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Process Control Technology

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ECDA tunes Gasunie pipeline corrosion predictions

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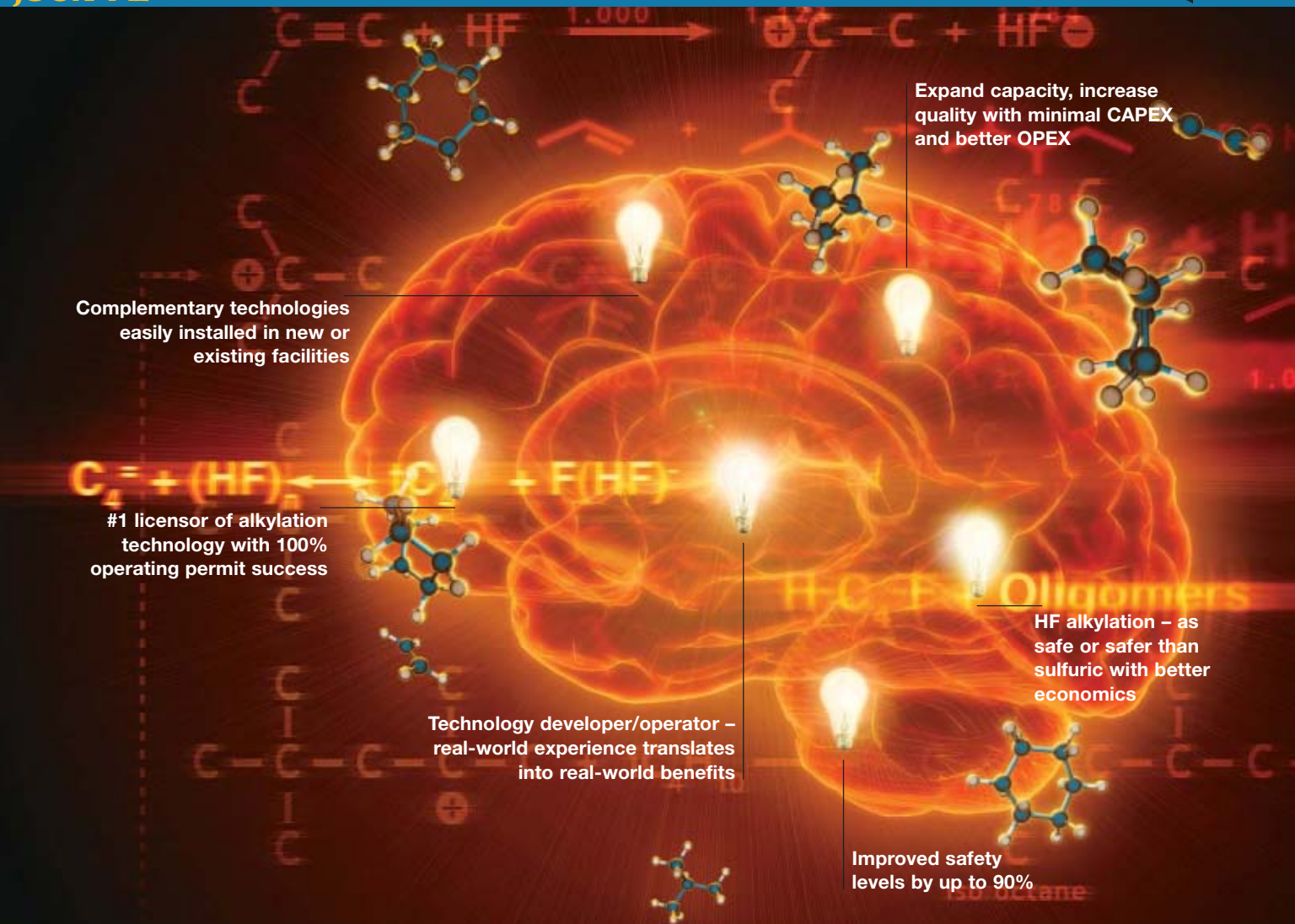
Oct. 9, 2006
Volume 104.38

PROCESS CONTROL TECHNOLOGY

REGULAR FEATURES

COVER

An operator controls an element of a processing plant with next-generation automation and control systems—a Honeywell Experion PKS and newly designed vertical series C I/O. Process control systems are becoming more important as refiners and petrochemical plant operators focus on them to improve operations. This issue's special report, Process Control Technology, begins on p. 44 with an article that discusses the issues of cyber and physical security risks to process control systems. The second article, p. 52, discusses a holistic, best-practices approach that helps refiners and petrochemical plant operators sustain and improve the performance of control system assets. Photo from Honeywell Process Solutions.



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General Interest

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Drilling & Production

Processing

Transportation

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Oct. 9, 2006

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General Interest — Quick Takes

Analysts see robust future for oil sands

The outlook for Canadian oil sands growth continues to improve, although the next 2 years could prove critical as oil companies face the risks of increasing cost overruns and project delays, said Friedman, Billings, Ramsey & Co. Inc.

In a Sept. 29 research note update on oil sands, an FBR analyst said increasing project proposals also increase the risk profile for the Canadian oil sands because of an already tight labor market.

"We believe that the risks of cost overruns and project delays will be increasing over the next 2 years, with the greatest risk being borne by those who have yet to firm up their cost estimates and to order key critical equipment," said Amir Arif, FBR senior vice-president.

He estimates 25-30% cost inflation from 2004 levels for new projects that will be firmed up in 2007 with risk of an additional 10-20% cost overruns related to labor, steel, and line pipe costs, along with infrastructure and logistic issues.

Noting that the number of oil sands projects planned in Alberta have been steadily climbing, FBR estimates the cumulative capital to be spent in the oil sands, based on announced projects, amounts to more than $125 billion (Can.) This is a 140% increase from FBR's 2003 estimate of $52 billion.

The increase is a result of both new projects being announced and additional cost pressures on previous cost estimates, Arif said.

Sakhalin-2 project faces more authorization woes

Part of the pipeline built for the Sakhalin-2 project may have been built without proper government authorization, according to Oleg Mitvol, deputy head of the Russian Federal Service for the Regulation of the Use of Natural Resources (Rosprirodnadzor).

Mitvol said the pipeline segment in question was built near the village of Sovetskoye and passes through the Zubrovyy nature reserve. He believes that segment was constructed after "unauthorized rerouting."

He said, "This is a crime punishable by law. We will examine the situation and transfer all the evidence to the prosecutor's office."

Meanwhile, starting Oct. 2 Rosprirodnadzor began taking aerial photographs of the complete pipeline, which was built as part of the Sakhalin-2 project. The photographic results will be compared to the relevant documents on file to establish whether there are discrepancies between existing work and work authorized.

Rosprirodnadzor inspectors flew over a 200-km section of the pipeline route by helicopter on Sept. 29. The survey revealed areas prone to mud slides due to pipeline construction, Mitvol said.

He also noted the presence of incorrectly constructed crossings over rivers. "There are problems over many crossings, which mean that most often these rivers have been made unsuitable for spawning," Mitvol said.

Mitvol said at least 3 months would be needed to draw up a full picture of the state of Aniva Bay after construction work has been carried out there for the Sakhalin-2 project.

Concerns aired over Brazil lease round exclusions

Some international oil company executives have voiced concerns about Brazil's National Petroleum Agency (ANP) excluding the Campos basin and parts of the Santos basin from the country's Nov. 28 licensing round.

Excluding these areas from the 8th licensing round makes it "less attractive," Alvaro Teixeira, executive secretary of the Brazilian Petroleum & Gas Institute, told OGJ.

Most of the field development activity undertaken by international firms is concentrated in the Campos basin, which produces 80% of Brazil's output of 1.8 million b/d of oil.

"Is the exclusion of these basins a sign that there will be changes concerning policies for future licensing rounds?" Teixeira posed. "Brazil's Mines and Energy Minister Silas Rondeau reaffirmed that the rounds will continue as normal and that the 9th Round will probably be announced right after the 8th round. We will see," he said.

The IBP executive said: "In the short term, there will be a reduction in the rhythm of annual investments in exploration. In the medium and long terms, there will be a postponement in investments to develop potential commercial discoveries of exploration work that was also postponed. The end result will be a reduction in the pace and or maintenance of the present rate of oil production in the next 6-7 years." IBP is a 50-year-old, nonprofit, private organization with 220 associates including most of the multinationals operating in Brazil.

ANP placed 284 blocks on offer in the upcoming 8th Round (OGJ Online, Sept. 12, 2006). The blocks being offered are in seven sedimentary basins and are considerably less in number than ANP's previous announcement of 1,153 blocks in 18 basins.

ANP justified excluding the Campos basin by saying, "A wide selection of acreage is to be put up for auction, including areas considered to have great potential for both oil and gas, new frontier blocks, and blocks in mature areas."

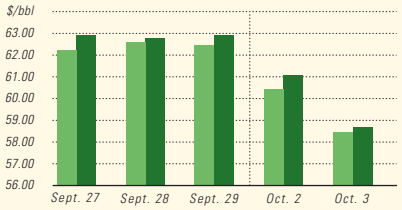
ANP considers 35 offshore areas as high potential blocks, 153 offshore blocks as new frontier basins, 47 onshore blocks as new frontier basins (with little geological data), and 49 blocks in onshore mature basins.

CAPP: Don't upset Canada's investment climate

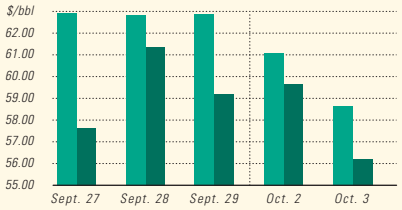
Speaking at the International Pipeline Conference & Exposition in Calgary, Kathy Sendall, Petro-Canada senior vice-president,

Industry Scoreboard

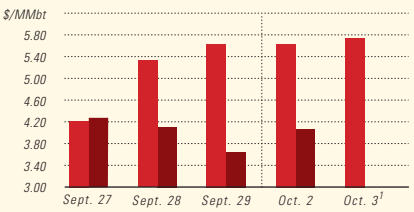
IPE BRENT / NYMEX LIGHT SWEET CRUDE



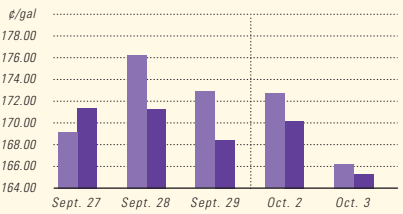
WTI CUSHING / BRENT SPOT



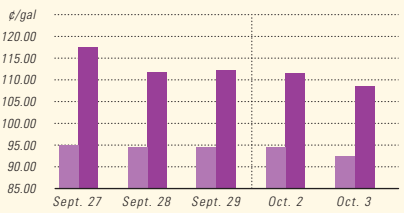
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



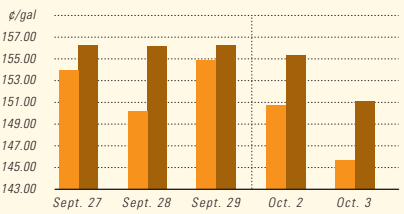
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[2]



[1]Not available at press time.
[2] Nonoxygenated regular unleaded.

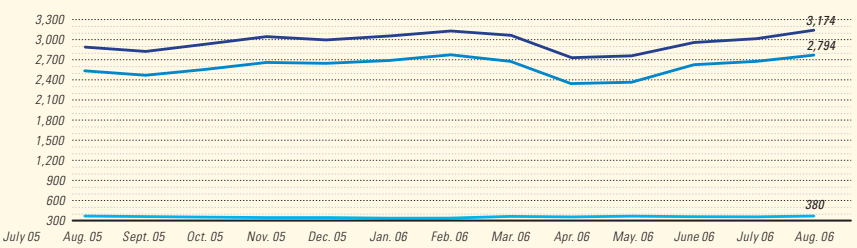
US INDUSTRY SCOREBOARD — 10/9

Latest week 9/29	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average	YTD avg. year ago*	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,684	8,897	8.9	9,760	9,126	6.9
Distillate	4,343	4,114	5.6	4,111	4,099	0.3
Jet fuel	1,604	1,606	–0.1	1,601	1,620	–1.2
Residual	602	1,039	–42.1	766	891	–14.0
Other products	5,188	4,441	16.8	4,928	4,903	0.5
TOTAL DEMAND	21,421	20,097	6.6	21,165	20,638	2.6
Supply, 1,000 b/d						
Crude production	5,127	4,214	21.7	5,101	5,278	–3.4
NGL production	2,379	1,475	61.2	2,209	1,768	24.9
Crude imports	10,829	9,078	19.3	10,244	10,066	1.8
Product imports	3,380	3,976	–15.0	3,483	3,295	5.7
Other supply[2]	1,147	1,166	–1.7	1,087	1,272	–14.6
TOTAL SUPPLY	22,861	19,910	14.8	22,123	21,679	2.0
Refining, 1,000 b/d						
Crude runs to stills	15,666	13,974	12.1	15,166	15,420	–1.6
Input to crude stills	16,153	14,371	12.4	15,581	15,697	–0.7
% utilization	93.2	83.9	—	90.6	91.7	—

Latest week 9/29	Latest week	Previous week*	Change	Same week year ago*	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	325,255	322,542	2,713	300,150	25,105	8.4
Motor gasoline	217,810	220,606	–2,796	197,970	19,840	10.0
Distillate	146,558	149,535	–2,977	128,017	18,541	14.5
Jet fuel	41,376	41,005	371	36,301	5,075	14.0
Residual	43,574	45,424	–1,850	32,960	10,614	32.2
Futures prices[3]						
Light sweet crude, $/bbl	62.41	61.07	1.34	66.05	–3.64	–5.5
Natural gas, $/MMbtu	4.84	4.86	–0.01	13.42	–8.58	–63.9

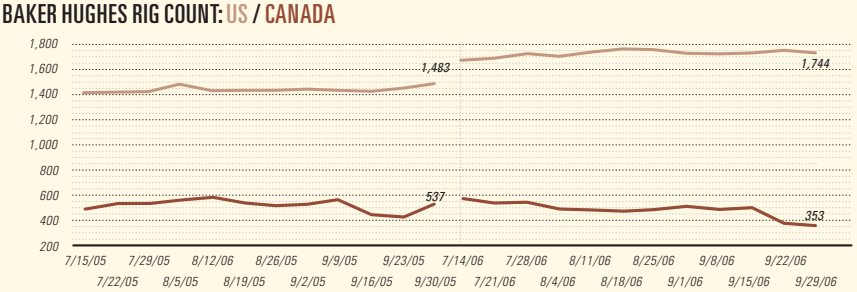
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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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North American natural gas, and chair of the Canadian Association of Petroleum Producers, implored the Canadian government to not "do anything stupid" regarding terms of investment in projects in the country.

Sendall said Canada's transparent and stable investment climate acted as a balance to the relatively high production costs in the region and that any adjustments to terms of investments should only be undertaken with the utmost caution, lest this balance be upset.

Sendall also said continued progress needs to be made to keep Canada's regulatory process untangled, making particular note of the manifold jurisdictions currently required to weigh in on any pipeline project before actual work can begin.

Even so, Sendall cited the combination of Canada's resource base, innovative technology, competitive global position, and environmental stewardship as key factors that will allow the country to succeed as it sets a course toward becoming an "energy superpower." She also said "pipeliners should be salivating" at the prospect of bringing Canada's hydrocarbon resources to market.

US House panel approves pipeline safety bill

The US House Energy and Commerce Committee passed a bill Sept. 27 reauthorizing federal oil and gas pipeline safety programs. It now has to be reconciled with a similar measure passed June 19 by the Transportation and Infrastructure Committee before there can be a final vote on the House floor.

Passage of the latest House pipeline bill by voice vote came hours before Senate Commerce, Science, and Transportation Committee leaders introduced their own pipeline safety bill.

Committee Chairman Ted Stevens (R-Ark.) and chief minority member Daniel K. Inouye (D-Hi.) sponsored the measure to reauthorize the federal Pipeline Safety Act for 4 years starting in 2007, with Trent Lott (R-Miss.) and Frank R. Lautenberg (D-NJ) as cosponsors. Other provisions include a 50% increase in the number of federal pipeline inspectors to 135 from 90 at a cost of $6 million over 4 years, application of Department of Transportation standards to all low-stress pipelines, and new civil enforcement authority against excavators and pipeline operators responsible for third-party damage. ✦

Exploration & Development — *Quick Takes*

Mariner makes Gulf of Mexico discovery

Mariner Energy Inc., Houston, said it has made a material discovery with its 5ST1 well on High Island Block 116 in the Gulf of Mexico.

The well, drilled to a TMD of 14,683 ft, encountered about 540 ft of net vertical pay in 13 sands. Completion operations are under way, and initial production is expected later in the fourth quarter.

Mariner estimates that the well's proved and probable gas reserves could be about 40-60 bcf. The company holds 100% working interest and a 72% net revenue interest in the well.

HI Block 116 is part of the asset base Mariner acquired from Forest Oil Corp. in March.

Total-led group tests Yemeni oil well

A group led by Total SA reported the KHA 1-16 oil well in Yemen's East Shabwa Development Area on Block 10 produced more than 8,400 b/d when tested through a $^{7}/_{64}$-in. choke, said participant Soco International PLC, London.

Test results extend Khairir oil field to the east beyond current 3D seismic survey data, Soco said. The well was drilled on the eastern-most 3D seismic parameter as part of a continuing appraisal and development of the field's basement reservoir.

KHA 1-16 spudded June 5 and reached a MD of 3,298 m. The group will evaluate the well results to decide the best way to access the extension, Soco said.

Block 10 participants are operator Total and Soco's Comeco Petroleum Inc., each with 28.57% under a production-sharing agreement with Yemen. Other joint venture partners are Occidental Yemen Ltd. 28.57% and Kuwait Foreign Petroleum Exploration Co. 14.29%.

Aramco lets two Khurais development contracts

Saudi Aramco has signed two contracts for the development of its 1.2 million b/d Khurais Increment Program. The Khurais crude contract went to Italy's Snamprogetti SPA and the Khurais gas contract was let to a consortium of Hyundai Engineering & Construction Co. Ltd. and Foster Wheeler Energy Ltd.

The Khurais program covers three oil fields: Khurais, Abu Jifan, and Mazlij. The Khurais gas facility will process sour associated gas produced from the three fields into an NGL product and a dry, single-phase sour shipping gas. The plant will process a total of 563 MMscfd of sour associated gas and 70,000 b/d of condensate.

The program is the largest crude increment undertaken in Aramco's history, the company said, and one of the largest industrial projects being executed in the world today. The program is slated for completion by mid-2009.

Snamprogetti's contract calls for construction of four identical crude processing and gas compression trains, along with the construction of inlet and outlet facilities to receive wet and sour crude through upstream trunklines.

The Hyundai-Foster Wheeler contract includes construction of two gas conditioning trains, crude and NGL storage facilities, product shipping facilities, and flares.

All related support facilities, such as roads, ponds, buildings, electrical systems, and process control systems, are also to be provided under these contracts.

Max Petroleum completes second Kazakh well

Max Petroleum PLC, London, has completed and begun production from the ZMA-2X well, the second of five wells planned on the Zhana Makat A structure on the E Block in the Pre-Caspian basin of Kazakhstan.

ZMA-2X, drilled downdip from the ZMA-1X discovery well to further delineate the field, encountered an oil column about 18 m thick, exceeding the company's initial expectations for the well.

As with the discovery well, the ZMA-2X production will be increased gradually to ensure minimal reservoir damage.

Max plans to announce the production volumes when the ini-

tial well testing is complete.

The operator also has begun drilling its ZMA-4X well, to be followed shortly by the ZMA-3X and ZMA-5X. These three additional wells are further updip on the Zhana Makat A structure, where the company believes the oil column thickness may exceed that seen in the flank areas drilled by the first two wells.

The discovery well is producing about 225 b/d of oil, an increase of 45 b/d from its initial rate in mid-September. Max is continuing to evaluate the well and optimize its production.

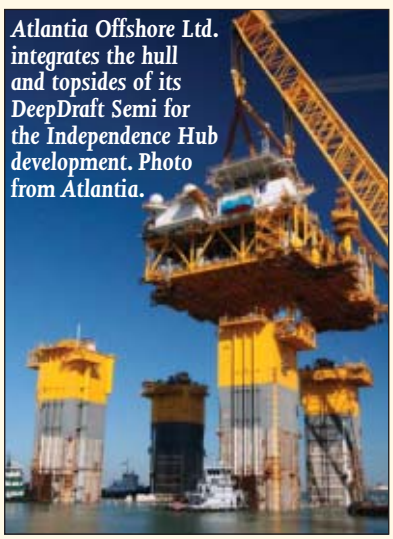
The initial drilling program on Zhana Makat A is scheduled for completion in mid-November, and Max will then have the structure's reserves independently certified before yearend.

Max said it intends to drill up to 30 shallow wells, 6 intermediates, and 3 deep wells by the end of 2007. ✦

Drilling & Production — *Quick Takes*

Hull, topsides completed for Independence Hub

Atlantia Offshore Ltd., Houston, has completed integration of the hull and topsides of its deep-draft semisubmersible for the Independence Hub platform on Mississippi Canyon Block 920 in the Gulf of Mexico.



Atlantia Offshore Ltd. integrates the hull and topsides of its DeepDraft Semi for the Independence Hub development. Photo from Atlantia.

The operation was completed Sept. 20 at the Kiewit Offshore Services facility in Ingleside, Tex. Kiewits's heavy lifting device was used to set the 8,400-ton deck onto the 10,000-ton hull.

Additional hookup and commissioning activities are expected to continue over the next several weeks.

The Hub will then be towed to another location to be moored in about 8,000 ft of water. Once installed, the Atlantia DeepDraft semisubmersible will connect to a 24-in. export gas line, and will have the capacity to connect to 16 infield flowlines and 12 umbilicals from an initial 10 ultradeepwater fields. Total designed throughput of the process facility will be 1 bcfd of gas.

Independence Hub is owned 80% by Enterprise Products Partners LP and 20% by Helix Energy Solutions Group Inc. Anadarko Petroleum Corp. will operate the hub on behalf of Atwater Valley Producers Group, which is comprised of Anadarko, Dominion Exploration & Production, Hydro Gulf of Mexico LLC, Devon Energy Corp., and Energy Resources Technology.

Stone resumes Amberjack platform production

Stone Energy Corp., Lafayette, La., has resumed production from its Amberjack platform on Mississippi Canyon Block 109 in the Gulf of Mexico. The platform had been shut down due to damages caused by Hurricane Katrina in 2005.

Stone repaired and rerouted a severed oil pipeline and expects production of 50-60 MMcfd of net gas equivalent during the fourth quarter. This brings Stone's overall fourth-quarter production to 250 MMcfd of gas equivalent.

Stone said limited oil production from the Amberjack platform was initially restored in early September via barging.

Stone is the operator on MC Block 109 and holds a 100% interest since this summer (OGJ, July 17, 2006, p. 30). It also owns a 24.8% interest in Block 108.

Mariner resumes Gulf of Mexico production

Mariner Energy Inc., Houston, has restarted production at Ochre and Pluto gas fields in the deepwater Gulf of Mexico.

Ochre field, on Mississippi Canyon Block 66, has resumed production of 10.5 MMcfd of gas equivalent (gross). The field was shut-in due to damages caused by Hurricane Ivan in 2004.

On MC Block 718, Mariner has brought Pluto production on stream. The field is expected to flow at 40-50 MMcfd of gas equivalent (gross). The field was originally shut-in for the drilling and completion of a new well, but start-up was delayed due to Hurricane Katrina last year.

Mariner holds a majority interest in and is operator of these two fields.

The company estimates that most of its remaining 2005 hurricane-related production shutins will restart in the fourth quarter. ✦

Processing — *Quick Takes*

Huntsman lets contract for Port Arthur repairs

Huntsman Corp., Salt Lake City, let a $60 million engineering, procurement, and construction contract to Shaw Group Inc., Baton Rouge, La., for repairs to Huntsman's olefins manufacturing plant in Port Arthur, Tex. The facility, damaged by fire in April, has production capacity of 1.4 billion lb/year of ethylene and 800 million lb/year of propylene.

The total cost of the cleanup, engineering, and rebuild is estimated at $110 million. The project is slated for completion in second quarter 2007.

Huntsman said it also will accelerate some maintenance work at the facility that was scheduled for a 2010 turnaround and inspection. Performing the work now will make the plant run more efficiently, the company said.

The maintenance work will not extend the time required to repair and restart the facility.

Coker contract awarded for Tatarstan refinery

CJSC Nizhnekamsk Refinery has let a contract to Foster Wheeler Ltd. subsidiary Foster Wheeler USA Corp. to design a process package involving its proprietary delayed coking technology.

The coker will be part of an integrated refining and petrochemical grassroots complex to be constructed at Nizhnekamsk in Tatarstan, Russia.

The contract's terms were not disclosed. Foster Wheeler also has the front-end engineering design contract for the integrated complex (OGJ, Sept. 25, 2006, Newsletter).

In the coking contract, Foster Wheeler will provide its thermal conversion process to upgrade heavy residue feed and process it into transport fuels.

Sabic, ExxonMobil settle technology dispute

Saudi Basic Industries Corp. (Sabic) said it has reached a full and final settlement of its disputes with ExxonMobil Corp. concerning technology and a patent that can be used in the production of polyethylene.

Under terms of the settlement, Sabic and its affiliates will have the right to use the technology without royalties and will equally share in any third-party royalties from the past or future licensing of the technology by ExxonMobil.

The companies will continue to collaborate on their other ventures in Saudi Arabia.

Hydrocracker due Cartagena refinery

Repsol YPF SA has selected IFP NA subsidiary Axens NA's technologies for the planned expansion of its 100,000 b/cd Cartagena refinery in Murcia, Spain.

The new refining train will include a 50,000 b/d hydrocracker that will convert a blend of heavy vacuum and heavy coker gas-oils into high-quality, ultralow-sulfur middle distillates for the European market.

Axens is committed also to provide a C_5-C_6 alkane isomerization unit to boost gasoline pool octane, two hydrodesulfurization units to produce ultralow-sulfur diesel from straight run and light coker gas-oil, and a coker naphtha HDS unit.

The new facilities are scheduled to start up in fourth quarter 2010. ✦

Transportation — *Quick Takes*

Gas deliveries to UK begin through new pipeline

Gassco AS on Oct. 1 began gas deliveries from Statoil ASA-operated Sleipner and Troll fields in the Norwegian North Sea to Easington in the UK after opening flow through the 600 km southern leg of the new Langeled pipeline.

This marks the completion of the first stage of the 1,200-km submarine gas pipeline, the cost of which currently is estimated at 17 billion kroner—about 3 billion kroner below budget.

"We will complete all pipelaying on the northern leg this week, which means we'll manage to finish ahead of the winter season," said Leif Solberg, Langeled project director.

"The project has progressed on schedule," he added. "What remains now is subsea connections and testing on the northern leg until next summer."

The northern leg, due to start up in 2007, lies in 360 m water as far as Sleipner East field (OGJ Online, Sept. 18, 2006, Newsletter). It is designed for an internal pressure of 250 bar, corresponding to water 2,500 m deep, a record for Norway's gas transport system.

The Langeled system will have a total capacity of 20 billion cu m/year, one fifth of Britain's annual gas requirements. This supplements the 12 billion cu m/year Vesterled system, which transports gas from the BC Hydro-operated Heimdal platform to St. Fergus in Scotland.

Wesfarmers plans Western Australia LNG terminal

Perth industrial conglomerate Wesfarmers Ltd. plans to build a $138 million (Aus.), 175-tonne/day LNG terminal and regasification plant in Kwinana, south of Perth in Western Australia. The plant will supply natural gas for heavy-duty trucks as well as domestic industrial and electric power generation markets.

