-4 10-9 2009	Districts 1-4 10-2 2009	District 5 10-9 2009	District 5 10-2 2009	Total US 10-9 2009	Total US 10-2 2009	Total US *10-10 2008
	1,000 b/d						
Total motor gasoline	648	993	42	18	690	1,011	1,452
Mo. gas. blending comp.	489	910	0	11	489	921	991
Distillate	124	194	40	20	164	214	91
Residual	248	265	0	0	248	265	258
Jet fuel-kerosine	5	17	84	76	89	93	73
Propane-propylene	162	99	9	7	171	106	102
Other	629	201	54	91	683	292	543
Total products	**2,305**	**2,679**	**229**	**223**	**2,534**	**2,902**	**3,510**
Total crude	**7,316**	**7,981**	**1,415**	**1,117**	**8,731**	**9,098**	**10,161**
Total imports	**9,621**	**10,660**	**1,644**	**1,340**	**11,265**	**12,000**	**13,671**

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

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

OIL&GAS JOURNAL online research center.

OGJ crack spread

	*10–16–09	*10–17–08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	79.90	84.99	–5.08	–6.0
Brent crude	72.26	69.89	2.37	3.4
Crack spread	7.65	15.10	–7.45	–49.3
FUTURES MARKET PRICES				
One month				
Product value	80.39	81.72	–1.32	–1.6
Light sweet crude	75.74	75.21	0.53	0.7
Crack spread	4.65	6.51	–1.85	–28.5
Six month				
Product value	87.73	88.99	–1.26	–1.4
Light sweet crude	78.21	77.30	0.91	1.2
Crack spread	9.52	11.69	–2.17	–18.5

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

Purvin & Gertz LNG netbacks—Oct. 16, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.13	4.09	5.33	3.99	4.66	5.25
Everett	3.07	1.52	2.73	1.69	1.60	3.35
Isle of Grain	4.46	2.57	3.85	2.53	2.94	3.87
Lake Charles	1.35	1.06	1.14	1.04	0.82	1.92
Sodegaura	4.84	7.03	5.09	6.74	6.03	4.19
Zeebrugge	5.72	3.72	5.07	3.65	4.15	5.13

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

Crude and product stocks

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	13,777	57,827	39,406	12,460	75,672	13,777	4,559
PADD 2	76,491	49,370	24,463	7,990	32,983	1,085	30,811
PADD 3	180,870	68,036	39,262	15,057	46,633	16,059	34,809
PADD 4	15,338	6,305	2,038	499	3,296	224	[1]2,277
PADD 5	51,284	27,621	22,342	9,330	12,088	3,926	—
Oct. 9, 2009	**337,760**	**209,159**	**127,511**	**45,336**	**170,672**	**35,071**	**72,456**
Oct. 2, 2009	**337,426**	**214,389**	**127,490**	**45,733**	**171,756**	**35,269**	**72,859**
Oct. 10, 2008[2]	**308,198**	**193,788**	**98,815**	**36,258**	**122,148**	**38,706**	**61,153**

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

Refinery report—Oct. 9, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,339	1,344	2,402	73	422	99	54
PADD 2	2,918	2,909	2,020	186	845	43	263
PADD 3	7,065	6,949	2,214	637	1,931	348	661
PADD 4	532	534	323	26	185	12	[1]59
PADD 5	2,441	2,361	1,494	399	493	158	—
Oct. 9, 2009	**14,295**	**14,097**	**8,453**	**1,321**	**3,876**	**660**	**1,037**
Oct. 2, 2009	**15,020**	**14,607**	**9,417**	**1,346**	**4,042**	**673**	**1,099**
Oct. 10, 2008[2]	**14,483**	**14,115**	**9,164**	**1,410**	**4,184**	**560**	**1,012**
	17,672 Operable capacity		**80.9 utilization rate**				

