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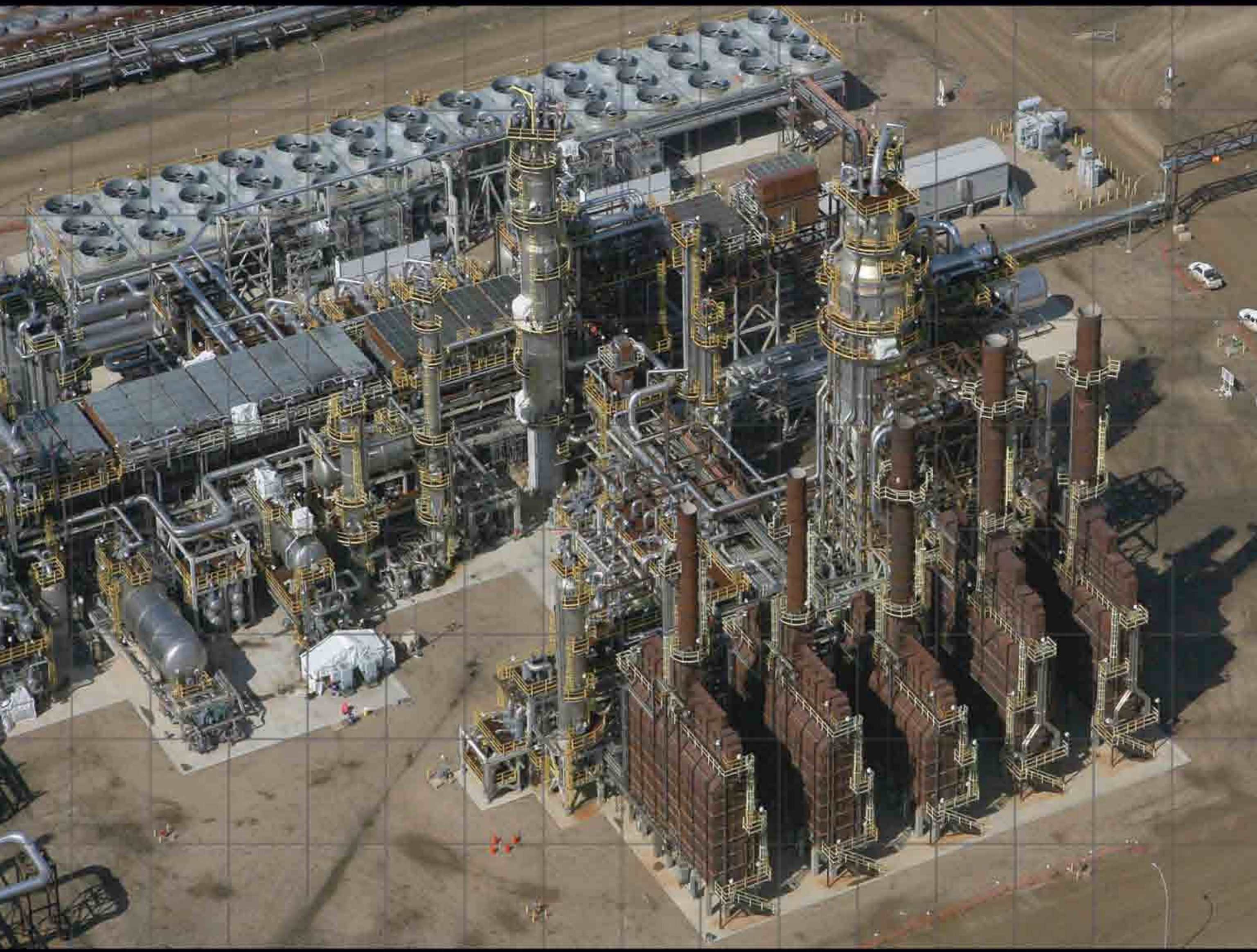

Major Upstream Projects

Coming from Russia: more crude, lighter and sweeter
Mexico, Brazil, Norway upstream readiness weighed
Changing US crude imports driving refinery upgrades
Improved methods broaden in-service tank inspection

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Aug. 10, 2009
Volume 107.30

Major Upstream Projects

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Cover

Steam injection in Phase 1 of the Long Lake integrated steam-assisted gravity drainage and upgrading project began in April 2007, with the upgrader starting to produce light crude in January 2009. When fully operational, Phase 1 is slated to produce 72,000 b/d of bitumen that will be upgraded to 58,500 b/d of 39° gravity sweet crude. The cover photo shows the OrCrude unit of the upgrader while the photo above shows part of the SAGD portion of the project. The project is in the Athabasca oil sands region, 42 km southeast of Fort McMurray, Alta. The special report, which starts on p. 38, lists many of the other major oil and gas upstream and integrated projects in the world that will be coming on stream in the next few years. Photos from Nexen Inc.

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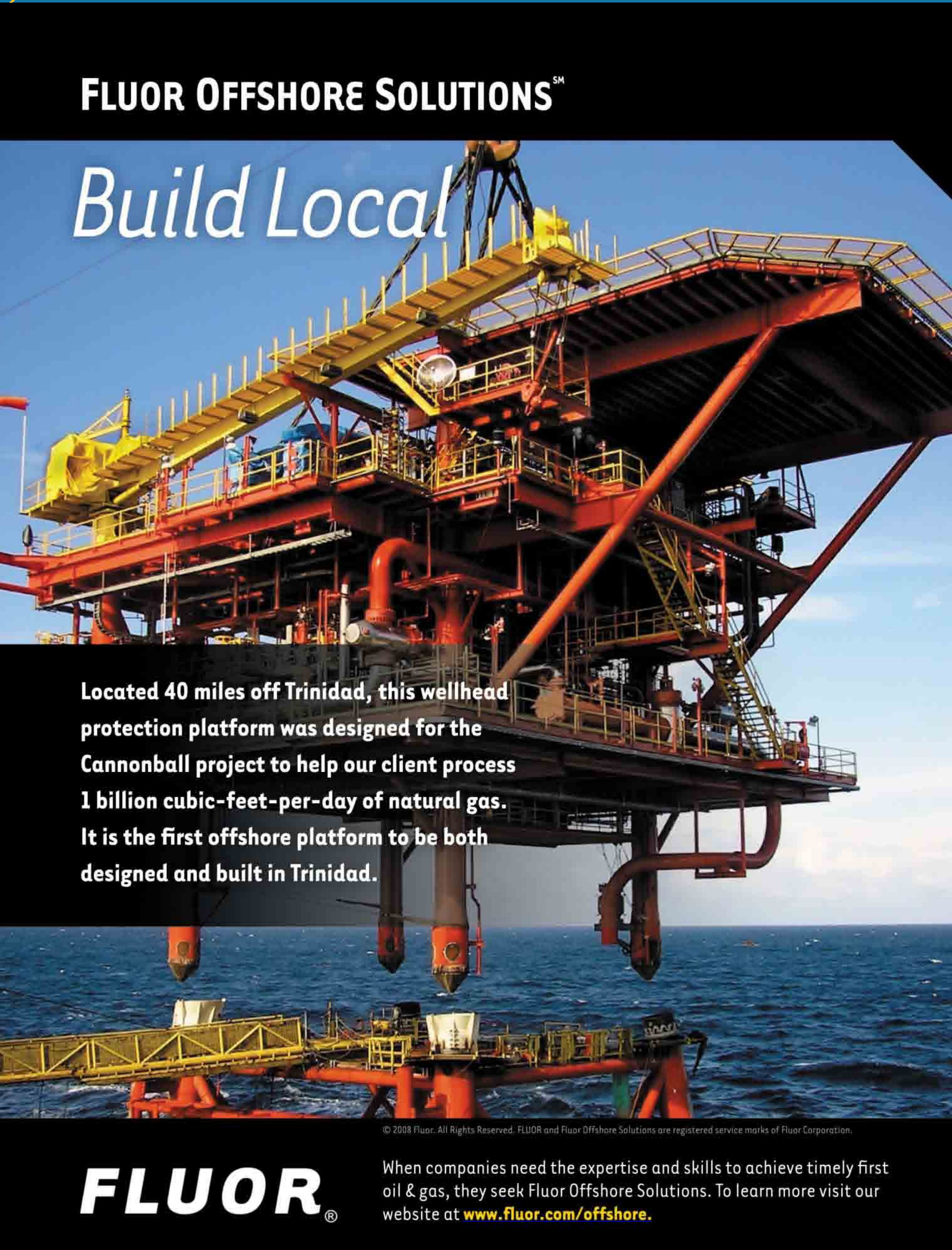
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General Interest — Quick Takes

ConocoPhillips asks to amend propane agreement

ConocoPhillips Co. has petitioned the Federal Trade Commission for approval to amend its propane supply agreement with NGL Supply Inc., the FTC announced.

The agreement is part of the antitrust regulator's consent order issued to resolve concerns stemming from the 2002 merger of Conoco Inc. and Phillips Petroleum Co. That order required the combined companies to divest propane business assets and supply propane to the purchaser, the FTC said on Aug. 5. ConocoPhillips sold the Phillips propane business to NGL to comply with the order.

ConocoPhillips now wants to amend the supply agreement to ensure that it has enough propane stocks at relevant times of the year, and that it is able to continuing supplying the product to its own customers and to NGL, according to the FTC. It said that the proposed amendments govern the summer supply of propane to NGL when ConocoPhillips's supplies drop below certain levels.

The commission said it would accept public comments on the request through Sept. 8. Copies of the petition can be found at its web site at www.ftc.gov.

Texas receiving grant to plug GOM wells

The Texas General Land Office will receive a nearly $1.4 million grant to seal abandoned Gulf of Mexico oil and gas wells in state waters, US Interior Sec. Ken Salazar announced.

The funding through the US Minerals Management Service's Coastal Impact Assistance Program will plug abandoned wells in bays and offshore waters to eliminate potential pollution threats to natural resources on the Texas Gulf Coast, he said Aug. 5.

The latest funding for Texas includes $48.6 million for each of fiscal years 2007 and 2008, and $35.6 million for 2009 and 2010, according to the US Department of the Interior. Eighteen coastal counties will share the funding of projects outlined in the state's approved plan, it said.

CIAP was created under the 2005 Energy Policy Act, according to DOI. It said that through the program, MMS provides $250 million in grants annually to six eligible Outer Continental Shelf oil and gas producing states: Alabama, Alaska, California, Louisiana, Mississippi, and Texas.

House GOP leaders urge to end OCS delay

Ninety-eight US House Republicans urged Interior Sec. Ken Salazar to end a 6-month delay early and move ahead with a 2010-15 federal offshore oil and gas leasing plan he halted on Feb. 10.

"By offering new leasing opportunities in the Atlantic and Pacific Oceans, as well as in Alaska and the Gulf of Mexico, the proposed plan is appropriately expansive, provides maximum flexibility to properly utilize all of our nation's domestic resources, and helps coastal communities pursue leasing and responsible development in the deep waters off their coastlines," the House Republican members said in a July 31 letter to Salazar.

"Important offshore areas, like those in Alaska, offer tremendous natural gas and oil resources. By some estimates the Chukchi Sea, off Alaska's coast, contains as much natural gas and oil as the country has produced in the Gulf of Mexico since 1942. The administration should not continue to stand in the way of American energy development," the letter said.

Salazar announced the delay to obtain more public comment and to broaden the plan to include alternative and renewable energy sources. His predecessor, Dirk A. Kempthorne, launched the lease plan earlier than scheduled last summer in response to record high crude oil and gasoline prices.

The letter said that the lawmakers also hoped the US Minerals Management Service maintains the current 2007-12 Outer Continental Shelf leasing plan for all available areas, including the Gulf of Mexico, Mid-Atlantic Coast, and Alaska.

Russians sign accords in Nicaragua, Venezuela

The Nicaraguan government, following the lead of Venezuela, has signed an agreement allowing exploration by a Russian consortium.

"The concessions include the Caribbean and Pacific, both offshore and on land," said Francisco Lopez, president of the Nicaraguan Petroleum Enterprise. He said a technical board would be installed to analyze implementation of the agreement.

Russia's Deputy Prime Minister Igor Sechin said the proposed exploration in Nicaragua would be carried out by the Russian National Oil Consortium, created on Oct. 8, 2008, and comprising Rosneft, Gazprom, Lukoil, TNK-BP, and Surgutneftegaz.

Sechin did not say how much Russia could invest in Nicaraguan exploration, saying only, "We must first carry out in-depth studies to calculate the investments."

Nicaragua last September became the only country to join Russia in recognizing the independence of Abkhazia and South Ossetia from the small Caucasus state of Georgia.

A month earlier, Russian military forces had invaded Georgia, a former Soviet republic, and forced the shutdown of major international oil and gas pipeline operations.

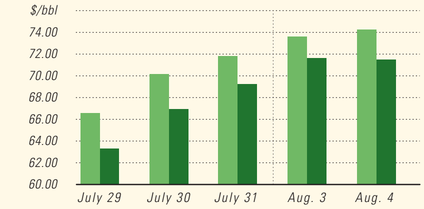
Prior to his visit to Nicaragua, Sechin also met with Venezuelan President Hugo Chavez and signed a range of economic agreements including one between OAO Gazprom and Petroleos de Venezuela on a joint venture in oil and gas services.

The Venezuelan newspaper El Universal reported the joint firm will take over some gas compression plants formerly operated by Exterran Holdings Inc.

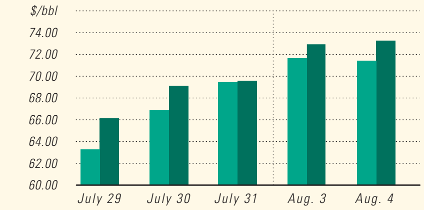
Earlier this year, according to El Universal, PDVSA nationalized

Industry Scoreboard

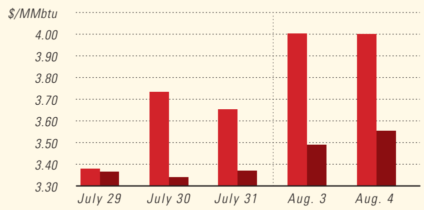
IPE BRENT / NYMEX LIGHT SWEET CRUDE



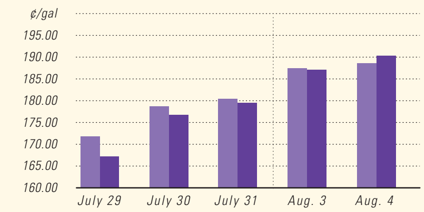
WTI CUSHING / BRENT SPOT



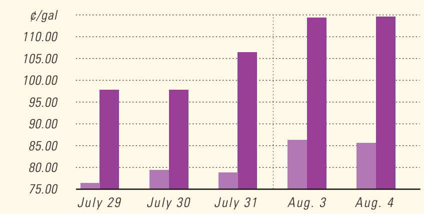
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



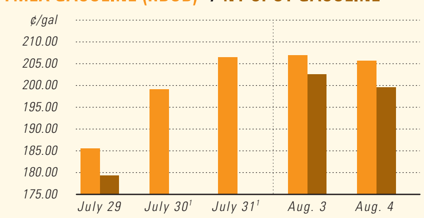
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

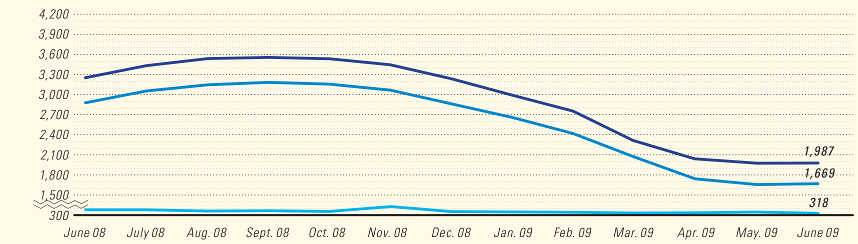
US INDUSTRY SCOREBOARD — 8/10

Latest week 7/24	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,205	9,130	0.8	8,975	9,050	–0.8
Distillate	3,300	3,694	–10.7	3,645	4,029	–9.5
Jet fuel	1,364	1,574	–13.3	1,384	1,585	–12.7
Residual	629	685	–8.2	604	651	–7.2
Other products	4,245	4,463	–4.9	4,022	4,546	–11.5
TOTAL DEMAND	18,743	19,546	–4.1	18,630	19,861	–6.2
Supply, 1,000 b/d						
Crude production	5,156	5,127	0.6	5,243	5,117	2.5
NGL production[2]	1,923	2,252	–14.6	1,886	2,139	–11.8
Crude imports	9,500	10,086	–5.8	9,320	9,836	–5.2
Product imports	2,671	3,058	–12.7	2,861	3,213	–11.0
Other supply[3]	1,906	1,492	27.7	1,706	1,550	10.1
TOTAL SUPPLY	21,156	22,015	–3.9	21,016	21,855	–3.8
Refining, 1,000 b/d						
Crude runs to stills	14,455	15,643	–7.6	14,455	14,934	–3.2
Input to crude stills	14,810	15,656	–5.4	14,810	15,266	–3.0
% utilization	83.9	88.9	—	83.9	86.8	—

Latest week 7/24	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	347,840	342,688	5,152	295,249	52,591	17.8
Motor gasoline	213,076	215,391	–2,315	213,560	–484	–0.2
Distillate	162,617	160,509	2,108	130,505	32,112	24.6
Jet fuel–kerosine	45,249	44,089	1,160	41,745	3,504	8.4
Residual	34,721	36,485	–1,764	38,029	–3,308	–8.7
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.4	22.9	2.2	19.3	21.2	
Motor gasoline	23.1	23.5	–1.7	22.8	1.3	
Distillate	49.3	48.7	1.2	31.3	57.5	
Propane	75.2	80.5	–6.6	45.5	65.3	
Futures prices[5] **7/31**			Change		Change	%
Light sweet crude ($/bbl)	65.01	65.86	–0.85	126.44	–61.43	–48.6
Natural gas, $/MMbtu	3.59	3.69	–0.10	9.75	–6.17	–63.2

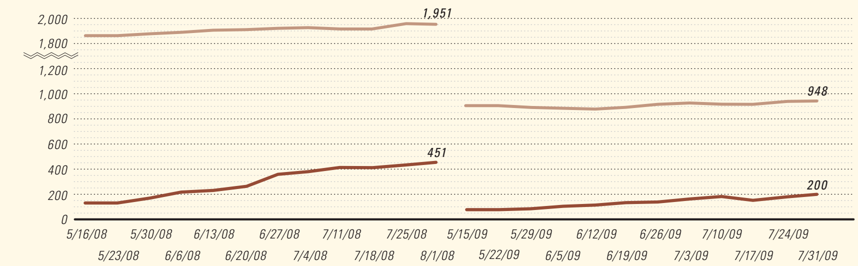
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count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nearly 50 gas units of Exterran after a new law gave the state-run firm control over the operation of several oil services, such as gas compression and gas injection, as well as transport of oil workers and equipment in Lake Maracaibo. ✦

Exploration & Development — *Quick Takes*

Development advances at East Siberian field

Verkhnechonskneftegas (VCNG), an affiliate of TNK-BP, has let a contract to KBR for front-end engineering and design of a production facility at giant Verkhnechonskoye oil field in Eastern Siberia.

The contract covers a single facility to handle 140,000 b/d of crude oil to be tied into a new 85-km link to the Eastern Siberian Pacific Ocean (ESPO) pipeline.

The remote field, 4,000 km from Moscow and 1,100 km north of the regional capital of Irkutsk, holds reserves of about 1.4 million bbl, development of which will require investment of $4-5 billion, according to TNK-BP. It was discovered in 1978.

VCNG, in which TNK-BP holds a 68.5% interest, completed a pilot development phase in 2007 and began an "early oil" project last year. That work included construction of the pipeline link to ESPO and a road to neighboring Talakan field. Deliveries into the ESPO line began last October.

Target flow from the early-oil project is 20,000-30,000 b/d by the end of this year. TNK-BP hopes to achieve plateau production of 140,000 b/d by 2014.

KBR said the field will produce at the plateau level through 430 production wells and have 215 water-injection wells. It will have 75 well pads.

The reservoir is about 1,700 m deep and has initial reservoir pressure of about 2,250 psia and temperature of 12°-20° C.

Rosneft is another major shareholder in VCNG.

Chesapeake adds volume in Granite Wash

The western Oklahoma Colony and Texas Panhandle Granite Wash oil and gas-condensate plays are delivering exceptional rates of return even in the current low commodity price environment, said Chesapeake Energy Corp.

The Colony play, in Custer and Washita counties, Okla., and the Texas Panhandle play in Hemphill and Wheeler counties, Tex., are Chesapeake's highest rate of return play due to high oil and natural gas liquids content. Pretax rates of return are 135-140% based on $7/Mcf gas and $70/bbl oil from a 4.75-5.7 bcfe horizontal well drilled and completed for $5.5-6.25 million.

Chesapeake holds 60,000 net acres in Colony and 40,000 net acres in Texas Panhandle. It is the largest leaseholder, most active driller, and largest producer in Colony.

In Colony, Chesapeake averages 90 MMcfe/d net or 165 MMcfe/d gross operated and plans to raise that to 105 MMcfe.d net or 190 MMcfe/d gross operated by the end of 2009 and 140 MMcfe/d net or 250 MMcfe/d gross operated by the end of 2010.

The company plans to average four rigs in the second half of 2009 to drill 10 net wells and seven rigs in 2010 for 40 net wells. Three recent completions in Washita County averaged initial 30-day rates of 17.1 MMcfe/d including 1,300 b/d of oil, 16 MMcfe/d including 900 b/d of oil, and 15.4 MMcfe/d including 1,100 b/d of oil.

In the Texas Panhandle play, Chesapeake produces 70 MMcfe/d net or 95 MMcfe/d gross operated and plans to reach 75 MMcfe/d or 100 MMcfe/d gross operated by the end of 2009 and 80 MMcfe/d net or 110 MMcfe/d gross operated by the end of 2010.

The company will average two rigs in the second half of 2009 and in 2010 to drill 10 and 20 net wells, respectively.

Dana Petroleum plugs Tafejjart-1 well

Dana Petroleum (E&P) Ltd. plugged the onshore Tafejjart-1 well (TAJ-1) in Morocco because it has not discovered commercial quantities of gas.

A 2,000 HP rig provided by Aladdin Middle East Ltd. drilled a TD of 3,274 m on the Bouanane license and targeted Ordovician sandstone. "However, cuttings information and wireline log data indicated poor reservoir quality with low porosity," said Tethys Oil AB, a partner in the well.

"This wildcat came in very close to prognosis. Several of the necessary criteria for a successful exploration well were fulfilled, and with better porosity in the reservoir it would have been a success," said Magnus Nordin, managing director of Tethys Oil.

The company will withdraw from the 2,000 sq km license to focus on projects in Oman.

Dana Petroleum has a 50% interest in the license, with its partners Moroccan state oil and mining company, ONHYM, holding 25%, Eastern Petroleum (Cyprus) Ltd. with 12.5%, and Tethys Oil AB with 12.5%. Tethys has a share of 16.66% of all expenditures on the license above $12 million.

Santos awards contract for Gladstone LNG

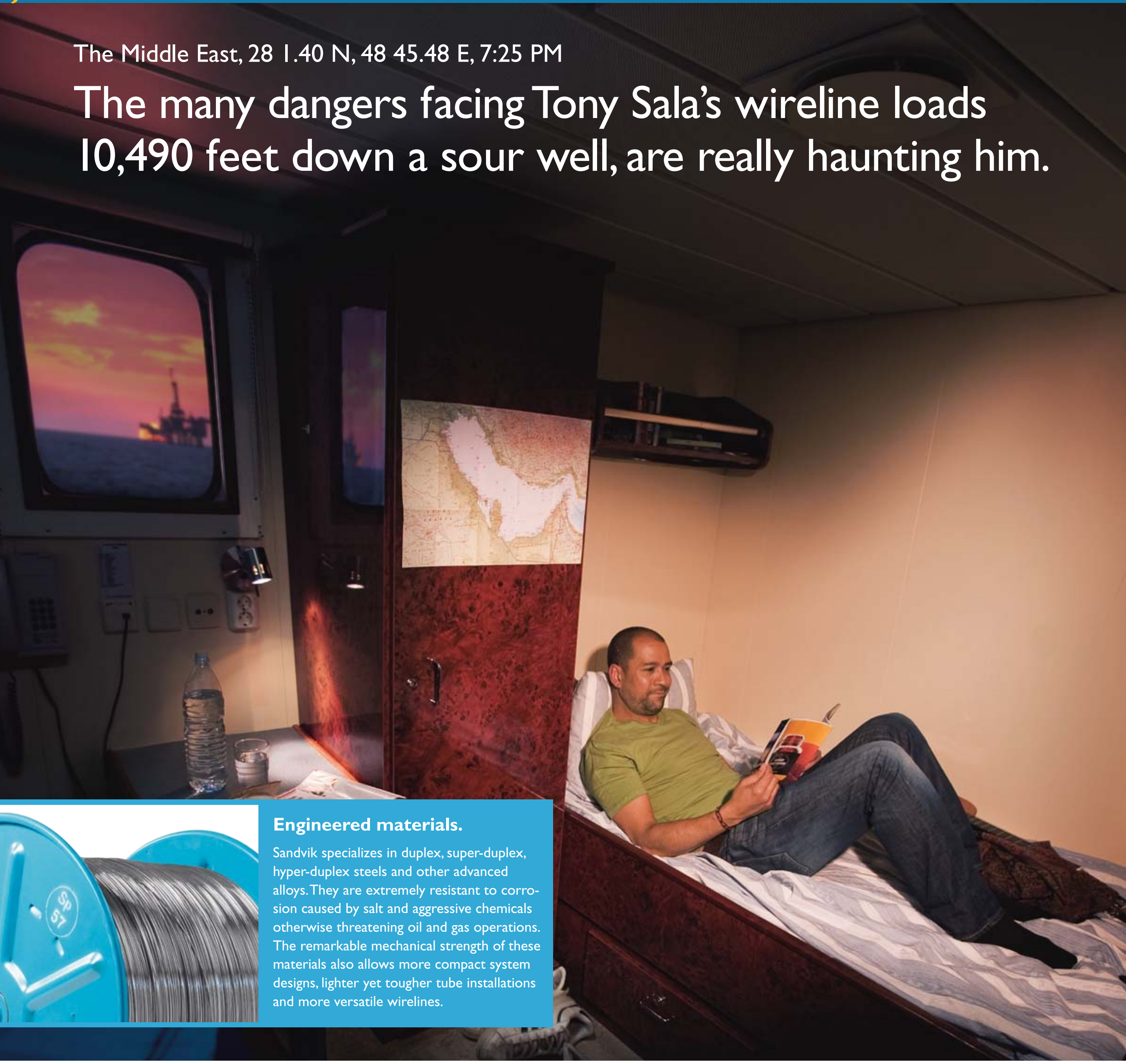
Santos Ltd. let a front-end engineering design contract to Foster Wheeler to determine how it should extract and transport coal-seam gas for the upstream phase of its Gladstone LNG project in Queensland, Australia. The value of the deal was not disclosed.