The company says that several years of trials involving 70 trucks traveling more than 12 million km around Australia, has shown that LNG is a viable alternative to diesel fuel.

Construction of the Wesfarmers plant is scheduled to begin in November and come on stream in early 2008.

During the first 10 years of plant operation, Santos Ltd. will supply up to 37 petajoules of gas feedstock from its 45% share of production in the John Brookes gas field operated by Apache Energy Australia in the offshore Carnarvon basin. Gas deliveries will be via the Dampier-Bunbury gas trunkline.

ABS issues design approval for CNG carriers

The American Bureau of Shipping has issued full-class design approval for CNG carriers to Sea NG Corp., Calgary. The approval is the first granted to CNG carriers, ABS said.

Sea NG's proprietary Coselle system uses small-diameter high-strength steel pipe coiled into a carousel to store the high-pressure gas. Each Coselle will comprise about 10 miles of 6-in. pipe used for storing and transporting CNG.

Sea NG is expected to let contracts for construction of three Coselle CNG carriers later this year. These first vessels, which will carry the notation "A1 CNG Carrier," will be designed to transport gas 200-2,000 miles. They are intended to service projects in the Caribbean or Mediterranean seas.

The vessels will be 120 m long and have the capacity to carry 50 MMscf of gas in 16 Coselles (160 miles of pipe). The 16 Coselles are arranged in four stacks of four high in a fully enclosed and inerted cargo house on the weather deck. The vessels will feature a dual fuel propulsion system with bow thruster and also a proprietary high- and low-pressure manifold system for efficient loading and unloading.

ABS Project Manager Harish Patel said, "This vessel design review and approval was undertaken using a risk-based design approach."

This included a series of risk assessment studies, including HAZID, HAZOP, gas dispersion, and explosion models, fire, flaring and heat radiation analysis, a jetting study, escape and evacuation studies, and inspectability analysis. ✦

Calendar

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

OIL&GAS JOURNAL online research center

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

OCTOBER

Europe Multiphase Pump User Roundtable, Amsterdam, (979) 458-2054, (979) 458-1844 (fax), e-mail: becky@pe.tamu.edu, website: http://mpur.org/europe. 9.

ERTC Petrochemical Conference, Dusseldorf, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 9-11.

API Fall Petroleum Measurement Standards Meeting, Denver, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-12.

GPA Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

International Bottom of the Barrel Technology Conference & Exhibition, Athens, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: conferences@europetro.com, website: www.EuroPetro.com. 11-12.

Pipeline Simulation Interest Group Annual Meeting, Williamsburg, Va., (713) 420-5938, (713) 420-5957 (fax), e-mail: info@psig.org, website: www.psig.org. 11-13.

PIRA Annual Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 12-13.

IOGCC Annual Meeting, Austin, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 15-17.

EAGE/EAGO/SEG International Conference & Exhibition, Saint Petersburg, Russia, +31 30 6354066, +31 30 6343534 (fax), e-mail: stpetersburg2006@eage.org, website: www.eage.org. 15-18.

SPE/IADC India Conference, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-18.

Oil Shale Symposium, Golden, Colo., (303) 384-2235, e-mail: jboak@mines.edu, website: www.mines.edu/outreach/cont_ed/oilshale. 16-20.

Annual European Autumn Gas Conference, Cannes, +44 1737 855 108, +44 1737 855 482 (fax), website: www.theeagc.com. 17-18.

Saskatchewan and Northern Plains Oil & Gas Symposium, Regina, (306) 787-2573, (306) 787-4608 (fax), e-mail: cgilboy@ir.gov.sk.ca, website: www.sgshome.ca. 17-18.

Energy Summit in Africa, Cape Town, 33 1 55 07 26 09, 33 1 55 07 26 55 (fax), e-mail: josee.foucault@enspmfi.com. 17-19.

ISA Expo, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 17-19.

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 17-19.

Annual International Petroleum Environmental Conference, San Antonio, (918) 631-3088, e-mail: cese@utulsa.edu, website: www.cese.utulsa.edu. 17-20.

World LP Gas Forum & Global Technology Conference, Chicago, (202) 452-8975, (202) 452-9054 (fax), e-mail: willis@propanecouncil.org, website: www.wlpgasforum2006.com. 17-20.

Annual Border Energy Forum, Tampico, Tamaulipas, (512) 463-5039, e-mail: Soll.Sussman@GLO.STATE.TX.US, website: www.glo.state.tx.us/energy.border. 19-20.

GTI's Natural Gas Technologies Conference, Orlando, (847) 768-0940, (847) 768-0858 (fax), e-mail: NGT2006@gastechnology.org, website: www.gastechnology.org. 22-25.

IPAA Annual Meeting, Grapevine, Tex., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 23-25.

Power-Gen India & Central Asia Conference, New Delhi, (918) 831-9160, (918) 831 9161 (fax), e-mail: registration@pennwell.com, website: www.pgen.events.pennnet.com. 24-26.

DryTree & Riser Forum, College Station, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.drytreeforum.com. 24-26.

West China International Oil & Gas Conference & Exhibition, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-27.

Annual Condensate & Naphtha Forum, Phuket, +65 6222 0230, +65 6222 0121, e-mail: condensate@cconnection.org, website: www.cconnection.org. 30-31.

Chad International Oil & Gas Conference, N'Djamena, +44 207 596 5148, +44 207 596 5071 (fax), e-mail: colins.tchanga@ite-exhibitions.com, website: www.african-events.com. 30-31.

API Fall Refining and Equipment Standards Meeting, San Francisco, (202) 682-8000, (202) 682-8222 (fax), e-mail: petroteam@api.org, website: www.api.org. Oct. 30-Nov. 1.

Carbon Capture and Storage in the UK Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 31.

NOVEMBER

AAPG International Conference and Exhibition, San Juan, (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 4-7.

AAPG International Conference & Exhibition, Perth, (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 5-8.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, +971 2 4446900, +971 2 4446135 (fax), e-mail: adipec@adnec.ae, website: www.adipec.com. 5-8

Purvin & Gertz Latin America LPG Seminar, Panama City, (713) 236-0318, (713) 331-4000 (fax), website: www.purvingertz.com/seminars. 6-9.

Oil Depletion Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 7.

IADC International Well Control Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 7-8.

✦Annual Petroleum Exhibition & Conference of Mexico, Villahermosa, (713) 529-1616, (713) 821-1169 (fax), e-mail: sales@ieimail.com, website: www.oilonline.com/mexico. 7-9.

✦International Marine Gas CNG Standards Forum, St. John's, Newf., (709) 754-9880, (709) 754-9881 (fax), e-mail: info@cmcng.com, website: www.cmcng.com. 7-9.

Calendar

International Petroleum & Petrochemical Exhibition, Beijing, (301) 493-5500, (301) 493-5705 (fax), e-mail: stout@ejkrause.com, website: www.ejkcn.com/ippe06/ippe06.htm. 7-10.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 8.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 9.

AIChE Annual Meeting, San Francisco, (212) 591-7338, (212) 591-8894 (fax), e-mail: meetmail@aiche.org, website: www.aiche.org. 12-17.

ERTC Annual Meeting, Paris, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

IADC/SPE Asia Pacific Drilling Technology Conference, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 13-15

Gulf Coast Well Control Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: kharli@pe.tamu.edu, website: http://WellCTRL.org. 15-16.

Annual Unconventional Gas Conference, Calgary, Alta., (403) 218-7721, (403) 920-0054, e-mail: info@csug.ca, website: www.csug.ca. 15-17.

European Biofuels Forum, Warsaw, 0044 20 7067 1800, 0044 20 7430 9513 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.wraconferences.com/wra112overview.html. 21-22.

PETEX Conference & Exhibition, Olympia, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: petex@pesgb.org.uk, website: www.pesgb.org.uk. 21-23.

International Symposium on Protective Coatings, Bombay, 022-25767891, 022-25723480 (fax), e-mail: khanna@iitb.ac.in. 24-26.

Petrochem Arabia Conference, Dubai, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 26-27.

IADC Drilling Gulf of Mexico Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

Power-Gen International Conference, Orlando, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pgen.events.pennnet.com. 28-30.

Ethanol Summit, Houston, (207) 781-9617, (207) 781-2150 (fax), e-mail: cgroff@intertechusa.com, website: www.intertechusa.com. Nov. 30-Dec. 1.

DECEMBER

Independent Operators Forum, London, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.operators-forum.com. 4-6.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 4-6.

GASTECH International Conference & Exhibition, Abu Dhabi, +44 (0)1895 454 592, +44 (0)1895 454 584 (fax), e-mail: info@gastech.co.uk, website: www.gastech.co.uk. 4-7.

✦Renewable Energy in the New Low Carbon Britain Conference, London, +44 (0) 20 7467 7100, +44 (0) 20 7255 1472, e-mail: info@energyinst.org.uk, website: www.energyinst.org.uk. 5.

OSEA International Exhibition & Conference, Singapore, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 5-8.

Annual CO_2 Flooding Conference, Midland, Tex., (432) 552-2430, (432) 552-2433 (fax), website: www.spe-pb.org. 6-8.

Annual China Gas Conference, Beijing, 65 6536 8676, 65 6536 4356 (fax), e-mail: marcy.chong@abf.com.sg, website: www.abf-asia.com. 11-12.

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JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

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

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8223 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 23-25.

✦SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multi-phasepumping.com. 10-13.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 12-13.

Traveling for good

Sam Fletcher
Senior Writer

Airlines recently have suffered financial losses because of high fuel costs, low fares, and other problems, but terrorism and a flagging economy apparently haven't yet reduced the number of passengers.

"In fact, it was a strong summer [for travel], as predicted," said Amy Ziff for Travelocity, one of the largest online US travel agencies and part of Sabre Holdings Corp., Southlake, Tex. "However, industry reports are starting to indicate a fall in travel levels. Some drop is normal for the fall, so it remains to be seen if this will truly occur."

To combine travel with public service, Travelocity launched its "Travel for Good" program with "three easy ways" to help the environment and other people while jetting about the globe.

Offset emissions

Travelers booking trips online can donate funds through the "Go Zero" program, in partnership with The Conservation Fund, Arlington, Va., to plant trees to offset carbon emissions from fossil fuels. The Conservation Fund has a web site calculator that can formulate donations based on home energy use, automobiles, and air travel. A family generating 39.77 tons/year of CO_2 emissions can plant 30 trees in a "Carbon Zero" forest at a cost of $159.08, plus a $5 administration fee. "Over the next 70 years, these trees will sequester approximately 39.77 tons of carbon dioxide—one of the most potent greenhouse gases," said fund officials. Since transportation is the biggest US source of CO_2 emissions, they suggest ways to reduce fuel use. Not surprisingly, a backyard vacation is not one of the suggestions.

Travelocity also encouraged travelers to participate in the annual Public Lands Day Sept. 30, with volunteers building trails and bridges, planting trees and plants, and removing trash and invasive plants at designated sites across the US.

A "growing travel trend," Travelocity said, is "to spend an entire trip or just a few hours" doing volunteer work among local inhabitants in some foreign country. It has teamed with Cross-Cultural Solutions, Earthwatch, and Globe Aware in such "voluntour" programs.

Cross-Cultural Solutions operates as a nongovernment "short-term alternative to the Peace Corps" in Brazil, China, Costa Rica, Ghana, Guatemala, India, Peru, Russia, Tanzania, and Thailand. It claims 10,000 participants since 1995 and offers three programs: Volunteer Abroad, the most popular, starts at $2,489/individual for 2 weeks; Intern Abroad for students seeking academic credit, work experience, or field research, $2,789 for 2 weeks; and Insight Abroad, a 1-week program "for people with limited vacation time" at $1,595. Those fees are tax-deductible for US residents, and Cross-Cultural Solutions can suggest fund-raising techniques to help finance trips.

No special skills are required, and, unlike the Peace Corps, no training is provided. It's not necessary to speak the local language, although English is required to follow staff instructions. Minimum age is 18 for volunteers unaccompanied by an adult, but younger volunteers are welcome if they demonstrate "understanding and maturity." The program welcomes volunteers "with special needs or disabilities," including "physically challenged, deaf, visually impaired, and mentally challenged." Diet restrictions "can be accommodated." Lodging is in "a comfortable house in a safe, conveniently located neighborhood." Medical, dental, and emergency insurance is included in the fee, and volunteers have free time for vacation fun "some afternoons, most evenings, and every weekend."

The work

The work may include infant and child care, teaching educational games, arts, crafts, and sports. "Simply holding infants, sharing your affection, and providing individual attention is important to their future well-being," said program officials. True, but one wonders how much more effective it might be if the caretaker could speak the child's language. Volunteers may "shadow" health practitioners, "exchanging ideas and experiences," officials said. Other programs include teaching English, as well as "science, music, sports, and drama," an ambitious agenda for just 1-2 weeks.

These are all good programs, but one needn't fly around the globe to be a volunteer. There are plenty of orphanages, hospitals, clinics, schools, and retirement homes seeking volunteer helpers in our own hometowns. Of course, there's no way to estimate the value of personal connections among the people of different nations. But a cynical news reporter has to wonder if it might be more effective if "voluntourists" donated the price of airfares and fees to hire local workers who already know the languages and customs of those exotic locales and who will be on the job for more than 2 weeks. ✦

Editorial

The ethanol craze

Private businesses shut down mistakes that can't be fixed. Governments make hopeless programs bigger and claim success.

With tax incentives and a market mandate, the US government has stirred up a national craze over fuel ethanol. Politicians from both major parties, including President George W. Bush, have oversold ethanol as a way to reduce US dependence on foreign oil and improve air quality. In truth, the purpose is political: to stimulate agricultural businesses and farm-state economies. There'd be nothing horrible about that if the help came at no one else's expense. But the ethanol program costs fuel consumers and taxpayers plenty.

The craze, however, has begun. Automakers enticed by tax breaks have co-opted the ethanol lobby's environmental exaggerations to tout flexible-fuel vehicles. Politicians claim to have done something for energy independence. And ethanol plants, some of them helped by tax breaks, are proliferating.

Overshooting standards

In fact, total US capacity to produce grain ethanol probably will overshoot the generous renewable fuel standards Congress set when it passed the Energy Policy Act of 2005. The law increases the ethanol mandate to 7.5 billion gal/year by 2012. According to Senate committee testimony last month by Keith Collins, chief economist of the Department of Agriculture, if many of the ethanol plants now planned come into being, capacity might reach 8.5 billion gal/year by 2008-09 and exceed 10 billion gal/year by 2010.

The tendency of manufacturing capacity to overshoot demand typifies any profitable industry with low barriers to entry. Lately, the production of ethanol has been very profitable. And tax breaks for blenders and small producers of ethanol encourage plant construction. With a government-sponsored boom under way, ethanol production capacity could be 33% overbuilt relative to the 2012 mandate within 3 years.

What then? According to Collins, if crude prices remain above $50/bbl, keeping gasoline and therefore ethanol prices high, and if corn prices don't rise "considerably," ethanol will stay competitive with gasoline and allow consumption to exceed the minimum levels set by Congress. But the wrong combination of oil and corn prices could make a lot of ethanol capacity surplus to demand. If that happens, ethanol prices will slump. At last report, of course, oil prices were falling. In his statement, Collins said corn prices could set record highs during the next 5-6 years.

When market-wrecking surpluses hit private business, manufacturers respond by idling capacity. They permanently close plants that show no hope of regaining profitability. Eventually, demand restored by low prices combines with supply lowered by capacity withdrawals to bring prices back to profitable levels. The process is painful. But it's business.

This won't happen with ethanol, which is not a real business. The fuel ethanol industry is a creature of government. Investors in ethanol plants threatened by adverse corn and ethanol price movements will naturally resort to government for protection against the types of market risks real businesses must manage on their own. And the government will respond.

Lawmakers in both houses of Congress already have proposed bills that would, in various ways, require more ethanol. There will be no overbuilding of ethanol capacity relative to the mandate, which Congress will just keep raising to prolong the building craze. Politicians take care of the industries they create. In response to potential problems with ethanol profitability, they'll simply make the industry bigger. And they'll claim success—reduced oil imports, environmental improvements, and all the other hokum that led to this mistake.

Program will expand

Ethanol won't deliver on the hype. Its manufacture and distribution, coupled with the increased fertilization required to boost crop yields to meet growing needs for grain, will require as much energy—most of it from fossil sources—as ethanol supplies. And rising use of gasoline-ethanol blends will, in many areas, aggravate ozone smog.

The program, however, will expand. Congress has made a political investment. There's no turning back. The ethanol mandate will grow. And the oil and gas industry should not let anyone forget that the expansion will occur to prop up the price of an already costly component of vehicle fuel. ✦

China seeks oil security with new tanker fleet

Gabe Collins
US Naval War College
Newport, RI

To guarantee its oil supply during times of crisis, China is building a national tanker fleet with which it aims to haul nearly three fourths of its oil imports within the next 15 years.[1] China's tanker-building program appears to be driven by a complex mix of commercial and national security factors as it seeks control over its entire oil supply chain.

The impact of this fleet-building program on world tanker rates and shipbuilding costs merits the attention of tanker operators worldwide. Paradoxically, however, the buildup of a state-controlled, Chinese-flagged tanker fleet may actually increase that country's vulnerability to energy supply interdiction.

"...once oil imports exceed [1.5 million b/d], it becomes necessary to use economic, diplomatic, and military means to secure the safety of one's oil supply."

US, Chinese oil demand

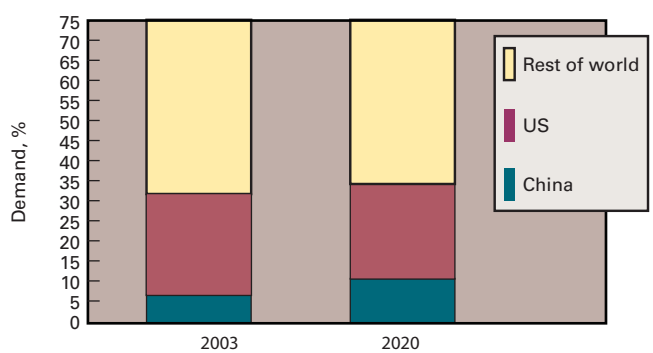
Maritime oil transport will be increasingly important for both the US and China in coming decades. As oil demand grows in each country, most of the increase in supply will be met via seaborne imports. As Fig. 1 shows, China's percentage of world oil consumption is set to more than double in the next 15 years, and combined US and Chinese oil requirements will represent 35% of total global demand by 2020.

The two countries have very different oil security strategies. The US and most Organization for Economic Cooperation and Development nations emphasize the role of the private sector, whereas China favors a state-led energy policy. Fig. 2 illustrates this divergence, which is a key driver of China's effort to create a large national tanker fleet.

On the whole, Chinese state oil carriers appear to be following the path of its state oil and gas companies. In peacetime, they will operate for profit. Yet, in an oil crisis, state-owned vessels would stand ready to be pressed into service.

SINO-US SHARE OF TOTAL GLOBAL OIL DEMAND

Fig. 1



Beijing's tanker fleet

By 2010, China intends to transport 40-50% of its oil imports in government-owned tankers. By 2020, it hopes to carry 60-70%.[2] Chinese analysts predict that by 2010 the country will need as many as 40 very large crude carriers (VLCCs) and a fleet capable of transporting more than 700 million bbl/year.

China currently owns 21 VLCCs that cumulatively account for about 30% of its tanker tonnage. Most of the remaining vessels are small or old tankers better suited for the coastal trade than for international oil carriage. Meng Qinglin, a senior manager at Dalian Ocean Shipping Co., estimates that Chinese tankers are on average 30% older than their international counterparts and much smaller, averaging only 20,000 dwt (compared with a typical 300,000 dwt VLCC).[3] Fig. 3 shows China's current oil carriers and their VLCC fleets.

As it upgrades its fleet, China's aggressive tanker-building campaign has made it one of the world's leading tanker builders. It also builds smaller tankers, but this article focuses primarily on VLCCs because most Chinese oil imports come from distant areas that require VLCC transport to remain economically competitive. As shown in Fig. 4, Chinese shipyards' share of new global tanker contracts has grown at an average annual rate of roughly 30% over the past 6 years.

Two primary national security factors drive Beijing's tanker fleet construction: insufficient overland oil supplies and the fear that terrorists, pirates, or the US Navy could bottleneck its sea lanes.

Editor's note: The views set forth in this article are the author's own and in no way reflect the official views and policies of the US Navy or any other US government entity.

Overland supplies

Oceanic oil transportation has become one of Beijing's chief strategic concerns. Despite a highly touted new pipeline from Kazakhstan and planned lines from Russia, China for the foreseeable future will receive most of its oil by sea. Indeed, many Russian observers believe that without immediately launching a full-scale exploration and production program in Eastern Siberia, Russia likely will be unable to fulfill its oil and gas commitments to China.[4]

Moreover, although private Russian companies such as TNK-BP are ready to supply China, assertive Russian state-controlled companies hold projects up until they can gain complete control. Russia also fears a repeat of its experience with the Blue Stream gas pipeline, which ran under the Black Sea to Turkey in 2003. Once gas began flowing, Turkey promptly refused to take further deliveries until Gazprom slashed its price, causing the Russian side serious financial losses.

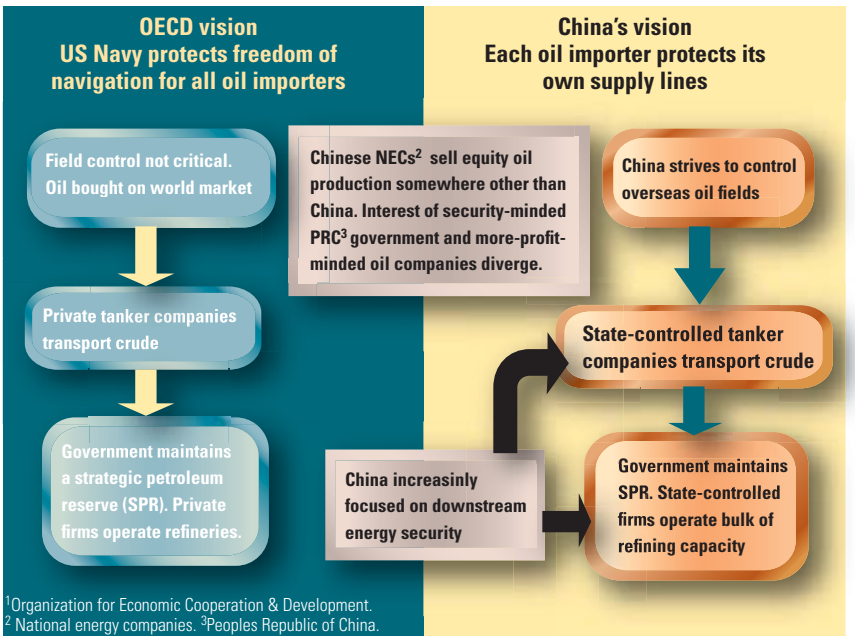
Thus, while overland oil imports from Russia and Kazakhstan likely will continue to grow, they will not solve China's dependence on seaborne oil. Fig. 5 offers an estimate of trends in China's pipeline imports that assumes Russia will be able to build and fill a pipeline from Eastern Siberia by 2008.

Chinese leaders find it unsettling that only 10-12% of the country's imports are carried by Chinese flagged vessels, compared with Japan, which can haul 80% of its oil, and South Korea, which carries 30% of its crude imports.[5] Japanese oil transport companies are among the world's largest, while South Korean and Japanese shipyards have for the last few decades been the world's premier tanker builders.

Chinese officials are especially concerned that Chinese tankers haul almost none of the cargoes that come from the Middle East and West Africa, which between them supply roughly 70% of Chinese imports.[6] In 2002, Chinese tankers carried less than 4% of China-bound cargoes from the Middle East and none at all from West Africa. Some analysts believe that Chinese-operated tankers can better secure oil shipments from unstable areas such as Africa and the Middle East.

OIL SECURITY VISIONS: OECD[1] VS. CHINA

Fig. 2



[1]Organization for Economic Cooperation & Development. [2] National energy companies. [3]Peoples Republic of China.

LICENSED CHINESE OIL SHIPPERS

Fig. 3

State-owned[1]	Private
• Cosco (Dalian) Shipyard Co. Ltd. (3 VLCCs[2])	• Dalian Haichang Group (1 VLCC, 3 on order)
• China Shipping (Group) Co. (2 VLCCs)	• China Merchants Group (7 VLCCs)
• China Changjiang National Shipping Group (1 VLCC, 10 on order[3])	
• Sinotrans Ltd. (4 ULCCs)	
• Hebei Ocean Shipping Co. (3 VLCCs)	

[1]State-owned shippers control almost two thirds of Chinese VLCCs, and this share is expected to grow by 2010.
[2]Very large crude carriers. [3]Most VLCCs on order are due to be delivered by 2010.

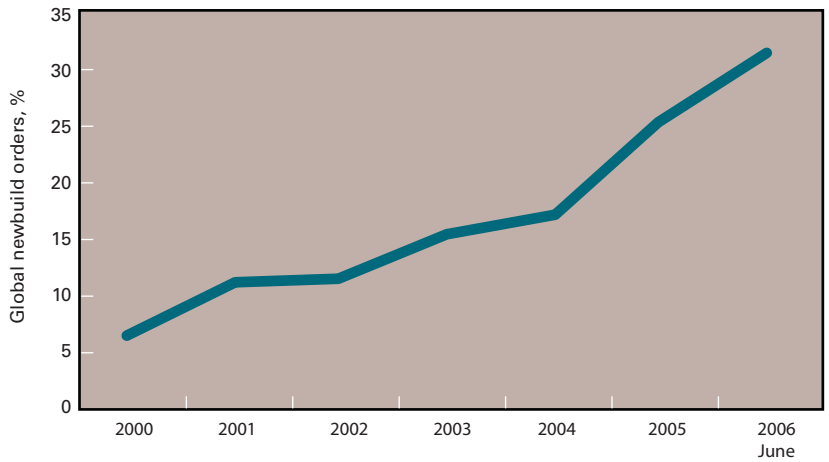
Choke-point worries

China worries about its present inability to militarily protect the sea lines of communication (SLOCs) and choke points through which much of its oil imports flow, especially the Hormuz and Malacca straits (Table 1).[7] Chinese energy security experts have dubbed this the "Malacca Dilemma."[8] They fear that terrorists or pirates could easily cork these bottlenecks, as could the US Navy in the event of conflict over Taiwan or some other serious Sino-American crisis.[9]

Chinese officials believe that whoever controls the Malacca Strait between Malaysia and Singapore also controls China's oil and economic security (see map, OGJ, Oct. 18, 1999, p. 23). They

CHINESE SHIPYARDS' PROPORTION OF GLOBAL TANKER ORDERS

Fig. 4



Source: International Association of Independent Tanker Owners (Intertanko)

GLOBAL CRUDE OIL SHIPMENT CHOKE POINTS

Table 1

Potential choke point	Volume shipped, million b/d
Bab al-Mandab	3.3
Bosporus	2.0
Hormuz Straits	17.0
Malacca Straits	*11.7
Panama (pipeline + canal)	0.6
Suez (pipeline + canal)	3.8
Total choke-point volumes	**38.4**
Percentage of total seaborne oil flow	75%

*At least 2.2 million b/d to China, or two thirds of Chinese oil imports.
Source: Energy Information Administration

concede that in the event of a security disturbance, such as a conflict over Taiwan, China's inability to secure the strait could be "disastrous" for its security.[10]

Moreover, the US Navy is not the only threat to China's maritime energy supply lines. Chinese planners worry that the rapidly modernizing Indian navy could use its naval superiority vis-à-vis China in the Indian Ocean to gain strategic leverage.[11] Beijing also casts a suspicious eye on the Japanese Maritime Self Defense Force (JMSDF) because Japan competes with China for energy resources in Russia and the East China Sea and because the JMSDF cooperates with both the US and Indian navies. Japan is interested in the Indian Ocean because most of its oil imports must also transit the Malacca Strait. Japan and Korea both appear comfortable relying on the US Navy to secure their sea lanes, however.