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

OGJ gasoline prices

	Price ex tax 10-14-09	Pump price* 10-14-09	Pump price 10-15-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	190.6	237.1	335.3
Baltimore	196.5	238.4	334.1
Boston	198.2	240.1	330.0
Buffalo	191.2	252.1	318.3
Miami	204.5	256.1	326.9
Newark	197.4	230.0	319.9
New York	186.1	247.0	329.9
Norfolk	191.7	230.1	318.7
Philadelphia	196.4	247.1	332.0
Pittsburgh	195.4	246.1	321.2
Wash., DC	209.7	248.1	320.8
PAD I avg	196.1	242.9	326.1
Chicago	203.7	268.1	328.1
Cleveland	216.4	262.8	302.7
Des Moines	202.7	243.1	308.7
Detroit	208.7	268.1	320.5
Indianapolis	193.7	253.1	315.5
Kansas City	192.1	228.1	299.4
Louisville	212.1	253.0	318.9
Memphis	191.3	231.1	302.9
Milwaukee	203.8	255.1	320.5
Minn.-St. Paul	208.1	252.1	312.2
Oklahoma City	183.7	219.1	280.1
Omaha	180.7	226.0	294.2
St. Louis	187.1	223.1	308.5
Tulsa	180.7	216.1	285.5
Wichita	184.7	228.1	297.7
PAD II avg	196.6	241.8	306.4
Albuquerque	191.2	227.6	310.9
Birmingham	194.3	233.6	302.8
Dallas-Fort Worth	194.7	233.1	293.5
Houston	192.7	231.1	296.9
Little Rock	187.4	227.6	300.0
New Orleans	195.2	233.6	318.2
San Antonio	196.2	234.6	307.6
PAD III avg	193.1	231.6	304.3
Cheyenne	215.8	248.2	313.5
Denver	216.3	256.7	341.2
Salt Lake City	207.8	250.7	323.7
PAD IV avg	213.3	251.9	326.1
Los Angeles	233.6	300.7	343.1
Phoenix	223.9	261.3	330.0
Portland	239.6	283.0	335.0
San Diego	235.3	302.4	350.2
San Francisco	241.9	309.0	355.4
Seattle	241.1	297.0	340.0
PAD V avg	235.9	292.2	342.3
Week's avg.	**202.7**	**248.3**	**317.7**
Sept. avg.	**211.0**	**256.6**	**367.2**
Aug avg.	**209.9**	**255.5**	**375.3**
2009 to date	**179.9**	**225.5**	--
2008 to date	**309.7**	**353.7**	--

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

Refined product prices

Spot market product prices	10-9-09 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	180.26
Gulf Coast	177.76
Los Angeles	187.26
Amsterdam-Rotterdam-Antwerp (ARA)	172.09
Singapore	175.71
Motor gasoline (Reformulated-regular)	
New York Harbor	177.26
Gulf Coast	178.26
Los Angeles	193.26
Heating oil No. 2	
New York Harbor	184.36
Gulf Coast	183.11
Gas oil	
ARA	183.21
Singapore	176.19
Residual fuel oil	
New York Harbor	156.48
Gulf Coast	155.88
Los Angeles	173.38
ARA	158.68
Singapore	162.17

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

Baker Hughes rig count

	10-16-09	10-17-08
Alabama	6	5
Alaska	6	7
Arkansas	38	57
California	22	45
Land	21	45
Offshore	1	0
Colorado	36	122
Florida	0	2
Illinois	0	1
Indiana	2	2
Kansas	24	11
Kentucky	11	12
Louisiana	160	198
N. Land	108	80
S. Inland waters	11	20
S. Land	12	32
Offshore	29	66
Maryland	0	0
Michigan	0	2
Mississippi	7	17
Montana	2	9
Nebraska	2	0
New Mexico	48	93
New York	3	6
North Dakota	53	74
Ohio	8	10
Oklahoma	74	193
Pennsylvania	57	26
South Dakota	0	1
Texas	394	925
Offshore	3	7
Inland waters	0	0
Dist. 1	26	27
Dist. 2	14	36
Dist. 3	29	64
Dist. 4	31	89
Dist. 5	67	186
Dist. 6	44	135
Dist. 7B	6	25
Dist. 7C	32	63
Dist. 8	66	129
Dist. 8A	16	29
Dist. 9	26	39
Dist. 10	34	96
Utah	15	38
West Virginia	21	30
Wyoming	40	75
Others—HI-1; NV-2; OR-2; TN-1; VA-5	11	15
Total US	**1,040**	**1,976**
Total Canada	**250**	**437**
Grand total	**1,290**	**2,413**
US Oil rigs	309	428
US Gas rigs	721	1,537
Total US offshore	33	78
Total US cum. avg. YTD	**1,079**	**1,879**