Foster Wheeler will focus on delivering coal-seam gas to the transmission pipeline and associated infrastructure and services, including power generation and water treatment facilities. The work is scheduled to be finished in the first quarter of 2010.

Santos will source 170-220 petajoules/year of coal-seam gas from Fairview, Roma, and Arcadia fields in Central Queensland to a planned single train onshore LNG facility. Gladstone LNG Pty. Ltd. (GLNG) will have a 3-4 million tonnes/year LNG processing train and associated infrastructure.

In June, Santos said Petronas of Malaysia was willing to buy 2 million tonnes/year of LNG starting from 2014 with an option of an additional 1 million tonnes/year under a heads of agreement. However, this was conditional only on the GLNG project's receiving final approval to proceed (OGJ Online, June 18).

Santos is the operator with a 60% stake in the project with Petronas holding 40%. The project is expected to cost $7.7 billion (Aus). ✦



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Drilling & Production — *Quick Takes*

Aramco: 400 wells prepped for Khurais start

Saudi Aramco said its Southern Area Production Engineering and Production Services Departments prepared more than 400 wells for completion before supergiant Khurais oil field came on stream in June (OGJ, July 20, 2009, p. 34).

The units managed 232 oil-production, 119 water-injection, and 58 observation wells, as well as stimulation work and the installation and testing of electrical submersible pumps.

The stimulation work covered 118 power-water injectors and 14 oil producers. It included the pumping of 12 million gal of fluid.

Aramco said the use of rigless coiled-tubing technology tripled injection rates in comparison with conventional methods using drill pipe in a rig.

At Khurais, which added 1.2 million b/d to Saudi production capacity, the company made its first use of distributed temperature sensors combined with multilateral tools in a number of reservoir access wells.

Khurais development made heavy use of permanent downhole monitoring sensors, remote-control chokes, and multiphase flowmeters. Data flow through a remote terminal unit at wellsites to field control rooms and eventually to 'Udhailiyah and Abqaiq for validation and interpretation.

Bolivia's Itau field declared commercial

France's Total declared Bolivia's giant Itau gas-condensate field commercial, 10 years after its discovery in Tarija Department.

Itau, discovered in 1999 in Block XX Tarija West, is scheduled to start production in mid-2010 at an initial 50 MMcfd of gas, the company said.

Gas is to be processed at Petrobras Bolivia's 210 MMcfd plant in adjacent San Alberto field just north of the border with Argentina and less than 100 miles west of the border with Paraguay. Total operates Itau with 75% equity.

The Itau X-1A discovery well tested gas-condensate from the Devonian Huamampampa formation. TD is 18,917 ft.

San Alberto was discovered in 1998 and began producing in early 2001. Itau's development has been delayed until its supply was needed for throughput in the Bolivia-Brazil gas pipeline.

The Total Group plans to spud an appraisal well by the end of 2009 at Incahuasi gas-condensate field found in 2004 on the Ipati block 80 miles north of Itau in Chuquisaca Department. It will drill the appraisal well on the adjacent Aquio license. Total owns 80% equity in both blocks.

Total, OAO Gazprom, and Yacimientos Petroliferos Fiscales Bolivianos in 2008 created a mixed company to explore the 4,764 sq km Azero block. Total and Gazprom will have equal stakes in the mixed company.

TAQA to operate Dutch gas field platform

TAQA Energy BV (TAQA Energy) will operate the L11b-A platform in the Dutch North Sea, which will start production from the southern part of L8-D gas field later this year.

The Abu Dhabi National Energy Co. subsidiary has acquired a 15% interest in the license, platform, and connection to the Noordgastransport (NGT) pipeline. TAQA's partner, Cirrus Energy Nederland BV, will operate the L11b license, which is 50 km north of Den Helder.

The L11b Group, comprising Chevron Exploration & Production Netherlands BV, DSM Energie BV, and EBN, sold the assets to the L8-D Field Group for an undisclosed amount.

The L8-D Group includes TAQA Energy, Cirrus Energy Nederland, DSM Energie, Energy Investments BV, EWE AG, and EBN.

The L8-D structure holds an estimated 323 bcf of gas in place, according to a report compiled by GLJ Petroleum Consultants Ltd.

In February, the L11b-A06 appraisal well (previously called L11-13) tested gas at a maximum stabilized flow rate of 30.6 MMscfd on a 48/64 in. choke at a flowing wellhead pressure of 200 bar (OGJ Online, Apr. 1, 2009). The group used the Noble Lynda Bossler jack up to reach a TVD of 4,200 m.

"Production from the nearly depleted L11b-A field has been shut-in, and modifications to the existing process equipment are under way to allow for the tie-in of the L11b-A06 well," said Cirrus Energy. "This is expected to be completed in the fourth calendar quarter of 2009, at which time L8-D field production is expected to commence from the L11b-A06 well."

A second L8-D field appraisal-development well is to be drilled from the L11b-A platform later this year, which, if successful, is expected to be on production during early 2010.

TAQA also will take over DSM Energy's share in the L8-D Group following its acquisition of the company. The deal is expected to close in the third quarter of this year, subject to regulatory approvals and notifications.

TAQA has a 15% share in the LD-8 Group. Cirrus Energy Nederland has 25.479%, DSM Energie has 2.88%, EBN holds 41.9%, Energy06 Investments BV has 1.341%, and EWE AG has 13.4%. ✦

Processing — *Quick Takes*

Contract let for German refinery integration

Shell Deutschland Oil GMBH has let an engineering, procurement, and construction management contract to Technip for integration of the 327,000-b/d Rheinland refinery near Cologne, Germany.

Until 2005, Royal Dutch Shell units operated the facility as separate refineries, with 140,000 b/d of crude capacity at Wesseling and 162,000 b/d of capacity at Godorf (OGJ, Dec. 19, 2005, p. 60).

Technip's initial work will be at Wesseling. It includes modification of desulfurization and hydrogen units and construction of new facilities. Wesseling will desulfurize gas oil from Godorf.

Technip handled basic design for the first phase of the integration project, called Connect, and is working on basic design packages for later phases.


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Uganda to study feasibility of refinery

Uganda is considering construction of a 50,000-b/d refinery to produce fuel for local and regional markets, according to the Ministry of Energy and Minerals Development.

Feasibility studies are to be launched before yearend for a refinery with capacity that might be doubled in 6-7 years. The ministry says production from recent discoveries might reach 100,000 b/d.

Heritage Oil Ltd., Tower Resources PLC, and Dominium Uganda Ltd. are exploring in the country.

The announcement of the refinery plan follows reports that Tower Resources has commissioned a reevaluation of the West Nile where the first well drilled, Iti-1, was dry). ✦

Transportation — *Quick Takes*

Midcontinent Express begins full operation

Natural gas service on the roughly 500-mile Midcontinent Express Pipeline (MEP) began Aug. 1 between Delhi, La., and Transcontinental Pipe Line's Station 85 in Butler, Ala. Interim service from Bennington, Okla., to Delhi began in April.

Completion of the final segment of MEP connects production from the Barnett shale, Bossier sands, and other plays in the region to the eastern US.

MEP has multiple receipt and delivery points along its length, crossing northeastern Texas, northern Louisiana, and central Mississippi between Oklahoma and Alabama.

Capacity is currently 1.25 bcfd in Zone 1, which interconnects with the Columbia Gulf Transmission system in Delhi and up to 0.84 bcfd in Zone 2, which interconnects with the Transcontinental Gas Pipe Line system in Butler. An expected 2010 expansion of the pipeline will further increase MEP's capacity to about 1.8 bcfd in Zone 1 and 1.2 bcfd in Zone 2. The pipeline's capacity, including the expansion capacity, is fully subscribed by long-term binding commitments.

Construction of two additional compression stations, one in Cass County, Tex., and a second in Hinds County, Miss., will start in fall 2009 to meet this expansion timeline.

MEP is a joint venture of Kinder Morgan Energy Partners LP and Energy Transfer Partners LP. Kinder Morgan constructed and will operate the pipeline.

Dolphin Energy announces financing

The Dolphin Energy consortium raised $4.1 billion to refinance debt, help fund construction of a gas pipeline, and pay for the refinancing fees.

Dolphin said the $4.1 billion will be used to repay a $3.45 billion loan secured in 2005, to provide 70% of the construction costs of the 244-km, 48-in. Taweelah-Fujairah pipeline, and to pay for fees related to the refinancing.

Dolphin's majority shareholder, the Abu Dhabi government's investment firm Mubadala Development Co. (51%), reportedly played a key role in raising the financing, while partners Total SA and Occidental Petroleum (24.5% each) are lending the project $1.2 billion.

Last month, Australia's export credit agency EFIC said it was guaranteeing Gasco's $6.5 million contract to supply and supervise installation of two heaters for the pipeline.

Gasco's client is Russia's Stroytransgaz, which was awarded a $418 million engineering, procurement, and construction contract for the pipeline in June 2008.

The Taweelah-Fujairah gas pipeline will link Dolphin Energy's gas-receiving facilities at Taweelah, on the coast of Abu Dhabi, with the ADWEA Power and Water Desalination Plant at Qidfa, in Fujairah.

TAQA Bratani operates Brent pipeline system

TAQA Bratani Ltd. assumed operatorship from Shell UK Exploration & Production for the Brent System pipeline in the UK North Sea, marking a change in management for the first time in almost 30 years.

The pipeline delivers 100,000 b/d of oil from 20 North Sea fields and constitutes around 8% of offshore oil production. It accounts for almost 60% of the input at the Sullom Voe terminal in the Shetland Islands, in which the company has a 24% stake.

TAQA will have a 16% interest in the system and has invested in experienced staff and first class IT and systems infrastructure to work with its other Brent partners, such as ExxonMobil Exploration & Production Norway AS and Lundin Thistle Ltd.

TAQA will focus on its operated Cormorant Alpha platform as well as the 150 km pipeline connecting Cormorant Alpha to the BP PLC operated Sullom Voe terminal.

Leo Koot, TAQA Bratani's managing director, said: "This is the latest step in our North Sea activity program, which this year already has seen TAQA increase production from our operated assets, initiate drilling, and near-field exploration."

In December, TAQA completed the $631 million purchase of assets in the UK North Sea from Shell UK Ltd. and ExxonMobil Corp. (OGJ Online, Dec. 7, 2008) TAQA operates Tjern, Kestrel, Eider, Pelican, Cormorant North, and Cormorant South fields and related assets. They lie in 150-167 m of water northeast of Lerwick in Shetland.

TAQA is the UK arm of the Abu Dhabi National Energy Co. ✦

Correction

A credit line for the photo of the Bw Cidade de Sao Vicente floating production, storage, and offloading vessel on the cover of the Aug. 3 edition of OGJ inadvertently was left out of the coverbox text on the table of contents. That photo was supplied by the Petrobras News Agency.

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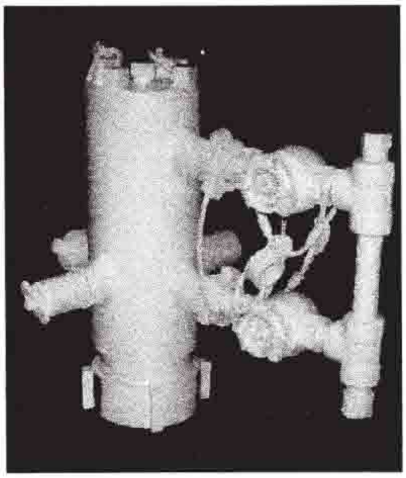

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2009

AUGUST

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

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

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

Coal-Gen Conference, Charlotte, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.coal-gen.com. 19-21.

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

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

SEPTEMBER

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

Coal-Gen Europe Conference, Katowice, Poland, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.coal-gen-europe.com. 1-4.

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

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

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

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.

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

Turbomachinery Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 14-17.

Annual IPLOCA Convention, San Francisco, +41 22 306 02 30, +41 22 306 02 39 (fax), e-mail: info@iploca.com, website: www.iploca.com. 14-18.

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

Drilling Engineering Association-Europe: ERD and Associated Technology Meeting, Stavanger, +44 (0) 1483-598000, e-mail: Dawn.Dukes@otmnet.com, website: www.dea-europe.com. 17-18.

Annual Energy Policy Conference, Oklahoma City, (202) 580-6532, (202) 580-6559 (fax), e-mail: info@energyadvocates.org, website: www.energyadvocates.org. 20-22.

Multiphase User Roundtable-Mexico, Villahermosa, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-mexico.org. 22-23.

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

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

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

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

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

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

OCTOBER

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

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

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

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

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

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.powergenasia.com. 7-9.

Renewable Energy World Asia Conference & Expo, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.renewableenergy-world-asia.com. 7-9.

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

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

Rocky Mountain EOR

Guntis Moritis
Production Editor

The northern portion of the Rocky Mountain region of the US may see more enhanced oil recovery projects as carbon dioxide from new sources becomes available because of concerns about the need for carbon capture and sequestration.

CO_2 injection for enhancing oil recovery holds much promise as demonstrated by the many successful projects in the Permian basin of West Texas and elsewhere, but CO_2 availability has been one factor limiting its use.

In the US, CO_2 injection has accounted for the recovery of about 1.5 billion bbl of oil, and CO_2 sales to US EOR projects reached an estimated 3 bcfd in 2008, with about 83% of it coming from CO_2 source fields, according to a presentation at the Third Annual Wyoming CO_2 Conference, Casper, Wyo., June 23-24.

The ExxonMobil Corp.-operated Shute Creek gas processing plant in the southwestern part of Wyoming has provided, since 1986, most of the CO_2 for EOR projects in the region.

Encore projects

Recently Encore Acquisition Co. announced plans to purchase 50 MMcfd of CO_2 for its Bell Creek EOR project in southeastern Montana from the ConocoPhillips-operated Lost Cabin gas plant in Fremont County, Wyo. (OGJ Online, June 29, 2009). The project involves building compression facilities adjacent to the plant and installing a 206-mile pipeline to transport compressed CO_2 to Bell Creek.

Encore estimates that CO_2 injection will recover an incremental 30 million bbl of oil during the project's 20-25 year life.

The company also has plans to inject CO_2 in various reservoirs on the 120-mile long, 6-mile wide Cedar Creek anticline, which lies mostly in Montana and extends into North Dakota. Cedar Creek is about 120 miles from Bell Creek.

Encore estimates CO_2 injection potentially could recover about 200 million bbl of oil from Cedar Creek.

CO_2 sources

Two potential new sources for CO_2 in Wyoming are a proposed underground coal gasification (UCG) project in the Powder River basin and a coal gasification and liquefaction project near Medicine Bow, Wyo.

Linc Energy Ltd., Australia, plans to start a UCG pilot by mid-2011 after it finalizes the purchase of the GasTech Inc. acreage in the Powder River basin of northwest Wyoming.

The other project is the Medicine Bow Fuel & Power LLC facility, which includes a coal mine adjacent to a coal-to-liquids plant. The first phase is slated to produce about 21,000 b/d of ultralow-sulfur diesel fuel.

A presentation at the Casper conference estimated that these two projects could supply 335 MMcfd of CO_2 for EOR in 2013.

Another CO_2 source that will become available in 2010 is from the completion of a $72 million expansion at ExxonMobil's Shute Creek gas processing plant. The expansion includes installation of 23,000 hp of CO_2 compression for increasing CO_2 sales by 110 MMcfd from the current 230 MMcfd.

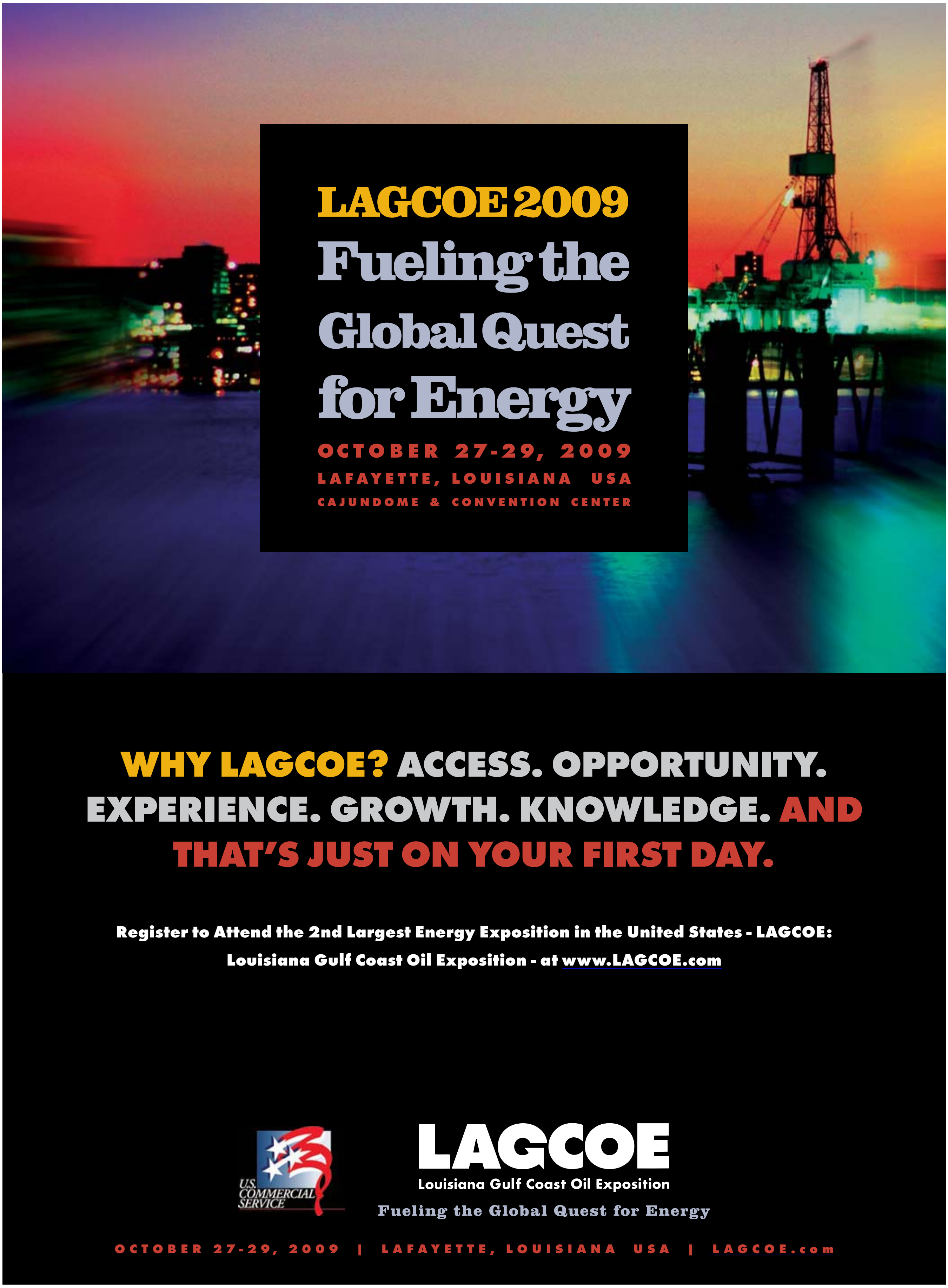
The Shute Creek plant has a 700 MMcfd of gas processing capacity and receives gas from LaBarge field in Sublette, County, Wyo. The composition of the gas from La Barge is 66% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulfide, and 0.6% helium. Presentations at the Casper conference noted that the Shute Creek plant is the largest gas sweetening plant in the world, produces 25-30% of the world's supply of helium, about 4 MMcfd, and injects the most acid gas consisting of 35 MMcfd of hydrogen sulfide and 25 MMcfd of CO_2.

La Barge is also the site of a $100 million pilot for demonstrating ExxonMobil's controlled freeze zone single-step process for CO_2 separation. The company plans to start up the pilot in 2010 and expects it to be a lower cost process that may make carbon capture and sequestration a more practical option for CO_2 separated from natural gas.

Currently ExxonMobil sells CO_2 to five EOR projects in Wyoming and one in Colorado. The Wyoming projects are the Anadarko Petroleum Corp.-operated Patrick Draw (Monell Unit) and Salt Creek fields, Devon Energy Corp.-operated Beaver Creek field, and Merit Energy Co.-operated Lost Soldier and Wertz fields.

In Colorado, Chevron Corp. operates an EOR project in Rangely field that receives CO_2 from Shute Creek.

A presentation at the Casper conference estimated that potential EOR projects in Wyoming could need up to 2.68 tcf of CO_2 to recover about 418 million bbl of oil. ✦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Politics and fuel choice

The folly of governmental fuel choice is playing out vividly in the shadowed margins of fiscal politics. Hydrogen, everyone's favorite vehicle fuel a few years ago, has fallen from grace—at least in some quarters.

Who can forget the hydrogen hooplah that gripped the US Department of Energy during the administration of George W. Bush? According to DOE's press notices, a "hydrogen economy" loomed. There, vehicles would emit nothing more than water. Global warming would cease. The country would quit importing oil. All that stood between the US and hydrutopia was reversal of a chicken-and-egg problem: Build a hydrogen distribution system, and the rest would take care of itself. It was only a matter of political will.

Of course, political will tends to change with inconvenient frequency. It's doing so now with hydrogen.

Nothing for hydrogen

In its federal budget proposal for fiscal 2010, the administration of President Barack Obama requested nothing for hydrogen research. Some of the reason no doubt reflects the administration's revulsion toward anything associated with the former president. But some, too, shows a measure of welcome pragmatism. The hydrogen fad, based though it was on genuine fuel advantages, overlooked huge commercial problems, most of them tied to the energy needed to isolate the hydrogen atom.

Explaining to Congress his department's loss of appetite for hydrogen research, Energy Sec. Stephen Chu in May said the government had better uses for the money. He, for one, sees greater potential in electric plug-in cars and biofuels, at least over the next 20-30 years. As a Nobel Prize-winning physicist and former director of DOE's Lawrence Berkeley National Laboratory, Chu brings impressive scientific authority to these judgments.

Yet it's not difficult to find similarly qualified scientists who think the government is foolish to abandon hydrogen research. Many of them work for the automakers that have committed themselves to commercialization of hydrogen vehicles or for universities hoping to soak up some of the $1.2 billion Bush channeled toward hydrogen.

Research funding notwithstanding, knowledgeable people can disagree honestly over the merits of one fuel in relation to others. Without question, upper-level disagreement such as this generates insights enlightening to energy choices. But it can't efficiently make those choices. If it's to produce policy, academic argument must yield to the clanking machinations of politics, with all its deal-making and insidious influences. Ultimately, the laboratory's soaring truth becomes the cloakroom's squirming compromise.

Energy choices are best left to free markets, fully informed. This historic verity, which tends these days to be dismissed as quaint ideology, has received no clearer or more immediate demonstration than with the national calamity developing from biofuels.

Now and even more so in the future, biofuels surely must contribute to total energy supply. They will do so only if the government confines itself to conducting research and disseminating the results. Instead, lawmakers and presidents of both major political parties have seen fit to push fuel ethanol and biodiesel into the market with mandates and generous subsidization. For the fuels themselves, the consequences are disastrous.

Overbuilding—encouraged in part by state-guaranteed loans—and market surprises have crushed the economics of ethanol manufacture. A rushed conversion of soybean agriculture into corn has raised the price of biodiesel's main feedstock while the product's price has sunk. Bankruptcy courts are selling distressed plants at dimes on the dollar.

Congressional mandates for biofuels, which rise each year through 2022, probably are futile. Because the gasoline market soon won't be able to absorb ethanol at mandated rates, the ethanol lobby wants increased blending levels. But that's just the immediate problem. Satisfying future mandates depends on the development and implementation of technology that's not yet commercial and on a delivered supply of plant waste that probably won't materialize.

Program fails

Biofuels haven't failed. The failure is an ill-considered program to rush them to market.

Renewable and other unconventional fuels have an important and growing role to play in energy supply. Governments have roles to play in stimulating their growth. Ultimately, however, fuels need solid commercial grounding, which never results from political caprice. ✦

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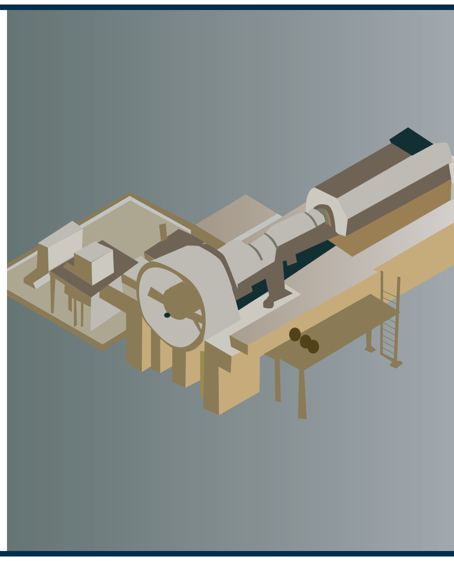

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Coming from Russia: more crude, lighter and sweeter

Andrew Reed
Energy Security Analysis Inc.
Wakefield, Mass.