The "Malacca Dilemma," on the other hand, reportedly is receiving significant high-level attention in Beijing. President Hu Jintao himself advocates revising China's oil import strategy because "some big countries attempted to control the transportation channel at Malacca." This strategy could mean a pipeline through Myanmar to China's Yunnan Province or a "Malacca bypass" pipeline across southern Thailand's Kra Isthmus.[12]

Chinese analysts also advocate strengthening the People's Liberation Army (PLA) Navy so that it is capable of "long range rapid responses and interventions in trouble spots" such as Malacca.[9] Indeed, Wu Lei, a prominent Chinese energy expert, said, "The fear that the US might cut [energy shipments] off as a result of the deterioration of Sino-US relations over the Taiwan issue drives much of Beijing's modernization of its navy and air forces."[13]

CHINESE FOREIGN TANKER CONSTRUCTION DEALS*

Table 2

Company	Customer	No. of tankers	Deal value, million $
China State Shipbuilding Corp. (CSSC) and China Shipbuilding Industry Corp. (CSIC)	PDVSA (Venezuela)	18	1,300
CSIC (Bohai Shipbuilding Heavy Industry)	BW Group (Norway)	2 VLCCs	240 (est.)
CSSC	Frontline (Norway)	4 VLCCs	440
Cosco (Dalian) Shipyard Co. Ltd.	Frontline	2 VLCCs	220 (est.)
Cosco, Kawasaki Heavy Industries	Sonatrach (Algeria)	1 VLCC	120

*Selected deals. Total value of non-Chinese deals = $2.4 billion.

Commercial motivations

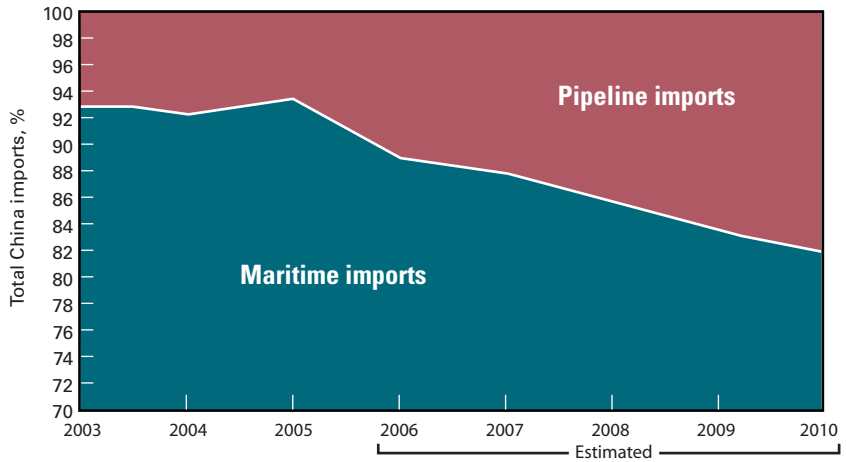
Beijing has powerful economic incentives to bolster its shipbuilding sector as well. A large-scale shipbuilding program aids domestic shipyards and the steel industry. It also boosts China's metallurgical and machine tool sectors. Some Chinese analysts estimate that every 10,000 dwt of tanker capacity built in a Chinese shipyard will create 100,000-200,000 man-hr worth of employment.[6] This means that building a single 300,000 dwt VLCC could create up to 6 million man-hr of work. On this basis alone, China's leadership has a strong argument for supporting its shipbuilders.

A clear indicator that China's tanker fleet expansion is at least partially driven by commercial interests and concerns is that a significant number of VLCCs are being built in China for foreign operators. These countries thus far include Norway, Iran, Germany, Japan, Venezuela, and Algeria (Table 2). The fact that foreign operators are hurrying to buy Chinese-made tankers also appears to be a vote of confidence in China's shipbuilding abilities.

Yet, while Chinese shipyards are poised to churn out large numbers of VLCCs and smaller tankers, many Chinese worry that an overly aggressive tanker-building program could raise shipbuilding costs and depress tanker rates. Although China's oil shippers are state-owned, they appear to operate much like the Chinese national energy producers, many of whom show a strong inclination to empha-

CHINA'S OVERLAND VS. MARITIME IMPORTS

Fig. 5



Sources: People's Daily Energy Intelligence, Asia Pulse, Prime-Tass

size profits over political interests.

Accordingly, a number of analysts propose buying or renting existing tankers in order to save money and reduce the possibility of creating overcapacity in the maritime oil transport market.[14] Assuming that China hopes to profit from tanker operations, second-hand ships are indeed a better bet than newbuilds. For example, a second-hand 280,000 dwt VLCC operating on the Saudi Arabia-China route pays out in 9.8 years at World Scale 65 charter rates, while a newbuild tanker would require 14 years to pay out.[15] The second-hand ship option seems to be gaining strength, as state-owned Sinotrans Ltd. and other Chinese tanker operators are said to be actively scouring the VLCC market for second-hand ships.[16]

Fleet structures

As shown in Fig. 3, seven Chinese companies now possess government-issued crude oil shipping licenses.[5] All but two of these license holders are state-controlled.[17] The tanker companies may be likened to China's state oil producers because they compete among themselves yet are collectively expected to act in the Chinese national interest.

Like the state oil companies, it is unlikely that the shippers will be entirely driven by a comprehensive state policy that orchestrates their every move. Some Chinese analysts even suggest that a lack of coordination among the state energy producers and the state energy shippers is partially to blame for the low proportion of crude imports carried on Chinese ships.[6] In response, they suggest some potential structures for a national tanker fleet, which are shown in Table 3.

The Chinese government will probably have to give economic incentives such as low-interest loans to Chinese tanker owners to entice them to work more closely with China's national energy companies. At present, an estimated 90% of China's oil shipping capacity, or more than 10.8 million dwt, is being used to serve foreign clients.[18] This number is significant in absolute terms but would not help China's long-distance oil transport situation because few of these ships are the VLCCs needed to bring crude from the Middle East, Africa, and other distant locales.

Political obstacles hinder efforts to build a Chinese tanker pool. Bringing Hong Kong shippers into any mainland consortium would help China expand its crude shipping capacity. Yet China's three main oil producers have so far refused to sign deals with Hong Kong ship owners, claiming that their fleets are "too small."[19] In reality, of Hong Kong's 72 registered tankers, at least 7 can carry a million bbl or more of crude oil.[20] Such ships could economically make long-distance crude hauls that are beyond the reach of the small coastal and shuttle tankers that comprise the bulk of mainland China's tanker fleet.

How much security?

It appears that, without a substantial blue-water naval capability (likely decades away), China may be painting a bull's-eye on itself by constructing a state-controlled Chinese-flagged tanker fleet.

China is strengthening its oil transportation capacity to ensure "smooth and uninterrupted" oil deliveries in times of crisis. Yet national tanker fleets do not protect oil importers from the internal security risks endemic to many oil exporting countries. Such instability generally does not affect oil shipments once they get offshore. Rather, many Chinese analysts fear that in a showdown over Taiwan or other crisis, the US Navy and its allies might blockade energy shipments to China.[21] However, blockading oil shipments to China would likely only occur if a shooting war had already broken out. A blockade of China would adversely affect the global economy and trigger economic, political, and military alienation of the blockading power.

One way a national tanker fleet might increase oil supply security would be for the PLA Navy (PLAN) to escort Chinese tankers through contested areas. Chinese "hawks" believe that the PLAN must modernize because its ability to secure vital SLOCs and ensure the safety of China-bound oil shipments "seriously lags" behind China's growing import demand.[22] The idea of sending naval forces to escort tankers is hardly unprecedented. When the Iran-Iraq "tanker war" heated up in 1987, the US Navy guarded tankers bringing oil out of the Persian Gulf.

However, without complete PLA naval and air superiority in a given sea zone, carrying oil on Chinese flag ships actually makes the People's Republic of China (PRC) more vulnerable to energy supply interdiction in the event

of a conflict because foreign navies would know precisely which tankers are headed to China. The PRC's best option might be to rely on private third party tanker operators, whose deliveries could be effectively stopped only by a close blockade of Chinese ports. Such action would expose the blockading state's naval forces to a wide range of military threats and would almost certainly spark a larger conflict.

POSSIBLE CHINESE TANKER FLEET STRUCTURES Table 3

Solution	Advantages to China	Disadvantages
Chinese oil importers and tanker operators reach exclusive long-term lease agreements[1]	Keeps entire oil supply chain under Chinese control. Reduces net capital outflow from China.	International tanker companies may offer more professional and reliable tanker services
Create a tanker shipping pool and reach a long-term agreement with oil importers	A shipping pool would increase shippers' negotiating power and reduce financial and operating risks[2]	Establishing a national shipping cartel could raise World Trade Organization compliance issues

[1] "Why Doesn't China have a National Oil Tanker Fleet?" Water Transportation Digest: Shipping Survey, September 2005, pp. 24-25. [2] Xiguang, Luo, and Zoujun, Liu, "The Step of Creating a United Chinese Oil Shipping Enterprise," Water Shipping Management (Shuiyun Guanli), Vol. 27, No. 10, October 2005, pp. 9-11.

An attacker theoretically could try to close Indonesia's Lombok and Sunda Straits as well, but after a temporary disruption energy shippers would likely find bypass routes to key East Asian markets. By interdicting key choke points, the attacking party might be sacrificing its Asian allies' well-being and by straining global tanker capacity would also drive up tanker rates for oil consumers around the world. Japan and South Korea have strategic oil stockpiles that, depending on the blockade's duration, could help them avoid supply shocks. Japan has 92 days' oil supply in its Strategic Petroleum Reserve, but the Asian and global diplomatic, economic, and political fallout of closing Malacca would be very serious.

Interdicting private tankers at sea also would be tough because it is difficult to determine the true end destination of an oil cargo. In normal commerce, cargoes may be bought and sold several times while still on the high seas. Finally, unless it risked environmental disaster by firing on uncooperative tankers, a blockader would lack the military assets to board and assume control of such ships, as 210 oil tankers/day pass through the Malacca Strait alone.[23]

Commercial implications

If China builds new VLCCs rather than leasing them, its tanker fleet growth likely will depress global tanker rates and raise shipbuilding costs. This would occur through expansion of the world fleet and increased demand for both shipyard berths and necessary raw materials such as high-grade steel.

The shipbuilding industry will be affected in other ways as well. Chinese shipyards are rapidly gaining operational experience and will be able to tap into China's vast labor pool and employ thousands of engineering graduates that Chinese universities produce each year.[24] China also appears interested in recruiting and training ship crews. Dalian's Qinglin advocates training a cadre of Chinese mariners to man its tanker fleet.[25]

Beijing may have to decide whether rapid oil tanker construction is worth the opportunity cost in military shipbuilding. If all the state shipyard spaces are filled with container ships, tankers, and other commercial orders, construction of warships may have to be put on hold.

It is unlikely that China will try to work outside the world oil shipping market because the opportunity costs of doing so are very high. Tanker operations driven by economic opportunity are more profitable than those driven by state directives, and they leave tankers accessible to Beijing in the event of a supply crisis. Similarly, Chinese shipyards' commercial deals with foreign tanker operators are likely to drive further Chinese integration into the global oil-shipping sector.

The precedent set by China's national energy companies also favors the adoption of a largely commercial approach to tanker fleet operation. Although China has spent billions of dollars on overseas equity oil acquisitions, state firm China National Petroleum Corp. sells the majority of its equity oil on the international market.[26]

Further supporting this case, oil from China National Offshore Oil Co. Ltd.'s new Akpo field in Nigeria likely will be sold in Atlantic Basin markets rather than shipped back to China. In sum, China appears to be pursuing a strategy of profiting from shipbuilding and tanker operation during peacetime but hedging its bets against future threats to oil shipments.

Security implications

So long as energy supplies flow uninterrupted, the Chinese tanker fleet will likely operate in a normal commercial fashion. Yet if a terrorist attack or other event disrupts oil production and the Chinese tanker fleet goes out to secure supplies for China accompanied by PLAN escorts, the possibility of naval conflict between China and other countries such as India, Japan, or the US would rise dramatically. Not all Chinese oil security contingencies would involve a Taiwan conflict. An attack on a Saudi export terminal that suddenly tightens world oil markets might be enough to trigger a government "call" on state-run tankers, which would then be given PLAN escorts.

Nonetheless, Chinese worries are substantially misplaced. Unless the US completely closed the Malacca Strait to oil shipments, affecting all East Asian oil consumers and possibly triggering a global oil price spike, there would be virtually no way to interdict private China-bound tankers at a distance from China. The global oil market is highly fungible, ship destinations are unclear because cargoes are often resold at sea, and oil can be transshipped to China through third ports in the region. The same logic applies to the Strait of

Hormuz and other oil shipment choke points.

In addition, the number of tankers transiting key choke points would most likely far exceed any potential blockader's physical ability to control uncooperative ships with means short of disabling fire.

It is hoped that these realities will come to inform energy security policymaking in Beijing and Washington. Global energy security can improve if China overcomes its mercantilist inclinations and relies on the world oil market to fulfill its oil and oil transportation needs. A minority of Chinese analysts, such as Zha Daojiong, now advocates a greater reliance on global energy markets and a turn away from mercantilism.[27] Washington would gain by giving China a place at the table through International Energy Agency membership, advising China as it creates a full-fledged energy ministry and strives for a sustainable energy future.

In the meantime, China's growing oil tanker fleet stands to substantially affect the global oil transportation sector. ✦

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OCS compromise eludes US Congress energy leaders

Nick Snow
Washington Correspondent

US Senate and House energy leaders headed into the preelection recess pledging to reach a compromise before yearend, but were still divided over Outer Continental Shelf oil and gas leasing reforms.

Senate Energy and Natural Resources Committee Chairman Pete V. Domenici (R-NM) said he was disappointed that an agreement was not reached before recess. "I hope the House will take the necessary time in October to step back and reflect on the number of compromises the Senate has offered to break the current impasse," he said.

"I hope the House recognizes what is politically possible in the Senate," Domenici added, possibly referring to the promise by Sen. Bill Nelson (D-Fla.) that he would filibuster any compromise that did not establish a 16-year leasing ban up to 125 miles off the state's coastline.

House Resources Committee Chairman Richard Pombo (R-Calif.) and five other House members—John E. Peterson (R-Pa.), Neil Abercrombie (D-Hi.), Bobby Jindal (R-La.), Charlie Melancon (D-La.) and Adam H. Putnam (R-Fla.)—issued a joint statement that they "have gotten very close to working out the differences between our bill and that passed by the Senate."

They said remaining issues include questions over boundary lines in S. 3711, which the Senate approved Aug. 1, and how the map lines will affect division of future federal OCS revenues among Louisiana, Alabama, and Mississippi.

Louisiana's two US senators apparently are divided over negotiating tactics. "While I was working with others to break the logjam between the House and the Senate, others in our delegation chose to divert their time and energy to blaming others," Republican David Vitter said Sept. 29.

'The deal is dead'

Three days earlier, Democrat Mary L. Landrieu said insistence by House conferees to retain HR 4761's language giving states on the east and west coasts shares of federal coastal revenues if they allowed drilling 100 miles off their own coasts was "holding back our chances for a fair compromise," adding, "Until the House moves off this position, the deal is dead."

Vitter said, "As we continue to work on this key legislation, it's not the time to attack the other party or the other chamber, or to take extreme measures like placing holds on dozens of unrelated bills. This will kill our chances, not improve them."

Landrieu did not respond directly, but her communications director Adam Sharp said Vitter was entitled to his opinion "but the people of Louisiana know that Sen. Landrieu's voice has been strong and effective in fighting for Louisiana's coast."

In a separate statement on Sept. 29, Landrieu said she hoped S. 3711's focused approach on OCS Lease Sale 181 acreage, which President George W. Bush withdrew during his first term, and adjacent deepwater tracts farther south "will motivate House negotiators to move away from their Atlantic drilling strategy and toward the Gulf Coast approach already embraced by the Senate and the president."

She said she would continue to work with Domenici, Majority Leader William H. Frist (R-Tenn.), Minority Leader Harry Reid (D-Nev.) and Sens. Trent Lott (R-Miss.) and Mel Martinez (R-Fla.) to achieve a compromise with the House when Congress returns on Nov. 13.

But Pombo and the five other House members said Senate negotiators have agreed that a bill must contain a provision to recover Gulf of Mexico deepwater royalties which were not collected because price thresholds were not included in leases issued during 1998 and 1999, and to use part of those revenues to help Gulf Coast states recover from 2005 hurricane damage.

"Finally, the Senate has acknowledged the need to expand and diversify America's energy infrastructure beyond the Gulf of Mexico," the six House members said. ✦

NGSA forecasts higher gas production this winter

Nick Snow
Washington Correspondent

A dramatic natural gas market recovery following last year's two major Gulf Coast hurricanes points to higher production and lower prices in the 2006-07 winter heating season, the Natural Gas Supply Association said on Sept. 28.

Onshore production, which was already growing moderately from expansions in the Rocky Mountains and Texas before Hurricanes Katrina and Rita hit, also contributed to the rebound, NGSA Pres. Chris Conway told reporters in Washington, DC.

"Going forward in 2007, the key market drivers point to a continued steady increase in production, reflecting high rig counts and the startup of major new deepwater developments," he said.

An average of 1,417 gas rigs were at work in the US during August, up from 1,230 a year earlier, according to NGSA's forecast, which was prepared by Energy & Environmental Analysis Inc., Arlington, Va. It said this suggests gas well completions will climb to 30,100/year in 2006 from 27,000/year in 2005.

US gas production could climb to an average 50.7 bcfd from 40.9 bcfd, while imports from Canada decline to 8.4 bcfd from 9.2 bcfd, NGSA said. It forecast an increase in LNG imports to 2 bcfd from 1.5 bcfd.

"Most of the increased activity in recent years has been onshore, concentrated in noncommercial gas production: tight gas, coalbed methane, and shale gas. Offshore activity, meanwhile, has been fairly constant during the past few years," said Conway, who also is president of ConocoPhillips's gas and power division.

Going into winter, gas storage will reach 3,500 bcf, with 65 bcf of additional capacity, up from 3,264 bcf and 20 bcf more capacity a year earlier, the forecast said.

NGSA warned that weather, which is expected to be colder this winter than during the 2005-06 heating season, could partially offset downward price pressure from increased supplies and higher production.

It said Global Insight, one of the consultants which NGSA used to develop its winter gas demand outlook, expects upward price pressure from economic expansion to be relatively flat as growth in gross domestic product falls to 2.7% from 3.4%, manufacturing declines to 3.5% from 4.7%, and the Department of Labor's Consumer Price Index slows to 3.3% from 3.7%.

The forecast suggests that unemployment will average 4.8% nationwide this winter, unchanged from a year earlier.

Consumers and policymakers should not become complacent, NGSA warned. "The country continues to appreciate the comfort and convenience of natural gas, which is 83% domestically produced. The industry has made tremendous strides in hurricane recovery, yet continues to seek additional sources of cost-effective supply for consumers," Conway said. ✦

US estimates Iraq lost $16 billion in oil revenues

Nick Snow
Washington Correspondent

Iraq lost an estimated $16 billion of potential oil export revenues from January 2004 to March 2006 because of insurgent attacks, criminal activity, and aging and poorly maintained infrastructure, an audit report by the US special inspector general for Iraq reconstruction said.

"In addition to lost export revenues, Iraq is paying billions of dollars to import refined petroleum products to support the consumption needs of its citizens," Stuart W. Bowen Jr. said in the Sept. 27 report.

Attacks against Iraq's oil and electric

power systems ebbed and flowed during that time period, Bowen said. Iraq's oil, electricity, and defense ministries combine to protect the systems and have varying capabilities, he said.

Security, however, is only one factor in Iraq's protection of its energy infrastructure, Bowen maintained.

"While much attention has been focused on insurgent attacks, it must be recognized that even if attacks ceased, other factors, such as criminal activity and the effect of aging and poorly maintained infrastructure on operating capability, would continue to affect oil exports and the availability of electricity," he said.

He noted that Iraq's oil exports remained below established targets and electric power generation was far below demand when there were few insurgent attacks from late April to early June of this year.

"Further, once damage or disruptions occur, it is critical that it be repaired quickly, but more needs to be done to enhance rapid repair capability," Bowen said.

Progress made

Bowen said the US government has done much over the past year to help make the Iraqi infrastructure security forces more capable, as well as developing initiatives both to protect the country's energy infrastructure and to facilitate transition of that responsibility to Iraq's government.

"The Iraqi government has much to do if it is to implement US proposals as well as proposals put forth by its ministries. Progress in acting on them has been slow, in part due to the lack of a permanent government and in part [due] to the limited initiative of some Iraqi ministries. Now that there is a permanent government in place, it must take bold action," Bowen said.

He said Iraq's new government is pursuing energy improvement initiatives, including steps to increase the country's oil exports. "The challenge for the United States is to help the Iraqi government move forward" to undertake these tasks, Bowen said.

One way for the US government to do this is to focus congressional attention on what Iraq's new government needs to do to protect and improve the country's energy infrastructure, he suggested.

Bowen said that current reports to Congress by the departments of State and Defense contain only general descriptions of progress in Iraq instead of specific information on actions that Iraq's government should take to enhance energy infrastructure integrity and progress it is making in those actions. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Nigerian oil in jeopardy

The news from Nigeria's oil and gas industry is not encouraging. It's that recurring problem of militants besieging the place again, but this time they seem to be ganging up on the industry.

Up to now, Nigeria—a member of the Organization of Petroleum Exporting Countries—has been Africa's leading oil producer and the world's sixth biggest crude exporter with a normal output of 2.6 million b/d. But militants are threatening that production.

Indeed, attacks on oil installations in the Niger Delta have cut about a quarter of oil production since the start of this year, and at least five Nigerian oil workers have been killed.

MEND speaks

Last week, the Movement for the Emancipation of the Niger Delta (MEND) announced a mobilization of its fighters to counter a new military offensive by the Nigerian government, a siege on ethnic Ijaw communities following the killing of 14 soldiers and kidnapping of 25 oil workers in Rivers State on Oct. 2.

"In response to the buildup of Nigerian military forces...we decided to send a number of our fighters into Rivers State to assist communities which we perceive will shortly be under siege by the Nigerian military," MEND said.

"These fighters will remain in the vicinity of Rivers State until the perceived threat to Ijaw communities in Rivers State ceases to exist," it said. That could be a long time, especially given MEND's declared aim.

"In good time we will redeem our pledge to the people of the Niger Delta to halt altogether the rape of our land by the Nigerian government and conniving oil companies," it said.

Aimed at destruction

"As long as the injustice persists in the delta, there will be no peace for those who loot the wealth of our oppressed people," it warned. Leaving little room for guesswork, MEND said: "Our goal remains the destruction of the Nigerian oil industry and all who stand on the pathway to our objective."

The statement came on the heels of the Oct. 2 attack on a site belonging to Royal Dutch Shell PLC in neighboring Rivers State, and it shows that the militants are linking up.

The Oct. 2 attack was by a group called the Joint Revolutionary Council, which said its attack was aimed at obtaining the release of Alhaji Mujahid Dokubo Asari, the imprisoned leader of the Niger Delta People's Volunteer Force.

Hardly had that attack occurred than another one took place on Oct. 4, when five foreigners working for ExxonMobil Corp. were abducted and two Nigerians killed by armed militants operating in the Niger Delta region.

This time, the militants were not immediately identified, and there was no immediate claim of responsibility. But the handwriting is on the wall: Militants by whatever name are joining up to threaten the oil industry of a major OPEC producer. That's worrying for everyone, Nigerian or not. ✦

Lawmakers urge MMS to aggressively recover royalties

Nick Snow
Washington Correspondent

Two US House Government Reform Committee leaders have demanded that the Department of the Interior develop a new plan to recover an estimated $2 billion of lost royalties from deepwater Gulf of Mexico leases issued in 1998 and 1999.

Committee Chairman Thomas M. Davis (R-Va.) and Energy and Resources Subcommittee Chairman Darrell E. Issa (R-Calif.) made their demand following US Minerals Management Service Director Johnnie Burton's recent statement that MMS did not have the power to recover royalties, which have already been lost. "This is absurd. That money belongs to the federal government and must be collected just as any other unduly conferred on a private citizen," the two lawmakers said in a Sept. 26 letter to Interior Sec. Dirk A. Kempthorne.

While deepwater Gulf of Mexico leases issued before and after 1998 and 1999 contain price thresholds when holders would begin to pay royalties, leases during those two years did not. Burton has said this apparently was the result of a communications breakdown within MMS, adding that an investigation now under way by DOI Inspector General Earl E. Devaney should provide a more definitive answer.

Burton also has said that some holders of the 1998 and 1999 leases may be reluctant to renegotiate because they based their operating budgets on the absence of royalties. Davis and Issa disagreed. "The intent of all parties was clear at the outset. Oil companies testified that they bid on the leases as if price thresholds were included, and with the understanding that it was the department's policy to include them," they said in their letter. ✦

Oklahoma Woodford gathering designed at 500+ MMcfd

Newfield Exploration Co., Houston, signed a 15-year agreement with MarkWest Energy Partners LP, Denver, to construct and operate gas gathering pipelines and related facilities for development of Newfield's Devonian Woodford shale play in the Arkoma basin of southeastern Oklahoma.

MarkWest plans to invest $175 million by yearend 2007 and $350 million over the next 4 years to build a gathering infrastructure, including compression, dehydration, and treating, over 200 sq miles in a four-county region. The system will include more than 400 miles of large diameter pipeline and 100,000 hp of compression for a takeaway capacity exceeding 500 MMcfd. The agreement includes a renewal option at the end of the agreement period.

Newfield has drilled more than 100 vertical wells and 30 horizontal wells in the Woodford shale. Late last year, Newfield shifted its drilling program to horizontal wells, which increased initial production rates and the expected estimated ultimate recovery. Its five most recent wells averaged initial production of 3.7 MMcfd/well. Company officials expect the average Woodford horizontal well to gross 2.9 bcf of gas.

Still acquiring acreage, the company has an interest in more than 350,000 gross lease acres (more than 125,000 net acres). Newfield expects to increase its drilling program to 13 rigs by yearend from 6 in late September and to as many as 20 rigs by the end of 2007. It plans to spud 60 horizontal wells in the Woodford play in 2006 and up to 155 horizontal wells in 2007.

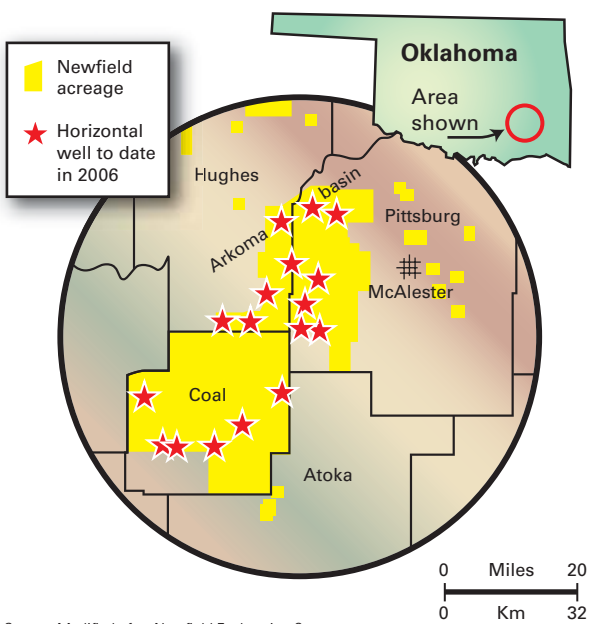
"By the end of 2009, we expect our gross Woodford shale production to increase from a current rate of about 65 MMcfd to more than 350 MMcfd," said Lee K. Boothby, president of the subsidiary Newfield Mid-Continent Inc. in Tulsa.