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

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

Smith rig count

Proposed depth, ft	10-16-09 Rig count	10-16-09 Percent footage*	10-17-08 Rig count	10-17-08 Percent footage*
0-2,500	64	4.6	85	3.5
2,501-5,000	78	67.9	142	49.2
5,001-7,500	117	21.3	272	17.6
7,501-10,000	223	7.1	464	2.5
10,001-12,500	198	13.1	460	0.8
12,501-15,000	154	1.2	382	0.2
15,001-17,500	142	--	170	--
17,501-20,000	59	--	79	--
20,001-over	36	--	31	--
Total	**1,071**	**11.6**	**2,085**	**6.6**
INLAND	17		31	
LAND	1,016		2,001	
OFFSHORE	38		53	

*Rigs employed under footage contracts.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ production report

	[1]10-16-09	[2]10-17-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	22	22
Alaska	687	702
California	653	653
Colorado	67	67
Florida	6	6
Illinois	27	26
Kansas	112	113
Louisiana	1,414	612
Michigan	17	18
Mississippi	63	62
Montana	85	86
New Mexico	167	164
North Dakota	204	198
Oklahoma	178	178
Texas	1,399	1,185
Utah	64	63
Wyoming	146	145
All others	66	74
Total	**5,377**	**4,374**

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

US crude prices

	10-16-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	78.50
California-Kern River 13°	69.75
Lost Hills 30°	78.30
Wyoming Sweet	70.28
East Texas Sweet	74.50
West Texas Sour 34°	70.00
West Texas Intermediate	75.00
Oklahoma Sweet	75.00
Texas Upper Gulf Coast	68.00
Michigan Sour	67.00
Kansas Common	74.00
North Dakota Sweet	64.75

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

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

World crude prices

$/bbl[1]	10-9-09
United Kingdom-Brent 38°	67.29
Russia-Urals 32°	67.14
Saudi Light 34°	66.40
Dubai Fateh 32°	68.12
Algeria Saharan 44°	68.15
Nigeria-Bonny Light 37°	69.20
Indonesia-Minas 34°	70.93
Venezuela-Tia Juana Light 31°	67.48
Mexico-Isthmus 33°	67.37
OPEC basket	67.87
Total OPEC[2]	67.44
Total non-OPEC[2]	66.98
Total world[2]	67.24
US imports[3]	66.32

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

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

US natural gas storage[1]

	10-9-09	10-2-09	10-9-08	Change, %
	bcf			
Producing region	1,182	1,169	888	**33.1**
Consuming region east	2,030	1,992	1,938	**4.7**
Consuming region west	504	497	439	**14.8**
Total US	**3,716**	**3,658**	**3,265**	**13.8**
	July 09	**July 08**	**Change, %**	
Total US[2]	**3,086**	**2,516**	**22.7**	