Russia has historically exported medium sour crude, but over the next decade there will be more than a 2 million b/d increase in light sweet exports. Several developments will bring about this transformation.

A geographic redistribution of Russian crude output, with new growth coming in such areas as East Siberia and Timan-Pechora, will reshape Russian output. Much of the new supply will be light sweet, while output of medium sour will decline.

Meanwhile, Russian export infrastructure will continue to develop in line with these internal shifts and Russian foreign economic objectives. Changes to the export infrastructure will enable more light sweet to reach the market without commingling with medium sour crude in the main pipeline system.

Growth of exports from Kazakhstan via Russia will also be significant. The transformation of Russian crude exports is already under way. The approaching launch of the East Siberia-Pacific Ocean (ESPO) pipeline and development of East Siberian fields will boost light sweet supply to Asia in 2010.

Based on an analysis and projections of production, consumption, and exports by Energy Security Analysis Inc., Russian crude oil output is projected to grow at an average rate of 0.3%/year through 2020, bringing output to nearly 10.2 million b/d.

The Russian government seeks to increase throughput of domestic refineries, which would undermine future crude exports. But there are reasons to believe that by 2020 throughput levels will actually decline. Based on an analysis of foreign and Russian fuel specifications, ESAI projects that lack of investment to equip refineries to supply quality products will force some Russian refiners to shut down. Russian oil product exports, mostly high-sulfur fuel oil and gas oil, will continue to become less competitive in traditional foreign markets.

European Union countries will continue to reduce Russian gas oil imports as their regional deficit declines and the availability of higher quality gas oil from the US increases. If there is a proliferation of emissions control areas for bunker fuel, exports of high-sulfur fuel oil will also become less competitive.

Russia is slowly moving to improve fuel quality on the domestic market, which will also reduce the viability of refineries that do not modernize. Russian and Commonwealth of Independent States refineries consumed 5.5 million b/d of Russian crude in 2008. ESAI presumes that number will fall to 4.6 million b/d in 2020, enabling Russia to export more crude oil.

In addition, ESAI assumes the launch of production at Kashagan oil field in the Caspian Sea will cause crude exports from Kazakhstan via Russia to rise from 950,000 b/d in 2008 to 1.3 million b/d in 2020. As a result of these trends, crude exports from Russia

RUSSIAN CRUDE OIL EXPORTS IN 2020

should rise to 6.6 million b/d in 2020 from 5.1 million b/d in 2008 (Table 1).

ESAI sees downside risks to Russian supply after 2020. For that reason, volumes will probably decline in the decade through 2030. It is very likely that 2020 will represent a peak in terms of Russian exports.

Exports to Europe

Russian light sweet crude exports to Europe will grow by 1 million b/d over the next decade. Meanwhile, outflows of medium sour will decrease. The trend toward greater light sweet exports will be shaped by several developments in Russia as well as by the growth of transit flows from Kazakhstan.

In northwestern Russia, Lukoil produces light sweet crude from South Khylchuya field in Timan-Pechora. ESAI estimates that the crude produced in Timan-Pechora and the Barents Sea will generally be light sweet, similar in quality to oil in the nearby North Sea.

ESAI assumes that future Russian supply from the Caspian Sea will also be light sweet. As already noted, growing volumes of Kazakh light sweet from Tengiz and Kashagan will feed into both the Caspian Pipeline Consortium and Transneft pipeline systems.

Meanwhile, Russia is developing oil export capacity via seaports, including the Black, Baltic, and Barents Seas in European Russia.

Based on plans for the expansion of CPC pipeline capacity to 1.34 million b/d (planned simultaneously with construction of the Burgas-Alexandroupolis pipeline), ESAI expects exports of Russian and Kazakh crude via the Black Sea will grow to 1.3 million b/d in 2020. Thus the lion's share of Black Sea exports will be CPC Blend.

The expansion of the Baltic Pipeline System (work on BPS-2 officially began in June) will divert oil from the Druzhba pipeline system that is now used for overland supply of 1.25 million b/d to Central and Eastern Europe. ESAI estimates that exports through the Baltic Sea will grow to more than 2 million b/d by 2020, while the Druzhba pipeline will transport diminishing volumes.

These infrastructure changes will enable strong growth in the amount of light sweet crude exported independently of the Transneft pipeline system. ESAI projects that exports of light sweet crude (including transit volumes) will grow from 764,000 b/d in 2008 to 1.76 million b/d in 2020, while exports of medium sour will decrease from 3.7 million b/d in 2008 to an estimated 3.3 million b/d in 2020 (Table 2).

Projected crude balance and exports*

Table 1

	Supply	Russia/ CIS demand	Russia surplus	Transit volumes	Total exports
	Million b/d				
2008	9.8	5.4	4.1	1.0	5.1
2010	9.9	5.3	4.2	1.0	5.3
2015	10.1	4.9	4.8	1.3	6.1
2020	10.1	4.6	5.2	1.4	6.6

*In reported Russian data the amount from oil exported is consistently about 350,000 b/d less than the volume implied in the supply-demand balance. ESAI has made a downward adjustment to the Russia surplus in this table to reflect the statistical difference and more accurately predict actual exports.

For Europe, growth of Russian light sweet exports will partially offset declining North Sea supply of light sweet. Additionally, when one combines the impacts of growing light sweet supply to the Transneft system with decline of heavy sour crude supply in the Volga region, the medium sour Urals blend exported from Russia will gradually become lighter and lower in sulfur.

Effects in Asia

Russia exported 212,000 b/d of light sweet crude from Sakhalin in 2008, so it is already a supplier of light sweet crude to Asia.

The first phase of the ESPO pipeline, to be completed by 2010, will provide up to 300,000 b/d by pipeline and rail to Kozmino Bay on the Pacific Ocean and another 300,000 b/d to China. The quality of crude from the main supply sources of the pipeline, Vankor and other East Siberian fields, will generally be light sweet.

Russia has a target to eventually raise capacity of the pipeline to 1.6 million b/d. Based on ESAI's projections for growth of Russian output and likely demand for crude, this objective will not be reached. However, ESAI estimates that growth in supply via the ESPO pipeline will enable overall exports of light sweet crude to Asia to reach 1.3 million b/d by 2020 (Table 3).

Russian light sweet crude will be an attractive substitute for China's declining output of medium sweet, especially for refiners that fail to invest in desulfurization capacity. China is just one important market where Russia will

Actual, projected crude exports to Europe[1]

Table 2

Crude type Crude quality (API gravity, sulfur content)	Urals 31.8°, 1.35%	CPC blend 43.3°, 0.6%	Other light sweet
	1,000 b/d		
2008	3,864	634	130
[2]2020	3,320	1,340	420

[1]Includes estimated transit volumes from Kazakhstan and Azerbaijan. Figures exclude deliveries to CIS refineries.
[2]Estimated.

Actual, projected crude exports to Asia

Table 3

Crude type	Light sweet (ESPO blend and Sakhalin)	Other (includes medium sour and offshore output of undetermined quality)
	1,000 b/d	
2008	212	182
2020*	1,335	200

*Estimated.

OGMT North America 2009 Preliminary Program

TUESDAY, SEPTEMBER 1, 2009

3:00 pm – 5:00 pm KEYNOTE/OPENING SESSION

Ricky Smith, *GPAllied, LLC*

WEDNESDAY, SEPTEMBER 2, 2009

8:30 am – 10:00 am SESSION 1: TESTING

Automated Diagnostics of Instruments, Controls and Valves Using Existing Plant Data
George Buckbee, *ExperTune, Inc.*

Web-Based 360-Degree Continuous Internal Corrosion Monitoring of a Multiphase Liquids Pipeline
Sam Cauchi, *FOX-TEK (invited)*

Paper Title & Speaker TBD

10:45 am – 12:15 pm SESSION 2: DOCUMENT MANAGEMENT

Pipe Handler Systems Struck by Lightening Results in 4 days of Downtime – How to Avoid This and Similar Drilling Control System Problems
Nestor Fesas, *Athens Group*

Learn how you can implement your own successful software management process and start reaping the benefits now.

Operations and Maintenance Portal
Andrew Bourne, *WayPoint Technologies*

Still using a binder? O&M Portal: the web-based solution that allows you to effectively manage operations and maintenance anywhere in the world.

Paper Title & Speaker TBD

1:30 pm – 3:00 pm SESSION 3: ASSET MANAGEMENT APPROACHES I

Measuring Sustainable Change
David Army, CMRP, *Strategic Asset Management*

Today's environment requires measurements that can predict, determine and influence desired outcomes rather than focusing on ony lagging or outcome indicators. Measuring Sustainable Change will discuss the reasons why new performance measures are required and the need to include people and behavioral indicators back into the equations.

Cost Effective Maintenance Strategies for an Uncertain Economic Business Climate
Tracy Strawn, *Marshall Institute*

Maintenance Performance Improvement & Contracting Strategies Roadmap – Practical Case Studies
Speaker TBD, *i-Quantum Solutions*

3:30 pm – 5:00 pm SESSION 4: ASSET MANAGEMENT APPROACHES II

Effective Planning Produces Millions in Processing Benefits
Bill Christ, *Maintenance Strategies Consultants (invited)*

Delivering Real Business Benefits by Aligning the Maintenance Activity with Corporate Objectives
David Kirkwood, *EC Harriss LLP (invited)*

Simulation Game
Rodolfo Stonner, *Petrobras America Inc.*

How to get an overall commitment to RCM practices through a stimulating and exciting simulation game, close enough to real world, depicting how these practices may really improve Production Losses, Budget Compliance and Manpower Utilization.

8:30 am – 10:00 am

10:45 am – 12:15 pm

1:30 pm – 3:00 pm

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THURSDAY, SEPTEMBER 3, 2009

SESSION 5: MAINTENANCE WORK PROCESSES

Integrated Safe Systems of Work Management Delivers Best Practice
Mike Neill, *Petrotechnics*
This presentation will deliver best practice of ensuring consistency in hazardous maintenance work execution across the entire)&G value chain (up-mid-downstream) by identifying, and implementing a uniform, enforceable & scalable approach to how all maintenance work is done at the frontline (job site).

CMMS "Can Make Management Smile"
Harry Baker, *ENI Petroleum (invited)*

Implementing O&M Best Practices to Improve Plant's Performance Right the First Time
Jim Leitch, *Fluor Global Services*
This presentation will examine some strategies and best practices to implement early, while the new plant is being designed and built, in order for Ower/Operators to launch their production facilities on schedule, and with the right asset integrity and reliability work processes in place from Day #1.

SESSION 6: MECHANICAL INTEGRITY

Rehabilitation of High Pressure Pipe by an Internal Reinforcement Technology
Stephen Catha, *Smart Pipe Company Inc.*
This paper presents the underlying technology for the design and manufacturing of a high-strengh thermoplastic composite material that is inserted in folded form into a degraded, high pressure, gas or liquid pipeline to restore its original operating pressure over long distances with minimal surface disruptions.

Risk Contingency Options For Fitness For Service Inspections and Repair of Degraded Pressure Vessels and Piping
Paul Manzon, *PMC Engineering*
Cost effective approaches in the analysis and repair of degraded pressure boundaries.

Replacing Chemical Biocides with Targeted Bacteriophages in Oil and Gas Operations
Neil Summer, *Phage Biocontrol*

SESSION 7: FACILITY MAINTENANCE

Use of Adhesively bonded Surface Mounted Fasteners to Reduce the Amount of Down-Production Time During Maintenance
Timothy Anderson, *(invited)*

Produced Water Treatment Equipment: Repair or Replace?
Frank Richerand, Sr, *Enviro-Tech Systems LLC*
Guide to determining whether produced water handling equipment should be repaired or replaced.

Paper Title and Speaker TBD

Speakers and/or presentation titles subject to change.

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increase its market share.

The volume of oil supplied from Russia to Asia is not the only impact Russia will have on that market. ESPO Blend may become an important regional price benchmark. Buyers in Asia, eager to have an alternative price benchmark to Dubai, will support the establishment of independent price discovery and the creation of a spot market for ESPO Blend. Consequently, Russian exports to Asia may also influence regional pricing.

Different crude supplier

Russia will be a very different crude exporter in 2020, as the accompanying map illustrates.

Exports from Russian sea ports will climb from 3.4 million b/d now to 5.6 million b/d, enabling Russia to develop flexibility in its export targets, reach new markets, and expand economic influence. Exports to Asia will soar to at least 1.5 million b/d from less than 400,000 b/d in 2008. In Europe, growth of exports will be mainly associated with increased transit volumes from Kazakhstan.

Russia's growth of light sweet production and the commingling of growing volumes of light sweet from Kazakhstan in the Russian export infrastructure will transform the quality of crude exports, making Russia a key supplier of both light sweet and medium sour qualities.

While ESAI expects 2020 to represent a peak in terms of the volume of crude exports, the trend of growing light sweet exports will continue. ESAI projects that by 2025 more than half of Russian crude exports will be light sweet. ✦

The author

Andrew Reed is CIS and European analyst at Energy Security Analysis Inc., producing ESAI's CIS Watch and Europe Watch. He recently launched ESAI's Eurasia Watch Natural Gas Outlook. Reed also contributes to ESAI's Atlantic Basin Stockwatch. Prior to joining ESAI, Reed was director of research at Trident Group, a corporate risk management firm specializing in Russia. Reed received an MA in international relations from the Paul H. Nitze School of Advanced International Studies of The Johns Hopkins University. For more information on this subject, contact him at areed@esai.com.

China, Petroecuador sign agreement on oil supply

Eric Watkins
Oil Diplomacy Editor

Ecuador's state-owned Petroecuador, eyeing an advance payment of $1 billion, has signed an agreement to sell 3 million bbl/month of oil to PetroChina International Co. Ltd. over a 2-year period.

Ecuador agreed to export 2.88 million bbl/month of Oriente and Napo crude, with the $1 billion—representing 28% of the total value of the oil PetroEcuador will export—serving as an initial payment.

Altogether, the contract envisages sales of 2.16 million bbl/month of Oriente crude and 720,000 bbl/month of Napo crude, with a further option that allows Petroecuador to deliver 5% more or less than the stipulated amount.

Petroecuador said revenues from the prepayment will be used for investment in the oil industry and for public works. The state firm also said the price of each oil shipment will be decided according to market conditions.

Diego Borja, Ecuador's minister of economic policy coordination, last week said Ecuador had asked China not to resell the oil to either Peru or Chile, which already buy much of Ecuador's exported oil.

However, Borja said China has not been restricted from selling the oil anywhere else, including California, long a market for Ecuadoran crude.

China's deals

The agreement is one of several in recent months in which China has extended loans in exchange for secure supplies of crude oil. The country has signed half a dozen such agreements since February, for a total of $46 billion, to secure long-term energy supplies.

Here are the recent agreements:

- Feb. 17—China Development Bank (CDB) lends $15 billion to Russia's OAO Rosneft and $10 billion to OAO Transneft in return for supplies from East Siberian oil fields over 20 years.
- Feb. 18—CDB finalizes an agreement to extend a $10 billion line of credit to Petroleo Brasileiro SA (Petrobras) for 100,000-160,000 b/d of oil to be sold at market prices.
- Feb. 21—China gives $4 billion in financing to Venezuela's Petroleos de Venezuela SA, which has increased shipments to China to reduce the country's traditional reliance on sales to US markets.
- Mar. 13—Angola confirms receiving another $1 billion loan from Beijing, bringing its total to $5 billion in oil-backed loans since 2002.
- Apr. 17—China National Petroleum Corp. enters into a $5 billion financing deal with Kazakhstan's KazMunaiGaz and also will jointly buy oil company MangistauMunaiGas.

Favorable conditions

Ecuadoran President Rafael Correa said that the negotiation with Petrochina will have favorable conditions for his country and that the advance payment will help to ease liquidity problems. In a television interview, Correa said his country experienced liquidity problems in June and July after repurchasing 91% of its 2012 and 2030 global bonds.

In addition to the $1 billion advance, Quito is also negotiating with Beijing on a separate $1 billion credit with a 4-year maturity.

While the financial terms of the agreement are considered generally favorable to Ecuador given its economic circumstances, analyst BMI said "the country might yet struggle to meet its supply obligations" since the agreement has taken Petroecuador's contracted commitments to nearly 100% of its output.

Ecuador, which is the fifth-largest producer of oil in South America after Venezuela, Brazil, Argentina, and Colombia, produced 486,000 b/d of oil in May. Petroecuador produces 280,000 b/d, or just over half of Ecuador's total output of 485,000 b/d. ✦

Oil companies slap Nigeria's petroleum reform legislation

Uchenna Izundu
International Editor

Nigeria's Petroleum Industry Bill (PIB) will substantially increase taxation for operators and discourage investment, companies complained last month at a public forum in Abuja.

The companies are unhappy that their contracts could be renegotiated, particularly those covering deepwater projects, with higher costs under the draft legislation that would allow the government to seize blocks that remained unexplored.

The PIB has received first and second readings in the Senate, but observers have alleged that different versions have been circulated among the National Assembly and other industry officials.

Minister of State for Petroleum Resources Odein Ajumogobia said that there was only one version of the PIB before the National Assembly and that this one had been approved by the Federal Executive Council.

Nigeria's petroleum industry provides more than 80% of the country's federal revenues, and the PIB, which has taken almost 10 years to reach this stage, has been touted as major reform that would address funding shortfalls, domestic gas shortages, and crippling fuel subsidies.

Legislation's objectives

Stakeholders were invited to present comments at hearings organized by the Senate and House of Representatives, which are debating the bill.

The legislation aims to introduce transparency through publication of all licenses, leases, and contracts, along with payments to the government.

The PIB will create new regulatory agencies, simplify the industry's structure, and transform Nigerian National

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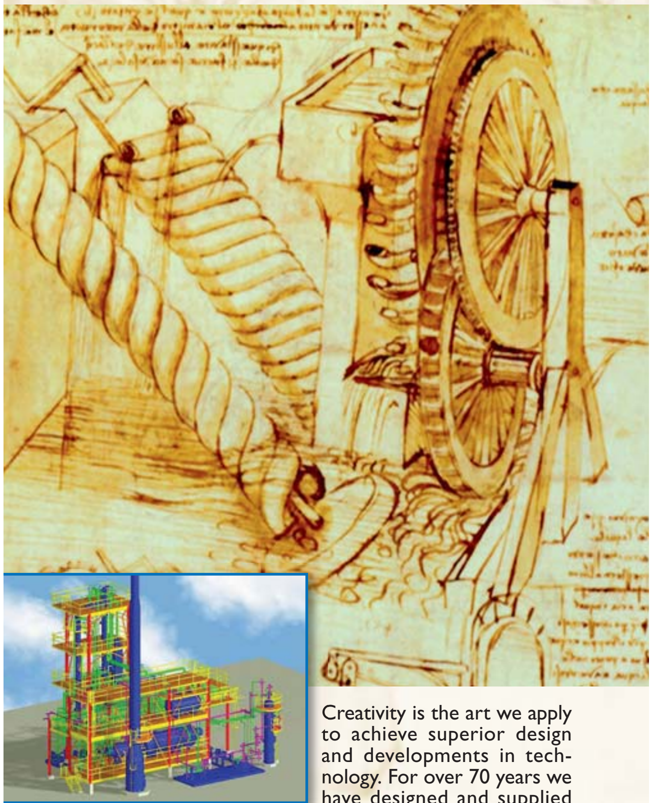
A masterpiece



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Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

The extravagant allegation club

No one in the oil and gas industry is immune to extravagant allegations, as evidenced by one court case after another. This time, China National Petroleum Corp. is the target.

CNPC helicopters visited camps of the Fuerzas Armadas Revolucionarias de Colombia (FARC) to provide logistical and medical support, according to a former hostage who escaped from the guerrillas.

The CNPC helicopters transported "doctors, medicine, provisions, and even guerrillas," according to former Sen. Oscar Tulio Lizcano, who was kidnapped on Aug. 5, 2000, and escaped in 2008.

Tulio Lizcaino told Spanish news agency EFE that the CNPC helicopters visited FARC camps seven times in 2006 "paradoxically, when the area was under military siege and President (Alvaro) Uribe's democratic security (policy) was in full force."

FARC guerrillas

FARC, founded in 1964, has 8,000-17,000 fighters. The Uribe administration, which has made fighting the FARC a top priority, has obtained billions of dollars in US aid for counterinsurgency operations.

"I don't understand why the country hasn't reacted…I investigated not only the (demobilized rebels) who received (assistance) from that Chinese multinational but also those who were transported in those helicopters," said Tulio Lizcaino, referring to peasants and mayors who allegedly accepted flights.

There has been no independent confirmation of Tulio Lizcaino's claims about CNPC. However, in 2006 the Chinese firm did join with ONGC Videsh Ltd. to acquire US oil firm Ominex De Columbia and began actively exploring the country with helicopters in June that year.

That August, rebels of FARC's rival, the Ejercito de Liberacion Nacional (ELN), kidnapped a helicopter pilot and two local workers from CNPC's exploration unit, the Bureau of Geological Prospecting (BGP).

BGP targeted

It marked the second time that BGP contract workers had been kidnapped since the company began exploring for oil in Colombia earlier in the year. In June 2006, FARC rebels kidnapped two other BGP workers.

Did CNPC do a helicopter deal with FARC in order to keep exploring for oil? Or is Tulio Lizcaino making unfounded allegations?

Western firms have long had to deal with such claims.

In 2003, Alberto Galvis sought punitive damages from Occidental Petroleum for the deaths of his mother, a sister, and a cousin, who were among 18 civilians killed when a Colombian military helicopter dropped a bomb on a village near the Cano Limon Pipeline in an antiguerrilla operation.

Occidental was named in the lawsuit because pilots of AirScan (a security firm Occidental used to protect its oil interests) mapped targets for the Colombian military.

Occidental Petroleum denied any responsibility either for the bombing or for the deaths of the civilians.

It remains for CNPC to comment about Tulio Lizcaino's claims. Meanwhile, let's welcome China's oil and gas industry to the club. ✦

Petroleum Corp. (NNPC) into an international oil company on a model similar to those of Petrobras or StatoilHydro (OGJ Online, May 6, 2009). Oil workers, however, have raised fears about whether their employment contracts would be changed under these new arrangements and what would happen if they lost jobs.

NNPC, which suffers from conflicting interests because it has operating, national assets management, and regulatory roles, has been unable to meet its financial obligations under joint ventures with foreign companies. In its new structure, Nigerian National Petroleum Co. Ltd. would be able to raise money in markets rather than rely on the government for funding.

According to the PIB, NNPC's joint ventures with Royal Dutch Shell PLC, Total SA, Chevron Corp., and ExxonMobil Corp. would be transformed into independent companies led by a new management team. But there are worries about who would manage them, how these firms would function, and how profits would be used.

Operators have welcomed the benefits of reform but urged the government to consider the effects on present and future work programs. International oil companies (IOCs) said in a joint presentation that their returns on investment would fall to below 8% from more than 15% if the bill passed.

Shell Nigeria Managing Director Mutiu Sunmonu said gas exploration in the country would become uneconomic. "The existing fiscal legislation recognizes the fundamental difference between oil and gas, but the proposed PIB treats oil and gas fiscals equally, making all gas projects uneconomic," he said.

The IOCs noted that the new law would affect returns on wet gas investments, leaving 65% of new gas production at risk.

They raised concerns about the fiscal terms for their joint ventures with the introduction of a multiplicity of taxes.

The Indigenous and Marginal Field Operators' group demanded that the fiscal regime be changed to recognize its members' need to work with leases that had been abandoned by the majors. It also said that the government needed to support indigenous operators up to a threshold of 50,000 b/d of production so Nigerian companies could provide 20% of national production by 2020.

The group called for preferential access to onshore and shelf acreage on an open and competitive basis.

Niger Delta backlash

A backlash against Minister for Petroleum Resources Rilwanu Lukman, with calls for his resignation, came from Niger Delta interests who believe they have been ignored in the PIB.

Some have called for the legislation to be withdrawn completely. Representatives from the Niger Delta, where militants have been campaigning for a greater share of oil revenues, criticized the draft legislation for stripping them of their privileges as host communities. They described it as draconian, adding they have seen a version of the law different from what is being debated in public.

Chief Favour Izoukumor, leader of the Izon-Ebe Oil Producing Communities Forum, said the PIB was anti-Niger-Delta and urged the government to incorporate the interests of host communities.

One suggestion was that institutions and individuals have equity shares in NNPC under the reforms, according to the Rivers State government.

Lukman's defense

Lukman launched a robust defense of the bill, arguing that future petroleum prospecting licenses and petroleum mining leases would be awarded through a truly competitive bidding process, open and accessible to all qualified companies.

"Every company involved in the upstream petroleum industry will be subject to the same system of rents, royalties, and taxes, depending on whether they operate in the onshore, shallow or deepwater, or inland areas," he added.

Pat Utomi, an economist, told the panel that the PIB could boost the gross domestic product of the country. He commended the legal framework, adding that climate change needed to be addressed.

Ajumogobia said that the PIB tried to reconcile all the 16 laws that regulate the petroleum industry.