The wells Newfield has drilled so far were located to define the Woodford shale resource. The low-pressure gathering system will fully support Newfield's drilling efforts over its entire operating position in the Woodford shale.

The company's western Arkoma exploration program is also aimed at gas in the Pennsylvanian Wapanucka and Cromwell, Mississippian Caney shale, and Siluro-Devonian Hunton formations. ✦

NEWFIELD'S ARKOMA WOODFORD ACREAGE

Fig. 1



Source: Modified after Newfield Exploration Co.

Gas focus in Brazilian licensing draws fire

Peter Howard Wertheim
OGJ correspondent

A new emphasis on natural gas in Brazilian exploration and production licensing drew criticism during a Rio Oil & Gas panel discussion in Rio de Janeiro.

Paulo Manuel Mendes de Mendonca, executive manager of exploration for Petroleo Brasileiro SA (Petrobras), complained that Brazil's eighth licensing round focuses on gas-prone areas and excludes the Campos basin, which accounts for 84% of Brazilian oil production. He also mentioned limits on the number of bids individual companies can make.

He directed his comments to Haroldo Lima, general manager of the National Oil, Natural Gas, and Biofuel Agency (ANP).

"We are following governmental guidelines," Lima responded. "After the nationalization of Bolivia's oil and gas reserves, the [Brazilian] government decided to give priority to E&P in gas-prone provinces like Santos and Espirito Santo basins."

Those basins are among seven in which the eighth round on Nov. 28 will offer a total of 284 blocks covering 101,000 sq km. Reports about the area to be offered have varied (OGJ, Aug. 7, 2006, Newsletter).

Brazil imports about half the gas it uses from Bolivia, where President Evo Morales on May 1 announced plans to take over his country's oil and gas fields. Petrobras has been Bolivia's most active foreign producer (OGJ, Aug. 28, 2006, p. 25).

Oil industry officials attending the panel discussion expressed surprise that the independent ANP, in the words of one executive, "now dances to the tune of the federal government."

On a separate issue, Joao Carlos de Luca, president of the Brazilian Petroleum and Gas Institute (IBP), called for quickened environmental licensing of Brazilian oil and gas projects and more resources for the ANP.

Alvaro Teixeira, IBP executive-secretary, predicted that oil and gas investments in Brazil during the next 5 years will total $100 billion and sustain oil self-sufficiency, achieved in May. ✦

Algeria's Berkine basin gets new area of promise

A new core area for future appraisal and potential development is emerging in the central part of Menzel Ledjmet Block 405b in eastern Algeria's Berkine basin, said operator First Calgary Petroleums Ltd., Calgary.

On the block's east side, First Calgary looks for Sonatrach to issue an exploitation license in late 2006 for giant MLE gas-condensate field. MLE, with gross probable and possible reserves of 6.6 tcf and 903 million bbl in Lower Devonian to Triassic pays at the end of 2005, is to start producing in 2009.

MLE, which First Calgary has appraised since obtaining the 1,104-sq-km block in 2001, is one of the largest gas discoveries in the country in recent years. Current mapping indicates it covers more than 85 sq km.

The deepest Devonian reservoir (Siegenian) is at 4,500 m, and reserve potential exists in the deeper Gedinnian (lowermost Devonian) formation.

Since shooting 600 sq km of 3D seismic west of MLE field in 2003, First Calgary has drilled five exploration wells and an appraisal well: LEC-1, MZLN-1, MZLS-1, LES-1, LES-2, and LEW-1. All were successful in multiple geological horizons in what the company calls its Central Area Field Complex.

LES-6 and LEC-2 are to be drilled by the end of 2006, completing the drilling of all of the block's attractive exploration targets, First Calgary said.

The company gave back the southwestern 30% of the block at the end of 2004 and must relinquish all other parts of the block on which it has made no discoveries at the end of 2006.

Further appraisal starting in 2007 will aim to secure the next commercialization stage following MLE.

Meanwhile, the company drilled, cased, and tested the Zemlet er Rakeb-1 exploration well in the northwest part of the block earlier this year. It gauged hydrocarbons at rates sufficient to support drilling ZER-2 at 4.3 km southwest.

GSM-1 near the south end of the block also tested hydrocarbons and is to be followed by GSME-1. ✦

China

Verona Development Corp., Vancouver, BC, is drilling two wells to assess coalbed methane potential south of Liulin on the 1,015 sq km Shilou North Block in the eastern Ordos basin in Shanxi Province.

The two wells, to be cored through the entire gas-bearing coal sequence, target coal seams of the Late Carboniferous Taiyuan and Early Permian Shanxi formations.

Verona also holds the 2,650 sq km Zhengzhou Block, which includes the 600 sq km Yinggong coal field, in Henan Province. The company plans to earn 60% interest in each block.

Colombia

The government awarded Emerald Energy PLC, London, the 365 sq km Maranta exploration and production contract northeast of producing oil fields in the Putumayo basin.

The 18-month first exploration period calls for gathering 30 km of 2D seismic data and reprocessing 40 km of existing 2D data. A second period, at Emerald's option, calls for drilling one well to 11,000 ft.

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France

Europa Oil & Gas (Holdings) PLC, London, expects to be awarded the Bearn des Gaves exploration permit in the Aquitaine basin in early 2007 following government approval.

The permit covers 928 sq km west of Lacq and Meillon gas fields. Europa plans to probe a possible western extension of the Lacq play and also sees oil potential on the northern part of the permit.

Peru

BPZ Energy Inc., Houston, spudded the first well from the Corvina platform on Block Z-1 in the Pacific Ocean off northwestern Peru.

The well is projected to TD of 10,114 ft in 30-40 days.

Previously penetrated by several wells but never produced, Corvina field is estimated to have 4 tcf of gas in place.

The company secured all environmental permits required to develop the Corvina gas-to-power project. The permits cover the 10-mile gas pipeline to shore, onshore gas processing facilities, and a 160-Mw thermal power plant to be built at the coastal village of Nueva Esperanza.

Philippines

Tap Oil Ltd., Perth, has taken 85% equity in the SC-41 exploration block in Philippines waters off northeastern Borneo.

The 2006-07 work program calls for gathering of more than 300 sq km of 3D seismic data on the block, in 800-1,200 m of water in the Sulu Sea.

Unocal Corp. identified a deepwater petroleum system in 2000 when it recovered oil from Wildebeest-1, the only well drilled in the deepwater fold belt. The fold belt is strewn with structural and structural/stratigraphic leads.

Tap Oil has three Philippine partners and plans to reduce its interest in the block. Fewer than 25 wells have been drilled in the entire Sandakan basin (see map, OGJ, May 10, 1993, p. 43).

Poland

FX Energy Inc., Salt Lake City, started gas production from the Wilga-2 well 25 miles southeast of Warsaw.

For several weeks the company plans to vary the producing zones and flow rates. The well has three pay zones of Carboniferous age at 7,732-8,550 ft. FX Energy is operator with 82% interest in the well and 250,000-acre concession. A unit of Polish Oil & Gas Co. owns the other 18%.

Wilga-2 is FX Energy's second well to go on production in Poland, the Kleka-11 well having started flowing gas in early 2001.

The company plans to start gas output from the Zaniemysl-3 well within weeks and to spud the Winna Gora exploratory well on a 2D seismic prospect in the Sroda area west of Warsaw within 2 weeks.

Yemen

Yemen Mayfair Petroleum Corp. plans to spud the Fatima-1 exploration well on Block 22 in western Yemen in mid-October, said participant Oracle Energy Corp., Vancouver, BC.

Projected TD is 2,250 m to target the Middle Miocene that tested 42° gravity paraffinic crude oil and dry gas in Jaizan basin wells to the north in southwestern Saudi Arabia in the early 1990s.

Oracle Energy holds 15% participating interest in Block 22 covering 8,151 sq km in the Tihama basin.

Colorado

Eden Energy Corp., Vancouver, BC, and Starlight Oil & Gas LLC, private Colorado independent, are drilling the first of two development wells on the 20,000-acre Ant Hill Unit in White River Dome field in 2n-96w and 97w in north-central Rio Blanco County.

The wells, on a farmout to Starlight from EnCana Oil & Gas (USA) in the Piceance basin, target the Cameo coal and Williams Fork sandstones of the Cretaceous Mesaverde Group at 8,100 ft.

White River Dome field has 100 active wells averaging a combined 11 MMcfd and has recovered 65 bcf from 157 wells.

Eden and Starlight may elect to drill as many as 68 other locations, earning interests as they go, extending unit life. The typical well starts at 710 Mcfd, 25% carbon dioxide, and recovers 1.07 bcf in 17 years.

Montana

Native American Energy Group., Forest Hills, NY, is attempting to restore production at idle oil wells in Richey field in the Williston basin.

Shell Oil Co. discovered Richey field in 1951 and drilled 10 producing wells in Dawson and McCone counties. Successor independent operators struggled with paraffin accumulation problems and eventually abandoned the field in 1995.

NAEG acquired the Beery oil lease and will rework the wells using the company's proprietary chemical called Petro-Flo, which it said was successful in revitalizing the Tribal 7-A and Cox 7-1 wells on the Fort Peck Indian Reservation.

Washington

Exxel Energy Corp., Vancouver, BC, said its US subsidiary boosted its mineral rights in the Columbia River basin to 325,000 net acres.

The interests are undeveloped, and Exxel Energy (USA) Inc.'s working interest is 100%.

The subsidiary is acquiring more acreage and reviewing its options for development. The area appears to contain an emerging basin-centered gas play, and several operators have obtained drilling permits for new wells.

Optimum compressor choice boosts Brent gas production

Thomas N. Schneider
Shell Exploration & Production
Aberdeen

Riccardo Brogelli
GE Oil & Gas
Florence, Italy

Three projects progressively modified gas compression on the UK Brent field to lower suction pressures in-line with late life reservoir and production requirements for depressurizing the field.

The long-term field development (LTFD) project laid the foundations for depressurizing Brent field, while the two-step low-pressure operation (LPO) and low-pressure operation plus (LPOP) compressor upgrade minimized risk and lifecycle cost.

Each new compressor design leveraged proved technology of its time so as not to jeopardize machine reliability and gas availability. The technical innovations incorporated in the LPOP compressor extended the operational envelope beyond that thought possible at LTFD.

Advances in modeling techniques and design verification provided the confidence to install the LPO and LPOP machines without an onshore string test.

Brent field

Brent field has been a cornerstone of the UK offshore oil and gas industry since its discovery in 1971, about 500 km northeast of Aberdeen. The coventurers, Shell UK Ltd. and Esso Exploration and Production UK Ltd., installed four platforms (Alpha, Bravo, Charlie, and Delta) to develop the field with an estimated 600 million cu m of oil equivalent and 290 million cu m of wet gas initially in place.

The companies originally configured the platforms for oil production with water injection. In the early 1990s, they decided to change the reservoir management strategy by reducing the reservoir pressure to 70 bara from 380 bara, liberating an incremental 58 million cu m of oil equivalent production.

The LTFD project involved the installation of an integrated two-stage separation, gas compression, and dehydration process module on three platforms (Bravo, Charlie, and Delta) to enable reservoir depressurization.[1]

Compressor selection

The need for a large gas compression capacity within limited weight and space constraints drove the equipment selection. The LTFD project involved fitting each platform with a single gas-export compression train, which required an aero-derivative gas-turbine driver to allow rapid turbine replacements during maintenance.

The project selected Cooper-Rolls' RB-211/6562 gas turbines as the prime mover with GE Oil & Gas gas compressors.

A single-helical gearbox coupled the two stage, back-to-back compressor to the driver. The gas turbine and gearbox shared the compressor lube oil system while the compressor was fitted with tandem dry gas seals.

Gas export availability was a key value driver for the project. This required a proven, reliable, and readily maintain-

BRENT GAS EXPORT COMPRESSOR COMPARISON

Table 1

Project	LTFD	LPO	LPOP
Model	2BCL506/A	2BCL506/A	2BCL506-8/A
Maximum continuous speed (MCS), rpm	8,086	9,083	9,508
Number of impellers/stage	3/3	3/3	4/4
Impeller diameter, mm	600	630	630
Bearing span, mm	1,953	1,953	2,166
Bearing diameter, mm	130	130	150
Suction/discharge pressure, bara	35/140	20/140	8/140
Polytropic head 1st/2nd stage, m	8,500/8,100	13,000/11,800	21,000/18,500
Flow, million standard cu m/day at maximum 17 Mw	11.76	8.02	3.86
Log decrement at MCS		0.169	0.226
Wachel log decrement at MCS		0.021	0.056
Balance drum seal	Stepped labyrinth	Stepped labyrinth	Tapered honeycomb
Shunt holes	No	Yes	Yes
Swirl breaks on impeller eye labyrinths	No	No	Yes
Impeller material	A182 Gr F22	A705 Gr 630	Virgo 38

able high-flow compressor. GE designed a compressor rotor with a 600-mm diameter, two-dimensional impellers in a three wheels and stage configuration (Table 1 and Fig. 1).

The vertically split barrel-type casing allows the replacement of the bundle without removal of the process pipe work.

Several factors made the LTFD compressor design difficult, considering the experience and methods available in the early 1990s. The compressor was specified in accordance with NACE,[2] because of the risk for the reservoir to sour in later field life. The need to deliver high flow and polytropic head in a single casing resulted in the impeller tip velocity being relatively high.

As a consequence, the impeller had high stresses and, therefore, the materials selected needed sufficient strength to sustain the stresses but also to have low enough hardness to satisfy the NACE requirement. The presence of carbon dioxide and water further complicated material selection.

The design used rotor-dynamic analysis that accounted for the destabilizing flow effects in the labyrinth seals. This was important particularly in the area of the center balance drum that separates the discharge volutes of the two compression stages.

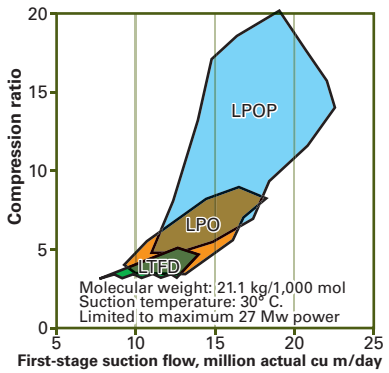
All three units underwent full-load testing in the factory using the contract drivers. The testing and in service encountered no stability problems. Rolls-Royce and GE staff maintained the compression trains for optimal performance under a healthcare contract that supported an enhanced maintenance program.

None of the three compressors required a major unplanned intervention in more than 20 years of cumulative run life.

Development options

As the gas reservoirs depleted, well productivity declined below the design flow rate of the compressor. Optimizing production required lowering well back-pressure. Lower back-pressure enhances well performance and reduces the ultimate reservoir pressure, which in turn increases gas recovery.

COMPRESSOR COMPARISON Fig. 1



Options evaluated to reduce back-pressure while maintaining export pipeline pressure included multiphase pumps and various suction and discharge booster compressor configurations. All these concepts were unattractive economically due to space, weight, power, and flow assurance. The most cost-effective approach was the modification of the existing gas export compression train on each platform for a lower suction pressure by upgrading the compressor, retaining the gas turbine driver, and reusing the base skid and auxiliaries.

The compressor upgrade reduced suction pressure and reduced mass flow in two phases to match the production decline of each platform. The work staggered the shutdowns and aligned it with other in-field activities to minimize avoidable production deferment.

Phase 1 included upgrading the compressor as far as possible within the existing casing design. The LPO project replaced the compressor bundle and gear internals. This well-proven upgrade method only required a short platform shutdown.

Phase 2 included the LPOP project that replaced the existing compressor with a new longer casing to accommodate additional impellers. This option only became feasible in recent years because of advances in rotor and labyrinth seal design techniques that enabled detailed evaluation of the behavior of such a compressor.

The upgrade required significant brownfield work and an extended shutdown to remove the original machine and install and align the new one. The project also replaced piping spools, valves, and gear internals.

It also included a review of the complete topsides process for flow, pressure, and temperature changes resulting from the new operating conditions.

Increased compressor discharge temperatures affected pipe class and valve specifications as well as piping and equipment stress levels. Although the heat load on the gas coolers remained essentially unchanged (given no change to compressor driver power), these required re-rating for the increased temperatures.

Lower pressure affected fuel gas, gas dehydration, and off-gas compression systems, which were then either modified or operated differently.

Rewheeled compressor

Optimizing the impeller geometry and increasing rotational speed increased the polytropic head of the LPO compressor when compared with the LTFD design (Table 1). The rotor line-up was again composed of two-dimensional impellers in three plus three configuration (Table 1).

The length constraint of the existing casing prevented the accommodation of additional impellers within the unit. The selected impellers had the highest head geometry available within the GE range of impeller families and an increased 630-mm diameter, the largest for the casing size.

The impeller tip speed together with the NACE requirement resulted in the LPO bundle being the limit state design of the time.

In the absence of a gas-turbine skid, compressor, or gearbox casing, it was not possible to factory test the new compressor or gearbox internals. The project mitigated start-up risk through design verification, use of proven im-

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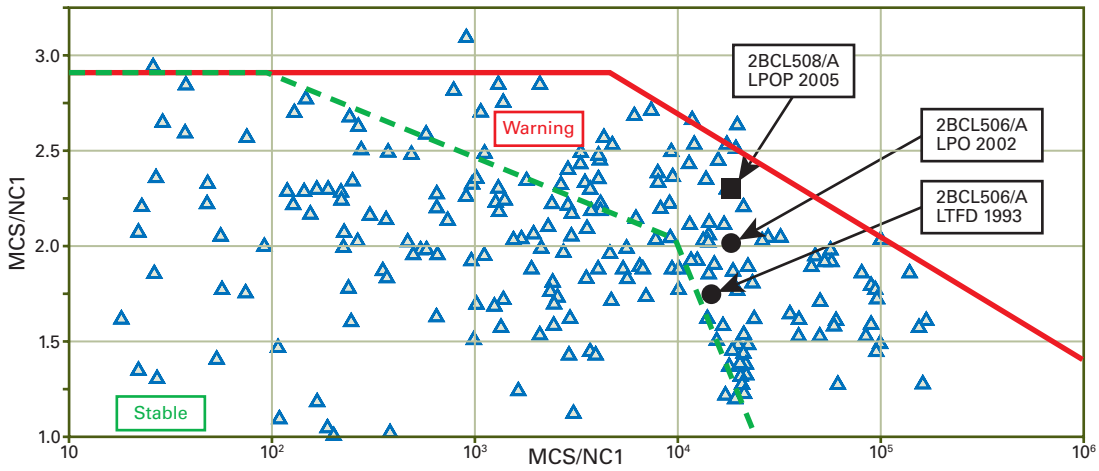
KIRK-DONALD PLOT

Fig. 2



Note: MCS - Maximum continuous speed, NC1 - First critical speed, P_d - Pressure discharge, P_s - Pressure suction

peller designs, GE quality control (high-speed verification and balancing of the rotor), and commissioning procedures.

Offshore testing showed a good match with the predicted performance. The modification activities were completed within the planned shutdown durations and all three rewheeled compressors were as reliable in service as the LTFD units.

LPOP compressor

The key objectives of the LPOP compressor design were:

1. Maximizing the polytropic head (minimize suction pressure).
2. Having a wide operating range (high start-up pressure required for fuel gas).
3. Using materials suitable for sour service.

Constraints included:

1. Maintaining casing diameter and reusing the existing compressor base plate.
2. Having a casing weight of less than 18 tonnes (vs. 21.5 tonnes standard weight).
3. Sustaining nozzle loads up to 5-times NEMA.
4. Maintaining the size and location of the discharge nozzles.

GE studied all aspects of the compressor design to find the best compromise between the conflicting requirements while ensuring a safe and reliable compressor with a high level of performance. Initial efforts focused on meeting the constraints.

A reduction in the wall thickness of the second-stage suction was the main change that reduced the weight, and finite element analysis, verified in a hydraulic test, validated the various load conditions on the casing.

The addition of impeller stages (four plus four vs. three plus three) and increased shaft speed (Table 1) was the only way to increase the polytropic head.

The increased gear ratio pushed the pitch-line velocity and loading of the gear teeth to the maximum allowed by Shell. GE selected a special material known as Virgo 38 for the impellers to maximize resistance to sulfide stress corrosion cracking while achieving the required strength. The use of finite element analysis optimized the impeller interference fit geometry.

The compressor's wide operating range caused the residual axial thrust due to the pressure distribution over the rotor to have much greater variation and higher peak values than in standard GE applications.

Numerous evaluations optimized the balance drum design. Constraint 4 limits the interstage wall thickness while Objectives 1 and 2 increase the differential pressure across the interstage diaphragm. Diaphragm deformation in the area of the balance drum seal had to be minimized because excessive movement would be detrimental for rotor stability.

The design minimized the axial length of the new compressor to prevent rotor stability problems. The use of computational fluid dynamics models optimized within the space constraints the aerodynamic design of the two inlet volutes.

LPOP compressor rotor

The design had to resolve rotor-dynamic stability concerns because of the bearing span, rotational speed, and polytropic head capacity of the LPOP machine. A comparison of the compressor design against GE's historical database shows the importance of these concerns (Fig. 2). All Brent machines are within GE's warning zone in the Kirk-Donald plot,[3] however, the LPOP compressor is close to the stability limit.

A design optimization and verification was required to avoid an unstable design. The analysis was conducted in parallel with a third party, the South West Research Institute.

Undamped critical speed

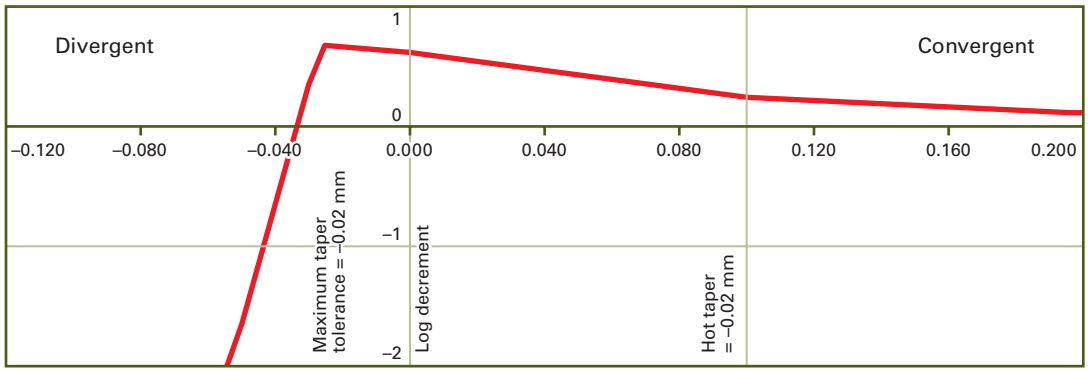
The starting point for the rotor-dynamic verification was an undamped critical speed analysis (UCSA) per API 617 during the compressor feasibility design study.[4] The first equivalent shaft was the result of a simple evolution of the previous (LPO) machine. Modifications of the scheme followed as the design proceeded to determine the final optimized shaft.

UCSA considers bearing character-

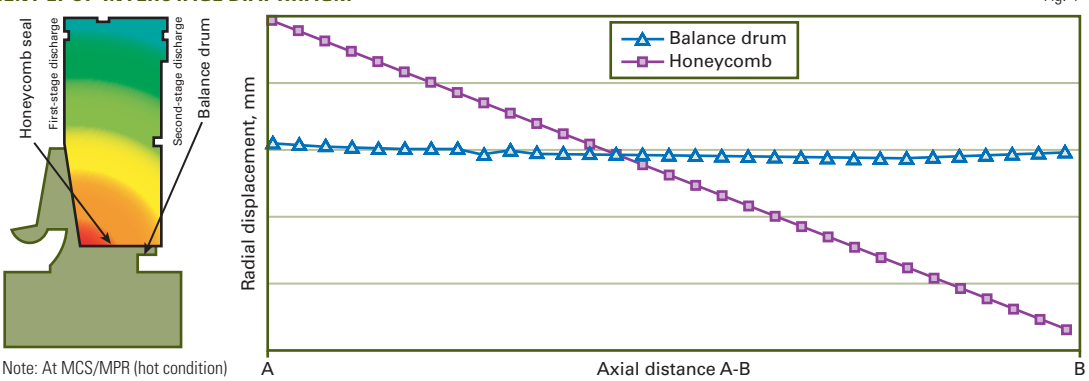
istics purely in terms of stiffness coefficients calculated with two different tools: an internal GE tool that has correlated well over many years with GE standard bearings, and XLTRC[2] from Texas A&M University.[5] The two sets of calculations provided a good match. The UCSA led to three decisions:

1. Increasing journal bearing diameter to increase the shaft stiffness and the damping effect from the bearings.
2. Increasing bearing journal clearances to increase the damping of the first mode.
3. Reducing coupling weight to increase the second critical speed. This also resolved the concerns of low damping ratios and low separation margins on the gearbox pinions at low load.

BRENT LPOP LOG DECREMENT Fig. 3



BRENT LPOP INTERSTAGE DIAPHRAGM Fig. 4



Note: At MCS/MPR (hot condition)

Rotor response

The rotor response to unbalance analysis adds the damping effect of the bearings to the system. Bearing characteristics calculations used the same tools as for the UCSA and again a found a good match between the two calculations.

The selected design included tilting pad journal bearings with five pads, load on pad, 0.6 offset pivot, and high preload. These journal bearings with a noncentered pivot have stiffness and damping coefficients that are frequency independent. This is in accordance with GE's experience and technical literature,[6] and allows the designer to follow a simplified synchronous stability analysis.

The results for the LPOP compressor confirmed the preliminary information obtained from the UCSA: the first critical speed (3,550 rpm) was well below the operational range and lightly damped; the second critical speed (8,700 rpm) was inside the operational range but highly damped.

The log decrement of the rotor and bearings system at MCS was 0.226 and hence close to Shell design and engineering practice requirements (minimum acceptable value is 0.2).[7] Further stability analysis included the effect of the seals and clearances.

Tests with different oil temperatures and bearing clearances showed that the second critical speed could sometimes be lower and more highly damped and sometimes higher and with less damping than in the nominal condition.

Synchronous vibrations seemed in the worst scenario to be manageable with slight changes to bearing clearances in case of problems during the machine run test. Selection of the bearing clearance that offered the best response over the wide operating range of the machine completed the design work with respect to synchronous rotor response aspects.