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

Statistics

World oil balance

	2009 2nd qtr.	2009 1st qtr.	2008 4th qtr.	2008 3rd qtr.	2008 2nd qtr.	2008 1st qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	18.73	19.07	19.53	19.20	20.05	20.31
Canada	2.12	2.20	2.26	2.28	2.19	2.31
Mexico	2.01	2.05	2.07	2.14	2.19	2.12
Japan	4.03	4.72	4.71	4.34	4.63	5.45
South Korea	2.17	2.34	2.14	2.10	2.11	2.35
France	1.81	2.02	2.04	1.95	1.95	2.01
Italy	1.52	1.55	1.62	1.64	1.64	1.66
United Kingdom	1.67	1.73	1.73	1.65	1.73	1.73
Germany	2.39	2.57	2.65	2.71	2.43	2.49
Other OECD Europe	6.81	7.05	7.40	7.60	7.33	7.44
Australia & New Zealand	1.10	1.08	1.12	1.10	1.11	1.10
Total OECD	**44.36**	**46.38**	**47.27**	**46.71**	**47.36**	**48.97**
NON-OECD						
China	8.28	7.55	7.56	8.10	7.89	7.86
FSU	4.16	4.11	4.38	4.35	4.31	4.30
Non-OECD Europe	0.77	0.77	0.80	0.80	0.79	0.79
Other Asia	9.26	9.09	8.76	8.96	9.61	9.52
Other non-OECD	16.06	15.15	15.48	16.30	15.94	15.04
Total non-OECD	**38.53**	**36.67**	**36.98**	**38.51**	**38.54**	**37.51**
TOTAL DEMAND	**82.89**	**83.05**	**84.25**	**85.22**	**85.90**	**86.48**
SUPPLY						
OECD						
US	8.97	8.78	8.46	8.18	8.75	8.67
Canada	3.25	3.39	3.40	3.40	3.22	3.38
Mexico	2.99	3.06	3.12	3.15	3.19	3.29
North Sea	4.00	4.40	4.37	4.06	4.31	4.44
Other OECD	1.54	1.55	1.60	1.60	1.58	1.53
Total OECD	**20.75**	**21.18**	**20.95**	**20.39**	**21.05**	**21.31**
NON–OECD						
FSU	12.87	12.60	12.46	12.42	12.60	12.59
China	3.98	3.92	3.99	3.97	4.00	3.94
Other non–OECD	12.45	12.43	12.36	12.32	12.15	12.22
Total non-OECD, non-OPEC	**29.30**	**28.95**	**28.81**	**28.71**	**28.75**	**28.75**
OPEC*	**33.60**	**33.24**	**35.16**	**36.18**	**35.84**	**35.72**
TOTAL SUPPLY	**83.65**	**83.37**	**84.92**	**85.28**	**85.64**	**85.78**
Stock change	**0.76**	**0.32**	**0.67**	**0.06**	**-0.26**	**-0.70**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	June 2009	May 2009	Average YTD 2009	Average YTD 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	458	272	484	537	–53	–9.9
Angola	447	505	547	506	41	8.1
Kuwait	179	93	174	223	–49	–22.0
Nigeria	830	600	679	1,091	–412	–37.8
Saudi Arabia	959	1,079	1,084	1,530	–446	–29.2
Venezuela	1,237	1,341	1,180	1,169	11	0.9
Other OPEC	704	581	836	1,017	–181	–17.8
Total OPEC	**4,814**	**4,471**	**4,984**	**6,073**	**–1,089**	**–17.9**
Canada	2,529	2,206	2,417	2,521	–104	–4.1
Mexico	1,183	1,186	1,274	1,308	–34	–2.6
Norway	173	171	136	118	18	15.3
United Kingdom	268	250	262	223	39	17.5
Virgin Islands	268	313	306	336	–30	–8.9
Other non-OPEC	2,667	3,000	2,843	2,498	345	13.8
Total non-OPEC	**7,088**	**7,126**	**7,238**	**7,004**	**234**	**3.3**
TOTAL IMPORTS	**11,902**	**11,597**	**12,222**	**13,077**	**-855**	**-6.5**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