He called for deregulation. "Nigeria's long-term energy security depends on our ability to deliver petroleum products in the domestic market at cost-reflective prices," he said. "This can only be attained in an environment where clear groundrules are set and oligopolistic market distortions are removed. For an effective and competitive domestic petroleum products market to be developed in Nigeria, the downstream petroleum sector must be deregulated. This will encourage investment in refin-

The Arab Republic of Egypt
Ministry of Petroleum

Ganoub El Wadi Petroleum Holding Company
(Ganope)

Announcement
For
The International 2009 Bid Round-2
" Seabird "

Ganoub El Wadi Petroleum Holding Company (Ganope) would like to announce the launch of its second 2009 Bid Round for the development and operatorship of the Seabird Block in the Gulf of Suez.
Further details of the Bid Round and the eligibility criteria can be found on the following website:

www.ganope.com

All interested parties are requested to submit to Ganope a letter expressing their interest to participate in the Bid Round on/ or before 20 August, 2009.

For more information, please contact
Vice Chairman for Agreements and Exploration
Ganoub El Wadi Petroleum Holding Company
(**Ganope**)
Tel. : +202 22686657 Fax: +202 22686658
E-mail:hnassar@ganope.com

ing and marketing infrastructure."

The two committees will consider the submissions and then choose whether to present the legislation or an amended version to parliament for its final vote. It is likely that the committees will introduce several alterations that would delay its progress through the National Assembly. ✦

Appeals court clarifies its decision on Alaskan OCS

Nick Snow
Washington Editor

Alaska state officials and environmental organizations each claimed victory following a federal appeals court's clarification late last month that its earlier order vacating the current federal offshore oil and gas leasing program applies only to the Alaska portion of the plan.

A second clarification allows for continued data gathering for oil and gas development in the Chukchi Sea while the US Minerals Management Service conducts more comprehensive environmental impact studies there and in the Beaufort and Bering Seas, Alaska Att. Gen. Dan Sullivan said.

He said that the ruling followed one on July 14 by another federal court that refused to rescind dozens of Chukchi Sea oil and gas leases.

"We will vigorously defend Alaska's interests in ensuring that oil and gas developments continue both in the state and in the federal outer continental shelf," Sullivan said. "Recent federal court rulings, while not definitive, are encouraging."

Environmental organizations portrayed the US District Court of Appeals for the District of Columbia July 28 clarifications as a warning to the US Department of the Interior to rewrite the Alaska portions of the current federal Outer Continental Shelf leasing program or risk seeing the entire plan thrown out.

"The court has told industry and Interior that they will be watching to ensure that the environmental sensitivity to this massive leasing program is brought to light," said David Dickson, Western Arctic and Oceans Program Director for the Alaska Wilderness League, on July 29. "Interior Sec. Ken Salazar has pledged to do just that. The court's ruling yesterday holds Secretary Salazar to his word while rejecting attempts by Big Oil to get around the fact that the current data about how oil and gas development will impact the fragile Arctic ecosystem is sorely inadequate."

US Sen. Lisa Murkowski (R-Alas.) urged Salazar to complete the new environmental analysis as soon as possible. "As I understand it, Interior started the environmental analysis almost immediately after the court's initial ruling this spring, which halted the leasing plan," Murkowski said. "Given that an analysis requires no new research or field work, I assume it can be completed relatively quickly and I urge the secretary to ensure that this task is completed in a timely manner so we can move forward on a path to energy security." ✦

Gas hydrate assessment needed, House panel told

Nick Snow
OGJ Washington Editor

Natural gas hydrates are a potentially significant energy source, but more work needs to be done to determine if they can be economically produced, three experts told a US House subcommittee late last month.

"Estimates from the US Geological Survey peg the amount of gas in hydrate form in the US to be more than 200,000 tcf. That sounds large by itself but is even more impressive when the total amount of conventional natural gas in the US is estimated to be around 1,700 tcf," said US Rep. Jim Costa (D-Calif.), chairman of the House Energy and Natural Resources Committee's Energy and Mineral Resources Committee, in opening statement at the subcommittee's second 2009 hearing on unconventional fuels, which focused on gas hydrates.

USGS made the first systematic assessment of US in-place gas hydrate resources in 1995 and found that the amount of gas in those accumulations was estimated to greatly exceed known conventional gas resources volumes, according to the first witness, Timothy S. Collett, a research geologist in the US Department of the Interior agency. However, gas hydrates represent both a scientific and technologic challenge, and much remains to be learned about their characteristics, he said.

While a huge amount of gas apparently is stored in hydrates and its production is technically feasible with existing technology, production of gas from hydrates also potentially could create hazards associated with seabed stability and release of methane into the oceans and atmosphere, Collett said.

The National Energy Technology Laboratory in the US Department of Energy's Fossil Fuels Office has researched gas hydrates since 2000, reported a second witness, Ray Boswell, an NETL senior energy advisor.

Methane 'storehouse'

"The program is driven by the

relatively recent recognition that gas hydrates represent a significant global storehouse of methane, a fact with far-reach implications for the environment and for the nation's, and the world's future energy supplies," he said. DOE has begun a series of field and modeling studies of gas hydrates' links to climate and carbon cycling, which it hopes will show the role gas hydrates could play in climate change, Boswell said.

Primary field efforts in DOE's research program have confirmed accumulations of the most promising gas hydrate resource targets, he continued. "We continue to prepare for the next stage of research and development, which will include extended testing of alternative production methods, as well as comprehensive resource confirmation and sample collection," he said.

But a third witness suggested that gas hydrate wells will be more complex than most conventional and unconventional gas wells. Steven H. Hancock, well engineering manager at RPS Energy Canada, said that technical challenges include maintaining commercial gas flows with high water production rates, operating with low temperatures and low pressures in the well bore, controlling formation sand production into the wellbore, and ensuring well structural integrity with reservoir subsidence.

"Technologies exist to address all of these issues, but they will add to development costs. Gas hydrate production also has one distinct challenge compared to other unconventional resources, and that is the high cost of transportation to market," Hancock said.

Collett said that while USGS's 1995 study found US in-place gas hydrate resources ranging from 113,000 to 676,000 tcf, an evaluation of technically recoverable amounts in 2008 found an estimated 25.2-157.8 tcf on Alaska's North Slope. That same year, the USGS official continued, the US Minerals Management Service assessed gas hydrate resources in the Gulf of Mexico and found a mean volume estimate of 21,436 tcf.

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Uinta basin's air assessed

A new air quality study of eastern Utah's Uinta basin was released on July 31, not by a government agency or academic researchers but by the Independent Petroleum Association of Mountain States.

IPAMS released the Uinta Basin Air Quality Study (UBAQS) by Environ Corp. a week after the US Department of Justice and Environmental Protection Agency announced that Colorado Interstate Gas Co. resolved federal air pollution charges involving its operations on the Uinta-Ouray Indian Reservation.

The settlement was 2009's fourth involving the oil and gas industry in the area. Six independent producers settled three federal air pollution complaints on the reservation on Apr. 17. The timing of IPAMS's release of the 394-page study was coincidental, an association officials told me. "We started this project in the summer of 2007. It took us about a year and a half to do the study," said Kathleen Sgamma, IPAMS government affairs director.

"We noticed there was a lack of data, and UBAQS provides comprehensive regional analysis of air quality in the Uinta basin from all sources," she explained.

Experienced evaluator

She said Environ, which has done extensive air quality modeling for government regulators, involved the US Bureau of Land Management, Forest Service, EPA, and Colorado and Utah state, county, and tribal agencies.

The study indicates that average concentrations of criteria pollutants within the Uinta basin will remain below national ambient air quality standards through 2012.

It used conservative modeling assumptions which overstated impacts from oil and gas activities to provide public land regulators with a worst-case scenario. Even with that scenario, UBAQS results showed that the basin would satisfy air quality standards, IPAMS said.

"It's unprecedented. I don't think there's another comprehensive, basin-wide study that has been conducted anywhere else in the West," Sgamma said.

Better understanding

IPAMS hopes the study will help regulators understand the cumulative impacts of producers' activities, she said. "It's going to take government agencies some time to digest this. Obviously, they'll want to make sure that they understand the results and the scientific basis is sound," she said.

"But it was done with the input of all managing governmental agencies by a respected third-party contractor with a stellar reputation and an interest in making sure it was a scientific study," Sgamma continued.

The study's executive summary suggests that these results should not be considered final. It notes that two ambient air quality monitors installed at Red Wash and Ouray in December 2008 should provide actual measurements indicative of real conditions.

"Updated model results from a continuing UBAQS effort would ensure that air quality within the Uinta basin is maintained at levels acceptable by regulators and those who live and work in the communities there," it said. ✦

'Not created equal'

"A key development in gas hydrates research in recent years is the realization, based on the findings of a series of recent scientific drilling programs around the world, that all gas hydrates accumulations are not created equal," Boswell said in his written testimony. "They range from large, diffuse accumulations in clay sediments to small, discrete, high-concentration accumulations in sand reservoirs. They occur both on the sea floor as solid massive mounds, as well as buried several thousands of feet below the sea floor."

Hancock said that stand-alone developments could be economic for onshore gas hydrate production with a gas price in the upper range of historic North American prices. For deepwater gas hydrates, developments could be economic with a gas price in the upper range of what India has paid for LNG imports on the spot market, he said in his written statement.

"As with all hydrocarbon developments, the economics of gas hydrates will be highly variable, depending upon such factors as well performance, sediment type, gas-in-place, thermodynamic conditions of a reservoir and access to existing infrastructure," he told the subcommittee. "It is also clear that comparable conventional gas reservoirs will be economically more attractive than gas hydrate-only reservoirs, suggesting that the production of gas hydrates on a large commercial scale may be delayed."

Collett said that the arrival at a technically recoverable estimate of US gas hydrate resources in 2008 was significant. "We have focused on concentrated reservoirs recently to work on resources which are more likely to be produced," he said.

The witnesses agreed that US gas hydrate production will likely occur first in Alaska. "The next big step is to conduct an extended production test. We are working with BP, ExxonMobil, and ConocoPhillips to do that, and we expect it to take a year," Boswell said.

"From an engineering standpoint, the next step will be to prove we can produce commercial amounts of gas from hydrates with technologies we have. We think we can," said Hancock. "In economic terms, each gas hydrate field is unique and will rise or fall based on its own characteristics. The price is only a few dollars more than conventional production, but as average prices rise, other unconventional sources become competitive too." ✦

Committee chairmen describe derivatives regulation concepts

Nick Snow
OGJ Washington Editor

The chairmen of two US House committees with commodities regulation oversight have released a concept paper describing how they would like to regulate over-the-counter (OTC) derivatives. The committees plan to start work on legislation when Congress returns from its late summer recess after Sept. 7.

"I think we have come up with a responsible approach that bridges the differences between those members who want to completely eliminate the over-the-counter market and those who think that just greater transparency is all that is needed," said Agriculture Committee Chairman Collin C. Peterson (D-Minn.). "Neither of those approaches is a real solution; what we are putting forth is."

Financial Services Committee Chairman Barney Frank (D-Mass.) said, "The fundamental purpose here is to improve the regulation of derivatives so that they continue to perform their important market function but are less likely to contribute to a kind of irresponsibility that can cause a crisis. Nobody here wants to ban them or even severely diminish them as an economic instrument."

They released the document as the US Commodity Futures Trading Commission completed two of three scheduled hearings on establishing energy position limits and possible exemptions. Position limits exist for most other commodities. Members of Congress and others have said their absence in energy markets may have contributed to the run-up of crude oil prices to record levels during 2008's first half.

Peterson and Frank's concept paper reflected several ideas US Treasury Sec. Timothy F. Geithner expressed on July 10 when he testified before their committees about the Obama administration's initial commodities regulatory reform proposals.

OTC derivatives

These included regulation of OTC derivative dealers, exchanges, and clearinghouses; mandatory clearing of OTC derivatives with a few exceptions; and stronger capital and margin requirements to strongly encourage dealers and customers to trade on regulated exchanges or have transactions cleared wherever possible.

The Peterson-Frank concept paper also described two possible approaches toward speculation, adding that others may be considered. The first, designed to limit speculation so it does not become excessive, would prohibit the purchase of any credit protection on a credit default swap (CDS) unless the party owns the referenced security or one or more of the securities in an index; the party has a bona fide economic interest that the contract will protect; the party is a bona fide market maker; and regulators have authority to monitor market activity and impose position limits when necessary.

The second approach, which the paper said is designed to enhance speculative position oversight, would require OTC derivatives dealers, investment advisors managing more than $100 million, and other entities that are deemed major market participants to report all short interests in CDS contracts to the appropriate regulator. To prevent abuse, regulators would have authority to impose position limits and to ban the purchase of credit protection using CDSs by any nondealer which is not hedging a risk.

Peterson and Frank also proposed in their paper protecting US financial institutions from lesser regulatory regimes in other countries by having US regulators coordinate with their foreign counterparts to harmonize OTC derivative market regulation, including establishing international standards covering clearinghouses. The US Department of the Treasury would be authorized to restrict access to the US banking system for institutions of any jurisdiction the US Treasury determines permits lower capital-related standards or promotes reckless market activity.

The concept paper suggested that members of the two committees will be asked to determine whether the US Securities and Exchange Commission, the CFTC, or both should regulate an OTC derivative dealer, exchange, or clearinghouse. A financial services oversight council would be established to resolve disputes between the two agencies within 180 days regarding authority over new products or joint regulation of derivatives products.

ICE positions

Meanwhile, the CFTC reported that it will include positions of ICE (Intercontinental Exchange) Futures Europe exchange traders of West Texas Intermediate crude oil contracts in its weekly Commitments of Traders (COT) reports. It said that the first publication of this data will be in the July 28 COT report, to be released on July 31.

US Sen. Maria Cantwell (D-Wash.), who has frequently criticized the agency for not moving to regulate foreign exchanges' commodities trading in the US, said that the CFTC needs to do more. "It needs to realize that it is the regulator and fully regulate the dark ICE market," she said on July 30. "Oil prices are far too high and apparently have been driven by unchecked speculation, according to the new CFTC. So I hope it will act to bring ICE into total compliance." ✦

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API denies claim that it supported a higher US ethanol blending cap

Nick Snow
OGJ Washington Editor

An ethanol advocacy group's suggestion that an American Petroleum Institute study supports increasing allowable ethanol levels in gasoline to 12% is misleading, the oil industry trade association said.

The Renewable Fuels Association recommended raising the allowable ethanol level to 12% as an interim measure in comments it filed last month with the US Environmental Protection Agency supporting a petition by another fuel ethanol group, Growth Energy, to increase the allowable limit to 15%.

"Already agreed upon science and ongoing research make clear the move to up to E15 blends is warranted. In addition, existing statutes allow EPA to take an interim step by approving the use of up to 12% ethanol blends," RFA Pres. Bob Dineen said. "In order to achieve the energy, economic, and environmental goals of this country, increasing the use of domestically produced renewable fuels like ethanol is essential. EPA has the authority, and now the science, to approve such a step."

Six recently completed research projects from the Coordinated Research Council (CRC), the University of Minnesota, Minnesota State University, and API confirm the safe and effective use of higher ethanol blends, RFA said.

But in a July 23 statement, API called the ethanol advocacy group's call for approval of a 12% ethanol limit premature.

"RFA fails to note there is a large-scale cooperative government-industry research effort under way seeking to better understand the impacts of intermediate ethanol blends. The API study, which is incomplete, is one part of that effort. The last field phase has not been conducted," API said. ✦

USW withdraws from standards talks with API

Paula Dittrick
Senior Staff Writer

The United Steelworkers (USW) has withdrawn from talks on refinery safety standards with the American Petroleum Institute and the oil industry.

The talks were in response to recommendations from the US Chemical Safety and Hazard Investigation Board (CSB) following the deadly Mar. 23, 2005, explosion at BP America Inc.'s Texas City, Tex., refinery (OGJ, Sept. 8, 2008, p. 20).

USW and API were working to develop two American National Standards Institute (ANSI) standards for process safety performance indicators and fatigue.

The two groups had worked together for more than a year on the upcoming standards, which API spokesmen say will be completed—with or without USW participation.

USW, API statements

Gary Beevers, USW international vice-president, said API excluded environmental and public interest organizations from committees developing the standards. He also said the process was weighted against refinery workers by giving one vote to each of the 22 oil companies and one vote to each of the three oil workers' union representatives.

"After months of very little progress, we found the API and the industry did not understand the meaning of consensus," Beevers said. "These oil companies try to get by with as few regulations and mandates as possible; we want a fair playing field."

API issued a statement saying it regretted that USW representatives withdrew from what API called "the multistakeholder consensus-building process, currently in its final stages."

The standards development work was conducted in accordance with procedures approved by the ANSI as directed by the CSB, API said.

"Unfortunately, the USW is attempting to undermine a process aimed at improving worker safety," API said. "USW is trying to silence the voices of other stakeholders on the committee by making specific demands directly tied to the national oil bargaining strategy."

API said the committees involved will continue their work to finalize the standards and expects new standards to be issued this year.

Issues of disagreement

USW said a contentious issue involved public reporting of safety indicators. USW and refinery safety advocates want all safety failures to be reported publicly so refinery communities can be aware of problems.

Beevers said API and industry fought USW on the level of transparency. He said API and industry also refused to commit to reducing the number of overtime hours worked by individuals.

API said the industry does not want a specific numerical target regarding work shifts written into a standard because "no one-size-fits-all approach" will work for all refiners.

Some refineries have 12-hr shifts while others have 8-hr or 10-hr shifts, API spokesmen said.

API noted it maintains more than 100 safe operating standards and safe work practices, many of which are cited by the US Occupational Safety and Health Administration. ✦

MMS data on OCS safety highlight the risks of lifting

Paula Dittrick
Senior Staff Writer

US Minerals Management Service statistics show a total of 2,724 safety incidents were reported during 2005-08 on the Outer Continental Shelf, of which 506 incidents involved lifting operations.

MMS spokesmen outlined the statistics during an Offshore Safe Lifting Conference last month in Houston sponsored by the American Petroleum Institute.

Phil Smith, manager of regulatory affairs for Shell Exploration & Production Co., helped organize the conference.

"Lifting operations offshore do not come without risk," Smith said. "It is one of the most dangerous things we do. We have to move heavy things around in difficult conditions."

Joe Levine, senior engineer with the MMS office in Herndon, Va., said that 351 lifting incidents stemmed from production activities, while 155 incidents stemmed from drilling activities.

These figures came from information that companies reported to the MMS for 2005-08.

Cranes were involved in 411 of the 506 total lifting incidents, while devices other than a crane accounted for the rest. Levine said devices other than a crane include air hoists, tuggers, winches, chainfalls, and come-a-longs.

During 2005-08, 1,128 injuries were reported on the OCS, of which 153 were lifting injuries. Of the lifting injuries, 105 were associated with cranes, and 48 were associated with other lifting devices.

Thirty fatalities were reported on the OCS, of which 13.3% were associated with lifting. There were two fatalities associated with cranes and two fatalities associated with other lifting devices, Levine said.

Consequently, MMS issued 337 total lifting incidents of noncompliance (INCs). MMS issues an INC to an operator upon identifying an infraction from an approved permit, plan, or regulation.

Ninety of the INCs were associated with slings either not correctly identified or improperly stored when not in use. Other common lifting INCs issued by the agency included:

- The crane not being taken out of service when deficiencies were known or failure to restrict the crane's activities to eliminate unsafe conditions.
- Repairs or replacements of critical components not being made promptly.
- Not having an annual inspection performed by qualified inspectors with records readily available for 4 years. ✦

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Mexico, Brazil, Norway upstream readiness weighed

George Baker
Mexico Energy Intelligence
Houston

The Mexican Competitiveness Institute, known by its acronym IMCO, released in mid-July its 2009 report on the state of the Mexican economy.

Patterned after the Global Competitiveness Report issued by the World Economic Forum (WEF), the Mexican report examined a diverse set of 137 variables and chose 48 countries where a useful comparison with Mexico might be made. In the statistical appendix, these countries are scored in relation to some 70 variables.

The variables are as diverse as "Liberalization of energy policy"—where, alone among all countries, Mexico (using 2007 data for all variables) scored a zero (0)—to "Talent"—where the variable refers to the ability of a country to produce and attract globally competitive skills—Mexico scored 38.8 on a scale of 100.

When it came to recommendations regarding oil policy, two were offered: the upstream should be opened to competition from private investment, and the restrictions on payments to Petroleos Mexicanos SA contractors should be liberalized.

"Energy reform that permits competition in the exploration and extraction of oil and gas, as well as in the liberalization of the regulation of the energy sector, is what all countries have done who are oil producers"—except for Mexico, the report adds.

Mexico's status

According to the report, Pemex is operating at its full capacity, and to expect more from Pemex given the same norms and legal conditions is "naive and irresponsible."

This is strong language and, in the Mexican context, these are even stronger recommendations, ones that were subject to the very strict rules of self-censorship in the 3 months of energy debate in the Mexican Senate that ended on July 22, 2008.

Both in the report, and in off-line discussions with IMCO officials, the two countries that are recommended as ones that Mexico should emulate in upstream policy are Brazil and Norway.

The report says little about Mexico's institutional, legal, and political readiness to carry out such reforms even on paper—to say nothing of putting them into practice.

How prepared is Mexico to undergo the chemotherapy, as it were, of an upstream liberalization in a body politic that suffers from the cancerous growths of 70 years of a government monopoly? And what clues—if any—are to be found in the voluminous statistics about how Brazil and Norway were ready for an upstream opening?

As a matter of curiosity, we also wanted to see how a few other countries, some oil producers, others not, scored on the same variables.

We want to see if any of the data suggest insights as to how both Norway and Brazil have world-class national oil companies that operate in deepwater environments, while Mexico has a regional-class national oil company that operates in shallow water (and, for decades, has been the world's top offshore oil producer).

Mexico compared

We had these questions in mind in looking at the comparative data supplied by the World Economic Forum (WEF) and IMCO.

The WEF, evaluating 134 countries, placed Mexico 60 in overall competitiveness, that is, in the 55th percentile. Brazil was placed 64, in the 52nd percentile, close enough to be regarded as an equal.

In its report, again, using 2007 data, IMCO placed both Mexico and Brazil below the median of 48 countries, with percentile scores of 33 and 35, respectively—but again so close as to be statistically equal. In both the WEF and IMCO studies, Norway and the US were at the other end of the scale, Norway scoring 89 and 92, respectively, and the

HOW MEXICO COMPARES REGARDING GOVERNMENT EFFECTIVENESS[1]

Table 1

	Finland[2]	Japan[2]	Oil producers: Brazil	China	Norway	US	UK	Avg. oil	Mexico	Var. oil, %
Regulation quality	92.4	74.8	43.7	37.8	85.9	86.0	97.8	70.2	56.0	–20
Effectiveness	90.5	70.9	24.9	33.7	96.1	80.1	84.8	63.9	32.8	–49
Promotion of competition	100.0	50.0	50.0	25.0	75.0	100.0	100.0	70.0	25.0	–64
Public policy re competitiveness	100.0	47.3	39.5	75.8	64.0	84.7	66.6	66.1	47.3	–28
Liberalization of energy sector	100.0	100.0	100.0	66.7	100.0	100.0	100.0	93.3	0.0	–100
Gov't. independence of interest groups	100.0	33.3	66.7	33.3	100.0	66.7	100.0	73.3	33.3	–55
e-Government	69.6	73.5	36.6	24.6	95.7	90.7	76.6	64.8	40.5	–38
Control of corruption	100.0	61.7	22.0	10.6	96.2	68.3	80.7	55.6	18.9	–66
Accountability	97.6	80.5	64.6	0.0	98.7	85.3	94.3	68.6	51.4	–25

[1]Shows index values of selected countries. Mexico's score is 20% or more lower than selected oil competitors. [2]Finland and Japan shown for reference. Finland scored 100 in 23 of 75 indexes. Data: IMCO 2009.
Sources: Regulation—World Bank Governance Indicators; Effectiveness—World Bank Governance Indicators; Competitiveness—IMCO; Energy liberalization—IMCO; Interest groups—Economist Intelligence Unit (EIU); e-Government—UN E-Government Survey; Corruption—World Bank Governance Indicators; Accountability—World Bank Governance Indicators.
Mexico Energy Intelligence, July 24, 2009. Data: IMCO 2009 (imco.org.mx) Table: MEI

US scoring 99 and 77.

These general country ratings do little, however, to clarify the upstream situation: they suggest that the US and Norway are much more competitive than Brazil and Mexico, whose rankings are similar; but since we know that Brazil and Mexico are not at all similar in matters of deepwater expertise, this scale is not helpful.

WHERE MEXICO STANDS RELATIVE TO THREE COUNTRIES WITH OPEN ENERGY MARKETS*

Table 2

	World Economic Forum rankings of 134 countries: Mexico	Brazil	Norway	US	Comparative advantage (No. of country rankings): Br>Mex	Nor>Mex	US>Mex
Institutions							
Transparency of gov't. policy-making	94	101	8	28	–7	86	66
Strength of auditing standards	71	60	11	20	11	60	51
Efficacy of corporate boards	82	42	9	12	40	73	70
Percentile score of boards	39	69	93	91			
Infrastructure							
Quality of electric supply	87	58	10	16	29	77	71
Technological readiness							
Availability of latest technologies	92	58	6	5	34	86	87
Firm-level technology absorption	92	42	9	3	50	83	89
Innovation							
Capacity for innovation	67	27	13	6	40	54	61
Quality of scientific research institutions	79	43	22	1	36	57	78
Company spending on R&D	71	31	19	3	40	52	68
University-industry research collaboration	84	50	17	1	34	67	83
Gov't. procurement of high tech products	104	84	16	4	20	88	100
Availability of scientists and engineers	105	57	18	6	48	87	99
Utility patents	56	58	19	2	–2	37	54
Average of innovation	81	50	18	3	31	63	78
Percentile ranking	40	63	87	98			

*Shows only indirect measures of efficiency of energy policy and markets. Mexico's scores are much lower than favorite policy models on key measures.
Sources: Data—World Economic Forum 2009; Table—Mexico Energy Intelligence; Date—July 26, 2009

Reform discussions

For most of 2008 Mexico was the battleground of ideas, proposals, and back-room negotiations regarding the reform of the oil sector.