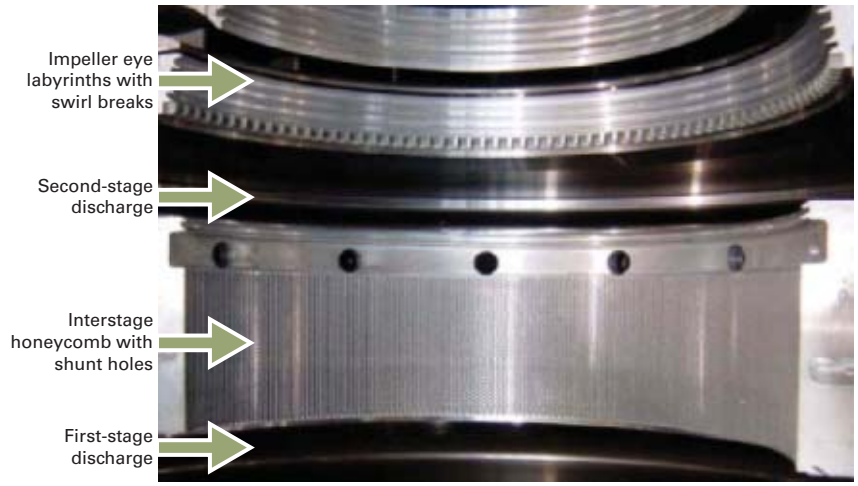
After selection of the internal seal for optimum rotor stability, a seal clearance study checked the potential for rubbing at the interstage balance drum. The analysis considered gravity sag and rotor bearing eccentricity and predicted no rubbing even for the most onerous condition, which occurs when operating at the alarm limit (MPR).

Stability analysis

A numerical model of the LPOP compressor was developed in XLTRC[2] to include all sources of direct and cross coupling, stiffness, and damping.[5] The

BRENT LPOP INTERSTAGE DIAPHRAGM SEAL

Fig. 5



primary analysis at MCS/MPR (maximum continuous speed/maximum pressure ratio) provided a check analysis at the MCS-choke condition. The manufacturer, client, and third party agreed to the following seal configuration:

- Impeller eye seals—toothed labyrinths with nominal clearance.
- Final balance drum seal—abradable seal with teeth on rotor.
- Interstage balance drum seal—tapered honeycomb.

The interstage balance drum seal near the center of the rotor is critical for rotor stability and generally the most important source of damping in this type of back-to-back compressor.[8]

A tapered honeycomb design for the LPOP machine guaranteed rotor stability. The LTFD and LPO machines had a stepped toothed labyrinth (Table 1). Moreover, to reduce the pre-swirl of gas entering the honeycomb, the design incorporated shunt holes in the interstage diaphragm.

The tapered honeycomb design needs correct modeling to avoid instability. Given particular conditions, a divergent honeycomb seal can exhibit strong negative stiffness, especially at low frequency.

Effective damping also can turn negative at low frequency. The ISOTSEAL code used for the analysis closely predicts the appropriate behavior and has been validated experimentally in the turbomachinery laboratory test rig.[9]

The tapered honeycomb seal is sensitive to the difference in clearance between the seal inlet and outlet. The design used a seal taper of 0.1 mm because this value is well centered in the stable region of the log decrement vs. seal-taper plot (Fig. 3).

A finite element analysis that considered thermal, centrifugal, and pressure effects determined the interstage diaphragm deformation, including the honeycomb seal and the balance drum (Fig. 4). The definitive honeycomb seal machining (cold) ensured that the honeycomb seal assumes the correct taper under working (hot) conditions.

The analysis at this point showed that the compressor was stable theoretically across the full operating range. The design, however, further incorporated a stability margin in the form of swirl brakes on the inlet of each impeller eye labyrinth (Fig. 5). A third party (SWRI) calculated that the swirl brakes increase the log decrement by 0.13 at MCS/MPR.

PTC 10 Type 2 testing of the final compressor with and without swirl breaks showed that the swirl brakes also had a positive effect on thermodynamic performance.[10]

LPOP construction

The design constraints imposed on GE limited changes to and maximized the reuse of existing equipment. Detailed design checks of the installed equipment for the new process conditions confirmed that no major equipment modifications were required external to the compressor. The brownfield implementation, however, posed its own challenges.

The platform cranes had to do all the lifts to avoid reliance on a lift vessel. Considering crane radii and dynamic factors, this limited the weight of a ship-to-platform lift to 18 tonnes and of a platform inboard lift to 35 tonnes.

The compressors were therefore dismantled after shop testing and packaged into custom containers for transport. A frame with an integral gantry crane provided a self-contained environment for offshore compressor reassembly prior to the shutdown. The assembly frame replicated the compressor baseplate supports, thereby allowing the use of the contracted special tooling.

Because no offshore hot-work (welding) was allowed, the installation required prefabricating all piping spools to exact dimensions. A 3D model of the new compressor within the module was developed based on an offshore laser scan survey of the existing configuration as well as a survey of the connection points on the new compressor. The work paid particular attention to the relative location of the spool termination flanges, flange angles, and bolt hole orientations.

Mechanical handling aids facilitated a safe installation (Fig. 6). The point-cloud data from the offshore laser scan survey provided a way to clash check and optimize the compressor installation path and temporary fixtures. The lift of the compressor went above the existing skid supports before the unit was moved off the skid and lowered onto the adjoining walkway.

After removal of the compressor piping spools, the work included construction of a temporary gantry within

the module. Fail-safe pneumatic hoists and trolleys operated from a remote console ensured a controlled lifting operation. The gantry was load tested onshore, match marked, and inspected on re-assembly to dispense with an offshore load test.

A temporary rail system, installed before the platform shutdown to minimize delay, provided the means to transport the compressors and the large tie-in spools, placed in cradles, through the module. The rail system distributed the compressor weight over the module structural members.

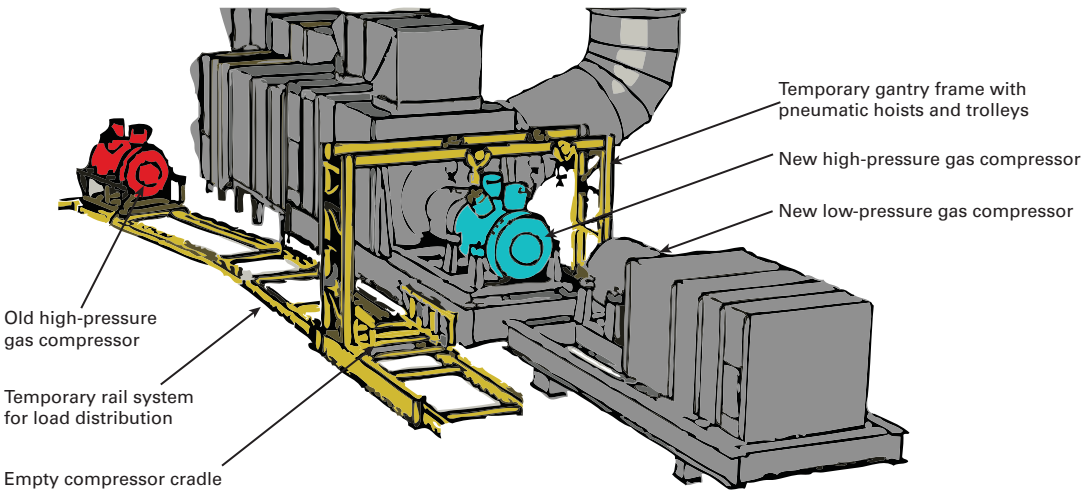
The cradles had built-in jacks to help realignment on the rails for direction changes and were pulled on skates using a chain hoist attached to the rail cross-beams. Onshore trials proved out all equipment and handling procedures, thereby minimizing the risk of problems offshore.

An onshore string test of the LPOP compressors was not possible. Design verification, API 617 mechanical run tests of each machine[4] as well as a successful PTC 10 Type 2[10] test mitigated the technical risk.

An offshore stability trial procedure was developed based on dynamic process simulations to explore the compressor operating envelope in a controlled manner and safely identify any potential limitations.

Offshore commissioning of the first of the three LPOP compressors on Brent Delta provided final confirmation that the design is stable for the complete operating range.

BRENT LPOP COMPRESSOR MECHANICAL HANDLING Fig. 6



Acknowledgments

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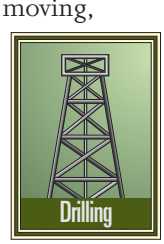
The new automated and self-elevating Rocket Rig (photo above) was unveiled in Oklahoma in September (Fig. 1; Ann Sherman Photography, provided by Cactus Drilling Co. LLC). The bull line attached to the hydraulic raising system (photo on right) is used to erect the Rocket Rig (Fig. 2; Ann Sherman Photography, provided by Cactus Drilling Co. LLC).

$10 million Rocket land rig takes off from Oklahoma

A newly designed, fast moving, self-elevating land rig debuted in El Reno, Okla., in September 2006. The triple rig can be erected in about 20 min and drill to 18,000 ft. It features fully integrated electronic controls and instrumentation in a driller's cabin from National Oilwell Varco.



Oklahoma's Cactus Drilling Co. LLC has finished Rig. 136,the first of four Rocket rigs currently under construction, and plans to complete and deliver the remaining three by January 2007. The first and second 1,000-hp rigs will go to work by yearend under 3-year contracts for XTO Energy Inc. (Fig. 1) XTO will use them to drill the Barnett shale in Tarrant and Johnson counties, Tex. The third and fourth rigs, both 1,500 hp, will drill for Newfield Exploration Co. under 2-year contracts. Newfield will use the rigs near Coalgate, Coal County, Okla., to drill the Woodford shale with a contained mud system.

Mast erection

The mast and substructure were designed by Ted Vora, at Houston-based Veristic Technologies Inc (www.veristictech.com). The raising system is unique, differentiated from both the typical self-elevating system and the Dreco slingshot system, which raises both mast and drawworks.

The Rocket Rig system uses hydraulic winches to raise the mast and the entire drill floor assembly with equipment, all in one single shot. The drill floor stays horizontal throughout the procedure, following an arc-path from near the V-door (mast-down position) to the hole (mast-up).

The fully erect mast is hoisted hydraulically by two spooled cables (Fig. 2).

Cactus Drilling has set up the first Rocket Rig to skid for pad drilling. XTO will pad-drill on 10-ft centers, and the substructure of the Rocket Rig

Rocket rig specifications

Table 1

Mast, substructure	
Mast, substructure design	Veristic Rocket Rig
Mast height	142 ft
Floor, clear height	25 ft, 21 ft
Mast capacity	800,000 lb static hook load
Substructure capacity	800,000 lb casing load 500,000 lb setback load
Hoisting, rotating equipment	
Drawworks	National 80-UE rated at 1,000 hp, driven by two GE 752 DC traction motors rated at 1,000 hp
Auxiliary brake	NOV DM236-M friction brake cooled by Halco BCE 2581019SS package
Rotary table	Hacker-Pyramid A 27.5-in. independent hydraulic drive
Traveling block	Veristic Technologies VT400-652 (400 ton)
Top drive	Varco TDS-11SA (500 ton) rated at 800 hp, powered by OmronIDM variable frequency drive (VFD)
Pipe-handling	Varco ST-80 iron roughneck, powered by Aberdeen Dynamics 18114-3 150-hp hydraulic power unit
Drilling control system	
Driller's cabin	NOV, climate controlled and pressurized
Controls	NOV fully-integrated electronic controls and instrumentation
Drilling system	NOV's EDS—electronic drilling system
BOP	
Annular	Hydril 11-in., 5,000 psi, type GK
Single/double ram	Cameron 11-in., 10,000 psi, Type U
Accumulator	T-3 Oilco Energy Services, 7-station, 220 gal
Choke manifold	Cameron 4⅛ in. x 4⅛ in., 10,000 psi
Mud system	
Mud pumps	Two Ideco T-1300 triplex pumps, each rated at 1,300 hp, driven by two GE 752 DC 1,000-hp traction motors
Shale shakers	Two Brandt King Cobra linear-motion shakers
Degasser	NOV D-1000-C vertical, vacuum-style
Desander	NOV 3-cone, 10-in.
Process pit	640 bbl, five compartments, 3 agitators
Suction pit	620 bbl, four compartments, 5 agitators
Trip tank	128 bbl
Power	
Engines	Three Caterpillar D398, rated at 915 hp
Generators	Three Kato 6P6-2400: 902 kw/1,288 kv-amp/0.7 pf (output capacitance)
SCR (silicon-controlled rectifier) system	OmronIDM with 3 generator bays and 10 section, Allen-Bradley MCC (motor control center)
Transport	
Estimated loads	29, without tubulars

can move forward while leaving other equipment in place.

Features

The new rig can build triple stands offline using a rotating, 90-ft mouse-hole. It features hydraulic slips, a Varco ST-80 iron roughneck, and a Varco TDS-11SA top drive (Table 1).

The mud system features two, triplex Ideco pumps, rated 1,300-hp, and NOV degasser, desander, and desilter.

Cactus chose to incorporate a North Sea rig feature from Scottish company P-Quip Ltd.—a hydraulic retention system for pump liners and pump rods. This holds proper tension on the pit liners, instead of having use a nut and sledgehammer.

The Rocket Rig can move in about 29 loads, not including tubulars.

Cactus

Before adding the new Rocket Rigs, Cactus Drilling had 34 rigs in the fleet, operating in the Midcontinent, the Barnett shale, the Permian Basin, South Louisiana, North Louisiana (Ark-La-Tex), and the Texas Gulf Coast. The fleet's depth capacity ranges 13,000-30,000 ft, 650-2,500 hp.

Cactus Drilling has about 900 employees and is closely held by Kaiser Francis Oil Co.

The rigs cost about $10 million each to build, and lease at a premium—about $3,000/day more than typical 1,000-hp land rigs—because of the integrated top drive, electronic drilling system, and reduced mobilization time.

Ron Tyson, manager at Cactus Drilling, told OGJ that the company has components or order for four more rigs, and would be willing to build more Rockets under contract if there is operator demand. "Everyone wants rigs that are automated and can move quickly." ✦

Workshops identify threats to process control systems

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Jason Stamp
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Recent industry workshops have identified the issues of cyber and physical security risks to process control systems (PCS). There are many cyber and physical security risks to the oil and gas infrastructure, and it is generally recognized that even a small process disruption could produce many serious consequences that result in safety, environmental, and economic impacts.

This article focuses on the characterization of the cyber risks associated with PCS and describes components of risk that can assist in understanding an organization's security posture and implementing effective mitigations and protection.

The increased connectivity between PCS and business networks and the widespread migration to off-the-shelf hardware and software has increased the exposure to outside threats and broadened known vulnerabilities. This has led to the increased awareness of PCS security and protection.

To address PCS risks, the Institute for Information Infrastructure Protection (I3P) has funded a multi-year research program to improve PCS security in the oil and gas industry (see www.thei3p.org/research/scada for more information on this project). Under this program, I3P hosted two PCS security workshops—which included oil and gas asset owners, PCS and security vendors, PCS researchers, and government officials—to explore the underlying security issues and discuss mitigation strategies.

These events occurred in June 2005 in Houston, and in June 2006 in La Jolla, Calif. Research and analysis performed by I3P were presented and interaction facilitated with industry through discussions about PCS security concerns, cyber risks for automation systems, emerging threats, and new technologies.

This article summarizes major concerns voiced at the I3P workshops and discusses a broader understanding of PCS security risks and solutions based on research and professional experience in this area. Risk is characterized in terms of threats, vulnerabilities, and consequences. Protective measures and business impacts are also addressed.

Industry can use this characterization as a starting point to assess major areas of concern in their own operations, possible consequences of an attack, and return on investment (ROI) of implementing defenses. Understanding and characterizing this risk will enable the development of strategies for preventing, detecting, mitigating, and recovering from cyber-security incidents with focused and defined objectives.

Input from industry collectively provides a strong basis for both decision-making and improvements with realizable, specific outcomes.

Critical industry observations

Input for the risk-characterization process was obtained primarily from industry stakeholders through workshops and interaction, gap analyses performed under I3P activities, and related PCS research. The first I3P workshop gathered a wealth of industry perspective. The second I3P workshop validated

the approaches towards technology, application, and emerging ideas on secure operations.

Industry concerns

Members of industry segments voiced their concerns at panels during the workshops. These concerns can be grouped into different technical domains:

- Wireless security. Security is lacking in wireless connectivity and remote access to enterprise systems. Wireless security must be addressed as part of the enterprise architecture. There is the 802.11 protocol in production fields, but a more secure, capable solution is needed across the infrastructure and in remote areas.
- Intrusion detection. Basic intrusion detection is often lacking in an architecture, which includes monitoring, event correlation, and alarms. This security control is essential to detecting and preventing attacks.
- Understanding and implementation of security. A comprehensive view and implementation of security is often missing; a piece-meal approach to security is common. Currently, there is sporadic or little implementation of controls across the system. One layer, such as a firewall or physical security, is not enough to prevent an attack. A layered, comprehensive approach is necessary.
- Legacy systems. Many legacy systems that have interoperability issues or hardware and software constraints are still in use. These systems have minimal security controls and are difficult to patch or upgrade, resulting in vulnerabilities without clear mitigation strategies and a weakening of the overall architecture. Addressing these legacy systems and developing a solution for protection is needed.
- Standards. No widely accepted standard for security implementation in control systems exists. Non-standard security controls are therefore applied over a variety of domains, including business systems, PCS, and physical (site) security. A comprehensive, layered approach is needed with guidelines for an enterprise approach to security.
- Training and awareness. Training and awareness of security configurations is necessary to prevent the incorrect implementation of security controls, such as firewalls.
- Design. Basic security, such as authentication, access control, and encryption, is not designed into many control systems. The need for add-on security can create implementation difficulties. Upgrades and added functionality to aging control systems can result in the introduction of commercial technology that can add new vulnerabilities. Considering security at the beginning and throughout the control system lifecycle is critical for continual, secure operations.
- Network structure. Many PCS are connected to business networks within the enterprise. Without separation or controls placed between the architectures, attackers have a potentially exploitable access path to gain control over operations. There is greater risk, therefore, to core functions and operations.
- Policies and plans. In addition to guidelines and standards in the approach to and implementation of security, enterprise level security policies and plans are needed to ensure security is implemented at the necessary levels of protection. The organizational divide that exists in many organizations between IT and PCS groups can thwart

Risk equation

Fig. 1

Threat (Resources) × **Vulnerability** (Weaknesses) × **Consequence** (Effect) = **Risk** (Business impact)

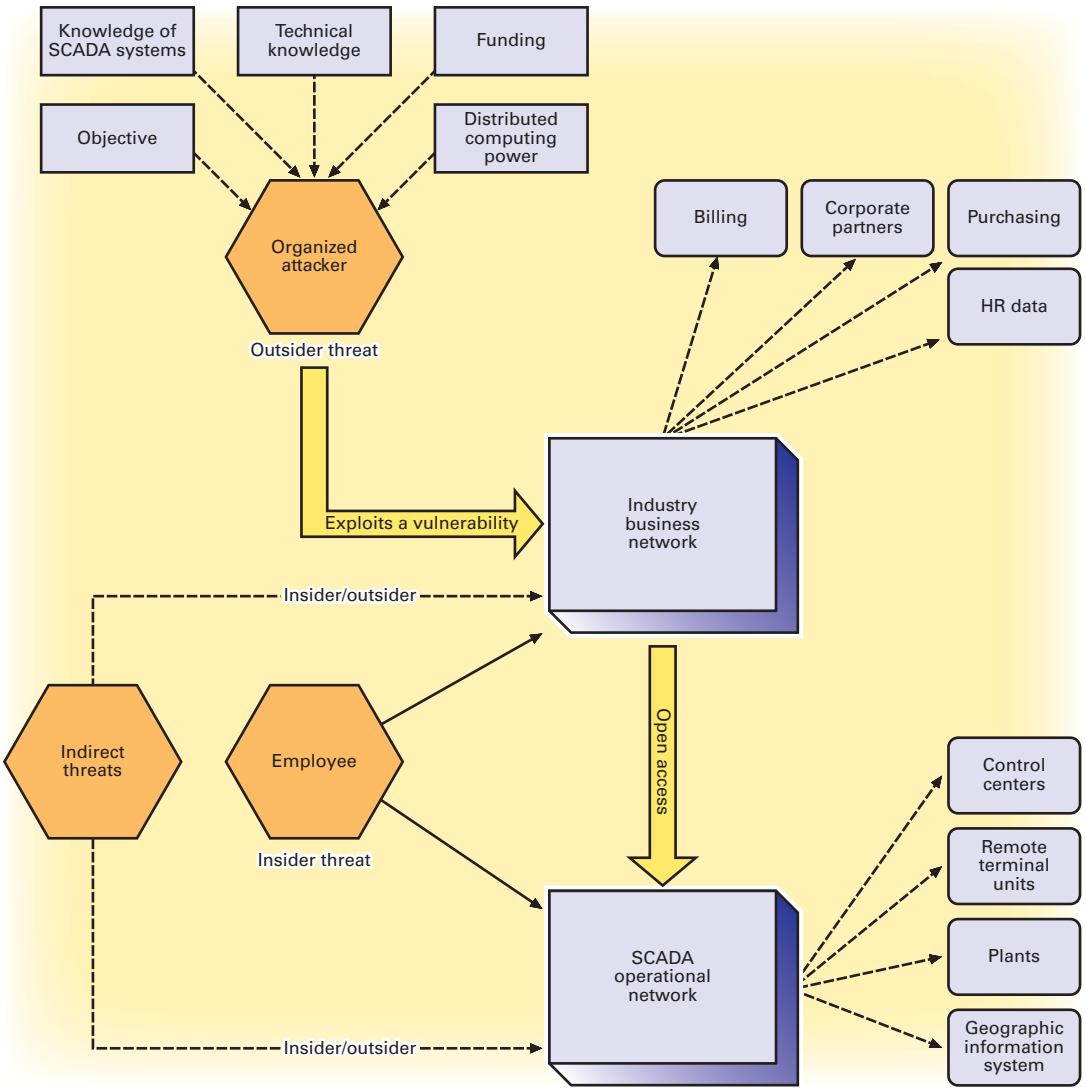
Discussion panel concerns

Table 1

Operator panel highlights	Vendor panel highlights	Shared, common concerns
Comprehensive security across spectrum of control systems is needed, not just patches or rudimentary security controls on systems.	Management must be engaged early in decisions about obtaining and implementing security controls.	Securing wireless capabilities as part of the network's overall security plan is necessary.
Interdependencies exist on other critical infrastructures, such as telecommunications.	Awareness and training amongst operators and integrators on security controls is needed.	A set of widely accepted standards, guidelines, and best practices would be very useful to industry in planning and implementing security across architectures.
There is a need for overall intrusion detection and prevention.	An industrial plant network should be considered a multi-layered enterprise rather than a collection of individual nodes.	An understanding of how interoperability affects security within the enterprise by various levels within an organization is necessary.
Facilitating an understanding of security needs and implementing a solution requires engaging stakeholders at all levels of an organization, including asset owners and managers.	Clearly defined roles and relationships between IT personnel and control system engineers are needed.	Security should be addressed by including it in the overall control system and network lifecycle.
Industry stakeholders in any position must be aware that the oil and gas, and national critical infrastructure as a whole, is considered a "target of opportunity" to threats.		Legacy systems will continue to operate in the oil and gas infrastructure and must be considered when securing architectures.
		Realization of economic justification for implementing security throughout the enterprise is critical.

SCADA ATTACK MODEL

Fig. 2



effective policy and procedure implementation.

• Incident handling. Part of robust security includes data backups as well as the preservation and analysis of forensic data. Developing a plan for maintaining this data is important to understand and mitigate future attacks.

Interestingly, concerns from industry members often reflect the body of industry they represent. For example, panel members at the first I3P workshop were divided into operator and vendor groups and it was interesting to note the differences and commonalities in their responses.

This emphasizes the need for increased communication across the stakeholder community in a multi-front approach to security.

Table 1 outlines highlights from both panel discussions.

Risk characterization

Characterizing risk for control systems is different than identifying risks purely associated with finances, safety, or IT. It is a blend of all those risks with their effect on operations and the ability to perform the critical functions necessary to continuously provide a product or service, e.g., refine crude or transport refined products in a pipeline.

In this case, risk is characterized in terms of threat, vulnerabilities, consequences, and impact on business (Fig. 1). Organizations that identify and fully define these components find them to be the first step in securing operations.

Threat assessment

Creating an understanding of threat and an awareness that critical infrastructure can be an attractive target is generally the first step in protecting critical operations.

The goal of a threat assessment is to determine the likelihood of an attack against a given target. Threats to control systems in the oil and gas sectors can be derived based on access, intent, and system vulnerabilities. A typical threat assessment includes:

• Identification of known and potential adversaries.

• Analysis of each adversary's motivations, goals, and capabilities.

• Assessment of the threat posed by each adversary to critical system assets.

When applied to a specific control system or set of systems, a threat assessment is normally quite detailed and specific.

Threats can be characterized by both their level of access, motivations, and their capabilities. A threat implies that an individual or group has the ability and access to carry out a

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CHARACTERIZED VULNERABILITIES

Table 2

Vulnerability category	Description, examples
System data	Lack of understanding of what data is considered sensitive, how it should be separated and protected.
Security administration	Lacking policies, standard procedures, training, and corporate/industry security plans. Formal configuration management needed for upgrades, legacy plans, and patching.
Architecture, design	No integrated security in SCADA designs. Security must be an add-on. Centralized storage or control mechanisms are single points of failure.
Platforms	Patching, backups, passwords, offsite security, application security, and security policies for access control and file sharing are needed. Physical access control is lacking.
Networks, communications	Wireless security, monitoring, encryption, access control, boundary security, and standards for implementation are all needed.
Incident response, handling	Response plans are lacking, as well as backup and disaster recovery plans. Forensic data collection and analysis needed. Redundant operational capability is beneficial.

process that creates damage to, or exploits, a system for a specific gain. The result can have physical, economic, environmental, and human consequences.

Threats to control systems can come from both insiders and outsiders and can vary in capability. Capability is a function of resources such as time, money, computing power, technical knowledge, and intelligence resources.

Threats and their capabilities are often divided into several specific categories such as nation-state, international terrorists, domestic terrorists, or hackers. Although individual hackers may have malicious intent and technical knowledge, organized cyber-terrorist groups often possess the resources necessary to carry out an effective, distributed attack that produces severe consequences.

Characteristics that can affect a threat's success in an attack include funding, goal intensity, stealth capability, access, cyber skills, implementation time, and cyber-organization size.

A targeted organization has no capability of controlling these characteristics, with the exception of access. An organization's physical and cyber defenses are therefore critical.

Access to information about control systems, including design details, weaknesses, and protective measures, are often available on the Internet. Likewise, industry and corporate-specific data can easily be gathered from basic Web investigative techniques.

In combination, this information can be very useful to a threat planning a coordinated attack and, because this information is readily available, increased protections implemented on networks become the primary line of defense. This defense can ensure operations are not disrupted or compromised.

Because these threats exist today and organized cyber-terrorists continue to gain resources and capabilities, industry must address this as a present and future issue.

Fig. 2 illustrates an attack and lists its potential effects, which include downtime, exploited information for financial gain, strained strategic partnerships, safety hazards, and damage to infrastructure.

For example, once a threat accesses a control system, often through a business system, it is possible for the attacker to assume privileges as though he or she were a trusted insider. This control could potentially result in access of control systems that manage the lifeblood of an organization.

In some instances, threats are not targeted toward an organization or one specific goal. For example, widespread worms and viruses can create an overall slowdown and damage, but are generally not used to produce a specific effect on one organization. Likewise, untrained employees or accidents by employees can pose a threat to the organization by inadvertently creating security holes.

These indirect threats should be considered when addressing security in control system operations in addition to threats with targeted, malicious intent.

Quantification of threat and understanding how that threat relates to their own assets can help industry members take the initial steps in building a secure operating environment.

Vulnerability analysis

A vulnerability is a weakness that exists in a system, network, application, or process that can be exploited by a threat to create an adverse effect. Examples of vulnerabilities can include open ports, unpatched software, dated virus protection, or exploitable system services.