OECD total net oil imports

	June 2009	May 2009	Apr. 2009	June 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	-1,385	-1,273	-1,225	-1,078	-307	28.5
US	9,939	9,581	10,073	11,252	-1,313	-11.7
Mexico	-989	-1,039	-1,065	-978	-11	1.1
France	1,687	1,798	1,641	1,653	34	2.1
Germany	2,105	2,146	2,273	2,003	102	5.1
Italy	1,297	1,532	1,481	1,498	-201	-13.4
Netherlands	1,103	937	1,060	1,042	61	5.9
Spain	1,487	1,330	1,376	1,473	14	1.0
Other importers	3,759	3,593	3,608	3,900	-141	-3.6
Norway	-1,779	-1,912	-2,098	-1,899	120	-6.3
United Kingdom	58	-85	-16	48	10	20.8
Total OECD Europe	**9,717**	**9,339**	**9,325**	**9,718**	**-1**	**0.0**
Japan	4,157	3,973	4,089	4,578	-421	-9.2
South Korea	2,070	1,964	1,965	1,891	179	9.5
Other OECD	929	835	927	797	132	16.6
Total OECD	**24,438**	**23,380**	**24,089**	**26,180**	**-1,742**	**-6.7**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	June 2009	May 2009	Apr. 2009	June 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	339	386	369	375	–36	–9.6
US	337	339	386	428	–91	–21.3
Mexico	4,814	4,471	4,754	6,035	–1,221	–20.2
France	808	855	567	779	29	3.7
Germany	365	450	464	399	–34	–8.5
Italy	969	927	963	1,213	–244	–20.1
Netherlands	533	516	533	661	–128	–19.4
Spain	756	758	653	788	–32	–4.1
Other importers	1,272	1,002	1,036	1,335	–63	–4.7
United Kingdom	348	315	257	391	–43	–11.0
Total OECD Europe	**5,051**	**4,823**	**4,473**	**5,566**	**–515**	**–9.3**
Japan	3,309	3,503	3,629	3,422	–113	–3.3
South Korea	2,384	1,950	2,072	2,277	107	4.7
Other OECD	547	522	482	638	–91	–14.3
Total OECD	**16,463**	**15,618**	**15,825**	**18,411**	**–1,948**	**–10.6**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	May 2009	Apr. 2009	June 2009	May 2008	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	173	176	173	177	–4	–2.3
Germany	281	281	279	273	8	2.9
Italy	129	133	132	137	–8	–5.8
United Kingdom	92	92	98	99	–7	–7.1
Other OECD Europe	732	720	727	687	45	6.6
Total OECD Europe	**1,407**	**1,402**	**1,409**	**1,373**	**34**	**2.5**
Canada	199	198	199	194	5	2.6
US	1,839	1,829	1,812	1,686	153	9.1
Japan	611	609	606	619	–8	–1.3
South Korea	149	149	152	147	2	1.4
Other OECD	110	112	115	108	2	1.9
Total OECD	**4,315**	**4,299**	**4,293**	**4,127**	**188**	**4.6**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

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CBO: Climate bill threatens oil and gas employment

US oil and gas workers have extra reason to find interesting the Congressional Budget Office's confirmation that cap-and-trade legislation passed by the House of Representatives would diminish employment.

A disproportionate number of job losses would occur in their industry.

CBO Director Douglas W. Elmendorf told the Senate Committee on Energy and Natural Resources on Oct. 14 that a House climate-change bill passed in June would suppress economic growth and employment.

The Editor's Perspective

by Bob Tippee, Editor

Pointing out losses against expectations without cap-and-trade would be small relative to overall economic growth, he nevertheless refuted claims that the bill would do no damage at all. He said implementation of the House bill would lower gross domestic product from what it otherwise would have been by 0.25-.75% in 2020 and by 1-3.5% in 2050.

"CBO projects that real (inflation-adjusted) GDP will be roughly two and a half times as large in 2050 as it is today, so those changes would be comparatively modest," Elmendorf said in written testimony. Aggregate loss of household purchasing power would be 0.1% in 2012 and 0.8% in 2050, averaging 0.4% over the entire period. The bill, Elmendorf said, "would probably have only a small effect on total employment in the long run." Because it would "shift production, investment, and employment away from industries involved in the production of carbon-based energy and energy-intensive goods and services," however, oil and gas workers can take no comfort.

"The industries that produce carbon-based energy—coal mining, oil and gas extraction, and petroleum refining—would probably suffer significant employment losses over time," the CBO chief warned.

Elmendorf didn't focus any further on refining, but job losses in that industry might be extreme. The bill makes refiners responsible for nearly half of all required emission cuts but allocates to it a relatively tiny share of total emission allowances. The costs would be huge.