What came out when a reform package was finally passed by congress in October 2008 was one in which a new Pemex Law created a stronger system of corporate governance, including four independent board members, plus the flexibility to devise new contractual models that fit the special needs for the oil industry. Of special concern in Pemex was the need to be able to incorporate new technology and innovations in management and field operations, especially in the upstream.

The reform package also had the intent of strengthening the government's ability to guide and monitor Pemex and the oil industry more broadly speaking.

We then looked at the data sets to see what could be learned about government effectiveness, corporate governance, and innovation, areas of special concern in the upstream.

Other comparisons

Looking at the data compiled by IMCO that bear on government effectiveness, we selected five oil producers, noted their individual scores across nine variables, then took the average of the oil companies and compared those scores with Mexico's.

Regarding the quality of regulation, IMCO gave Mexico a score of 56, Brazil 44, and Norway 89, but something here is also not right: Brazil has an upstream regulator that makes international tenders practically, legally, and philosophically workable; Mexico, however, has none.

Regarding the variable concerning liberalization of the energy sector, all countries under review scored 100, except China which scored 66.7 and Mexico, which, as mentioned, scored 0 (Table 1).

Turning to the WEF dataset, a promising variable concerns the efficacy of corporate boards. Here we find that Mexico's ranking is 82 of 134, while those of Brazil, Norway, and the US are 42, 9, and 12, respectively. In terms of percentile rankings, Mexico ranked in the 39th percentile, while Brazil was in the 69th and Norway and the US above the 90th (Table 2).

Looking at innovation, the WEF offers seven variables, including a general one for capacity for innovation, where Mexico was ranked 67th out of 134, Brazil 27th, Norway 13th, and the US 6th. Here we start to see Brazil pulling away from Mexico as would be expected by the upstream performance of the two national oil companies.

Taking the average of the variables for innovation, Mexico would be ranked 81st, Brazil 50th, Norway 18th, and the US 3rd. The more telling, nonparametric statistic is the percentile rankings: Mexico ranks in the 40th percentile, while Brazil is in the 63rd, Norway the 87th, and the US the 98th (Table 2).

Observations

There are incompatibilities in the data not only because of the different data sets but because the IMCO data are from 2007, well before the oil reforms of 2008 and their implementation in 2009. IMCO might rate Mexico higher were these reforms taken into account.

The countries chosen for comparison in the IMCO study did not include major oil producers from Africa and the Middle East; a situation that means that the reader is not given a full picture of the competitive position of Mexico in the global oil market.

The data sets provide only hints, not hard facts, as to why Brazil and Norway pulled ahead of Mexico. Unfortunately, this means that there is no clear path shown, statistical or otherwise, as to how Mexico should catch up.

The data sets, especially those regarding government effectiveness and innovation, suggest that Mexico is significantly behind other oil-producing countries.

It seems premature, therefore, for IMCO to propose an upstream opening for competition in the exploration and production; or, in terms of the simile used earlier, the patient is not healthy enough to undergo chemotherapy. ✦

The author

George Baker (g.baker@energia.com) is publisher of Mexico Energy Intelligence, a business and policy advisory service based in Houston since 1996. His contributions as an OGJ author date to 1981, and PennWell Corp. released his current book on deepwater issues affecting Mexico in February 2009.

Tunisia

AuDAX Resources Ltd., Perth, invited 15 contractors to bid to drill the Sambuca prospect in the Sicily Channel off Tunisia in the first half of 2010.

Sambuca is in the contiguous G.R15.PU exploration permit northwest of Pantelleria Island off Italy and the Kerkouane permit off Tunisia. It appears to be one of the largest undrilled structures in the Mediterranean with a mean unrisked potential of 270 million boe recoverable.

The prospect covers 60 sq km in 400 m of water in the Pelagian basin north of Tazerka oil and gas field. Main objective is the Miocene Birsa sandstone at 1,440 m, and other targets are Miocene Ain Grab and Cretaceous Abiod as deep as 2,500 m.

Quebec

Questerre Energy Corp. and Talisman Energy Canada plan to spud at least two horizontal wells later in 2009 to test Ordovician Utica shale in Quebec's St. Lawrence Lowlands.

Four Talisman-operated vertical wells have tested gas in the formation, earning Talisman a 75% working interest in 720,000 acres. Questerre has 25% working interest and a 4.25% gross overriding royalty on production.

The horizontal wells will have full-length laterals and multistage fracs in an attempt to prove the play's commerciality, Questerre said.

Talisman is testing the Utica in the fourth vertical well, St. Edouard-1, and expects to have results in early August. Subject to the final results, the companies will evaluate pilot locations for horizontal wells adjacent to the vertical wells.

Alaska

Rampart Energy Co., Denver, is drilling an exploratory test in interior Alaska's Nenana basin.

The well on the Nunivak prospect 3 miles west of Nenana and 55 miles southwest of Fairbanks is projected to about 12,000 ft. Drilling and testing are to be completed by September 2009.

Rampart said the well is part of a regional, multiyear onshore oil and gas exploration drilling program in the summer months.

Utah

Pacific Energy & Mining Co., Reno, Nev., signed a farmout agreement with Mar/Reg Oil Co. for the drilling of a horizontal leg in an existing well in Tin Cup Mesa oil field, San Juan County, Utah.

The field, discovered in 1981 by Marathon Oil Co. in the Paradox basin 21 miles southeast of Blanding, has produced more than 2.6 million bbl of oil and 3 bcf of gas from a 120-ft thick carbonate buildup in the Pennsylvanian Upper Ismay formation.

PEMC plans to spud a 2,500-ft lateral in the Federal 4-26 well in the second half of August 2009. Geological and engineering analysis indicates that a horizontal well drilled in Sec. 26 would intersect the fracture system that has not been drained by the vertically drilled wells.

The vertical 4-26 well has produced more than 156,000 bbl of oil and 355 MMcf of gas, and engineering analysis shows it did not efficiently drain the northern part of the oil field.

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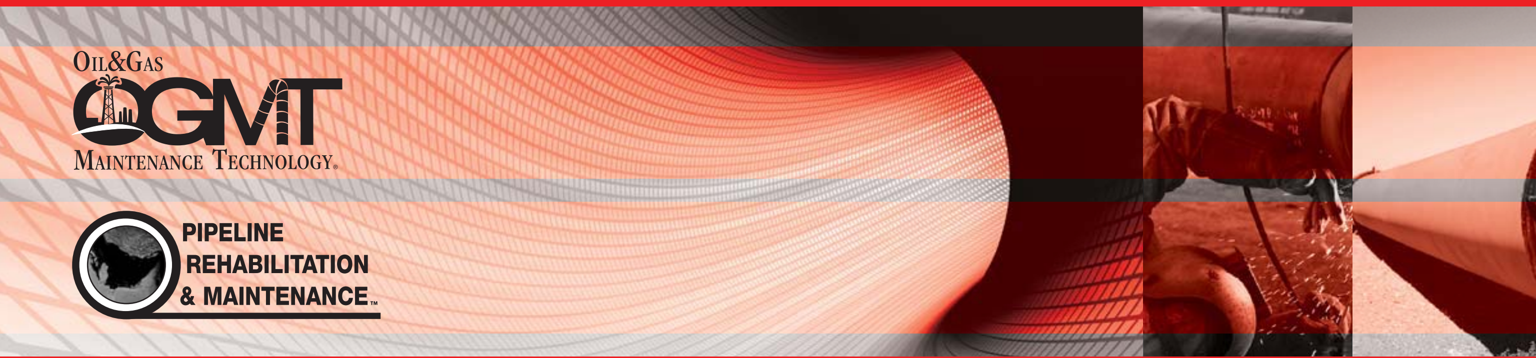

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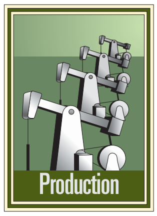
Project start, completion dates become less definite

Guntis Moritis
Production Editor



Many oil and gas development projects remain on schedule, but companies also have deferred many projects so that start-up and completion dates have become less certain.

The accompanying table lists projects in 45 countries that may proceed. Expected peak production from these projects will occur in 2009 or after.

If all the projects' peak production rates occurred in the same year, world production capacity would increase by 30 million b/d of liquids and 70.5 bcfd of gas.

The list includes both individual fields and in some cases, the accompanying infrastructure. Listed are:

- Discoveries that have announced publicly available development plans.

- Field redevelopments for recovering bypassed oil.
- Stranded-gas projects and projects to eliminate gas flaring. These projects often include new infrastructure such as pipelines for transporting gas to end users or facilities for producing LNG and gas-to-liquids.
- Heavy-oil projects that may include new infrastructure such as pipelines, crude oil upgraders, and mines.
- Deepwater projects, some of which rely on long flowline tiebacks and hub facilities.
- Unconventional resources such as tight sands, shale gas, and coalbed methane.

Although joint ventures operate some projects listed in the table, for simplification, the table only lists the name of one company in each joint venture (see accompanying table listing the parent companies' full names).

The year shown in the project list reflects when production may peak or enter a peak production plateau that could last for several years. The + after the year indicates that the year of peak production is uncertain and may occur later than the year shown.

Asia-Pacific

LNG projects continue to dominate the Asia-Pacific region with Australia having several.

Greater Gorgon will develop fields containing about 40 tcf of gas. The proposed Gorgon project will have three 5-million tonne/year LNG trains on Barrow Island and will also supply gas to the domestic market. The project also involves reinjection and sequestration of carbon dioxide on Barrow Island. Gorgon may start shipping LNG in 2014.

Development of the Sunrise and Troubadour projects off East Timor and Australia remain in the planning stages. The projects would involve development of about 8 tcf of gas that an expansion of the Bayu Udan LNG plant at Darwin would process.

Ichthys is a large 9.5-tcf deepwater gas and condensate project off northwest Australia that may include a semisubmesible production facility with a flowline to shore connected to a new liquefaction plant.

Other Australia LNG projects include a two-train, 4.3 million ton/year project for Wheatstone and Iago fields and the Burrup Park LNG project for Pluto field. Woodside also has plans to

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Petrobras, in September 2008, started a long-term production test of a subsea completed presalt well in the Jubarte field, off Brazil. The presalt 30° oil flows to the P-34 floating production, storage, and offloading vessel that also processes production from wells completed in a Jubarte heavy oil reservoir above the salt layer. Photo from Petrobras.

develop 14 tcf gas and 37 million bbl of condensate from Torosa, Brechnock, and Calliance fields.

In Indonesia, several new fields will supply gas to existing and new LNG plants and power stations. The largest new LNG project is Tangguh that started shipping LNG in June of this year. The gas is from fields in Papua Bintuni Bay.

Indonesia's largest new oil development is Banyu Urip field in the Cepu block on Java. The field may go on stream in August at an initial 15,000-20,000 bo/d. The project includes a floating storage vessel moored off Tuban in the Java Sea for oil export.

Development of Natuna D-Alpha field in South China Sea remains in question because ExxonMobil Corp. and the government of Indonesia failed to reach an agreement on the project. The field, discovered several decades ago, contains about 40 tcf of gas. Complicating field development is the large amount of carbon dioxide present in the gas.

India has both onshore oil and gas discoveries. The gas off the eastern coast will be produced through subsea-completed wells brought ashore with long flowlines.

New projects will develop fields off China in both the South China Sea and Bohai Bay.

Development of gas fields in the Southern Highlands of Papua New Guinea includes construction of a 960 MMcfd gas conditioning plant and a 440-mile gas pipeline to a new 6.3 million tonnes/year, two-train LNG liquefaction and storage facility near Port Moresby. The gas would come from Hides, Angore, Juha, Gobe, Moran, and Kutubu fields.

Western Europe

The UK and Norway offshore holds the main fields under development in Western Europe. Most of these fields are small and will tie into the extensive existing infrastructure in the area.

In Italy, the onshore Tempa Rossa project will develop an estimated 200 million bbl of heavy oil reserves.

Eastern Europe, FSU

Phased development of Tengiz field, in Kazakhstan, continues with a $9.5 expansion project that will increase oil production by 260,000 b/d after 2010. Also in Kazakhstan, an expansion of Karachaganak field will increase production by 1.6 bcfd in 2012.

Because of delays, the first phase of the 13-billion-bbl Kashagan field, off Kazakhstan, is now slated to start producing after 2012. With future phases, the field's production may surpass 1 million b/d.

The largest proposed development in Russia is the 130-tcf Shtockman field in the Barents Sea. The first phase of Shtockman may start producing gas in 2013 at 2.4 bcfd with LNG exports starting in 2014. Subsequent phases may increase production to 8.7 bcfd.

The 70-tcf Kovykta is another large field under development in eastern Russia. Gazprom now operates the field that will require new pipelines for moving the gas to potential users, such as in China.

Middle East

Iran continues to develop light and heavy oil resources, including the phased development of offshore South Pars gas field, which is an extension of Qatar's giant North field.

International oil companies largely rejected Iraq's terms for developing its many oil fields with only BP PLC and China's CNPC International Ltd. accepting a $2/bbl agreement to work in Rumaila oil field, which has reserves of 17.7 billion bbl of oil. The table lists some potential fields that might be developed to allow Iraq in the next 5 years to increase oil production to 4 million b/d from the current 2.4 million b/d.

Kuwait continues to redevelop several fields that will increase its production capacity by 450,000 bo/d in 2012.

In Oman, several enhanced oil recovery projects are planned for several fields. The main processes include steam injection and sour-gas injection.

Phased development of 900-tcf North field off Qatar continues with additional LNG trains and a GTL plant. Saudi Arabia is adding production capacity, such as the Khurais expansion with a designed 1.2 million bo/d peak production capacity.

ADCO in Abu Dhabi is expanding production capacity in various fields by 560,000 b/d. Also ExxonMobil is involved in the Upper Zakum redevelopment that will increase production by about 250,000 b/d from the field.

ConocoPhillips is also involved in developing the Shah sour gas field in Abu Dhabi.

Africa

Activity levels remain high in deepwater Angola and Nigeria. Projects mostly involve installation of floating production, storage, and offloading (FPSO) vessels and subsea wells.

Also being built in Angola is a one-train LNG plant that will receive associated as well as nonassociated gas.

Nigeria also has several new LNG projects that will monetize primarily associated gas, some of which is now flared.

Jubilee is a 300 million bbl deepwater development off Ghana. Production will flow to a leased FPSO that can process 120,000 bo/d

Western Hemisphere

Petrobras, besides its phased development of several giant fields in the Campos basin, also has substantial discoveries in the deeper presalt layer in both the Santos and Campos basins. It currently has under test two wells in the Tupi block that may contain about 7 billion bbl of recoverable areas. These new fields will add several billion bbl of reserves and may produce more than 1.8 million bo/d by 2020 from about 20 development projects, not listed in the table.

Although Petrobras is the main producer in Brazil, new companies with development projects include units of El Paso Corp., Chevron Corp., StatoilHydro ASA, Devon Energy Corp., and the Shell Group.

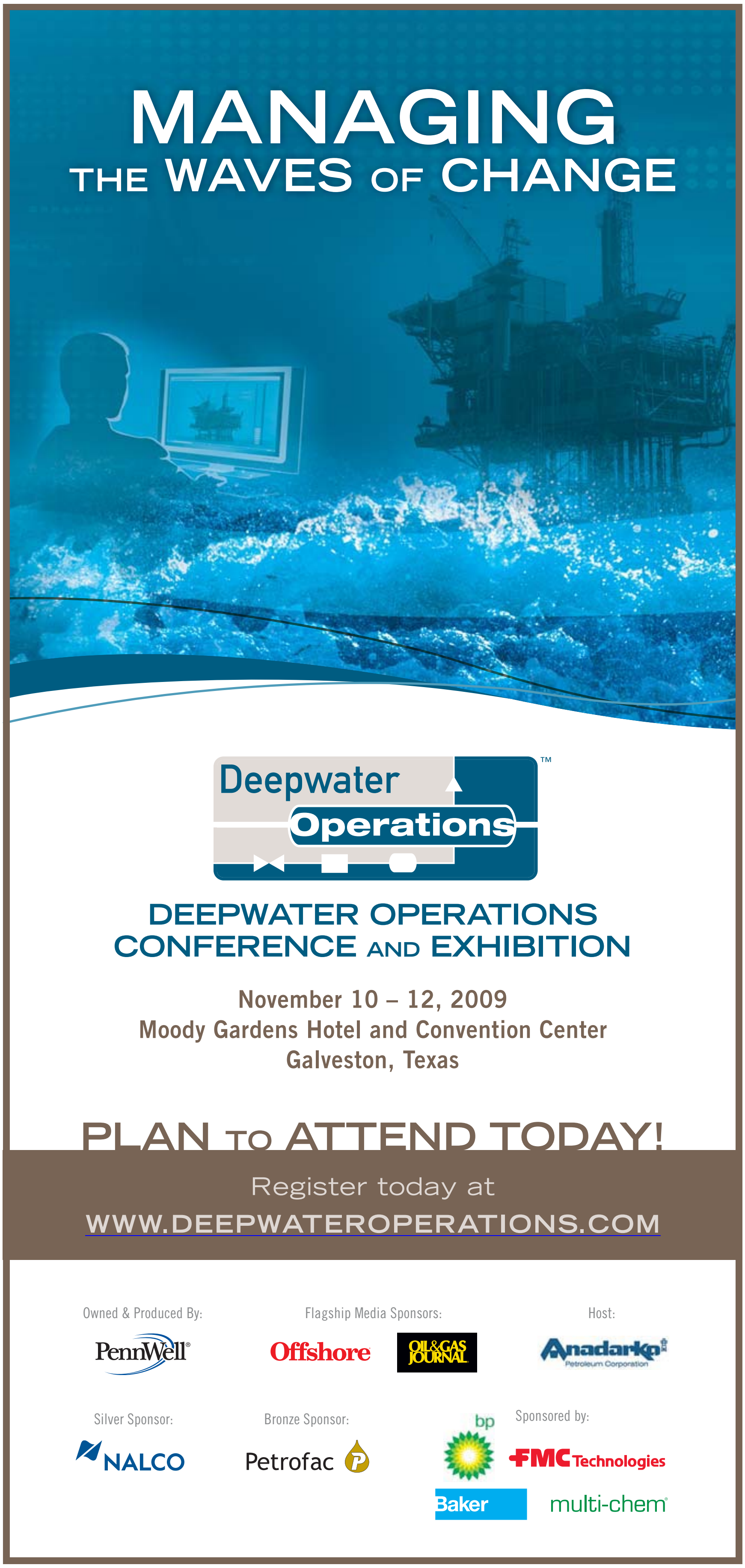
Chevron's Frade field went on stream in June 2009 and Shell Group's Parque de Conchas field started producing in July 2009.

Although companies have deferred, many Canadian oil sands projects, most likely will be developed but timing is uncertain. In its June report on Alberta's 2008 reserves and supply-demand outlook for 2009-18, Alberta's Energy Resources Conservation Board lowered its forecast of bitumen production to 2.7 million b/d in 2018. Last year's report showed production reaching 3.2 million b/d in 2017.

The projects listed in the table would

Company names

ADCO	Abu Dhabi Co.	Nexus	Nexus Energy Ltd
Addax	Addax and Oryx Group	NIOC	National Iranian Oil Co.
ADNOC	Abu Dhabi National Oil Co.	Occidental	Occidental Petroleum Corp.
AED	AED Oil Ltd.	Oilexco	Oilexco Inc.
Anadarko	Anadarko Petroleum Corp.	OGI	OGI Group
Apache	Apache Corp.	Origin Energy	Origin Energy Ltd.
Aramco	Saudi Arabian Oil Co.	OMV	OMV AG
ATP	ATP Oil & Gas Corp.	Pan American	Pan American Energy LLC
Avarasya	Avrasya Technology Engineering and Construction Inc.	PDO	Petroleum Development Oman LLC
Barrett	Barrett Resources LLC	Pdvsa	Petroleos de Venezuela SA
BHP	BHP Billiton Ltd.	Pemex	Petroleos Mexicanos
BlackRock	BlackRock Ventures Inc.	Pertamina	PT Pertamina (Persero)
BP	BP PLC	Petrel	Petrel Resources PLC
Cairn	Cairn Energy PLC	Petrobank	Petrobankl Energy and Resources Ltd
Chevron	Chevron Corp.	Petrobras	Petroleo Brasileiro SA
CNOOC	China National Offshore Oil Corp. Ltd.	PetroCanada	PetroCanada
CNPC	China National Petroleum Corp.	Petrodar	Petrodar Operating Co.
CNRL	Canadian Natural Resources Ltd.	Petrofac	Petrofac Group
Connacher	Connacher Oil and Gas Ltd.	Petrom	Petrom SA
ConocoPhillips	ConocoPhillips	Petronas	Petroliam Nasional Berhad
Coogee	Coogee Resources Ltd.	Petrovietnam	Vietnam Oil & Gas Corp,.
Daewoo	Daewoo International Corp.	Pioneer	Pioneer Natural Resources Inc.
Devon	Devon Energy Corp.	Pluspetrol	Pluspetrol Peru Corp.
DNO	DNO ASA	Premier	Premier Oil PLC
DPS	DPS Ltd.	PTTEP	PTT Exploration & Production PLC
El Paso	El Paso Corp.	Qeshm	Qeshm Energy Oil Industries Development Co.
EnCana	EnCana Corp.	QP	Qatar Petroleum Corp.
Enerplus	Enerplus Resources Fund	Reliance	Reliance Industries Ltd.
Eni	Eni SPA	Repsol	Repsol YPF SA
ExxonMobil	ExxonMobil Corp.	Rosneft	OAO Rosneft
First Calgary	First Calgary Petroleums Ltd.	Santos	Santos Ltd.
Gazprom	OAO Gazprom	Shell	Shell Group
Helix Group	Helix Energy Solutions	Sinopec	Sinopec Corp.
Hess	Hess Corp.	Soco	Soco Internationa Ltd.
Hunt Oil	Hunt Oil Co.	Sonangol	Sonangol
Husky	Husky Energy Inc.	Sonatrach	Sonatrach
Inpex	Inpex Holdings Inc.	StatoilHydro	StatoilHydro ASA
Imperial Oil	Imperial Oil Ltd.	Soyuzneftegaz	Soyusneftegas Ltd.
Ivanhoe	Ivanhoe Energy Inc.	Suncor	Suncor Energy Inc.
JACOS Ltd.	Japan Canada Oil Sands	Syncrude	Syncrude Canada Ltd.
KNPC	Korean National Oil Co.	Synenco	Synenco Energy Inc.
KOC	Kuwait Oil Co.	Talisman	Talisman Energy Inc.
KPC	Kuwait Petroleum Corp.	Toreador	Toreador Resources Corp.
Lukoil	OAO Lukoil	Total	Total SA
Maersk	Maersk Group	TPAO	Turkish Petroleum Corp.
Marathon	Marathon Oil Corp.	Tullow	Tullow Oil PLC
MEG Enegy	MEG Energy Corp.	Value Creation	Value Creation Inc.
Murphy	Murphy Oil Corp.	Venture	Venture Production PLC
Nexen	Nexen Inc.	Verenex	Verenex Energy Inc.
		Walter	Walter Oil & Gas Corp.
		Woodside	Woodside Petroleum Ltd.



add 2 million b/d to the current 1.2 million b/d being produced from the oil sands.

Operators and the Canadian government are still negotiating an agreement for the proposed $6-billion (Can.), 760-mile Mackenzie Delta pipeline that would allow for producing the large stranded gas resources in the Northwest Territories. First gas seems farther off and production may not be realized until later in the decade. The large amounts of unconventional gas discovered in the US and British Columbia have lessened the importance of developing Northwest Territory gas.

The large unconventional gas discoveries also may delay construction of a gas pipeline from the Alaska North Slope, with its estimated 40 tcf of stranded gas.

The undelineated projects in the Arctic National Wildlife Refuge in Alaska may contain an estimated 10 billion bbl. These prospects could produce up 1 million bo/d if the US congress allows drilling in ANWR.

Deepwater developments in the Gulf of Mexico will continue to add substantial new production capacity. Chevron's Tahiti, Shell's Perdido, and BHP's Shenzi are three of the largest deepwater fields to start producing in 2009.

Technological advances as well as higher gas prices have made feasible many tight gas, shale gas, and coalbed gas developments, such as the Piceance tight-gas projects in Colorado, the coalbed methane in the San Juan basin, and the Barnett shales of Texas.