Vulnerabilities can be identified through a frequent assessment process or review, and can be reduced using different mechanisms. These mechanisms can include patches, access controls, network protocols, monitoring, and physical controls.

Vulnerabilities discussed at the I3P workshops include descriptions of broad categories as well as specific examples. Table 2 outlines these categories.

Understanding vulnerabilities and how they exist and evolve within an architecture is necessary when selecting and applying security protective measures. As a whole, the oil and gas industry is becoming more aware of vulnerabilities and how they arise, and are now looking for ways to mitigate them.

Vulnerabilities can be identified and reduced, but continual maintenance is required to safeguard elements of the architecture and operations as a whole.

Vulnerability assessments are particularly useful in determining the current state and robustness of an organization's architecture. Identified technical vulnerabilities, however, are often not meaningful to management when making choices to invest in security.

Vulnerabilities must be viewed as only one part of a whole when considering risk to control systems and the organization. Different members of the organization, and of the industry, may have different priorities. Awareness and communication is required to create a comprehensive security plan that prioritizes assets and provides guidelines for applying protective measures.

Consequences

A consequence is the resulting loss, damage, or impact resulting from a threat successfully exploiting a vulnerability. Consequences can include access and alteration of data, disruption of service, destruction of the system, and severe environmental and public health results of an attack.

Based on the threats and vulnerabilities discussed, consequences to control systems could potentially be severe due to physical and operational effects. Some consequences can have serious effects on business operations, to the industry as a whole, and to the national critical infrastructure.

Understanding consequences of a successful attack can help an asset owner identify areas of the architecture that need higher levels of protection and prioritize the deployment of protection mechanisms. The consequences of an attack have direct effects on the organization or industry as a whole.

These effects include:

- Physical effects that encompass direct consequences of control system misoperations. The most devastating potential effects include personal injury or loss of life. Other effects include the loss of property (including data) or damage to the environment.
- Economic effects are secondary results of physical impacts ensuing from an attack. Physical impacts could result in repercussions to system operations, which in turn inflict a greater economic loss on a plant or company. On a larger scale, these effects could negatively affect the local, regional, national, or possibly global economy.
- Social impacts or public image. A side effect that is often overlooked is the consequence of losing national or public confidence in an organization or industry. It is, however, a very real objective and one that can be accomplished via a cyber attack.
- Impact on national critical infrastructure. Industry sectors are a part of the whole national infrastructure. Loss or adjustment of capacity and delayed purchasing and transportation create secondary effects on the national infrastructure. Likewise, attacks on other industries in the national infrastructure can affect the oil and gas sectors. An example reiterated at the workshops is the reliance on the telecommunications industry.

Table 3 breaks down example consequences, effects, and overall impacts. If a threat exists that can exploit an existing vulnerability, any number of these consequences can occur.

Although Table 3 does not contain every potential consequence, it is important to understand how a threat with an opportunity can create negative consequences. Understanding components such as the network, platforms, system data, and operational policies can help in creating a layered approach to protecting the infrastructure.

Business effects, ROI

Determining the consequences of an attack based on an analysis of threats and vulnerabilities is useful to understanding exactly what to protect on control system networks. Workshop participants recognized, however, that implementation of security controls is often an expensive task. There must be a visible ROI to justify the expense of deploying additional security technology such as hardware, software, or physical controls.

It is probably most analogous to insurance, although the financial benefit to stopping attacks on a daily basis is rarely quantifiable. An asset owner must therefore consider the potential cost of not employing these controls. Downtime and the halted production or transport of oil and gas can be directly translated to profit losses.

To some extent, safety can also be quantified in the number and cost of accidents and injury. The social impacts, however, such as quality of life and the effect on critical infrastructure at a national level are not easily measured.

For example, an organization must consider how customers and the market will view it if it suffers a publicized attack. Likewise, if a corporation's unsecured control system network is used as an entry point or active node in a coordinated attack on the national infrastructure, it can have devastating business consequences in addition to the infrastructure damage.

This scenario is not unlike that of airline companies who have suffered a business loss or faced near bankruptcy due to eroding public confidence caused by a hijacking or safety-related crash. The price of inaction can be far costlier than implementation of security to the architecture.

Protective measures

Defenses against cyber attacks are most effective when applied in multiple layers of security through what is sometimes referred to as a "defense-in-depth strategy." Often specific controls are implemented that only partially address protection, such as firewalls, but protection and defense must be viewed as a comprehensive task.

Vulnerabilities can be mitigated and threats deterred by using a layered approach that groups areas of concern. These logical areas that require defense can include data, applications, platforms, networks and communications systems, and perimeter systems. Breaking apart these layers, organizations can map their processes and determine exactly what needs to be protected and how to defend it.

TECHNICAL EFFECTS, RESULTS

Table 3

Technical consequence	Effect	Result
Access, read, alter data	• Theft or alteration of corporate, industry data. • Theft or alteration of critical operations data used for future attack. • Theft of personnel data. • Divulge corporate trading partner information. • Billing and purchasing data changed.	• Economic (i.e., loss of trading partner, market instability, downtime). • National critical infrastructure (i.e., weaknesses in operations may be exploited, downtime, unavailability). • Quality of life (i.e., identify theft, negative publicity for corporate and industry). • Safety issues. • Physical effects on equipment.
Gain control of SCADA systems	• Full operation of control systems. • Can alter, stop, or destroy equipment and operations.	
Denial of service	Halt operations on process control, business systems, or telecommunications.	
Access systems as jump points	Use systems as part of a large scale, coordinated attack.	
Physical access to SCADA systems	• Can physically damage systems. • Access as a trusted insider if electronic access controls are not in place.	
Introduction of a virus, worm	Can slow or halt operations.	

These defenses and protective measures could include:

- Access control.
- Authentication.
- Applied operating system and platform security.
- Data separation.
- Functional separation.
- Network design.
- Encryption.
- Patches, upgrades.
- Monitoring and event correlation.
- Backups and disaster recovery plans.
- Alerting mechanisms to discover coordinated attacks.
- Redundancy in connectivity.
- Firewalls and perimeter security.
- Secure remote access.
- Trusted computing platforms.
- Accepted measures for risk characterization elements.

In combination, and with an operational focus, these measures can provide the best defense against attack. Understanding the critical functions and data types in the system and applying appropriate security controls to segregated architectural enclaves is essential for a comprehensive defense.

In addition to the use of technology in security controls, a comprehensive and well-understood security plan is required. This plan should address physical, personnel, and information security, and should mandate as many controls as required to secure operations. In this plan, it is also necessary to address the technology lifecycle.

As operations and equipment evolve, security must be fluid and provide the functionality required by the current situation. In addition to lifecycle planning, legacy systems must be assessed and a methodology developed for either upgrading or replacing these systems.

In developing a plan and applying controls, forging a common understanding among different industry and organizational groups is essential. This means creating awareness and discussion among all stakeholders to include asset owners, vendors, IT personnel, operators, and management. Involving and obtaining feedback from members across the enterprise can result in a security plan that is most effective while ensuring continuity of operations.

Further work

A growing understanding of threat, vulnerabilities, and consequences in the oil and gas industry can lead to effective implementation of security technology and methodologies. These implementations will produce inherently secure operations, ensuring reliability, continuity, safety, and important steps toward a secure national infrastructure.

Implementing robust security measures across facets of an organization takes communication across all levels of the organization, established objectives, and a committed effort to ongoing maintenance. Because all threats cannot be eliminated and vulnerabilities continue to evolve, a layered approach to security and a comprehensive implementation plan is necessary.

Continued collaboration between industry and researchers will yield new technologies and approaches that mitigate risk and foster a secure operating environment. A third I3P workshop is planned for February 2007 that will include demonstrations of common vulnerabilities and associated mitigation tools and techniques.

This I3P effort is coordinating with other PCS security research programs and industries to develop ideas for comprehensive security. These activities will yield an accurate picture of the most important issues.

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Best practices improve control system performance

David Shook
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PROCESS CONTROL—1

A holistic, best-practices approach will help refiners and petrochemical plant operators sustain and improve the performance of control system assets.

In many plants, there is a significant gap between the long-term benefits promised and those actually delivered in the long term by multivariable predictive control (MPC) assets. The difficulty of diagnosing and resolving issues with MPC controllers results in the eventual failure of many systems.

Performance can be sustained when the application is monitored and maintained. Effective MPC application maintenance requires the plant owner to monitor many interacting systems, including the MPC itself, regulatory controls, and instrumentation. It also requires effective work processes and documentation of the benefits of the application being maintained.

This first of two articles, discusses MPC systems, causes of poor performance, and the best-practices approach.

The conclusion, next week, will discuss a case study that describes how a particular software solution facilitates the maintenance of an MPC controller, quickly identifying problems in the MPC itself and in the regulatory control and instrumentation layers.

Process control

Constrained MPC has been widely adopted in the refining and petrochemical industries worldwide. In most cases, these controllers are designed to push and maintain a plant at its most profitable operating point over extended periods. These types of technology are a key element for corporations in achieving pacesetter status within their respective industries.

Despite the industrial success of implementing these technologies, realizing the benefits they can deliver over the long term has proven to be a significant difficulty. It is not uncommon to see controllers disabled altogether, or controller limits pinched in by operators, leaving engineering or operations management to explain why this asset is not delivering expected benefits.

Model-plant mismatch, constraint problems, misbehaving analyzers and on-line estimators, poorly tuned regulatory controllers and sticky valves are common faults with these types of controllers. Complicating matters is that maintenance and support organizations have been downsized, leaving fewer resources to maintain both existing and future applications.

One solution to the problem of maintaining benefits of MPC applications with constrained resources is to use systems to monitor and diagnose problems with MPC controllers, and with the foundation of regulatory control that they reside upon. This article explores a best-practices methodology to ease the support and maintenance challenges associated with these types of controllers given new economic realities for process companies worldwide.

Background

MPC is distinct from other control technologies in two fundamental ways. First, all MPC controllers use dynamic models that link the controlled variables (CVs) and the manipulated variables (MVs) in a process. These models allow the controller to effectively predict the future behavior of the process.

Second, a mathematical algorithm (usually a linear program—LP) calculates the most efficient method of moving the process to and keeping it at the desired constraints.

The deployment and use of MPC is now commonplace in the refining and petrochemical industries. In a recent survey paper, Qin and Badgwell describe how over the past two decades thousands of applications have been developed and deployed worldwide.[1]

MPC benefits are generated directly from its ability to control and maintain a process at constraints that represent the most profitable operating point at a particular instant in time. Payback in most implementations has been reported in months and in some cases weeks. The practical result of operating any of these processes near their constraints have typically been reported as:

- Higher plant throughputs.
- Higher yields of more valuable products.
- Reduction in product quality variations.
- Lower energy consumption.

• Improved unit operability and stability.

Although the relative cost of implementing these applications is small, maintaining these assets and ensuring they continue to accrue benefits over the long term has proven to be a much greater challenge. It is now common to see MPC controllers shut off, or constraints pinched in such that they are delivering little benefit. Users regularly report that without the proper maintenance and attention, the benefits are difficult to sustain.

Controller assessment, monitoring

Throughout the process industries, "operational excellence," "continuous improvement," "six sigma," and similarly named programs target improving the corporate bottom line by improving operating efficiencies. MPC, often implemented under one of these programs, has helped significantly improve plant performance.

Unfortunately, during the life of an application, controllers may go through several cycles in which the controller is shut off and recommissioned. Worse, the controller may be abandoned altogether if it is troublesome to maintain. It is common to find MPC and real-time optimization (RTO) applications delivering only 50% of their original value within 3 years. Within 5 years, there is often a project initiated that closely resembles the original.[2]

Shell recently noted that advanced process control (APC) uptime averaged 86% in a survey and a Solomon study on ethylene plants showed average controller up-times of 77%.[3]

MPC applications typically take one of four paths depending on the level of support and monitoring they receive. The path chosen, conscious or otherwise, affects the application performance tremendously (Fig. 1):

• 25% fail within just months of commissioning.

• 40% fail within about 3 years of commissioning with inadequate support and no monitoring.

• 25% continue to deliver reduced benefits albeit reduced with good support and no monitoring.

• 10% will deliver increased benefits with adequate support and online monitoring.

Poor MPC performance

There are two groups of factors that affect control performance, technology and organizational factors. In any solution to this problem, both must be addressed to sustain long-term benefits from improving the performance of these assets.

Technology factors

Several factors inherently related to the technology used during the deployment of MPC are known contributors to the decline in performance of any MPC application. These include:

• Poorly performing regulatory controls or faulty instrumentation.

• Faulty or poorly performing process analyzers (gas chromatographs, etc.) and online property estimators.

• MPC model error.

• Disturbance problems.

• Constraint issues.

• MPC tuning.

All MPC applications are built on a foundation of regulatory and advanced regulatory controls. Ironically, this hierarchy is often depicted as a pyramid synonymous with enduring strength (Fig. 2). In reality, it can be as fragile as a house of cards with each layer dependant on all of the layers below functioning well.

Each element in the regulatory control loop from the primary sensor to the final control element must perform well in order for the advanced controller to also perform well. This is of course why one of the first steps in any MPC project involves a regulatory and instrumentation layer tune-up. Valves are fixed, transmitters calibrated and controllers are tuned accordingly prior to the implementation of any advanced controller.

Unfortunately, over time the regulatory controller performance also declines. Control element and sensor performance, controller tuning, and controller design are the top causes of poor regulatory control.

Several studies have been done across industries and have documented that anywhere from 40-80% of the regulatory controls in a process plant can be significantly improved.[2 4 5]

The effect of regulatory controller performance on MPC performance can be significant because poorly performing regulatory controllers affect the accuracy of the MPC models as well as the effectiveness of the MPC control action.

Online analyzers such as gas chromatographs and inferential property measurements are commonly used as CVs in the design and deployment of an MPC controller. Online analyzers are installed to measure important plant quality variables and are usually expensive, complex, and difficult to maintain. To compensate for this, as well as for the sample delay induced by most plant analyzers, online property estimators are used.

These estimators or inferential models use auxiliary measurements to infer the property measure of interest. Gas chromatographs may take more than 15 min to analyze a sample so estimated values are used in the control application between analyzer samples, permitting control action to take place often than once a sample. Estimators also provide a useful means to cross-check analyzer results; a large discrepancy between the estimator and the analyzer often indicate the analyzer result is suspect.

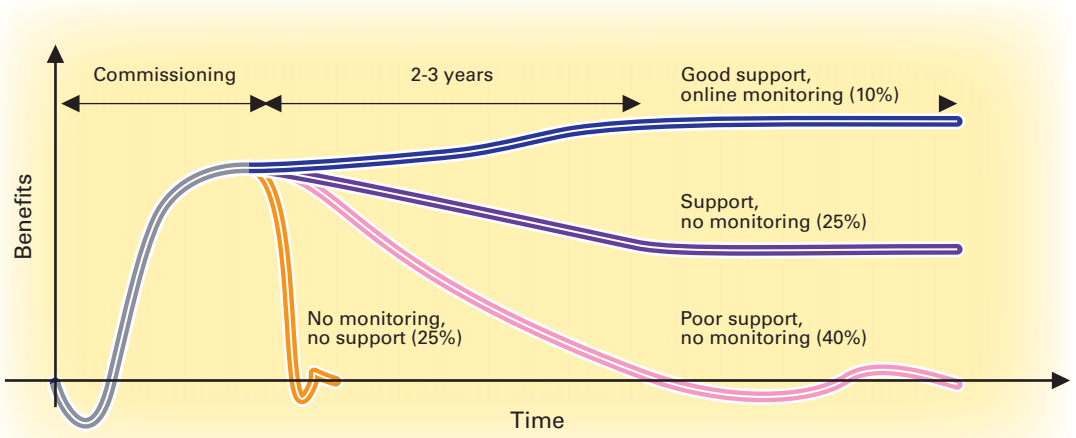
MPC-specific issues

Specific problems with the MPC controller itself of course prevent an application from generating benefits.

The simple fact that MPC controllers optimize the process in the presence of physical constraints allows them to generate the significant financial benefits that justify their implementation. Constraint handling ensures the MPC controller is keeping the plant at or near an economic optimum. The effect of

POSSIBLE MPC PERFORMANCE

Fig. 1



active constraints, however, is to change the effective process matrix and the effective controller gain.

The controller can therefore change behavior significantly as the active set of constraints changes. Bakker[3] provides an excellent discussion of the need for monitoring active constraints; this can assist in determining the value of plant debottlenecking projects that would mean relaxing that constraint.

MPC controllers are uniquely able to make use of feedforward information. The models provide an excellent means of predicting the result of an anticipated disturbance, allowing the controller to respond in a coordinated way, which prevents undesired effects. Unfortunately, it is impossible to anticipate every significant disturbance at each operating point that will affect the controller's performance.

Over time, it is necessary to re-assess the significant disturbances that affect the MPC controller to determine whether they should be added as feedforward variables or if existing feedforward models are adequate. The relatively slow scan rates and detuned nature of most MPC control applications imply that the controller is ill-equipped to deal with fast disturbances.

MPC controllers use models to calculate both the response of the process if no control is taken as well as the optimum control action to take based on current conditions. Model errors cause controllers to over or under-react, react too soon or too late, and worst of all, decrease a controller's ability to anticipate.

Model degradation can occur with something as simple as heat exchanger fouling. Changes in production rate, pressure profile across the plant, utility allocations can all result in models that are no longer adequate.

Troubleshooting model problems is not always a simple task because a large MPC controller with will have hundreds of models. On a large controller, determining if in fact model performance is the problem can be challenging, let alone isolating the specific model set that is responsible.

Organizational factors

Organizational factors that affect MPC performance are more critical than the technology issues. In the absence of technology, a good organization will always succeed; whereas technology alone without organizational support cannot achieve results.

Organizational factors considered are the organization's business goals, management support for advanced process control, human resources, and work processes in place at the operating site.

Business goals

On the business side, changing market conditions can dramatically influence the performance of an MPC application that was commissioned under a particular set of operating conditions. Changes in product demand, feedstocks, plant rates, product mix, or energy prices will all affect performance of an MPC controller. If business conditions change significantly or often, the goals that were critical in justifying the controller implementation initially, typically no longer apply.

Consider an MPC application in a plant where the business conditions have changed. Instead of the plant being sold out of product where the primary business objective is to maximize throughput, the plant is now running at lower rates and the business objective has changed to minimizing operating costs.

The new operating objectives create three potential problems with the existing controller:

- Tuning. The effective tuning at any given instant depends on the initial tuning, process dynamics, and current constraint set. The effective controller tuning depends not only on the original tuning, but which manipulated variables are available to move the CVs and which are saturated. Those MVs that are saturated are effectively removed from the control calculation. This can change the effective gain of the controller when the more effective MVs are saturated. A controller that is tuned when the plant is operating at maximum rates may not work effectively when the plant is operating at a different operating point.
- Constraints. The optimum operating point will be at different constraints

Assessing the Financial

Opportunities and Operational Challenges

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Independent operators are playing a vital role in oil and gas exploration and production, and their increased participation in the international E&P arena has created information needs particular to that group.

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when minimizing cost as opposed to maximizing rates. New constraints mean that new MVs are saturated and new MVs are available to control the process. Because it is likely that the controller was not commissioned with this set of active constraints, it may perform poorly. Mitigation may require controller recommissioning or even a redesign.

- Models. Because the plant is now running at a different operating point, process dynamics may be significantly different. MPC controllers rely on models to predict the effects of control moves and disturbances. If the models do not reflect the current dynamics, the predictions will be poor resulting in poor control.

Management support

Management personnel are typically sold on the benefits of an APC project before implementation. Because MPC technology is mature, vendors are able to quote typical results in similar facilities and the project is given the go-ahead.

An average crude unit MPC controller implementation, for example, will exceed several hundred thousand dollars in cost, but will return this investment many times during the life of the application, with payback within the first year of operation. On a typical project, at completion of the job, results are typically delivered as promised and everyone is satisfied with the results generated.

For many reasons, several months after the project team has moved on, the application may no longer be in service. Management is faced with the dilemma of why a significant investment in technology, time, and resources has not continued to accrue benefits to the business. Although management has bought and paid for the initial application, they typically have little day-to-day insight into the long-term performance of these applications. They are therefore challenged in attempting to make sound financial decisions regarding the ongoing support and maintenance.

Human resources

MPC controllers are typically commissioned and maintained by well-trained and skilled process control engineers. At the beginning of an MPC project, these resources are typically employed either on a contract basis from a control vendor's organization, or from within the organization itself.

An assumption often made by management is that when implementation is complete, the project team will maintain the applications over the long term. Often, however, the control engineers that commissioned the controllers move on to new projects often with little or no overlap between implementation and support personnel; documentation from the commissioning team is often inadequate to effectively maintain these systems.

Additionally, many skilled control engineers leave these organizations, often leaving a large number of legacy applications to be maintained by a smaller, less-skilled workforce.

Similarly, maintenance groups have been asked to do more with less. Fewer instrumentation and electrical (I/E) resources are monitoring more regulatory controllers. A ratio of several hundred regulatory control loops per maintenance person is not uncommon.

Because good regulatory control performance is a necessary requirement for good MPC performance, the lack of routine regulatory controller maintenance is a significant contributor to the inadequate performance of an advanced controller.

Operations staff, of course, interact on a day-to-day basis with the control applications implemented in their area. As a general rule, as long as these applications make for a smoother operation and do not make the operators' job functions more difficult, they will remain in service. Controllers that are pushing constraints that are illogical or not understood by the operator will be adjusted or shut off quickly.

A well-executed advanced control project includes key operations personnel not only to provide valuable process insight, but also to gain acceptance for the new technology and provide critical operator training on the use and troubleshooting of the application.

With adequate training, insight, and skill to identify performance degradation early, operations personnel are invaluable at spotting trouble and providing the process control engineer with valuable diagnostic information. Conversely, if the operators do not understand the application, its purpose, and limitations, or if it causes too much extra work, it will likely be unused.

Despite advances in the ease of use and tools to more effectively deploy and support these applications, knowledgeable well-trained human resources still remain a prerequisite in maintaining the long-term performance of these applications.

Maintenance work processes

Another cause of the decline in MPC performance is the lack of effective work processes and methods to support these applications and underlying regulatory controllers. Work processes are the methods and procedures by which the organization addresses the technical issues described previously.

Most companies we have encountered working with MPC applications do not use rigorous work processes to address both the technical and organizational factors that affect MPC performance. Maintenance on the MPC layer is typically done by control engineering personnel. A single engineer may have several control applications that he is responsible for as well as other responsibilities in the plant.

The most commonly used criteria to determine if maintenance is applied to an application is the "service factor" and operator feedback. Both are good measures of MPC performance, but should not be the only criteria by which decisions are made to spend money maintaining an application.

Diagnosing MPC problems is another matter. It can take days or even weeks to diagnose problems with large MPC applications. Without the proper tools and

work processes, the control engineer typically looks at tens or even hundreds of trends to isolate the cause. Obviously this is a time-consuming, laborious process.

Because there are hundreds or even thousands of regulatory control loops in a plant, maintenance is typically done on an ad-hoc basis in the absence of a control performance monitoring system. At best, valves and sensors may receive maintenance on a scheduled basis; but in general, loops causing significant operational issues are addressed in order of priority once they have caused enough trouble to be noticed. Maintenance planners and I/E staff do their best to get to the high-priority problems, leaving most others waiting until they become a higher priority themselves.

Currently, the work process to control maintenance at both the regulatory and MPC layer in most organizations is reactive. Problems occur and control engineers or maintenance personnel respond applying corrective maintenance where it's believed necessary.

In most organizations, maintenance is done based on priorities set by a combination of operations, maintenance, or engineering personnel. In the absence of objective data of which applications are misbehaving and why, decisions where to apply maintenance is done subjectively rather than based on any evidence of economic payback. In most instances, the "squeaky wheel" receives the most attention.

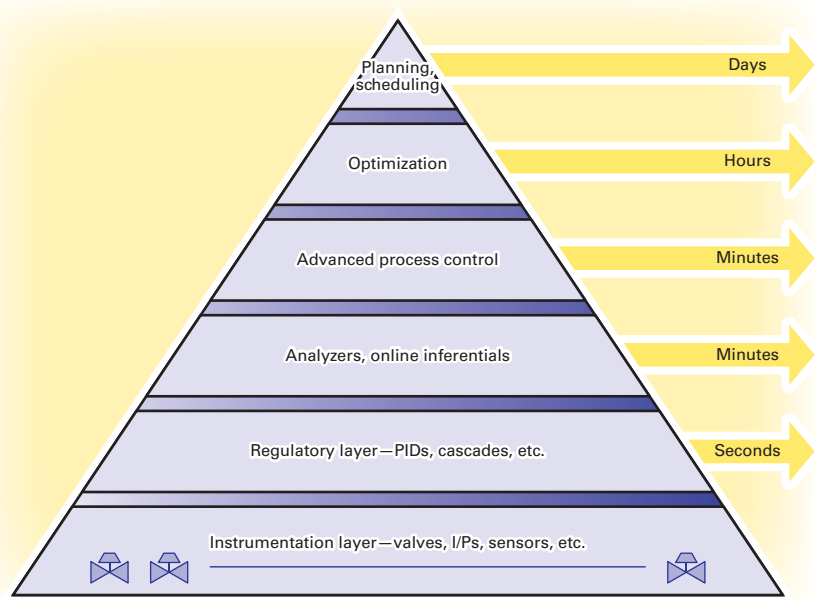
Best-practices approach

Corporations that are successful in implementing and maintaining MPC applications long term have adopted a best-practices approach to the problem that involves implementing work processes that target both the technical an organizational factors that limit sustained performance of these applications.

In general, the work process will include:

- Documentation and management of change procedures.

TYPICAL PROCESS CONTROL HIERARCHY Fig. 2



- Control monitoring and reporting.
- Effective diagnostic and troubleshooting and maintenance tools.

Documentation, management of change

Successful control applications require rigorous ongoing support of management. Critical to management support, however, is understanding what benefits the applications have delivered to date, and what ongoing benefits are currently generated.

Applications in which ongoing benefits are clearly documented are likely to receive the necessary maintenance funding required to keep them performing optimally. Ongoing monitoring of the benefits accruing from the application, either directly (via an online benefits estimator) or indirectly, by statistically measuring changes to the CVs with the controller in and out of service, is a necessary requirement for ongoing management support.

Brown described perhaps the most rigorous method of documenting MPC benefits.[6] Not every application must be audited as rigorously, but it is important to document the actual benefits that accrue from an MPC project.

Rigorous technical documentation of the application is also necessary. Documenting design and implementation details, maintenance records, and ongoing operating details help ensure the application is kept running smoothly. Understanding the performance history of an application as well as the previous maintenance and upgrades help ensure that experienced and new staff are able to effectively maintain it.

A management of change process ensures that upgrades are documented and that they are not made without the knowledge and approval of appropriate individuals in the organization.

Control monitoring, reporting

In our experience, if the performance of these applications is not regularly measured and made visible to those who own the applications in the plant, the application cannot be sustained for the long term.

Because MPC is at, or close to, the top of the control hierarchy (Fig. 2), the lower layers must function properly for the MPC to deliver benefits. Monitoring and maintaining these assets is as

important as monitoring the application itself.

Because any one of these layers can be responsible for problems with the MPC application, an effective monitoring application will link MPC performance with performance of the other layers including the estimators, regulatory controls, and instrumentation. Ideally, the application should support an investigative workflow that flows from symptom to cause wherever it happens to be.