Elmendorf pointed out that a cap-and-trade system would open career fields in emerging energy industries.

Indeed, unofficial reports from the field indicate that people who like being outdoors and are comfortable with height have no trouble finding work scraping bird droppings off windmill blades.

(Online Oct. 16, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Crude climbs to higher price range

On Oct. 14, the front-month crude contract closed above $75/bbl on the New York Mercantile Exchange for the first time since the same date in 2008, ending a long period when intraday prices were "neatly shoe-horned" into a precise $10/bbl range. The next day, it traded as high as $77.97/bbl before closing at $77.58/bbl. "If the dollar does not strengthen, crude will probably test $80 within the next week," predicted analysts at Pritchard Capital Partners LLC in New Orleans.

Benchmark NYMEX crude "first got within range of $75/bbl all the way back in June," said Paul Horsnell, managing director and head of commodities research at Barclays Capital in London. "Barring a few days in early July when fears about spare storage at Cushing, Okla., running out got somewhat overblown, it has been $65 to $75 range trading all the way." Now, he said, "For the first time in months, the future exists."

It won't be a radical change from the market's past performance, however—more likely a transition to a new $70-80/bbl spread, with $70/bbl "perhaps starting to seem more like the bottom of the range than the middle," Horsnell said.

The price breakout occurred amid continued optimism that the economy is recovering, even as the US dollar hit a 14-month low against the euro. On Oct. 14, the Dow Jones Industrial Average climbed above the 10,000 level for the first time since early October 2008—the latest in a series of indications of a more robust economy.

Yet industry analysts looked in vain for major improvements in supply and demand fundamentals to support the oil price increase. Instead, the dollar index appeared to be the main influence on crude prices. Olivier Jakob at Petromatrix, Zug, Switzerland, expressed the outlook of many market observers when he said: "Based on [supply and demand] fundamentals, we have no confidence at all in the current oil rally." The world economy was not able to digest crude prices above $100/bbl in 2007, Jakob noted. "So we need to stay cautious before thinking it can digest $80/bbl oil now," he said.

Jakob said, "To be convinced that we are not in the middle of a dollar bubble and that genuine recovery is behind the rise of the stock market and genuine oil demand behind the rise of the oil markets, we would want to see both of them continuing their advance under a stable dollar. For now we have nothing but a falling dollar and because of that we have to remain extremely cautious about the current dynamics in equities and energy."

Gas and winter

The Energy Information Administration reported the injection of 58 bcf of natural gas into US underground storage in the week ended Oct. 9. That boosted the total working gas in storage above 3.7 tcf, approaching total capacity of 3.9 tcf with 3 weeks left in the gas-injection season. Storage was then 450 bcf higher than a year ago and 474 bcf above the 5-year average. "While the next few injections may appear bullish, we are experiencing a record cold mid-October and, with storage almost full, continue to face storage constraints," said analysts in the Houston office of Raymond James & Associates Inc.

Meanwhile, Joe Bastardi, chief meteorologist for AccuWeather.com, predicts a fading El Nino will produce "the stormiest and coldest" winter in recent years over an area from Maryland to the Carolinas.

"The areas that will be hit hardest this winter by cold, snowy weather will be from southern New England through the Appalachians and mid-Atlantic, including the Carolinas," he said in mid-October. Eastern Seaboard areas that had little snowfall the past two winters should expect above-normal snowfall. New York, Boston, and Philadelphia could get up to 75% of their total snowfall in "in two or three big storms," he said. Snowfall in some parts of the Appalachians could reach 50-100 in.

Bastardi expects the winter storm track to bring storms into southern California, across the South, and up the Eastern Seaboard. That would differ from the last 2 years, when storms tracked farther west from Texas into the Great Lakes, bringing unseasonably mild weather to major East Coast cities. In the South, the Interstate 20 corridor from Dallas to Atlanta will be "a strike zone for ice and snow," Bastardi said. "It is not out of the question that snow and ice are as far south as College Station and San Antonio, Tex."

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