Venezuela has many potential development projects, but its government's actions have created uncertainty as to their completion. ✦

MAJOR PROJECTS

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Algeria					
EKT, EMK, EMN, EME	2010	155		Anadarko	Block 208 $2 billion, oil and condensate
El Merk	2011	130	600	Anadarko	Block 404a, $3.8 billion oil and condensate
Berkine Block 405b	2009	40		First Calgary	Condensate
El Gassi, El Agreb, Zotti	2009	15		Hess	$500 million redevelopment
Rhourde El Baguel	2009	100		Sonatrach	Redevelopment of one of Algeria's largest oil fields
Zarzaitine	2010	15		Sinopec	$500 million redevelopment
Angola					
Plutao, Saturna, Venus, Marte (PSVM)	2010+	150		BP	Block 31, 500 million bbl of oil, FPSO, 150,000 bbl storage, 5,900-6,730 ft water
Platino, Chumbo, Cesio	2012+			BP	Block 18, FPSO, 1,600-m water
Palas, Ceres, Juno, Astrea, Hebe, Urano, Titania	2012+	150		BP	Block 31 discoveries, 2,000 m water
Terra Miranda, Cordelia, Portia	2012+	150		BP	Block 31 discoveries
Lucapa	2012+	100	75	Chevron	Block 14 discovery
Negage	2010+	75	100	Chevron	Block 14, FPSO 1.5 million bbl storage, 1,500-m water
LNG various fields	2012+		1,000	Chevron	Onshore, one train, 5.2 million LNG tonnes/year, 10 tcf of reserves in associated gas from Blocks 15, 17, 18, 0, and 14, and nonassociated gas from Blocks 1 and 2.
Tombua, Landana	2009	100	210	Chevron	Block 14, compliant tower in 400-m water
Kizomba Satellites	2010+	125		ExxonMobil	Block 15, FPSO, 1,000-m water
Gimboa	2009	50	20	Sonangol	Leased FPSO, 1.8 million bbl storage, production started April 2009
Cravo-Lirio-Orquidea-Violeta (CLOV)	2012+	150		Total	Block 17, FPSO
Pazflor - Perpetua, Zinia, Hortensia, Acacia	2011+	200	150	Total	Block 17, FPSO, 1.9 million bbl storage in 2,500 ft of water, 3 subsea separation stations, 25 subsea oil wells, 2 gas injection wells, and 22 water injection wells
Gindungo, Canela, Gengibre (GCG),	2012+	120		Total	Block 32, 300 million bbl of oil, FPSO, 4,600-5,900 ft water
Mostarda Cola, Salsa, Manjericao, Caril Louro, Caminhos, Colorau, Alho	2012+			Total	Block 32 discoveries
Argentina					
Cerro Dragon	2009+			Pan American	$550 million IFC field development loan, Golfo San Jorge basin, Chubut province
Australia					
Van Gogh	2009	60	80	Apache	FPSO, 600,000 bbl storage, 350-m water
Pyrenees	2010	100	60	BHP	FPSO, 1 million bbl storage, 200-m water
Stybarrow	2009		80	BHP	FPSO, 800 million bbl storage, 825-m water
Gorgon, Jansz, Io, Chandon, Geryon, Maenad, Orthrus	2014	10	1,575	Chevron	Greater Gorgon 15 million tonnes/year LNG from 3 trains on Barrow Island and 300 MMscfd domestic gas, 40 tcf of gas reserves, subsea wells tied back to shore
Wheatstone, Iago	2014+		1,000	Chevron	Carnarvon basin gas field in 650-ft water, 4.5 tcf reserves, 4.3 million tonne/year, two LNG trains.
Montara, Skua, Swift-Swallow	2009	40		Coogee	Platform, FPSO, subsea wells in 80-m water
Blacktip	2009		180	Eni	$325 million, Northwest shelf, platform in 50-m water and 108-km pipeline
Kipper, Tuna	2010+	20	150	ExxonMobil	Gippsland basin gas, Kipper includes initially two subsea completed wells tied back to West Tuna platform
Scarborough	2010+		965	ExxonMobil	10 tcf of gas
Ichthys	2012+	100	1,200	Inpex	Northwest shelf, semisubmersible in 230-m water, onshore LNG plant, 6 million tonnes/year, 200-km flowline, 9.5-tcf gas, 312 million bbl condensate
Crux	2010	35		Nexus	$540 million, Browse basin condensate, leased FPSO, 190-m water.
Angel	2009	50	800	Woodside	$1.6 billion (Aus.), Northwest shelf gas-condensate field, processing platform, 80-m water, 1st production Oct. 2008
North West Shelf Train 5	2009		800	Woodside	$2.6 billion (Aus.), 4.2 million tonnes/year, 1st production Aug. 2008
North Rankin 2	2013			Woodside	$5 billion (Aus.), new platform for low-pressure gas from North Rankin and Perseus gas fields
Pluto	2011		800	Woodside	$12 billion (Aus.), LNG, 4.1 tcf offshore development, 5-6 million tonnes/year
Torosa, Brechnock, Calliane	2012			Woodside	Karratha project with 14 tcf gas, 370 million bbl condensate
Vincent	2009	120	100	Woodside	$720 million, FPSO, 1.2 million bbl storage, 8 subsea wells, 350-m water, first production August 2008
Azerbaijan					
Shah Deniz FF	2012		2,600	BP	$10 billion gas-condensate project
Bangladesh					
Bibiyana	2010		500	Chevron	Onshore, production started in 2007
Brazil					
Frade	2011	90	20	Chevron	$2.8 billion, 200-300 million bbl, FPSO, 1.5 million bbl storage, 18-20° oil, 3,500-ft water, production started June 2009
Pinauma	2008		30	El Paso	$90 million, 50 million bbl of light oil in Camamu basin, off Brazil's northeastern Bahia state

MAJOR PROJECTS—(CONTINUED)

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Peregrino	2010		100	StatoilHydro	$2.5 billion, 300-600 million bbl heavy oil, Campos basin, BM-C-007, leased FPSO, 2 fixed platforms, 30 horizontal producers, 7 water injection wells.
Baleia Azul	2012		100	Petrobras	FPSO Espadarte, BC-60 heavy oil
Cachalote, Baleia Franca, Baleia Ana	2010		100	Petrobras	FPSO Capixaba Espirito Santo basin, heavy 19° oil, 1,400 m water
Camarupim	2009	36	350	Petrobras	FPSO Cidade de Sao Mateus, 700,000 bbl storage, 760-m water
Carioca	2014+			Petrobras	Santos basin, subsalt discovery, 2,140-m water
Caxareu	2013+			Petrobras	Campos basin subsalt discovery, 30° gravity oil
Espadarte Module 3	2012		100	Petrobras	FPSO
Golfinho Module 3 (ESS-130)	2008	100	100	Petrobras	Espirito Santo basin
Jubarte Phase 2 P-57	2011	180	20	Petrobras	FPSO, 1,8 million bbl storage, 1,250-m water, 17° oil
Marlim Leste P-53	2009	180	210	Petrobras	FPSO Cidade Niteroi Jabuti, turret-moored, 2 million bbl storage, 1,080-m water, 15-27° oil., production started Feb. 2009
Marlim Sul P-51	2009	180	210	Petrobras	Semisubmersible spread-moored, 28° oil, 1,255-m water, production started Jan. 2009
Marlim Sul P-56	2011		100	Petrobras	Semisubmersible spread-moored, 1,700-m water
Mexilhao	2009	20	600	Petrobras	Fixed platform, 172-m water, FPSO
Papa-Terra	2013+	180		Petrobras	Tension leg well platform P-61 and FPSO P-63, BC-20, 1,200-m water, 14-17° gravity oil, 700-1,000 million bbl
Pirambu	2013+			Petrobras	Subsalt discovery, 29° gravity oil
Roncado P-62 Module 4	2013	100		Petrobras	FPSO
Roncador P-55	2013	180	20	Petrobras	Semisubmersible, 22° oil, 1,800-m water
Urugua-Tambau	2010	35	350	Petrobras	Santos basin gas development tied into Mexilhao platform
Tupi extended well test	2009	30		Petrobras	FPSO BW Cidade de S. Vincente, 15 month duration with start in May 2009, 28-42° oil from 2 test wells.
Tupi pilot	2010	100	175	Petrobras	FPSO Cidade de Angra dos Reis, extended well test of 5-8 billion bbl discovery in subsalt, Santos basin, 2,140-m water, 5 producers, 2 water injectors, 1 gas injector
Guari pilot	2013		100	Petrobras	FPSO, subsalt production in Santos basin
Iara pilot	2013+		100	Petrobras	FPSO, subsalt production in Santos basin
Presalt production	2015+	2,500		Petrobras	Includes the installation of 20 production units in 2015-20
Parque das Conchas - Abalone, Argonauta, Nautilus, Ostra	2009	100	150	Shell	BC-10, FPSO, 2 million bbl storage, 1,500-2,000 m water, production started July 2009
Peregrino	2010		100	StatoilHydro	FPSO 1.5 million bbl storage,
Canada					
Hebron	2012	140		Chevron	$5 billion offshore heavy oil, 300 km off Newfoundland in North Atlantic
Ells River	2015+	100		Chevron	Thermal project
Birch Mountain Phase 1	2013+	30		CNRL	SAGD
Birch Mountain Phase 2	2015+	30		CNRL	SAGD
Gregoire Lake Phase 1	2016+	60		CNRL	SAGD
Grouse	2016+	60		CNRL	SAGD
Horizon Phase 1	2009	110		CNRL	Mine and upgrader, 6 billion bbl resource, production started July 2009
Horizon Phase 2	2011+	45		CNRL	Mine and upgrader
Horizon Phase 3	2011+	90		CNRL	Mine and upgrader
Horizon Phase 4	2015+	145		CNRL	Mine and upgrader
Horizon Phase 5	2017+	162		CNRL	Mine and upgrader
Primrose East	2009+	30		CNRL	Cyclic steam, Primrose upgrader Phase 1, 2012, 145,000 b/d, Phase 2, 2019, 58,000 b/d
Algar	2010	10		Connacher	Great Divide Pod 2, SAGD, 60 million bbl
Parsons Lake	2014+			ConocoPhillips	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd Mackenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields.
Surmont Phase 2	2012+	85		ConocoPhillips	SAGD, $1.1 billion (Can.) four phase project with Phase 1 production starting in 2007
Surmont Phase 3	2012+	85		ConocoPhillips	
Surmont Phase 4	2014+	25		ConocoPhillips	
Jackfish Phase 2	2011	35		Devon	SAGD, $500 million (Can.)
Borealis Phase 1	2010+	35		EnCana	SAGD
Borealis Phase 2	2011+	35		EnCana	SAGD
Borealis Phase 3	2012+	35		EnCana	SAGD
Christina Lake Phase 1C	2010	30		EnCana	SAGD
Christina Lake Phase 1D	2011+	30		EnCana	SAGD
Christina Lake expansion 1	2012+	30		EnCana	SAGD
Christina Lake expansion 2	2013+	30		EnCana	SAGD
Christina Lake expansion 3	2014+	30		EnCana	SAGD
Christina Lake expansion 4	2015+	30		EnCana	SAGD
Christina Lake expansion 5	2016+	30		EnCana	SAGD
Foster Creek Expansion 1	2009	30		EnCana	SAGD, $440 million (Can.)
Foster Creek Expansion 2	2011+	30		EnCana	SAGD
Panuke Deep	2010+		300	EnCana	Production jack up (MOPU), 44-m water
Kirby Phase 1	2013+	10		Enerplus	SAGD, 244 billion bbl of reserves
Kirby Phase 2	2017+	25		Enerplus	SAGD
Kearl Phase 1	2011+	100		ExxonMobil	$8 billion (Can.), mine, 4 billion bbl resource developed in three phases
Kearl Phase 2	2012+	100		ExxonMobil	Mine
Kearl Phase 3	2014+	100		ExxonMobil	Mine
Mackenzie gas project	2016+	10	830	ExxonMobil	

Major Projects—(continued)

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Sunrise Phase 1	2012+	50		Husky	SAGD, 40-year phased project with expected recovery of 3.2 billion bbl
Sunrise Phase 2	2014+	50		Husky	SAGD
Sunrise Phase 3	2016+	50		Husky	SAGD
Sunrise Phase 4	2018+	50		Husky	SAGD
Taglu	2014+			Imperial Oil	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd Mackenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields.
Tamarack Phase 1	2013+	20		Ivanhoe	SAGD, $1.25 billion (Can.)
Tamarack Phase 2	2015+	39		Ivanhoe	SAGD
Hangingstone Phase 1	2010+	35		JACOS	SAGD
BlackGold Phase 2	2010+	10		KNPC	SAGD
BlackGold Phase 1	2012+	20		KNPC	SAGD
Christina Lake Phase 2	2009	24		MEG Energy	SAGD, 2 billion bbl recoverable
Christina Lake Phase 2B	2011+	35		MEG Energy	SAGD
Christina Lake Phase 3A	2013+	75		MEG Energy	SAGD
Christina Lake Phase 3B	2015+	75		MEG Energy	SAGD
Long Lake Phase 2	2014+	72		Nexen	SAGD
Long Lake Phase 3	2016+	72		Nexen	SAGD
Long Lake Phase 4	2018+	72		Nexen	SAGD
Long Lake South	2010+	70		Nexen	SAGD
Long Lake South	2012+	70		Nexen	SAGD
Card Phase 1	2010+	40		PetroCanada	SAGD
Fort Hills Phase 1	2011+	165		PetroCanada	Mine, upgrader, 2.8 billion bbl
Fort Hills debottlenecking	2014+	25		PetroCanada	Mine, upgrader
Lewis Phase 1	2011+	40		PetroCanada	SAGD, 3 billion bbl
Lewis Phase 2	2011+	40		PetroCanada	SAGD
MacRiver expansion	2010+	40		PetroCanada	SAGD
Meadow Creek Phase 1	2010+	40		PetroCanada	SAGD, $800 million (Can.), 1.3 billion bbl.
Meadow Creek Phase 2	2010+	40		PetroCanada	
May River Phase 1	2009+	10		Petrobank	Toe-to-heel air injection (THAI)
May River additional phases	2012+	90		Petrobank	Toe-to-heel air injection (THAI)
Carmon Creek Phase 1	2010+	37		Shell	Cyclic steam
Carmon Creek Phase 2	2015+	50		Shell	Cyclic steam
Muskeg mine debottlenecking	2010+	115		Shell	Albian Oil Sands project, with Scotford upgrader expansion of 135,000 b/d by 2009
Jackpot mine Phase 1	2010+	100		Shell	Albian Oil Sands project
Jackpot mine Phase 2	2012+	100		Shell	Albian Oil Sands project
Jackpot mine Phase 3	2014+	100		Shell	Albian Oil Sands project
Niglintgak	2014+			Shell	Northwest Territories, 1.8 tcf gas, awaiting $7.8 billion (Can.) 760-mile, 1.2 bcfd Mackenzie Delta pipeline, $3.5 billion (Can.) gas-gathering system, $4.9 billion (Can.) anchor fields.
Orion Hilda Lake Phase 2	2010+	10		Shell	SAGD $115 million (Can.) expansion
Pierre River Phase 1	2018+	100		Shell	Mine
Pierre River Phase 2	2021+	100		Shell	Mine
Kai Kos Dehseh Phase 1 (Leismer)	2010+	10		StatoilHydro	SAGD pilot
Leismer commercial	2010+	10		StatoilHydro	SAGD with upgrader
Leismer expansion	2011+	20		StatoilHydro	SAGD with upgrader
Comer	2012+	40		StatoilHydro	SAGD with upgrader
Thornbury	2013+	40		StatoilHydro	SAGD with upgrader
Comer expansion	2014+	40		StatoilHydro	SAGD
Hangingstone	2016+	20		StatoilHydro	SAGD
Thornbury expansion	2017+	20		StatoilHydro	SAGD
Northwest Leismer	2018+	20		StatoilHydro	SAGD
South Leismer	2020+	20		StatoilHydro	SAGD
Firebag Phase 3	2010+	62		Suncor	SAGD
Firebag Phase 4	2011+	62		Suncor	SAGD
Firebag Phase 5	2012+	62		Suncor	SAGD
Firebag Phase 6	2013+	68		Suncor	SAGD
Steepbank mine and upgrader expansions Voyageur project	2011+	250		Suncor	$6 billion (Can.) [Mine, $350 million (Can.), upgrader $2.1 billion (Can.)]
Thickwood Phase 1	2011+	10		Sunshine	
Thickwood Phase 1	2012+	30		Sunshine	
Thickwood Phase 1	2013+	25		Sunshine	
Syncrude expansion Stage 3	2011+	46		Syncrude	Mine and processing
Syncrude Stage 4	2015+	140		Syncrude	Mine and processing
Northernlights Phase 1	2010+	50		Synenco	Mine and upgrader, recover 1 billion bbl over 28 years
Northernlights Phase 2	2012+	50		Synenco	Mine and upgrader
Joslyn Phase 3B	2011+	15		Total	SAGD
Joslyn Mine Phase1	2012+	50		Total	Mine and upgrader, 100 b/d upgrader
Joslyn Mine Phase 2	2013+	50		Total	
Joslyn Mine Phase 3	2016+	50		Total	
Joslyn Mine Phase 4	2019+	50		Total	
Terre de Grace Pilot	2011+	10		Value Creation	SAGD
Terre de Grace Phase 1	2012+	40		Value Creation	SAGD
Terre de Grace Phase 2	2014+	40		Value Creation	SAGD
China					
Chuandongbei, Tieshanpo, Dukouhe-Qilibei, and Luojiazhai	2010		740	Chevron	Sichuan province gas fields with 5 tcf of gas, 8-17% H_2S, 5-10% CO_2
Liwan				Husky	4-6 tcf discovery, 1,345-m water
Puguang expansion	2010+		390	Sinopec	

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Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Tahe expansion	2009+			Sinopec	1 billion bbl oil
South Sulige	2012			Total	Unconventional tight gas sands, Ordos Block, Inner Mongolia, 18.85 tcf gas, discovered 2002, production started in 2002
Colombia					
La Cira-Infantas redevelopment	2010	20		Occidental	New wells, waterflooding, steam, gas injection, horizontal drilling
Congo (Brazzaville)					
Azurite	2009	40	18	Murphy	FPSO, 1.3 million bbl storage, 1,370-m water, 400 boe discoveries made in 2006
Moho North	2012			Total	
East Timor and JPDA					
Kitan	2011		35	Eni	JPDA Block 06-105, Timor Sea, FPSO, 3 subsea wells, 1,000 ft of water, 30-40 million bbl of oil
Sunrise and Troubadour fields	2013			Woodside	$7 billion (Aus.), 8 tcf of gas, and 300 million bbl of condensate, 90-550 m of water, tied into Bayu Undan LNG expansion
Ecuador					
Pungarayacu	2013+	100		Ivanhoe	Block 20. 4.5+ billion bbl of heavy oil
Gabon					
Anguille redevelopment	2011	30		Total	$2 billion, new wells and facilities to add 150 million bbl, field on production since 1966.
Ghana					
Jubilee	2010	60	80	Tullow	FPSO, 1 million bbl storage, 1,500-m water
India					
Dhirubhai field, Krishna-Godavari Block D6	2009		2,800	Reliance	$5.2 billion, 12 tcf; 40-60 km southeast of Kakinada, 400-2,700-m water
MA-D6	2008	60	100	Reliance	FPSO, 1.3 million bbl storage, 1,150-m water
Indonesia					
Tangguh LNG liquefaction project	2009		1,400	BP	$2.2 billion project, 7 million tonnes/year of gas from Papua Bintuni Bay fields, 225-ft water, first cargo to China July 2009
Banka, Gendalo, Gehem	2013			Chevron	Kutei basin, deepwater gas
North Duri	2009			Chevron	$1.3 billion, steamflood on Sumatra Island
Sadewa	2010			Chevron	Kutei basin gas, 150-600 bcf reserves
North Belut	2009+			ConocoPhillips	Tied into Belanak, 54,000 boe/d
Banyu Urip	2010+	165	20	ExxonMobil	$2.6 billion, Cepu block, onshore Java, 50 wells drilled from four well pads, 60-mile pipeline to 2 million bbl FSO moored off Tuban
Natuna D-Alpha	2014		1,100	ExxonMobil	46 tcf of gas, 70% carbon dioxide, South China Sea
Jeruk	2009			Santos	50 million bbl oil discovery off Madura island, project downgraded and under reevaluation
Iran					
Azadegan North Phase 2	2012		110	NIOC	Heavy oil
Azadegan South	2009		125	NIOC	$3 billion, heavy oil
Kushk-Hosseinieh	2009		300	NIOC	Heavy oil
South Pars Phases 9 and 10	2009		80	NIOC	$1.9 billion, condensate, gas
Yadavaran	2011		300	NIOC	Medium oil
Azar				StatoilHydro	Anaran Block, western Iran, 2 billion bbl in carbonates
Iraq					
Subba-Luhais expansion	2010+	240		Petrel	1.3 billion bbl, southern Iraq
West Qurna expansion	2010+	600			21 billion bbl, west of Basra
Khurmala	2010+	70		DPS	Near Kirkuk
Hamrin	2010+	60		OGI	1.3 billion bbl, southwest of Kirkuk
Majnoon	2010+	500			12.6 billion bbl, 28-35° API, 30 miles north of Basra
Al-Ahdab	2010+	90			Southern Iraq
Al-Qayyarah	2010+	120		Ivanhoe	Heavy 17.1° oil
Halfaya	2010+	120			5 billion bbl
Amara	2010+	60			0.1 billion bbl
Nahr Umr	2010+	440			6 billion bbl
Rafidain	2010+	100			0.3 billion bbl
Gharraf	2010+	100		TPAO	0.3 billion bbl
Chemchamal, Jaria Pika, Khashm al Ahmar, and Mansuriya	2010				10 tcf gas fields
Nassiriya	2015+	1,000			4 billion bbl
Rumaila	2012+			BP	17.7 billion bbl
Ireland					
Corrib	2010		320	Shell	Subsea wells in 350-m water tied back to shore with 83 km, 20-in. flowline
Italy					
Tempa Rossa	2011	50	20	Total	$700 million, 200 million bbl of heavy oil
Kazakhstan					
Karachaganak Expansion III	2012+		1,600	BG	$8 billion expansion

MAJOR PROJECTS—(CONTINUED)

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Tengiz expansion	2010+	260		Chevron	$9.5 billion expansions to develop 3.3 billion bbl of oil with Phase 1
Kashagan Phase 1	2012+	450		Eni	$29 billion, 13 billion bbl of oil, carbonate reef, 10-30 ft of water, 45° gravity oil, 19% H2S, production start in 2011, 1.2 million bo/d from all phases
Kashagan future phases	2014+	1,000		Eni	
Vladimir Filanovsky	2009	100		Lukoil	Caspian Sea, 600 million bbl of oil and 1.2 tcf of gas
Komsomolskoe	2010	10		Petrom	Onshore $190 million project
Kuwait					
Kuwait North redevelopment	2012	450		KPC	
Libya					
Sirte basin redevelopment	2012	200		Oxy	$5 billion over 5 years, increase to 300,000 bo/d from 100,000 bo/d, develop 2.5 billion bbl of oil
Area 47 Phase 1	2010	50		Verenex	Oil discoveries in the Ghadames basin
Malaysia					
Gumusut-Kakap	2012+	150		Shell	Semisubmersible, 1,250-m water
SK8	2010+		90	Shell	
Mauritania					
Tiof	2010	75		Petronas	TLP, 1,200-ft water
Myanmar					
Shwe, Shwe Phyu, Mya	2009			Daewoo	4.8-8.6 tcf recoverable
Namibia					
Kudu	2012			Tullow	Offshore, 170-m water, 4 tcf gas reserves, initial for power plants, later for possible 5 million/tons/year LNG train
Netherlands					
Schoonebbeek	2010+		20		Steamflood of heavy oil
New Zealand					
Kupe	2009	7	60	Origin Energy	$980 million (NZ), 400 bcf, gas, NGL, condensate offshore in Taranaki basin, 35-m water, wellhead platform with six wells
Nigeria					
Ofrima North	2009			Addax	OML 137, oil and gas discovery, FPSO, 75-m water depth
Agbami	2009	250	450	Chevron	$5.4 billion, FPSO, 2.3 million bbl storage, 1,460-m water, production start mid-2008
Nigeria GTL	2010	35		Chevron	$2.9 billion
Escravos gas project 3 (EGP3)	2009+		800	Chevron	$2.8 billion
Nsiko	2012+	100		Chevron	OPL 249
Olokola LNG	2010+		2,200	Chevron	$7 billion first stage to produce 11 million tonnes/year of LNG
Brass LNG	2012		1,300	Eni	$7 billion, 2 trains LNG associated gas and gas from OML 60 and 61 gas fields
Oyo	2009+	40		Eni	$600 million, FPSO. 300-ft water
Bosi	2011	135		ExxonMobil	$2 billion, FPSO, 2 million bbl storage, 1,700-m water
East Area NGL II	2008+	40		ExxonMobil	
LNG IPP Project	2010+		700	ExxonMobil	
Satellite projects	2010+	125		ExxonMobil	
Bonga Ullage	2009+	70	50	Shell	Oil deepwater
Bonga North, Northwest	2010+	150	80	Shell	FPSO in 4,000-ft water
Bonga Southwest	2012+	140	105	Shell	FPSO
Gbaran Ubie Phase 1	2012+	70	1,000	Shell	30 wells and gas gathering facilities in Bayelsa state, Niger delta
NLNG 7	2012+		1,600	Shell	Bonny Island , 8 million tonnes/year
Egina	2012		200		Total OML 130, 1,500-m water depth
Akpo	2009	175	320	Total	$2.3 billion, OML 130, FPSO 2 million bbl storage, 1,314-m water, gas to Bonny NLNG, 620 million bbl of 53° gravity condensate, 1 tcf gas, 44 subsea wells
Ofon 2	2010+		400	Total	OML 102 gas for LNG
Usan	2011	160	175	Total	$2 billion, OPL 138, FPSO, 2 million bbl storage, 23 producing well, and 19 water and gas injection wells, 2,395-2,790 ft of water. 500 million bbl reserves
Ukot, Togo	2010			Total	$4 billion, FPSO in 2,600-ft water
Norway					
Skarv-Idun	2011	90	665	BP	Skarv FPSO oil and gas development, Idun subsea tie-back to Skarv in 390-m water, reserves of 105 million bbl liquids and 1.7 tcf gas
Valhall redevelopment	2010+	150	175	BP	New platform
Tyrm	2010			DONG	Block 3/7-4, subsea wells tied back to Harald, gas condensate
Gjoa	2010	50	350	StatoilHydro	60 million bbl of oil, 35 bcf gas, semisubmersible, 360 m water
Morvin	2010			StatoilHydro	2 subsea tie backs to Asgard B
Tyrihans	2010	80	330	StatoilHydro	$2.2 billion, 460 million boe, 2 subsea completed fields tied into Kristin semisubmersible platform, production start July 2009
Vega	2010			StatoilHydro	2 subsea templates tied back to Gjoa
Yme redevelopment	2009	60	20	Talisman	Production jack up with subsea storage tank (MOPU Stor), 95-m water