REQUIRED INFORMATION FROM MPC SYSTEM Table 1

Application owners	Controller performance factors			
	Utilization	Performance	Diagnosis	Benefits
Board operator		√		√
Instrumentation, electrical technicians	√	√	√	
Control engineering	√	√	√	√
Plant operations	√	√		√
Plant management	√			√

Targeted information

Key to addressing many of the organizational issues is providing timely, targeted information to the correct individuals in an organization. Clearly, the requirements of the control room operator for control application health information are different from those of either the control engineer or the plant manager.

Plant management for example, typically would like to know if the application is being used and business benefits being generated by the application are reported in dollars. Conversely, if the controller is off, the cost to the business unit is valuable information.

With this type of management visibility, management obtains a clearer picture of the value of the MPC application. Table 1 highlights the type of information that each owner of a typical MPC application will require.

A monitoring application should address all of the needs of these various stakeholders, not just the control engineer.

Remote or central monitoring

Many organizations have downsized both control engineering and maintenance teams. Corporations are now interested in using control expertise wherever it exists in an organization. Control engineers located centrally in some organizations now support many applications in several remote locations across an organization.

A monitoring solution should be scalable so that it can support many MPC applications on a single site such as a refinery, or physically distributed at small sites with a central server.

Multiple controller technologies

As organizations have grown larger, often through mergers and acquisitions, multiple controller technologies can be found in plants throughout the organization. Some organizations must now support two or more technologies, in some cases on the same site.

It is most effective if a single tool can be used to monitor all control assets and applications within an organization. Otherwise, a patchwork of monitoring systems will result in an inability to compare performance of one application to another, and it becomes difficult to track problems in the MPC controller through the lower levels of the control hierarchy.

Moreover, from a management reporting point of view, it is much simpler to have a single monitoring application report on all of the assets in a business, rather than having to combine reports from several sources. ✦

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The author

David Shook is chief technical officer for Matrikon Inc., Edmonton. He has extensive process industry experience and has provided leadership to Matrikon's product development teams and its research partnerships with the University of Alberta. Shook also works closely with professional services groups and industry boards. He holds a PhD in chemical engineering (process control) from the University of Alberta.

DIRECT ASSESSMENT—
Conclusion

ECDA tunes Gasunie corrosion predictions

Menno van Os
N.V. Nederlandse Gasunie
Groningen, The Netherlands

External corrosion direct assessment (ECDA) can serve as a powerful tool in determining not only the current but also the future health of a given pipeline system. Gasunie has developed software (PIMSlider) to aggregate ECDA data and allow increasingly accurate projections of line-failure probability.

Part 1 of this article, presented last week, provided the overall integrity management (IM) context in which PIMSlider is being applied. This concluding part examines the direct examination and postassessment steps of the IM process in greater detail and provides an ECDA example from Gasunie's own system.

Direct examination

The direct examination step evaluates all inspected ECDA regions sequentially, starting with the highest-risk ECDA region found in preassessment. The outcome of each determines whether additional excavations need to be carried out, after which pipeline integrity is evaluated again.

The priority list generated by the two aboveground surveys allows selection of bell-hole excavation sites.

Excavations generally take place at locations:

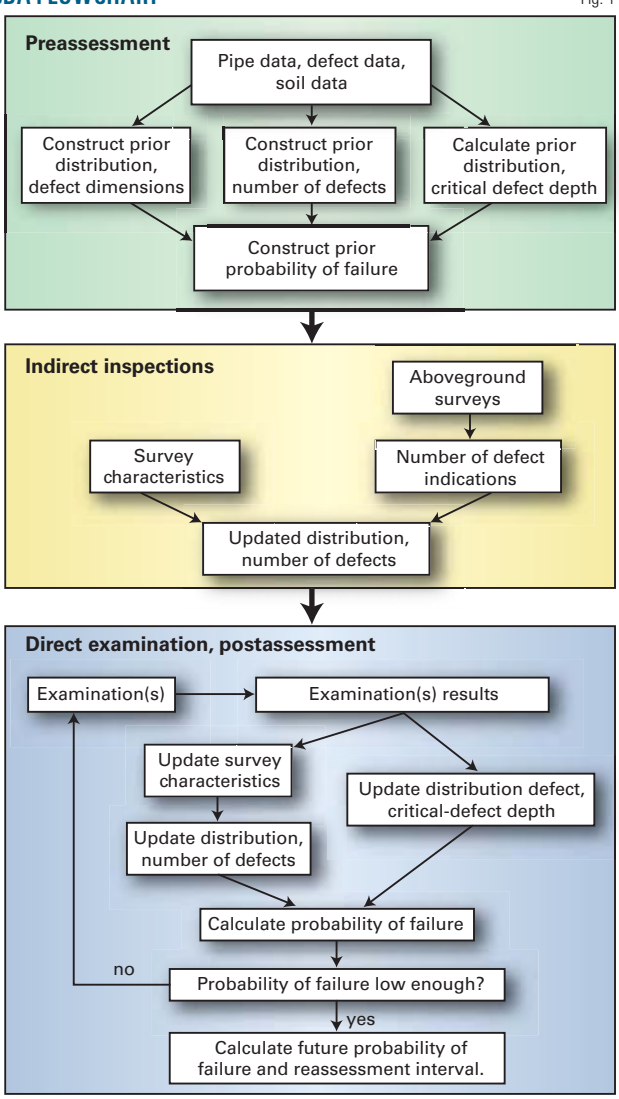
- Where both surveys (coating and corrosion) have given an indication; usually to determine the size of corrosion defects and repair any critical defects.
- Where only one of the surveys has given an indication; usually to check the survey characteristics and determine the size of any found corrosion defects.
- Where no indications were given; these excavations are generally referred to as blind digs, and may be used to assess the confidence in the probability of detection of the survey technique(s).

Information found at the excavations updates the information used in the preassessment and indirect inspection steps. This updating includes updating survey characteristics, number of defects, defect depth, corrosion rate, time of initiation, defect length, and the critical defect depth. These updates provide the basis for calculating new values for the probability of failure both of the defect and per km of the ECDA region.

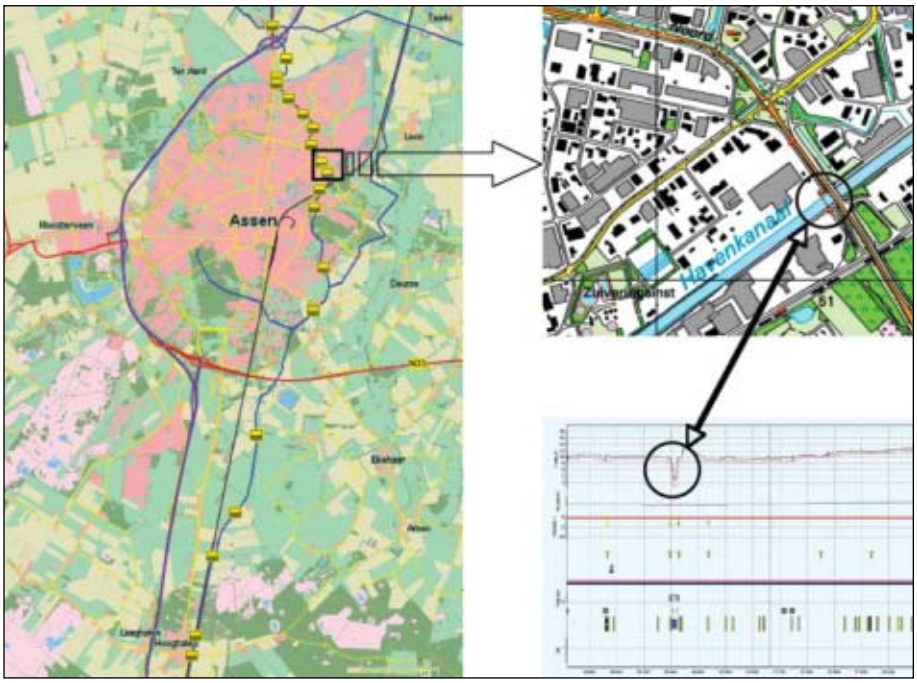
The bell-hole excavations must

ECDA FLOWCHART

Fig. 1



Based on presentation to the World Gas Conference, Amsterdam, June 5-9, 2006.



PIMSlider identifies ECDA regions by retrieving and graphically displaying data necessary for preassessment (Fig. 2).

gather information on: location of coating and (active) corrosion defects, dimensions of corrosion defects (defect depth, defect length in axial direction), and clock position of the corrosion defects (not relevant to the current model). Information should be used from every excavation, including those where no or only small defects were found.

All ECDA regions must perform model calculations. The direct-examination step makes the following groups of calculations (updates) for each ECDA region:

- Survey characteristics.
- Number of defects (coating and corrosion) as a function of time.
- Defect depth, corrosion rate, and time of initiation.
- Defect length and critical defect depth.
- Probability of failure (of a defect and per km of the ECDA region).

The updating process for the number of coating defects is represented by a normal distribution. The prior estimate uses information collected during the preassessment step (e.g., coating condition, age of the pipeline), but may also be deduced from previous surveys on other similar pipelines. New information from the indirect inspections uses Bayesian statistics to immediately update the prior distribution. The excavations allow an update of the survey characteristics, after which the number of coating defects can be updated again.

PIPELINE INFORMATION, ECDA SEGMENT Table 1

Total length	13.7 km
OD, nominal	165 mm
WT, nominal	4.8 mm
Grade	B
External coating type	Bituminous
CP type	Impressed current
Commissioning date	1953
Maximum operating pressure	40 bar

The probability of failure increases with the growth of corrosion defects and an increasing number of defects, but generally decreases as a result of the indirect inspections and direct examinations. The probability of failure, however, will increase again due to ongoing corrosion processes.

ECDA assumes that all found corrosion defects are repaired (or recoated). The repair of coating defects will not have a significant effect on ECDA calculations, but assumes for consistency that all coating defects found are repaired.

The updated probability of failure of a defect at the time of excavation depends on the updated value of distribution of the defect depth, distribution of the critical defect depth, and expected number of corrosion defects. The updated probability of failure/km at the time of excavations depends on the updated distribution of failure of a defect and the length of the ECDA region.

The probability of failure for a single defect will change with each excavation as the distribution of the corrosion rate and time of initiation also change. A confidence interval is calculated for the probability of failure. As the number of excavations increases, the probability of failure/km normally decreases, until the criterion for the probability of failure is met, showing that sufficient excavations for the specific ECDA region have been carried out.

As mentioned earlier, excavation of ECDA regions occurs sequentially, starting with the region with the highest initial risk.

Results of the calculations for an ECDA region can provide the starting point for the next ECDA region. The user can replace the initial values for corrosion rate, time of initiation, and defect density for that ECDA region with the values calculated for the ECDA region with the higher initial risk. Inspectors repeat this process until all ECDA regions have been covered.

Postassessment

According to the NACE, the objectives of the postassessment are to define reassessment intervals and assess the overall effectiveness of the ECDA process. For the developed structural reliability analysis (SRA) model, this step consists of:

- Calculating the future probability of failure/km due to external corrosion for each ECDA region, based on indirect inspections and direct examinations.
- Calculating the future probability of failure/km for each ECDA region for all other considered failure modes.

ECDA RESULTS USING SRA MODEL

Table 2

Step 1: Preassessment			
Maximum operating pressure	Constant		40 bar
OD, nominal	Constant		165 mm
WT, nominal	Normal distribution	Mean	4.8 mm
		Standard deviation	0.26 mm
Material yield strength	Normal distribution	Mean	269 MPa
		Standard deviation	15 MPa
Defect depth	Weibull distribution	Shape parameter, β	2.33
		Scale parameter, η	0.81
Defect length	Weibull distribution	Shape parameter, β	0.88
		Scale parameter, η	130
Number of coating defects	Normal distribution	Mean	713
		Standard deviation	142
Number of corrosion defects	Normal distribution	Mean	6.2
		Standard deviation	1.2
Failure probability, 2005	per defect		0.36
	per pipeline		0.93
	per km		0.18

Step 2: Indirect inspection			
Survey 1, DCVG	100% of pipeline	Severe, %IR > 35	23
		Moderate, 15 < %IR ≤ 35	132
		Minor, %IR ≤ 15	687
Survey 2, CIPS	100% of pipeline	Number of coating defect indications at which the IR-free potential does not meet the CP protection criterion	35
Survey 3, soil resistivity	Every 50 m	Slightly corrosive, (50 Ω × m) < ρ < (1,000 Ω × m)	

Step 3: Direct examinations

- 21 coating defect indications were excavated
- 8 of these indications were not sufficiently protected by CP
- No blind digs were performed

Step 4: Postassessment				
Updated incident frequency after indirect inspection	Expected number of coating defects	Initial (normal) distribution	Mean	713
		Number of DCVG indications		842
		Probability of detection		75%
		Probability of false indication		10%
			Prior	Updated
		Number of coating defects	713	957
	Expected number of corrosion defects	Initial (normal) distribution	Mean	6.2
		Number of DCVG indications with possible corrosion		35
		Probability of detection		60%
		Probability of false indication		20%
			Prior	Updated
		Number of corrosion defects	6.2	58.9
Updated incident frequency after direct examinations	Expected number of coating defects	Number of excavations at a DCVG coating defect indication		21
		Number of coating defects found		21
			Prior	Updated
		Probability of false indication	10%	4%
		Since no excavations were performed at sites without coating defect indications the probability of detection cannot be updated		
			Prior	Updated
		Number of coating defects	713	1,076
	Expected number of corrosion defects	Number of excavations at a CIPS corrosion defect indication		8
		Number of corrosion defects found		4
			Prior	Updated
		Probability of false indication	20%	38%
		Number of excavations not at a CIPS corrosion defect indication		13
		Number of corrosion defects found		2
			Prior	Updated
		Probability of detection	60%	27%
			Prior	Updated
		Number of corrosion defects	6.2	181.0
Updated uncertainty analysis after direct examinations			Prior	Updated
	Defect depth	Scale parameter η, 2005	4.04	0.87
	Defect length	Scale parameter η, 2005	130	91
	Corrosion growth rate	Mean	0.054 mm/year	0.015 mm/yr
		Standard deviation	0.025 mm/year	0.007 mm/yr
	Failure probability, 2005	per defect	0.36	3.0×10^{-10}
		per pipeline	0.93	5.5×10^{-8}
		per km	0.18	4.0×10^{-9}

• Depending on the calculated probability of failure/km, calculating the time interval until the next direct assessment is required.

When new aboveground surveys are carried out on an already inspected pipeline the pipeline becomes subject to a new direct assessment. The results of a previous direct assessment are available for use in the preassessment step of the next direct assessment.

Fig. 1 gives a summary of the most important routines that the operator will go through when using the DA module for PIMSlider.

Case study

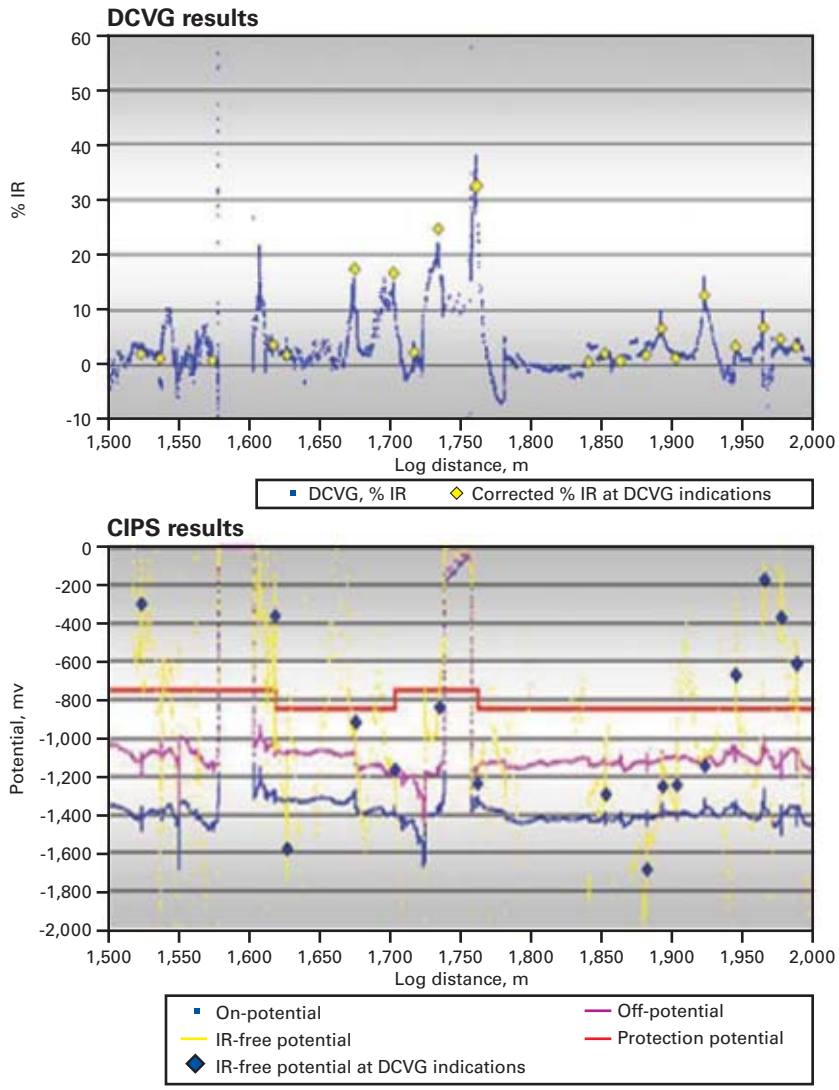
Table 1 contains the details of a pipeline subjected to ECDA in 2005. Assessing all relevant input parameters related to pipeline geometry, material properties, defect dimensions, and incident frequencies, including their respective uncertainties, yields a first estimate of the current integrity of the pipeline.

The first section of Table 2 shows this estimate: a prior failure probability per km of pipeline in the year 2005 (52 years after commissioning) of P_F = 0.18/km; unacceptably high according to ASME B31.8.

Fig. 2 gives an example of how PIMSLider can be used to assist a pipeline operator in performing a preassessment, displaying the geographic position of the pipeline under consideration, allowing the user to zoom in on any segment of interest, and showing corresponding pipeline, environmental, incident, or operational data. If the required data are missing for a specific pipeline, the DA module can retrieve data from similar pipelines to estimate the prior condition of the pipeline. The DA module also identifies and calculates the ECDA regions, following user definition of the relevant parameters and criteria to be considered.

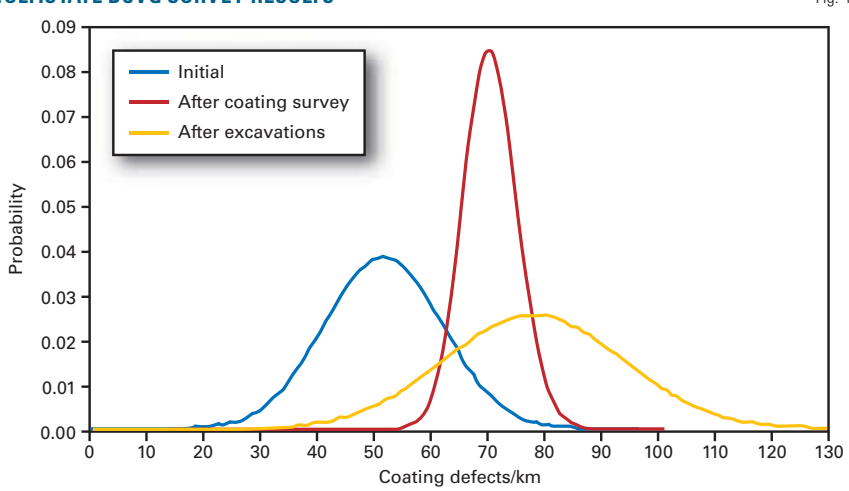
DCVG RESULTS

Fig. 3



MULTISTATE DCVG SURVEY RESULTS

Fig. 4



In the indirect inspection step, the DA module allows the user to store and analyze data from aboveground surveys, assess the severity of defects, and identify areas where corrosion may occur (Fig. 3).

The last section of Table 2 shows the postassessment effect of the direct-current voltage gradient (DCVG) survey on the expected number of coating defects. The DCVG survey found 842 coating defect indications. Bayesian updating of the number of coating defects results in an increase of the expected number of coating defects from 713 (52/km) to 957 (70/km), taking into account DCVG's initially estimated probability of detection and probability of false indication.

Applying Bayesian statistics also updates the number of corrosion defects.

The results of the cathodic protection survey showed that both the on and off-potential of the pipeline meet the applicable protection criterion described in European standard EN 12954:2001. Calculation of the IR-free potential, however, revealed 35 coating defect indications without sufficient CP protection and therefore possibly corroding, increasing the expected number of corrosion defects from 6.2 to 58.9.

The direct examinations step performed 21 excavations, all at DCVG indications. Each excavation found actual coating defects, allowing the probability of false indication of DCVG to be decreased to 4% from an initial value of 10%.

The absence of excavations at sites without DCVG indications (e.g., blind digs) prevented any update of the probability of detection.

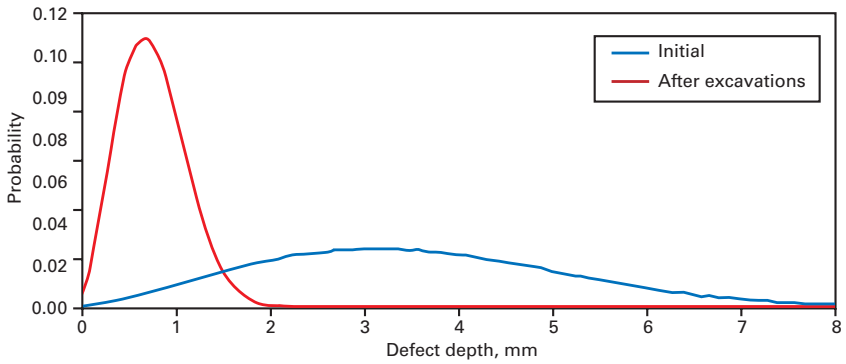
The combination of these adjustments updated the expected number of coating defects after excavations to 1,076 (e.g., 79/km).

Fig. 4 shows the effect of the DCVG survey and the direct examinations on the probability density function of the number of coating defects.

The 21 excavations included eight excavations at sites where CIPS data indicated insufficient protection by the CP

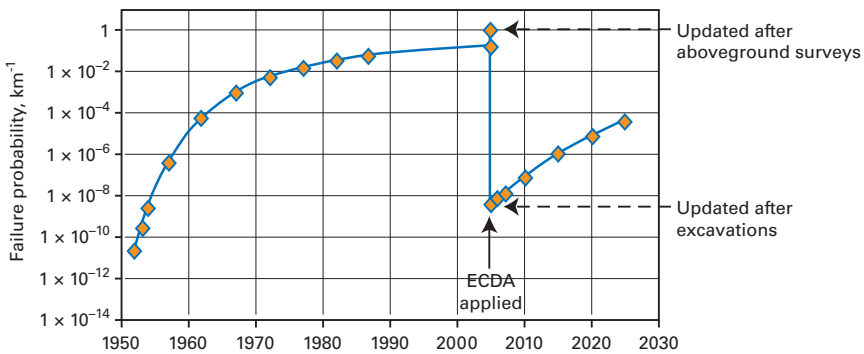
PRE, POSTEXAMINATION DEPTH DISTRIBUTION

Fig. 5



ECDA EFFECT

Fig. 6



system. Actual corrosion anomalies were found at four of these sites. This information updated the probability of false indication of CIPS to 38% from 20%.

The other 13 excavations, where no corrosion was suspected based on the CIPS data, resulted in two additional corrosion defects, leading to a decrease in the probability of detection of CIPS to 27% from its initially estimated value of 60%. The updated performance indicators (probability of detection and probability of false indication) of both indirect inspection tools led the expected number of corrosion defects to increase to 181 from a prior value of six.

Accurate measurements of corrosion defect depths and lengths during the excavations allow an updating of their respective distributions. Updating the defect depth distribution allows calculation of the corresponding corrosion growth rate (Fig. 5).

Table 2 shows that the corrosion growth rate decreases significantly to 0.015 mm/year, as compared to its prior value of 0.054 mm/year, resulting in a much lower probability of failure as compared to the preassessment.

ECDA, in combination with SRA, effectively demonstrated the integrity of the pipeline. Even though the expected number of corrosion defects is much higher than estimated initially, the corrosion anomalies found were all minor in nature, resulting in a significantly lower average defect depth than initially estimated.

Fig. 6 shows the overall effect of the ECDA process on the probability of failure. The adjusted probability density function of the number of corrosion defects, together with the updated defect depth distribution and the updated critical defect depth distribution, result in a decrease of the probability of failure to $P_F = 4.0 \times 10^{-9}$/km. ✦

Equipment/Software/Literature

New frequency converter for oil field operations

The new SSG Series 500VA frequency converter is suited for use in process control and drilling operations.

The new 500VA unit is a high performance single-phase on-line frequency converter, voltage regulator, and line conditioner that provides flexible and reliable AC power. Utilizing field-proved double-conversion design, the new 14 lb converter offers power quality including galvanic isolation without sacrificing efficiency, size, or weight, the firm says.

Accepting a 45-440 hz input and yielding a fixed crystal controlled 50 or 60 hz output, the compact converter promises precise voltage regulation and line conditioning, the firm notes.

The unit operates in temperatures of 0-40° C., which helps suit it for oil field environments.

Source: **Falcon Electric Inc.**, 5106 Azusa Vanyon Rd., Irwindale, CA 91706.

New unit delivers moisture analysis to 2 ppb

Here's the new DF-745 nano trace moisture analyzer. It offers a low detection limit of 2 ppb for applications that don't require the most demanding detection limits. It provides an economic alternative to higher detection analyzers like the firm's flagship DF-750 product that has a lower detection limit of 200 ppt.

The DF-745 uses tunable diode laser absorption spectroscopy technology to achieve high sensitivity, drift free operation, high accuracy, performance, and low maintenance with no recalibration.

It features:

- Accuracy: greater of ±3% of reading or ±1 ppb.
- Speed of response (typically) 10 min.
- Upset recovery time of <5 min.
- Range 0-20 ppm.

The analyzer is suited for rack mount configuration or use on a mobile cart. Also it is suited for applications that include checking gas distribution system integrity, process troubleshooting, monitoring bulk gas supplies to LCD plants or fabs, gas plant control, and QA.

The DF-745 is covered by assistance for a broad array of application problems including measurement of semiconductor high purity gases. The unit can be configured for a range of outputs for data collection and process control systems. An optional safety system is available for hydrogen use.

Source: **Delta F Corp.**, 4 Constitution Way, Woburn, MA 01801-1087.

Services/Suppliers

Implicit Monitoring Solutions LP (IMS) and Wilson

Dallas, have announced a partnership agreement whereby Wilson will market IMS' Intellisite remote asset data capture and reporting service to customers in the major producing areas of the US.

Implicit Monitoring Solutions LP provides technologies and resources to help companies effectively manage remote oil and gas producing assets. The Intellisite service delivers secure field production data to the client via the Internet.

Wood Group Production Services (WGPS)

Houston, has promoted Louis Gueniot to senior vice-president, and Jim Justice to Louisiana business unit manager, succeeding Gueniot.

Gueniot joined WGPS in 1990 as manager of its Houma business unit.

Justice, who has 28 years of experience in offshore operations and human resources, has been with WGPS since 1994.

Wood Group Production Services, a part of John Wood Group PLC, is a leading provider of operations and maintenance services to the Gulf of Mexico inland, shelf, and deepwater operations, and internationally.