MAJOR PROJECTS—(CONTINUED)

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Oman					
Mukhaizna steamflood	2010+	150		Occidental	Block 53, 16-18° oil, 1 billion bbl potential with steam
Harweel Phase 2, Harweel, Zalzala, Rabab, and other fields	2010+	100	70	PDO	$1 billion, facilities and gas injection in oil fields in southern Oman
Qarn Alam steamflood	2010	30		PDO	Thermally assisted gas-oil gravity drainage (TAGOGD), 16° gravity oil, fractured carbonate with 1 billion bbl initially in place
Papua New Guinea					
PNG gas	2014	20	570	ExxonMobil	$10-11 billion, gas from fields in Southern Highlands to LNG plant at Port Moresby
Peru					
Block 67	2010	100		Perenco	Three fields, 12-21° gravity oil, 248 mile pipeline
Qatar					
Al Khaleej gas Phase 2	2009+	70	1,140	ExxonMobil	$1 billion, gas to local markets
Barzan Phase 1	2010	135	1,500	ExxonMobil	1.5 bcfd for local markets
Qatargas 2 Train 5	2009	80	1,250	ExxonMobil	7.8 million tons/year
RasGas Train 7	2009	75	1,250	ExxonMobil	7.8 million tons/year
Al-Shaheen expansion	2009	285		Maersk	$3 billion, production increase to 525,000 b/d in 2009 from 240,000 b/d in 2006.
Pearl GTL	2009	133		Shell	$7 billion
Russia					
Verkhnechonskoye	2015	100		BP	1 billion bbl resource
Sakhalin-1	2007+	250		ExxonMobil	Started production in 2005 and reached peak production in Feb. 2007
Sakhalin-1 Future Phases	2010+		800	ExxonMobil	Gas pipeline from offshore 17-tcf Chayvo, Odoptu, and Arkutun-Dagi
Kovykta	2015		2,500	Gazprom	70 tcf gas, awaiting pipelines for regional sales and sales to China
Prirazlomnoye	2009+	150		Gazprom	560 million bbl reserves in Pechora Bay 35 miles offshore, 60 ft water
Shtokman	2013+		2,400	Gazprom	130 tcf, Barents Sea, Phase 1 includes 3 subsea templates with 20 producers flowing to a FPSO and 36-in. pipelines tied to a 7.5 million tonne/year LNG plant
Shtokman additional phases	2019		6,600	Gazprom	
Yuzhno-Russkoye	2010		3,900	Gazprom	21 tcf of reserves, involves completing a pipeline to Germany, first production in 2008
Yuzhno-Russkoye	2013			Gazprom	2nd pipeline to Germany completed
Khvalynskoye	2011+		1,000	Lukoil	Caspian Sea, off Russia, 12 tcf gas, 265 million bbl oil, and 148 million bbl NGL, production start in 2009
Vankor	2013	120		Rosneft	900 million bbl 2P; Krasnoyarsk Kray, western East Siberia
West Salym, Western Siberia	2013	143		Shell	Started production in late 2004
Kharyaga Phase 3	2011			Total	Yamal-Nenets, field under production since 1986
Saudi Arabia					
Karan			1,000	Aramco	Offshore Khuff gas field
Khurais expansion, Abu Jifan, Mazalij	2009+	1,200		Aramco	$8 billion, light oil
Manifa	2010+	900		Aramco	$1.0 billion, Arab heavy
Dammam	2010	1,000		Aramco	
Sudan					
Melut basin Blocks 3 and 7, Palogue, Adar-Yale, Agordeed	2010	300		Petrodar	$1.9 billion, 1,349-km, 32-in.pipeline, expansions may increase production to 500,000 bo/d, production start in 2006 at 150,000 bo/d
Thailand					
Platong II	2011		420	Chevron	$3.1 billion, processing platform, 12,000 ton topsides, 5 wellhead platforms, 320 km from shore, 200-ft water
Bongkot South	2011		330	PTTEP	$1 billion, 17,000 tonne topsides and 5,000 tonne steel jacket for central processing platform. High H_2S gas.
Trinidad					
Starfish	2010			BG	Blocks E and 5a, 1998 discovery, 427-ft water
Savonette	2009			BP	Standardized Cannonball platform, gas to Mahogany B for processing
UAE					
ADCO expansions	2012+	560		ADCO	
Shah sour gas	2012+		1,000	ConocoPhillips	
Upper Zakum redevelopment	2012	250		ExxonMobil	$2 billion, light oil
UK					
Alder	2011	9	80	Chevron	West of Britannia field
Huntington	2010			E.On Ruhrgas	UK Blocks 22/14b, 39-41° gravity oil.
Laggan-Tormore	2011	90		Total	West of Shetlands, gas-condensate fields, 600-m water, Block 205/5a
Pilot	2009	30		Venture	Cylindrical FPSO spread-moored, leased, 0.3 million bbl storage, 120-m water
US					
Caesar, Tonga	2011	40		Anadarko	Green Canyon blocks, $1.3 billion, 200-400 million boe reserves, tie back to Constitution spar

Major projects—(continued)

Project	Peak year	Liquids, 1,000 b/d	Gas, MMscfd	Operator	Development type
Telemark	2010+	25	50	ATP	Atwater Block 63, mini TLP in 4,385-ft water, B in 1,200-m water., 6 dry tree wells
Shenzi	2009	100	50	BHP	$4.4 billion, Green Canyon Block 653, TLP in 4,400-ft water, 350-400 million boe
Atlantis North Flank	2009			BP	Green Canyon blocks, 4,500-6,900 ft water
Dorado	2009			BP	Viosca Knoll Bock 915, 3,500-4,000 ft water
King South	2009			BP	Mississippi Canyon Block 129, tie-in to Marlin
Liberty	2011	15		BP	Alaska light oil discovered in 1997, wells with record departures of 34,000-44,000 ft
Puma	2010			BP	Green Canyon 823, 4,129-ft water
San Juan CBM	2011			BP	$2 billion in next 13 years to develop 2.7 tcf gas
Tubular Bells	2012			BP	Mississippi Canyon Block 725, 4,334-ft water
Wamsutter tight gas	2010+		250	BP	$15 billion during next 15 years developing 450 million boe gas
Big Foot	2015			Chevron	Walker Ridge Block 29, 5,268-ft water
Jack	2013			Chevron	Walker Ridge Block 759, 6,962-ft water
St. Malo	2014			Chevron	Walker Ridge Bock 678, 6,996-ft water
Tahiti	2009	125	70	Chevron	$3.5 billion, truss spar, 1,220-m water
Longhorn	2009		200	Eni	$580 million, Mississippi Blocks 502 and 546, three subsea wells tied back 32 km to Crystal platform, 2,400-ft water
Piceance tight gas Phase 1	2009+		200	ExxonMobil	Colorado
Piceance tight gas future phases	2010	10	870	ExxonMobil	Colorado
Phoenix	2010	45	70	Helix	FPU, to restore production from Typhoon field
Droshky	2010			Marathon	Green Canyon Block 244, 2,900-ft water
Ozona	2010			Marathon	Garden Banks Block 515, 3,000-ft water
Thunder Hawk	2009	45	70	Murphy	Semisubmersible, 5,700-ft water, production started July 2009
Cascade, Chinook	2010	80	16	Petrobras	FPSO, 600,000 bbl storage, Walker Ridge Blocks 206 and 469, 8,300-ft water
Great White, Tobago, Silvertip	2010	100	200	Shell	Perdido spar hub, subsea separation, boosting, in Alaminos Canyon Blocks 857, 815, and 859, 8,000-ft water
Mississippi Canyon Block 241	2010+			Walter	2,415-ft water
Alaska Gas/Point Thomson	2013+	70	4,500	ExxonMobil	Initial condensate production, gas awaiting the $20 billion, 3,400-mile, 4.6-bcfd Alaskan pipeline.
Venezuela					
Loran	2012+			Chevron	5 tcf of gas
Carabobo 1	2012+	200		Pdvsa	9 billion bbl of heavy oil
Corocoro	2010+	70		Pdvsa	West Paria Gulf
San Cristobal	2010+		400	Pdvsa	Block 2, Manatee area, 6 tcf LNG project
Deltana	2010+			Pdvsa	38 tcf off Venezuela and 21 tcf off Trinidad and Tobago
Mariscal Sucre	2010+		600	Pdvsa	Offshore gas
Mariscal Sucre expansion	2011+		600	Pdvsa	Offshore gas
Vietnam					
Vietnam gas project	2012		500	Chevron	$3.5 billion, Blocks B, 48/95, 52/97, production start in 2011
Dua/Chim Sao	2011	50		Premier	2 platforms, storage vessel

Note: This table to be archived at www.ogjonline.com and updated periodically; please email project information to news@ogjonline.com

Changing US crude imports are driving refinery upgrades

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Christopher Buehler
Exponent Inc.
Houston

In the last 15 years, overall crude oil imports to the US have grown at 3%/year. During this time, the sources of these imports and their proportional shares have changed significantly, with a corresponding movement toward crudes that are heavier and more sour in average quality.

The steady growth in crude oil imports to the US from Canada has been accompanied by significant investments in oil sands production in Canada, development of pipeline infrastructure to transport these crudes to the US, and refinery expansions in the US to enable processing of heavy crudes. These modifications to refining infrastructure, which result in increased requirements for hydrogen, steam, and power, are opportunities for gasification and cogeneration projects.

Based on a presentation to the NPRA Annual Meeting, Mar. 22-24, 2009, San Antonio.

This article discusses historical trends in US crude oil imports with an emphasis on synthetic Canadian heavy crudes and examines their impact on the configuration and profitability of US refineries.

Import trends

Since 1994, imports of foreign crude oil to the US have consistently exceeded its domestic oil production with a rapidly increasing margin (Fig. 1). A study of data compiled by the US Energy Information Administration shows that during this period, imports of foreign crude oil have increased at 3%/year to more than 10 million b/d in 2007 from 7 million b/d in 1994.[1]

This timeframe has also seen the steady rise of Canada to the largest country of origin for imported crude oil to the US in 2007 (19% of total imports) from the third largest in 1994 (14%).[2] EIA data also show that the imports from such other large suppliers as Saudi Arabia and Venezuela have stayed relatively flat during this period, while imports of North Sea crude have decreased steadily.

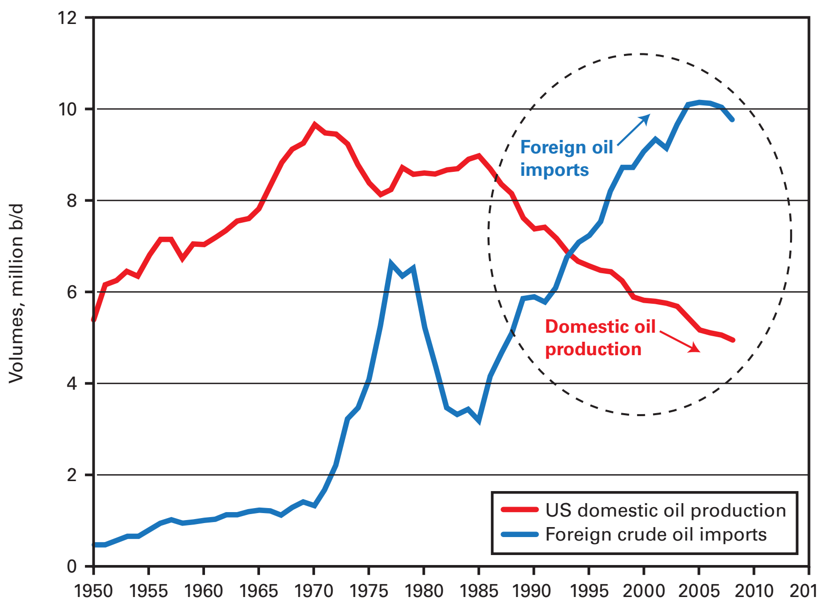
Since 2000, crude oil imports from Nigeria have been on the rise, while imports from Mexico peaked in 2004 and have begun trending down since. These trends underlie a remarkable growth in the share of total crude imports: The US imported about 66% of its crude feedstock in 2007 in contrast to about 25% in the mid-1980s.[3]

These trends in the quantity and origin of imported crude oil to the US have been accompanied by a trend of deteriorating quality of the crude oil processed in US refineries (Fig. 2), namely toward heavier crude oil with a greater sulfur content. This trend is expected to continue due to the decreasing availability of light sweet crude and the relative price discount for heavy sour crudes.

According to EIA, the average sulfur content of imported crude to the US 1985-2005 increased to 1.4% sulfur from 0.9%, while the average API gravity has declined to 30.2° API from

US OIL PRODUCTION, FOREIGN IMPORTS

Fig. 1



Source: Heritage Foundation; http://www.heritage.org/Research/EnergyandEnvironment/EneryCharts.cfm

32.5° API as heavier crudes have been imported.[4] Processing the increasing quantity and decreasing quality of imported crude oil while meeting increasingly stringent specifications on the allowable sulfur content in gasoline and diesel fuel has wrought modifications to US crude oil refining infrastructure over these years.

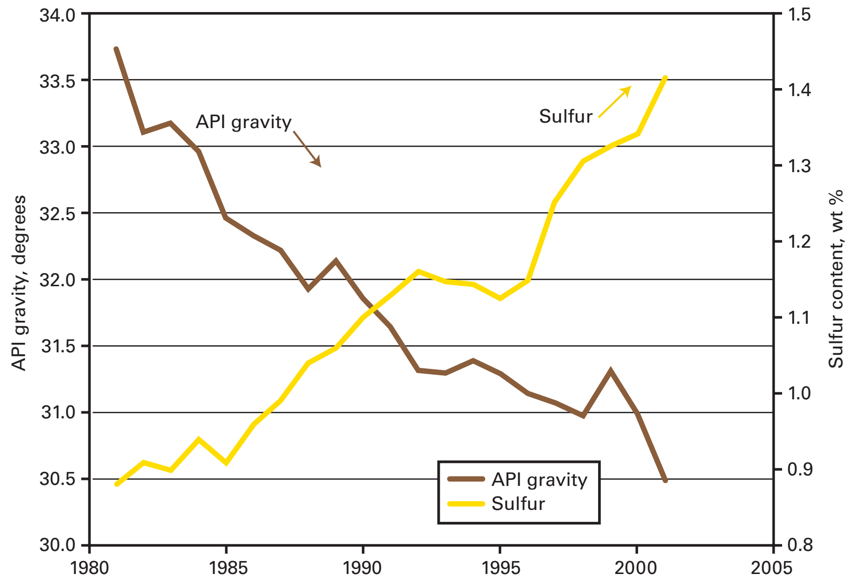
In 2004, Canada overtook Saudi Arabia to become the largest exporter of crude oil to the US and has consistently strengthened its position since.[5] US imports of crude oil from Canada for 2007 totaled 1.9 million b/d and have increased at 5%/year since 2000.[6]

Supporting this trend are large project investments in Alberta to increase production of oil sands-derived heavy crude (including bitumen blends), development of pipeline infrastructure to transport these crudes to the US, and investments in refinery projects in the US Midwest to process oil sands-derived heavy crude.

Reduced credit availability, however, increasing market uncertainty, and oil price volatility due to the current economic downturn have temporarily slowed development of current and proposed Canadian heavy crude and downstream refining projects.

US REFINERY CRUDE FEEDSTOCK QUALITY

Fig. 2



Source: Shore, J., "Refining Challenges: Changing Crude Oil Quality & Product Specifications," Energy Information Administration, World Fuels Conference, Washington, Sept. 25-28, 2002

Infrastructure developments

Imported crude to the US arrives predominantly by crude oil tankers to various locations along the Gulf Coast and the East and West coasts. The US Gulf Coast currently receives about 55% of US crude oil imports, the majority of which is processed in Gulf Coast refineries, while the remainder moves inland to distribution hubs via the Seaway and Capline crude pipelines.

Crude oil imports via tanker to the East and West coasts are generally intended for regional refinery consumption and represent about 12% and 10%, respectively, of total US imports (or about 1 million b/d each). The remaining US crude imports are mainly from Canada, which currently accounts for about 1.9 million b/d delivered to the upper Midwest and north central US by an extensive network of pipelines.

Fig. 3 shows the average crude oil import flows in 2007 to US Petroleum Administration for Defense Districts and highlights the major countries of origin of the imported crude.

A predominant trend in the recent decade with respect to crude oil imports into the US has been the growth in supply of heavy Canadian crude, in particular from the oil sands region in the western province of Alberta. In addition to investment in upstream production and downstream processing of heavy Canadian crude oil and bitumen blends, several projects are under way further to expand existing pipeline infrastructure. The softening of market demand due to the current economic downturn has temporarily moderated the need for additional pipeline capacity beyond the existing projects.

The Canadian Association of Petroleum Producers annually provides a detailed overview of existing and planned pipeline infrastructure to transport heavy Canadian crude to US refining markets.[7] According to the 2009 CAPP market update,[8] around 1.7 million b/d of crude oil from Western Canada moved to US refineries in 2008 via three major pipeline systems: the Enbridge system and Kinder Morgan's Express and Trans Mountain pipelines.

The largest among these pipelines, the Enbridge system, has an estimated crude capacity of 1.9 million b/d (1.2 million b/d heavy crude) and a trunkline that runs from Edmonton to Chicago in the US Midwest.[7] Additional segments in the Enbridge system deliver crude to Cushing, Okla., Patoka, Ill., and Ontario. In March 2006, the 66,000 b/d ExxonMobil-Enbridge Pegasus pipeline was reversed, connecting Patoka to Nederland, Tex., thereby providing Canadian heavy oil producers access to the US Gulf Coast market.[7]

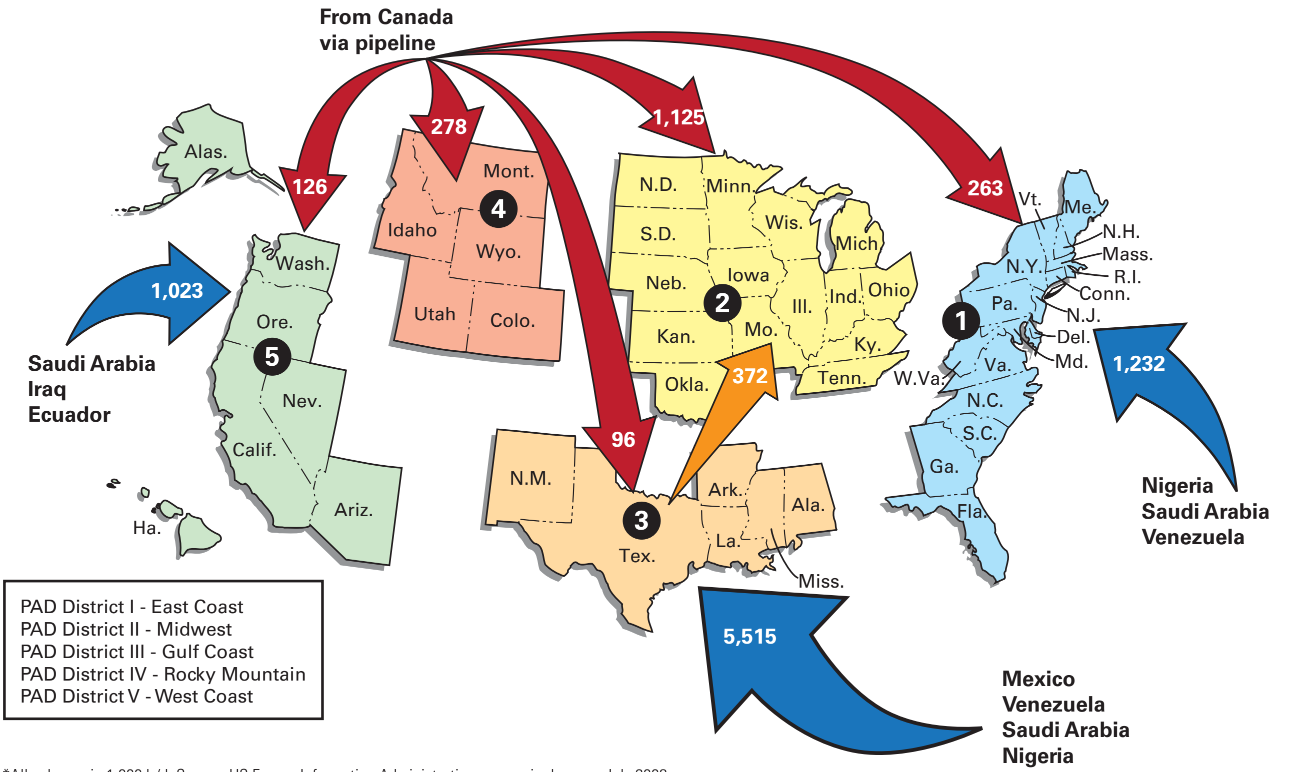
Kinder Morgan's Trans Mountain pipeline runs west from Edmonton and delivers predominantly light Canadian crude to refineries near Burnaby in Canada and the state of Washington, while its Express pipeline transports Canadian heavy crude from Hardisty, Alta., south to refineries in the US mountain states of Montana, Wyoming, and Utah.

The lines have estimated crude capacities of 280,000 b/d and 300,000 b/d, respectively, for a total crude capacity of nearly 580,000 b/d.

In Casper, Wyo., the Express pipeline

US CRUDE IMPORTS: 2007*

Fig. 3



*All volumes in 1,000 b/d. Source: US Energy Information Administration, www.eia.doe.gov, July 2008.

connects with the Platte pipeline that runs due east to Wood River, Ill.[7] The existing pipeline infrastructure for Canadian crude, including those discussed thus far, appear in Fig. 4 as solid black lines.

Several projects have been proposed and are under way to expand the distribution of heavy Canadian crude further in the US, with an estimated 1 million b/d of pipeline capacity anticipated by 2011.[7]

Key projects include construction of TransCanada's 435,000 b/d Keystone line from Hardisty to Wood River and Patoka by 2010, with a subsequent extension to the US Gulf Coast by 2013. A major expansion of Enbridge's main trunkline, the Alberta Clipper project, is under way from Edmonton to Superior, Wisc., as well as an extension southwards from Superior to Flanagan, Ill., which is labeled the Southern Access Expansion and Extension project.

Extensions of the Enbridge system to the US East Coast and to the US Gulf Coast have also been proposed, the latter delayed by a short-term outlook for oil sands development due to rising costs and regulatory delays. Enbridge has proposed an interim project to reverse its pipeline sections between Portland, Me., and Sarnia, Ont., which would enable shipment of Canadian heavy crude oil down the US Atlantic Coast to the US Gulf Coast.[9] Discussions are ongoing about the timing and market viability of the proposed project.

Enbridge also has a project under way to transport diluent from Flanagan to Edmonton in order to address the demand for condensate among Canadian heavy crude producers.[7] Ongoing and proposed Canadian crude pipeline projects appear as dashed blue lines in Fig. 4.

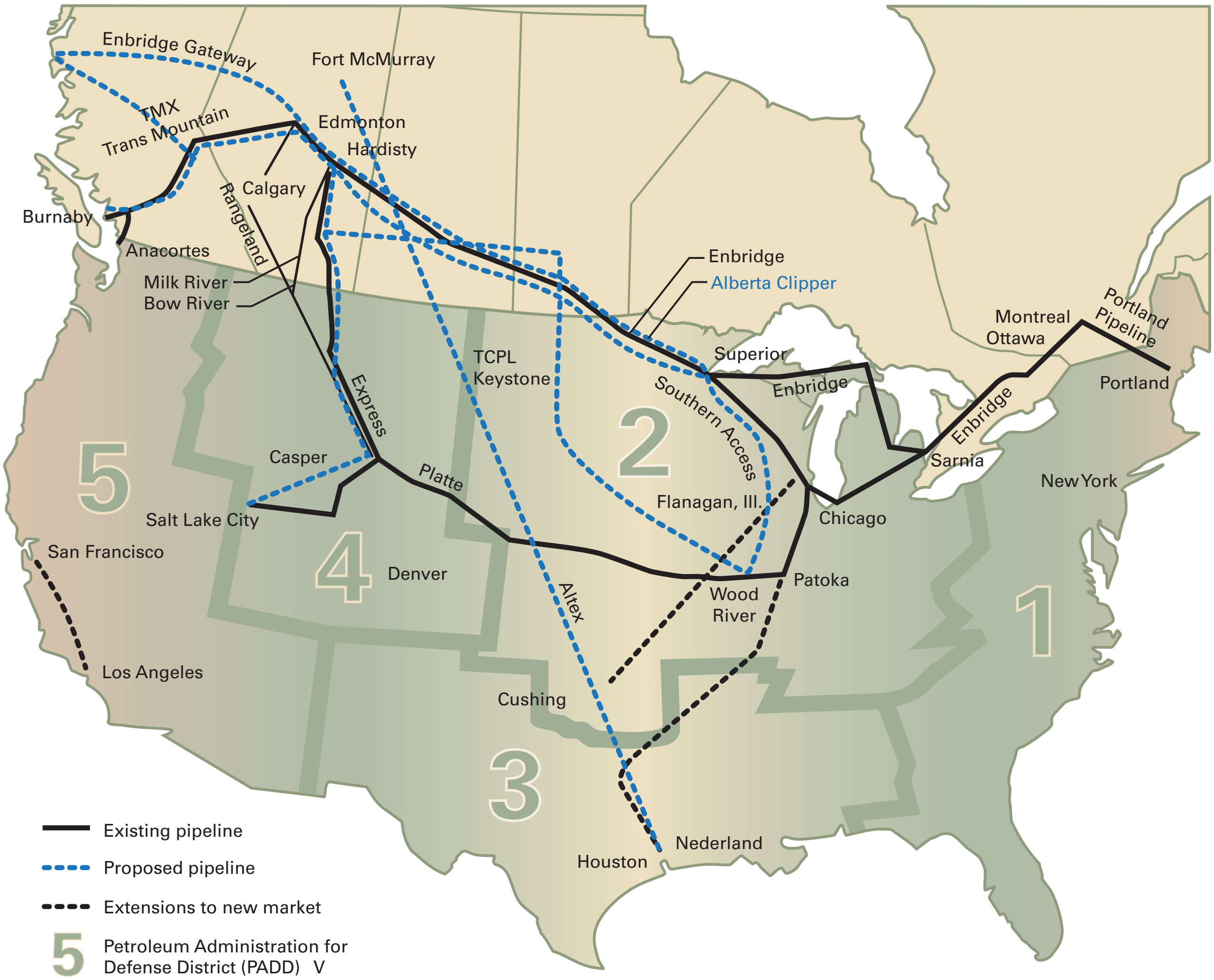
In August 2008, Enterprise Products Partners LP, TEPPCO Partners LP, and Oiltanking Holdings Americas Inc. announced a joint venture to develop a massive offshore crude oil receiving terminal labeled the Texas Offshore Port System (TOPS) in order to meet increasing demand for US crude imports, in particular at regional Gulf Coast refineries of which some are slated for major expansions.