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

Fulbright & Jaworski LLP

Houston, has announced that Brian Bradshaw has joined the firm as an energy partner. Bradshaw's practice is focused on cross-border and international projects, with emphasis on development and financing of LNG liquefaction and regasification terminals, and other large-scale energy infrastructure projects. He earned his JD and MBA from the University of Houston, and his AB from Washington University.

Founded in 1919, Fulbright & Jaworski LLP is a leading international law firm with more than 970 lawyers in 14 locations around the world.

Pride International Inc.

Eads

Houston, has announced the appointment of Rodney W. Eads as executive vice-president and chief operating officer. His responsibilities cover the company's worldwide offshore operations and Eastern Hemisphere land assets.

Eads, who holds a BS degree in chemical engineering from West Virginia Institute of Technology, and an MBA from Rice University, joins Pride from Diamond Offshore Drilling Inc. He previously was employed by Exxon Corp., where he held primarily international assignments from 1980 to 1997.

Pride International Inc. is one of the world's largest drilling contractors, providing onshore and offshore drilling and related services in more than 25 countries.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	9-29 2006	[1]9-22 2006	9-29 2006	[1]9-22 2006	9-29 2006	[1]9-22 2006	9-30 2005
	1,000 b/d						
Total motor gasoline	413	466	55	64	468	530	340
Mo. gas. blending comp.	638	723	143	39	781	762	482
Distillate[2]	328	399	23	79	351	478	319
Residual	237	258	25	20	262	278	562
Jet fuel-kerosine	113	130	54	76	167	206	117
LPG	377	350	0	1	377	351	293
Unfinished oils	319	579	21	17	340	596	532
Other	395	494	5	11	400	505	400
Total products	**2,820**	**3,399**	**326**	**307**	**3,146**	**3,706**	**3,045**
Canadian crude	1,295	1,513	87	157	1,382	1,670	1,907
Other foreign	6,999	8,261	1,650	940	8,649	9,201	6,816
Total crude	**8,294**	**9,774**	**1,737**	**1,097**	**10,031**	**10,871**	**8,723**
Total imports	**11,114**	**13,173**	**2,063**	**1,404**	**13,177**	**14,577**	**11,768**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

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

	*9-29-06	*9-30-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	66.35	90.14	–23.79	–26.4
Brent crude	58.82	62.44	–3.62	–5.8
Crack spread	7.53	27.70	–20.17	–72.8
FUTURES MARKET PRICES				
One month				
Product value	67.19	90.71	–23.52	–25.9
Light sweet crude	62.22	66.05	–3.83	–5.8
Crack spread	4.97	24.66	–19.68	–79.8
Six month				
Product value	74.00	84.49	–10.48	–12.4
Light sweet crude	65.87	67.06	–1.19	–1.8
Crack spread	8.14	17.43	–9.29	–53.3

*Average for week ending
Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[2]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	14,926	59,472	29,635	11,666	67,121	17,933	8,666
PAD II	68,021	54,983	17,371	7,322	29,132	2,343	14,923
PAD III	175,204	67,207	28,361	11,761	33,866	16,925	45,753
PAD IV	13,403	6,031	1,787	478	3,089	522	2,723
PAD V	[1]53,701	30,117	21,171	10,149	13,350	5,851	20,347
Sept. 29, 2006	**[1]325,255**	**217,810**	**98,325**	**41,376**	**146,558**	**43,574**	**92,412**
Sept. 22, 2006[3]	**322,542**	**220,606**	**96,899**	**41,005**	**149,535**	**45,424**	**93,811**
Sept. 30, 2005	**300,150**	**197,970**	**69,750**	**36,301**	**128,017**	**32,960**	**87,842**

[1]Includes 3.135 million bbl of Alaskan crude in transit by water. [2]Included in total motor gasoline. [3]Revised.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

API REFINERY REPORT—SEPT. 29, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	2,925	1,428	1,453	1,618	89.8	1,824	92	458	116
App. Dist. 1	104	95	95	95	100.0	15	0	30	1
Dist. 1 total	**2,658**	**1,669**	**1,681**	**1,713**	**98.1**	**1,872**	**95**	**452**	**152**
Ind., Ill., Ky.	2,229	2,117	2,132	2,355	90.5	1,096	156	638	46
Minn., Wis., Dak.	381	343	343	442	77.6	226	26	101	68
Okla., Kan., Mo.	912	778	783	786	99.6	449	34	272	7
Dist. 2 total	**3,522**	**3,238**	**3,258**	**3,583**	**90.9**	**1,771**	**216**	**1,011**	**59**
Inland Texas	887	621	636	647	98.3	487	42	197	6
Texas Gulf Coast	3,364	3,095	3,173	3,264	97.2	1,346	355	867	77
La. Gulf Coast	3,309	3,214	3,227	3,264	98.9	1,329	398	879	84
N. La. and Ark.	217	191	198	215	92.1	92	9	46	3
New Mexico	170	109	112	113	99.1	94	3	35	0
Dist. 3 total	**8,677**	**7,366**	**7,599**	**8,270**	**91.9**	**3,471**	**742**	**2,077**	**244**
Dist. 4 total	**662**	**541**	**561**	**596**	**94.1**	**252**	**28**	**172**	**18**
Dist. 5 total	**2,777**	**2,574**	**2,777**	**3,173**	**87.5**	**1,781**	**414**	**604**	**142**
Sept. 29, 2006	**18,667**	**15,242**	**15,743**	**17,335**	**90.8**	**9,114**	**1,492**	**4,352**	**580**
Sept. 22, 2006*	**19,165**	**15,624**	**16,197**	**17,335**	**93.4**	**9,215**	**1,507**	**4,265**	**675**
Sept. 30, 2005	**13,228**	**11,337**	**11,777**	**17,115**	**68.8**	**7,481**	**1,101**	**2,999**	**4866**

*Revised.
Source: American Petroleum Institute.
Data available in Oil & Gas Journal Energy Database.

Statistics

OGJ GASOLINE PRICES

	Price ex tax 9-27-06	Pump price* 9-27-06	Pump price 9-28-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	194.9	238.4	260.2
Baltimore	204.5	246.4	266.4
Boston	205.5	247.4	296.7
Buffalo	190.8	258.7	286.8
Miami	203.7	254.0	287.1
Newark	215.5	248.4	287.1
New York	194.8	262.7	290.8
Norfolk	187.4	225.4	277.6
Philadelphia	203.2	253.9	296.5
Pittsburgh	197.7	248.4	274.0
Wash., DC	220.4	258.8	294.7
PAD I avg.	201.7	249.3	282.9
Chicago	209.3	264.4	303.7
Cleveland	169.1	215.5	278.6
Des Moines	164.5	204.6	252.7
Detroit	173.7	226.6	264.8
Indianapolis	167.5	216.5	271.8
Kansas City	176.7	212.7	259.8
Louisville	172.7	209.6	268.7
Memphis	188.7	228.5	276.8
Milwaukee	195.2	246.5	285.7
Minn.-St. Paul	182.3	222.7	259.6
Oklahoma City	175.2	210.6	258.9
Omaha	176.0	221.4	277.6
St. Louis	186.9	222.9	276.8
Tulsa	173.2	208.6	258.8
Wichita	172.2	215.6	268.7
PAD II avg.	178.9	221.8	270.9
Albuquerque	201.4	237.8	271.7
Birmingham	175.4	214.1	275.2
Dallas-Fort Worth	170.9	209.3	271.2
Houston	174.8	213.2	279.2
Little Rock	176.9	217.1	269.6
New Orleans	200.7	239.1	NA
San Antonio	194.0	232.4	266.4
PAD III avg.	184.9	223.3	272.2
Cheyenne	218.9	251.3	280.9
Denver	222.4	262.8	292.6
Salt Lake City	229.3	272.2	282.6
PAD IV avg.	223.5	262.1	285.4
Los Angeles	203.4	264.0	297.9
Phoenix	199.0	236.4	299.0
Portland	220.4	263.7	275.7
San Diego	207.3	267.9	309.6
San Francisco	218.6	279.2	300.7
Seattle	224.1	273.6	286.0
PAD V avg.	212.1	264.1	294.8
Week's avg.	**193.8**	**238.2**	**272.2**
Sept. avg.	**208.9**	**253.3**	**282.5**
Aug. avg.	**252.4**	**296.7**	**250.2**
2006 to date	**222.1**	**265.6**	—
2005 to date	**177.6**	**219.7**	—

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

REFINED PRODUCT PRICES

	9-22-06 ¢/gal		9-22-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	150.75	New York Harbor	157.88
Gulf Coast	144.88	Gulf Coast	162.00
Los Angeles	163.55	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	143.91	ARA	169.21
Singapore	157.14	Singapore	170.98
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	147.80	New York Harbor	84.83
Gulf Coast	148.05	Gulf Coast	86.31
Los Angeles	168.55	Los Angeles	117.41
		ARA	97.62
		Singapore	104.56

Source: DOE Weekly Petroleum Status Report.
Data available in Oil & Gas Journal Energy Database.

BAKER HUGHES RIG COUNT

	9-29-06	9-30-05
Alabama	5	5
Alaska	6	8
Arkansas	26	12
California	34	32
Land	30	27
Offshore	4	5
Colorado	96	81
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	9	7
Kentucky	10	7
Louisiana	199	176
N. Land	58	51
S. Inland waters	20	19
S. Land	45	34
Offshore	76	72
Maryland	1	0
Michigan	1	2
Mississippi	12	9
Montana	15	25
Nebraska	0	0
New Mexico	89	94
New York	8	6
North Dakota	35	24
Ohio	9	9
Oklahoma	191	155
Pennsylvania	14	14
South Dakota	3	5
Texas	790	671
Offshore	8	9
Inland waters	2	1
Dist. 1	25	13
Dist. 2	25	38
Dist. 3	56	104
Dist. 4	93	68
Dist. 5	138	74
Dist. 6	118	106
Dist. 7B	46	17
Dist. 7C	38	41
Dist. 8	95	76
Dist. 8A	29	24
Dist. 9	41	35
Dist. 10	76	65
Utah	46	25
West Virginia	26	25
Wyoming	112	83
Others—HI-1; ID-1; NV-1; OR-1; TN-1; VA-1; WA-1	7	6
Total US	**1,744**	**1,483**
Total Canada	**353**	**537**
Grand total	**2,097**	**2,020**
Oil rigs	310	203
Gas rigs	1,422	1,273
Total offshore	95	87
Total cum. avg. YTD	**1,625**	**1,351**

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

Source: Baker Hughes Inc.
Data available in Oil & Gas Journal Energy Database.

SMITH RIG COUNT

Proposed depth, ft	Rig count	9-29-06 Percent footage*	Rig count	9-30-05 Percent footage*
0-2,500	50	—	24	41
2,501-5,000	83	38.5	64	34.3
5,001-7,500	238	20.5	149	20.8
7,501-10,000	398	3.7	337	4.1
10,001-12,500	388	2.0	320	1.5
12,501-15,000	293	0.6	297	—
15,001-17,500	112	—	112	—
17,501-20,000	71	—	49	—
20,001-over	35	—	17	—
Total	**1,668**	**6.3**	**1,369**	**5.3**
INLAND	38		40	
LAND	1,564		1,275	
OFFSHORE	66		54	

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

Source: Smith International Inc.
Data available in Oil & Gas Journal Energy Database.

OGJ PRODUCTION REPORT

	[1]9-29-06	[2]9-30-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	755	815
California	679	696
Colorado	7	50
Florida	29	6
Illinois	91	31
Kansas	1,337	91
Louisiana	14	488
Michigan	50	17
Mississippi	92	39
Montana	161	95
New Mexico	104	158
North Dakota	172	99
Oklahoma	1,351	169
Texas	44	1,144
Utah	141	45
Wyoming	69	143
All others	69	77
Total	**5,183**	**4,184**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in Oil & Gas Journal Energy Database.

US CRUDE PRICES

$/bbl*	9-29-06
Alaska-North Slope 27°	66.71
South Louisiana Sweet	58.95
California-Kern River 13°	51.15
Lost Hills 30°	58.60
Wyoming Sweet	63.16
East Texas Sweet	61.01
West Texas Sour 34°	50.75
West Texas Intermediate	59.50
Oklahoma Sweet	59.50
Texas Upper Gulf Coast	56.25
Michigan Sour	52.50
Kansas Common	58.50
North Dakota Sweet	52.25

*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 Oil & Gas Journal Energy Database.

WORLD CRUDE PRICES

$/bbl[1]	9-22-06
United Kingdom-Brent 38°	60.49
Russia-Urals 32°	57.28
Saudi Light 34°	56.80
Dubai Fateh 32°	57.94
Algeria Saharan 44°	61.60
Nigeria-Bonny Light 37°	62.15
Indonesia-Minas 34°	62.61
Venezuela-Tia Juana Light 31°	55.33
Mexico-Isthmus 33°	55.22
OPEC basket	58.81
Total OPEC[2]	57.55
Total non-OPEC[2]	55.60
Total world[2]	56.38
US imports[3]	54.46

[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 Oil & Gas Journal Energy Database.

US NATURAL GAS STORAGE[1]

	9-29-06	9-22-06	Change
	Bcf		
Producing region	942	915	27
Consuming region east	1,874	1,835	39
Consuming region west	438	427	11
Total US	**3,254**	**3,177**	**77**
	July 06	**July 05**	**Change, %**
Total US[2]	**2,779**	**2,450**	**13.4**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in Oil & Gas Journal Energy Database

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	July 2006	June 2006	7 month average production 2006	7 month average production 2005	Chg. vs prev. year Volume	Chg. vs prev. year %	July 2006	June 2006	Cum. 2006
	Crude, 1,000 b/d						Gas, bcf		
Argentina	670	640	638	656	–19	–2.9	160.0	134.7	968.06
Bolivia	45	45	45	40	5	12.5	40.0	40.0	273.00
Brazil	1,725	1,630	1,702	1,610	92	5.7	30.8	29.5	203.60
Canada	2,491	2,333	2,448	2,288	160	7.0	485.5	502.9	3,518.68
Colombia	536	533	531	525	7	1.3	17.5	17.5	120.00
Ecuador	543	518	542	531	11	2.2	0.3	0.3	2.18
Mexico	3,232	3,287	3,322	3,330	–8	–0.2	165.0	163.8	1,104.58
Peru	122	120	114	113	1	1.1	6.8	4.3	30.82
Trinidad	152	130	149	149	—	–0.2	112.2	96.1	720.35
United States	5,171	5,219	5,095	5,431	–335	–6.2	1,625.0	1,671.0	11,288.00
Venezuela[1]	2,470	2,590	2,597	2,731	–134	–4.9	80.0	85.0	575.00
Other Latin America	78	79	80	81	–1	–1.5	7.5	7.5	50.97
Western Hemisphere	**17,235**	**17,124**	**17,264**	**17,485**	**–221**	**–1.3**	**2,730.6**	**2,752.5**	**18,855.25**
Austria	17	17	17	17	—	0.3	5.6	5.5	38.27
Denmark	344	336	338	386	–48	–12.4	22.7	30.0	217.14
France	21	21	21	21	—	0.5	3.0	3.7	24.84
Germany	66	69	71	68	2	3.0	45.6	58.3	390.36
Italy	104	110	111	115	–4	–3.1	32.0	33.0	228.00
Netherlands	20	28	28	44	–16	–37.3	140.0	200.0	1,885.00
Norway	2,571	2,365	2,538	2,738	–200	–7.3	243.0	260.0	1,793.12
Turkey	43	47	42	42	—	0.1	2.0	2.7	18.73
United Kingdom	1,468	1,410	1,569	1,755	–186	–10.6	188.1	241.3	1,803.92
Other Western Europe	6	6	5	5	—	–6.0	0.2	3.1	17.87
Western Europe	**4,661**	**4,408**	**4,740**	**5,192**	**–452**	**–8.7**	**682.2**	**837.5**	**6,417.24**
Azerbaijan	630	600	590	391	199	51.0	14.0	24.0	172.00
Croatia	17	16	17	18	–1	–4.3	4.9	4.2	33.06
Hungary	15	17	17	20	–3	–15.7	8.5	7.6	63.00
Kazakhstan	1,300	1,200	1,107	969	139	14.3	60.0	100.0	496.00
Romania	98	98	99	100	–1	–0.7	18.0	18.0	119.00
Russia	9,520	9,600	9,446	9,113	333	3.7	1,750.0	1,925.0	13,315.00
Other FSU	500	500	514	400	114	28.6	400.0	450.0	3,200.00
Other Eastern Europe	46	43	44	49	–5	–9.6	41.8	31.3	286.49
Eastern Europe and FSU	**12,126**	**12,074**	**11,835**	**11,059**	**776**	**7.0**	**2,297.2**	**2,560.1**	**17,684.54**
Algeria[1]	1,330	1,350	1,351	1,341	10	0.7	286.0	268.0	1,879.00
Angola	1,462	1,303	1,393	1,142	251	22.0	2.4	2.2	16.40
Cameroon	90	91	89	81	9	10.9	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	650	640	680	697	–17	–2.5	42.0	41.0	282.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.42
Gabon	230	240	239	230	9	3.7	0.3	0.3	2.12
Libya[1]	1,720	1,700	1,689	1,633	56	3.4	22.0	22.0	150.50
Nigeria[1]	2,260	2,290	2,220	2,406	–186	–7.7	75.0	74.0	480.00
Sudan	290	290	290	290	—	—	—	—	—
Tunisia	68	67	65	72	–7	–9.4	7.1	6.2	46.77
Other Africa	243	243	242	243	–1	–0.3	10.2	10.2	70.35
Africa	**8,923**	**8,794**	**8,838**	**8,715**	**124**	**1.4**	**445.1**	**424.0**	**2,927.56**
Bahrain	170	172	173	175	–1	–0.7	26.6	26.7	181.65
Iran[1]	4,250	3,950	3,876	3,926	–50	–1.3	285.0	275.0	1,893.00
Iraq[1]	2,060	2,070	1,886	1,830	56	3.0	5.5	5.0	35.90
Kuwait[1,2]	2,475	2,510	2,507	2,403	104	4.3	31.0	31.0	213.50
Oman	730	740	750	744	6	0.8	59.0	59.0	407.00
Qatar[1]	840	830	823	783	40	5.1	119.0	116.0	797.00
Saudi Arabia[1,2]	9,215	9,210	9,249	9,247	1	—	176.0	190.0	1,264.00
Syria	430	430	436	467	–31	–6.7	15.5	15.5	108.00
United Arab Emirates[1]	2,670	2,630	2,630	2,383	247	10.4	135.0	132.0	909.00
Yemen	360	350	346	347	–1	–0.4	—	—	—
Other Middle East	—	—	—	—	—	9.9	9.3	6.0	47.09
Middle East	**23,200**	**22,892**	**22,675**	**22,305**	**370**	**1.7**	**861.9**	**856.3**	**5,856.13**
Australia	496	352	376	448	–72	–16.2	134.0	112.0	794.50
Brunei	190	194	201	184	17	9.5	35.3	31.9	249.26
China	3,716	3,737	3,704	3,624	80	2.2	169.5	162.6	1,210.03
India	679	706	676	684	–8	–1.1	82.5	82.7	564.08
Indonesia[1]	890	900	914	949	–34	–3.6	190.0	195.0	1,340.00
Japan	15	16	17	16	—	2.2	8.6	10.0	70.09
Malaysia	740	750	741	789	–47	–6.0	144.0	140.0	969.00
New Zealand	12	16	15	15	—	–0.9	12.5	10.0	77.50
Pakistan	65	65	65	65	—	0.2	122.0	118.0	834.59
Papua New Guinea	55	58	58	46	12	25.2	0.5	0.5	3.50
Thailand	203	210	215	172	43	25.1	73.0	72.7	497.66
Viet Nam	340	340	340	340	—	—	15.0	15.0	105.00
Other Asia–Pacific	29	30	31	35	–3	–9.3	65.5	66.5	452.05
Asia Pacific	**7,430**	**7,373**	**7,353**	**7,366**	**–12**	**–0.2**	**1,052.3**	**1,017.0**	**7,167.27**
TOTAL WORLD	**73,575**	**72,666**	**72,706**	**72,122**	**584**	**0.8**	**8,069.3**	**8,447.4**	**58,907.99**
*OPEC	30,180	30,030	29,741	29,631	110	0.4	1,404.5	1,393.0	9,536.90
North Sea	4,397	4,125	4,461	4,888	–428	–8.7	495.6	591.0	4,377.93

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

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Faculty Positions in Petroleum Engineering

The Petroleum Institute in Abu Dhabi is seeking applications for faculty positions in the Petroleum Engineering program. Applicants should possess an earned PhD degree in Petroleum Engineering or a closely related field. Outstanding records or potential in teaching, research and service relevant to industry problems in the region are critical. Areas of specialization are open; experience with carbonate reservoirs will be a plus, as will industrial experience. Appointments at all levels (Assistant Professor, Associate Professor, and Professor) are available. For truly exceptional candidates, appointment as Distinguished Institute Professor is possible. This appointment comes with additional recognition, rank, salary and benefits.

Program faculty report directly to the Program Director who has overall responsibility for leadership of the Petroleum Engineering program. Faculty will teach undergraduate and graduate courses, develop an active research program, and engage in departmental and institutional service. They will have outstanding opportunities to interact with national and international Petroleum Institute stakeholders for development of research and service (consulting, continuing education) programs. Involvement in professional society activities is encouraged and supported.

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To Apply: Application materials must include (1) a letter of interest, which addresses the applicant's qualifications for the position; (2) a current resume; and (3) the names, email and business address, and home and business telephone numbers of at least three references. Electronic Submission is greatly preferred, and should be sent to The Recruiting Coordinator at The Petroleum Institute (**recruiting-coordinator@pi.ac.ae**) and submission of materials as an MS Word/PDF attachment is strongly encouraged.

Candidates are encouraged to submit applications as soon as possible, indicating their timeframe of availability. Review of applications will begin on November 1, 2006 and continue until the available positions have been filled. Appointment could begin as early as January 2007. Recruitment will continue until suitable candidates are found for all positions available.

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Where's the money worry in US bans on OCS leasing?

The US Congress deserves credit for its concern about those federal offshore oil and gas leases that lack price thresholds for deepwater royalty relief.

It's gratifying to see elected officials quiver with indignation over mistakes of governance. It's reassuring to watch them demand that public coffers not be denied a penny of their possible due.

Even more welcome in these matters, however, would be a measure of consistency.

For some reason, deepwater Outer Continental Shelf leases issued during 1998 and 1999 omitted oil and gas price limits on royalty relief. Production from those leases is coming on stream at a time when prices exceed price thresholds in leases granted in other years. Congress estimates the government will be denied $2 billion as a result.

The Department of the Interior, which manages OCS leasing through the Minerals Management Service, has drawn heavy, bipartisan fire for the lapse. It hardly eases the pressure that the best explanation so far has been a probable breakdown of communication.

It doesn't help, either, that it's an election year, when winning back some or all of that theoretically lost money can be made to look heroic. Indeed, lessees are negotiating possible compensation, although legalities and partner relationships make the task tougher than politicians make it appear. Leases are contracts. Companies signed them in good faith and, by all reports, have met their commitments.

Noteworthy in all this is sudden congressional worry about money from offshore oil and gas leasing. Commendable as it is, where's that worry in leasing exclusions covering the OCS off the East and West Coasts and in the Gulf of Mexico off Florida?

In fiscal 2005 alone, the MMS collected $6.3 billion from federal offshore leases—almost all from the 15% of the Lower 48 OCS that's available for lease. The rest is precluded from leasing by congressional and presidential action.

Without a test of the resource, there's no way to tell how much revenue the government forswears with its antileasing policies. But it's probably more than $2 billion.

So where's the indignation? As a mistake of governance, this one's more appalling than Interior's.

(Online Sept. 29, 2006; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

October gas contract ends near 4-year low

The expiring October natural gas contract dropped to a near 4-year low on the New York Mercantile Exchange during the last week of September, while crude prices continued to fluctuate as traders speculated whether the Organization of Petroleum Exporting Countries might soon cut production.

The October natural gas contract expired at $4.20/MMbtu Sept. 27 after trading as low as $4.07/MMbtu during that session in anticipation of a continued build in winter storage. The November gas contract continued to fall, down by 27.7¢ to $5.39/MMbtu Sept. 28 on NYMEX.

Gas storage

The US Energy Information Administration reported the injection of 77 bcf of gas into US underground storage in the week ended Sept. 22, down from 93 bcf injected the previous week (OGJ Online, Sept. 28, 2006). US gas storage then stood at nearly 3.3 tcf, up by 377 bcf from year-ago levels and 354 bcf above the 5-year average.

That reduced injection rate "reflects the start of some 'line pack' issues [gas occupying pressurized sections of the pipeline network] along with perhaps some constrained wellhead output concurrent with the pipeline pressure builds and, in our opinion, is not the result of any sudden sharp uptick in demand due to the drop in natural gas prices," said Robert S. Morris, Banc of America Securities LLC, New York.

Analysts with Raymond James & Associates Inc. in Houston said, "We now anticipate...gas storage levels will be between 3.4-3.6 tcf at the end of October. Because this is likely to test the limits of full storage (noncoincidental storage from each region over the past 12 years has only totaled as high as approximately 3.467 tcf including salt dome additions), gas should still be extremely volatile over the course of the next 6 weeks."

Analysts at Friedman, Billings, Ramsey & Co. Inc. (FBR) in Arlington, Va., said they see similarities between the present gas market and 2001 "when gas fell from $10.20 to $1.74 but rebounded in 2002, even as storage was at record levels." They said, "We maintain our bullish outlook on the E&P sector but recognize that the near term looks volatile." FBR analysts said, "Multiple near-term catalysts should positively influence the commodity. Gas storage is showing a 380 bcf overhang (7 days demand), which should be whittled away by declining production, rebounding industrial demand, and normal winter weather....High initial decline rates across major US basins provide further cover, despite robust rig counts and capital programs. We have begun to see producers shutting in marginal wells as prices hover below cash margins in high-cost basins."

In a separate report in late September, EIA said US gas reserves grew by 6% in 2005, the largest annual increase in 35 years, with onshore gas reserves up for the seventh consecutive year, offsetting a 10% decrease in gas reserves in US waters of the Gulf of Mexico (OGJ Online, Sept. 28, 2006). However, Morris said a survey in May of Banc of America Securities' group of 55 independents and 12 major integrated companies, representing 58% of total US gas reserves, showed their proven reserves (including revisions and "improved recovery") increased 12% in 2005.

Total US gas production declined 4% in 2005 because Hurricanes Katrina and Rita shut in 80% of gulf production, EIA said. Gulf gas production was in 10% annual decline prior to those hurricanes. EIA reported US crude reserves also increased in 2005 for the first time in 3 years.

Oil price fluctuates

The November contract for benchmark US light, sweet crudes temporarily touched $64/bbl Sept. 28 on reports from Nigeria of possible OPEC action to shore up prices. But it closed at $62.76/bbl, down 20¢ for the day on NYMEX after OPEC dispelled those rumors. "We believe the commotion could be an attempt to 'talk up the markets' in the heat of considerable plunges in crude prices, and if any OPEC producer were to reduce supply, it would likely be countries that are currently producing above their quota (Saudi Arabia and other Persian Gulf producers), as opposed to Nigeria, where output has declined by 800,000 b/d in the last few months," said Raymond James analysts.

Meanwhile, US gasoline demand trends remained positive, with gasoline imports up "a surprisingly large 660,000 b/d (83%)" during the week ended Sept. 22, said FBR analysts. "Given the large decline in US refined product margins that has occurred over the past month and the commencement of European maintenance season, we expect imports to decrease materially over the coming weeks," they said.

(Online Oct. 2, 2006; author's e-mail: samf@ogjonline.com)

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