In April 2009, Enterprise and TEPPCO announced their dissociation from the project citing disagreements with Oiltanking.[10] Despite this development, Oiltanking remains interested in developing the proposed terminal, which has an anticipated capacity of 1.5 million b/d of crude (nearly 15% of current US crude oil imports) and was scheduled to start up in late 2010.

In January 2008, Sempra announced plans to develop a 500,000-b/d marine terminal near Port Arthur, Tex., for crude oil, LPG, and refined products.[11] In October 2008, Valero signed a memorandum of understanding with Sempra with the intention of becoming a major recipient of crude oil at the proposed terminal and also to assist with marketing efforts to third parties and develop connecting pipelines from

CANADIAN, US CRUDE OIL PIPELINES

Fig. 4



Source: "Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018," Fig. 2.16, pp. 2-26, Energy Resources Conservation Board, June 2009

the terminal.[12]

These announcements, as well as the ongoing expansions of Canadian heavy crude pipelines, underscore the increasing US dependency on foreign crude oil and represent essential infrastructure developments that are needed to keep pace with the anticipated long-term growth in demand for crude oil imports.

Effects on US refining

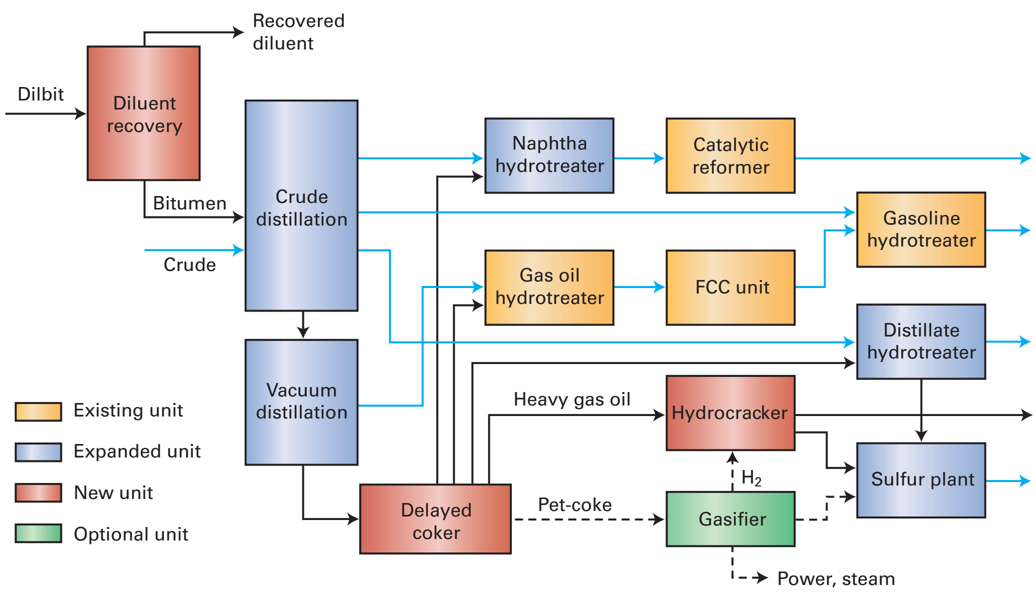
The steady increase in crude oil prices between 2000 and mid-2008 has been a key demand driver for the increased use of heavy Canadian crude and bitumen blends in US refineries, as refiners sought to take advantage of the substantial price differentials between heavy and light crude oils. With the increasing emphasis in the US on the security of energy supply, the stable political relations with Canada have served to support this trend.

Increasing investment in production in the oil sands region and pipeline infrastructure to transport Canadian heavy crude to the US Midwest has been accompanied by announcements of refinery expansion projects in the US Midwest to process heavy Canadian bitumen blends. These projects include Marathon's Detroit refinery (80,000 b/d heavy oil processing capacity after expansion),[13] BP's Whiting, Ind., refinery (260,000 b/d heavy oil),[14] and ConocoPhillips's refineries in Borger, Tex., and Wood River (total of 550,000 b/d heavy oil consisting of 275,000 b/d bitumen).[15] While these projects are still under way, a few have been scheduled for a later completion in response to current market conditions.

In 2007, Husky Energy, a Canadian energy company and oil sands producer, purchased Valero's Lima, Ohio, refinery with the intention of ultimately modifying it for heavy Canadian crude.[16] In December 2007, Husky Energy also announced an alliance with BP that included a retrofit of BP's Toledo,

REFINERY UPGRADES TO PROCESS DILBIT*

Fig. 5



*With delayed coking.

Ohio, refinery to run on bitumen.[17] Hyperion Resources is going through the permitting process as a part of its plan to develop a $10 billion, 400,000-b/d grassroots refinery in South Dakota based on heavy Canadian crude.[18]

In 2008, Valero announced that it has secured capacity on the proposed Keystone XL pipeline extension to the US Gulf Coast and would be expanding and modifying its Gulf Coast refineries to process heavy Canadian crude in 2012.[19]

These developments highlight the growing market for Canadian oil sands-derived crude and bitumen in the US refining industry.

The modifications required to enable a refinery to process heavy Canadian crude will depend on several factors, such as existing refinery configuration, characteristics of the heavy crude to be processed, and desired refined product mix. For simplicity, this article will focus on bitumen blends, particularly dilbit, which continues to be of great interest to the US refining industry due to its relative price discount to conventional light crude. Dilbit is a mixture of bitumen diluted with light naphtha (or condensate).

It is noteworthy that due to condensate shortages in Alberta, the market share of other bitumen blends and synthetic crudes such as synbit (bitumen diluted with synthetic crude) and Western Canadian Select (WCS) has increased slightly in recent years, but the development of condensate-return pipelines from the US to Alberta such as the Enbridge Southern Lights project may serve to reverse the trend.

While it is technically viable and proven to upgrade bitumen in Alberta to synthetic crude oil for subsequent transportation to US for refining, it is worth noting that the economics of transporting the bitumen directly to US refineries (that are near or connected to Canadian crude pipeline systems) for upgrading and processing can be competitive and potentially superior.

A major modification is typically required to enable a refinery to process bitumen blends such as dilbit. The first step to consider is the recovery of diluent from the bitumen blend before processing, which is an economic decision based on the market value for the condensate and the infrastructure available to transport it to the end market, be it for reuse as a diluent for bitumen or as a petrochemical feedstock. Diluent recovery from dilbit is technically straightforward and accomplished with atmospheric distillation.

The upgrading of bitumen to lighter product streams that are amenable to conventional refinery processing is the central step in adapting a refinery to process dilbit. Two predominant upgrading approaches have been pursued commercially: delayed coking and resid hydroprocessing. Both approaches involve the use of a vacuum column on the front end to recover light fractions, resulting in a heavy vacuum residuum that is then upgraded.

US refiners that have announced modification projects to process heavy Canadian crude have favored the delayed coking approach to bitumen upgrading. This can be largely attributed to the fact that delayed coking is commercially proven and widely used in US refineries and has a lower perceived technical risk.

In this approach, the vacuum residuum is processed in a coker unit to recover the lighter fractions that can be fed to conventional refinery units; the by-product is solid petroleum coke ("pet-coke"). This pet-coke is often stockpiled but is a good feedstock for gasification to produce hydrogen, steam, and power for the refinery.

Refinery expansion projects that use the delayed coking route to bitumen processing typically require a subsequent hydrocracking step to upgrade the heavy coker gas oils into distillate-range products. This typically involves construction of a new hydrocracking reactor (unless spare hydrocracking capacity is available), which also gives the refinery more operating flexibility with regard to production of distillate vs. gasoline. Fig. 5 provides a simplified overview of the typical refinery configuration changes that can be expected when the delayed coking route to bitumen upgrading is selected.

In the resid hydroprocessing approach, the heavy vacuum residuum is typically upgraded in two steps: a severe hydrocracking step in an ebullated bed that cracks the residuum into lighter fractions, and a hydrotreating step that reduces the sulfur and nitrogen to acceptable levels.

The resid hydroprocessing bottoms are typically sent to a solvent deasphalting unit to remove insoluble asphaltenes. The asphaltenes stream is typically not conducive to further refinery processing and is either sold as or blended into low-end refined products or ideally gasified to produce hydrogen, steam and power for refinery use. The gasification option is especially attractive due to the significant hydrogen requirements for resid hydroprocessing as well as for desulfurization of the refined product streams and is discussed later in this article.

The resid hydroprocessing route has been chosen for upgrader projects in Alberta, but it is yet to be selected for bitumen upgrading in US refinery projects.

Refinery units that are typically added or expanded as a part of a refinery expansion project in order to enable the processing of heavy Canadian crude are:

- Diluent recovery unit.
- Crude and vacuum units.
- Delayed coker.
- Hydrocracker.
- Hydrogen plant(s).
- Distillate hydrotreater.
- Naphtha hydrotreater.
- Sulfur plant.

The addition and expansion of these units will result in an increase in the Nelson's complexity index for the refinery, which is a measure of its ability to convert heavy crudes into light products and generally translates to increased refinery profitability.[20] The upgraded refinery will have increased requirements for utilities such as hydrogen, steam, and power, which can be generated on site or imported over-the-fence, depending on the relative economics.

These additional utility requirements, however, will increase the greenhouse gas footprint of the refinery due to the incremental CO_2 emissions from fuel combustion to meet the increased power and steam requirements and from increased process CO_2 emissions when steam-methane reformers are used to satisfy the incremental hydrogen demand.

Recent regulatory[21 22] and legislative[23] developments in the US in support of curbing GHG emissions from manufacturing facilities may eventually pose a barrier to future refinery expansions, particularly those based on heavy crude.

The use of cogeneration to increase the efficiency of steam and power generation can help offset a portion of the incremental GHG from refinery expansion projects. Cogeneration units can be integrated with either conventional hydrogen plants or gasification units to realize additional efficiency benefits.

The possibility of the integrated, on site generation of hydrogen, steam, and power is particularly attractive due to the potential for gasification of the residuals from the refinery processing of heavy Canadian crudes and is described in more detail in the following section.

Gasification

The increasing need for hydrogen, both to process heavier crude oil and bitumen with greater sulfur content and to produce cleaner fuels, is a key driver for petroleum refining-based gasification systems. Other factors include the increasing uncertainty in natural gas prices, reducing the generation of waste, and improving efficiency.

As of January 2008 the US Environmental Protection Agency considers gasification to be a production or manufacturing operation rather than a hazardous-waste management activity,[24] while in April 2009 EPA proposed a new rule for mandatory greenhouse gas reporting.[21]

Gasification is the chemical conversion of any carbonaceous fuel into a mixture of carbon monoxide and hydrogen known as synthesis gas through an exothermic reaction of the fuel with oxygen or steam at elevated temperature.

Additional hydrogen can be recovered through a water-gas shift reaction of the carbon monoxide with steam leaving a stream of concentrated CO_2. Another option is to use some or all of the synthesis gas and steam produced for electric power generation.

Commercialization of the gasification process began more than 50 years ago with most applications supporting the production of chemicals or liquid fuels.[25]

Several vendors, such as Shell, General Electric, ConocoPhillips, and Sasol-Lurgi, provide commercial-scale gasification technologies,[26] and hundreds of commercial gasifiers currently operate around the world.[27] All the commercial gasification technologies recover heat from the gasifier through steam production.

Gasification of refinery by-products of low or negative value allows conversion of these by-products into hydrogen, steam, or electric power. In many cases, a concentrated stream of CO_2 is produced that can be captured for potential use, such as in enhanced oil recovery or for sequestration.

Petroleum coke or asphaltenes produced during the upgrading of bitumen as well as coke and heavy residuals from other refining units are well suited for gasification. Due to its ability to process refinery streams as feedstock and generate products that can be consumed in refinery units, a gasification unit naturally lends itself to integration within a refinery.

To date, several US refineries currently operate gasification units, including those in Delaware City, Del.; Baytown, Tex.; and El Dorado, Kan.[25] Although a

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discussion of how petroleum refining fits into the GHG puzzle is provided in more detail elsewhere,[28] the potential integration of gasification is a promising avenue to manage the GHG footprint in refineries that process heavy crude oil. ✦

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Zulia, Venezuela

Storage

Improved ultrasonic (UT) inspection methods address storage tank integrity monitoring and assessment without removing tanks from service. By acquiring large amounts of high-density UT data and evaluating them with readily available analysis tools, inspectors can now provide tank owners and regulators with insight into the integrity of above-ground storage tank (AST) floors not otherwise available.

Electronic advances over the past 5 years have improved floor inspection of ASTs by in-service robotic technology, yielding not only better inspection and tank cleaning abilities, but greater operational efficiency and a broader user base. The number of tanks inspected with in-service robotics now exceeds 1,000. Inspections can now occur without the tank being taken out of service.

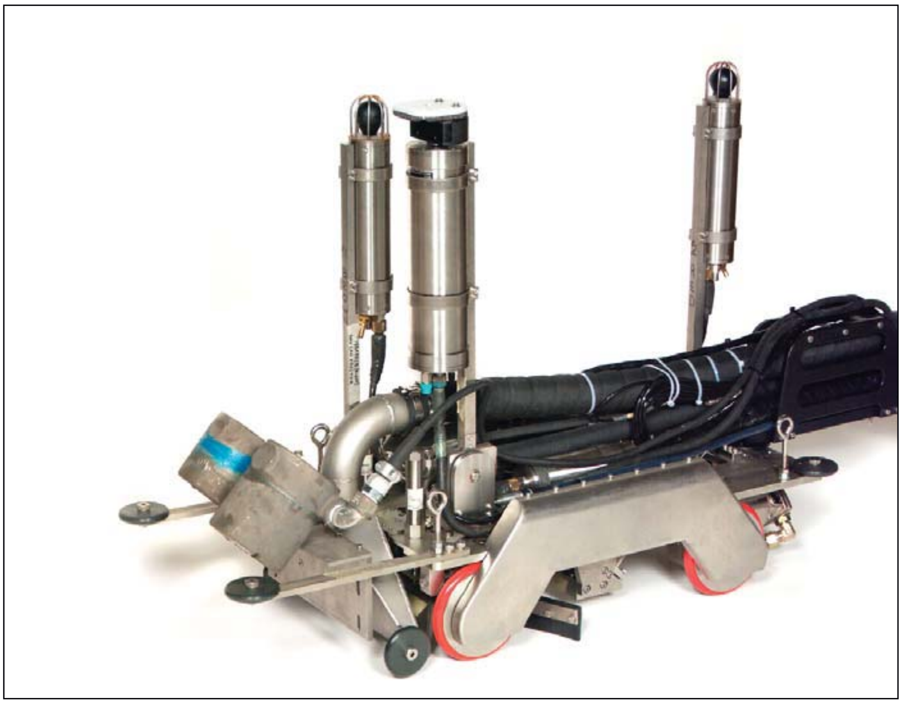
Compliant with API Std 653 (Ref 1) guidelines for determining tank floor corrosion rates and when combined with an API 653 tank external survey, TechCorr, Houston, uses in-service robotics with high-density ultrasound scanning to give tank owners a full picture of AST condition without removing the tank from service and while staying in compliance with tank inspection requirements.

Some tanks require out-of-service inspections because of their condition, age, and inspection history, but a growing population of tanks will benefit from this technology, especially given current demand for storage capacity and difficulty in removing a tank from service for full inspection.

This article discusses specific technical capabilities for use of in-service, high density, ultrasound scanning to assess the condition of AST floors. It will also cover safety, environmental risk reduction, and cost savings.

Conventional inspections

Conventional tank inspection requires an operator to clear the tank



An in-service AST robotic floor scanner can remove water and sediment from the tank floor to take thickness readings and gauge corrosion (Fig. 1).

completely of product and vapor. Product drains first through fixed lines and then temporary lines to remove most of the volume. Squeegees, diesel diluent, and water frequently serve as means for removing residual product. Fans, sometimes in conjunction with vapor-recovery burning equipment, occasionally enter service to remove tank vapors. Once the tank is vapor free, its floor is prepared for inspection, often by sand blasting.

A variety of techniques including magnetic flux exclusion (MFE) and contact ultrasound testing (UT) inspect the tank. Crews then make any necessary repairs, reseal the tank manways, and return the tank to service. The entire process may take 1 week to 6 months depending on tank size, product, plant and contractor schedules, and scope of repairs.

Robotic inspections

The robotic process for tank inspection uses a robot tethered via an umbilical to an advanced control and monitoring system. The robot (Fig. 1) descends to the tank bottom while the tank is in service and navigates across its floor using a system capable of mapping locations where high-density UT data are collected. Robot location accuracy is ±2 in. A pump mounted behind the robot removes water and sediment from the tank floor, and a series of immersion transducers under the robot take UT thickness readings on the tank floor to identify both top-side and bottom-side corrosion.

Inspectors can at the same time conduct a traditional API 653 external tank survey and combine the results in an inspection report satisfying API 653 guidelines. Any repair work can be scheduled in the future and competitively bid to reduce repair expenses and plant disruption. The benefits of the robotic process include:

- Reduced project planning. Keeping the tank in service during inspection eliminates scheduling difficulties. Planning also requires fewer internal resources and contractors since the project is simpler.
- Reduced safety, environmental risks. Keeping product in the tank removes the need to vapor-free it or place personnel inside it.
- Deferred tank repairs. Delaying repairs until the optimal year allows reduction of costs and disruption.
- Maximized asset lifecycle. Establishing a database on the lifecycle and reliability of the floor allows for more frequent monitoring than is practical with conventional process.

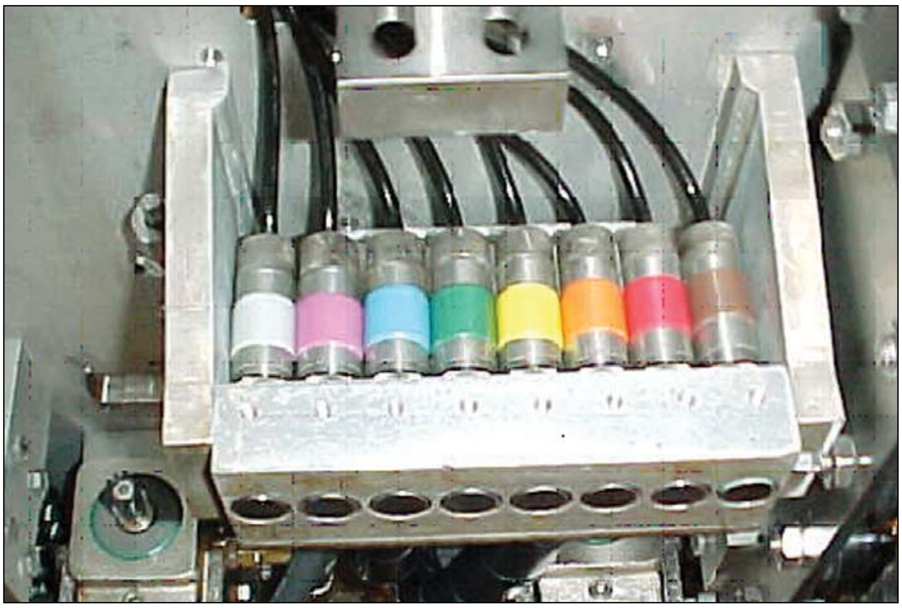
The accompanying table compares and contrasts the two tank inspection strategies.

Inspection strategy comparison

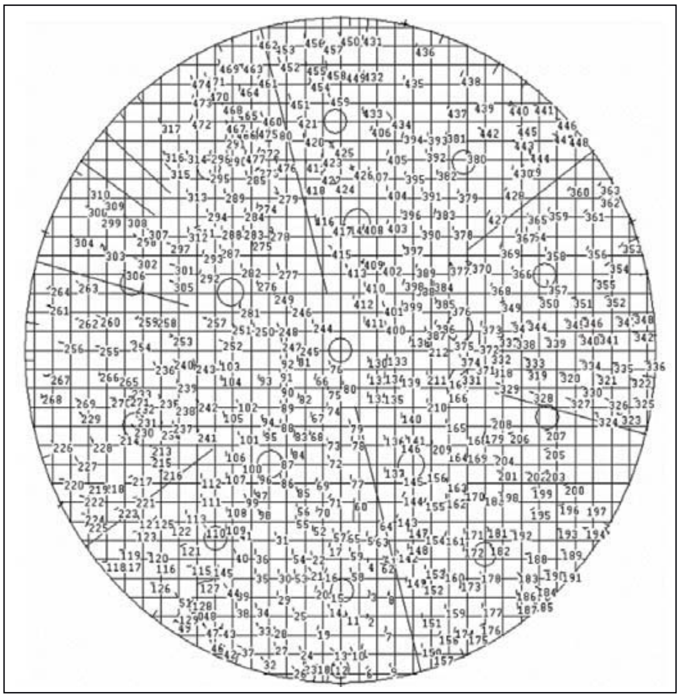
Conventional inspection	In-service robotic API 653 bottom inspection
Tank has to be drained and cleaned. Waste has to be collected, treated, and disposed.	Tank can remain operational and full of product.
Turnaround and tank outage planning required.	Scheduling is on as-needed basis.
Continuous oxygen, toxicity monitoring, and hole-watch required.	Confined air space entry is 0 hr for fixed roof; 4-8 man-hr for floating, internal floating roof
Alternate storage a factor.	Need for alternate storage eliminated.
Tank has to be degassed and vented.	Tank air emissions near zero.
Spot inspections, limited surveys not cost effective.	Spot inspections, routine limited surveys possible.
Typical tank survey consists of visual, magnetic flux leakage, and UT survey of discrete UT data points.	Ultrasonic survey automated; able to record more than 15,000 discrete UT data points/hr.
Can save data in A, B, and C scan formats and differentiate and quantify top-side and bottom-side corrosion.	Can save data in A, B, and C scan formats and, in most instances, differentiate and quantify top-side and bottom-side corrosion.
Extent of repairs unknown until outage.	Based on survey, tank repairs can be projected with materials and services preplanned, reducing turnaround.
Commissioning and refill required.	No refill required.

Deployment methodology

Typical robot deployment necessitates finding the equipment control room and associated utilities adjacent to the tank within the berm area. The deployment process usually requires one or two crane lifts to the top of the tank. Equipment at the top of the tank consists of the submersible vehicle and umbilical, pumping systems, and in-tank deployment gear. The vehicle enters through the roof's top manway



The robotic floor scanner typically uses eight 5-Mhz transducers for tank inspections, making 6,000-10,000 readings per tank plate (Fig. 2).



Inspection of a typical 100-ft diameter tank floor would yield an ultrasonic testing data distribution similar to the one pictured here (Fig. 3).

(≤24-in. diameter). A 350-ft (107-m) umbilical supports vehicle operation.

While readying the system for deployment from the top of the tank, the crew locates tank navigation transducers at their proper locations around the tank, entering these locations, as well as the position of all other tank appurtenances, into a computer-assisted drafting (CAD) system.

A video recording by the on-board camera during deployment ensures proper positioning onto the tank bottom. Accurate drawings are sometimes unavailable, requiring special procedures to accurately plot various objects—roof supports, inlet and discharge pipes, sumps, and related internals—within the tank. Once the CAD drawing is properly annotated and the vehicle properly positioned, the vehicle is ready for floor scanning. A camera deployed through the manway records the condition of roof structures and degree of corrosion, if present.

UT methodology

Before recent improvements, a typical UT run consisted of capturing data from all eight transducers every 0.16 in. (0.4 cm) while the vehicle travelled in a straight path for 6.56 m, providing roughly 1,200 A scans, converted into B scans for each individual run. Data were collected, analyzed, and reported. New ultrasonic systems use real-time data streaming for continuous UT thickness surveying throughout the tank rather than simply by performing one run on each plate. A standard tank plate now may get 6,000 to 10,000 readings.

Fig. 2 shows an in-service robotic immersion transducer. Most tank inspections use eight 5-megahertz (Mhz) transducers.

Fig. 3 shows the distribution of UT data in a typical 100-ft tank without obstructions (other than legs, inlet, and suction lines). Thickness measurements are loaded into a spreadsheet that checks the B scan data limits. Proprietary signal processing software highlights any location with a measured thickness less than a predetermined value, which are then reviewed by an analyst. This review determines the cause of the low thickness measurement. Causes could include actual component thinning, gate error, loss of signal, sludge-sediment, or the vehicle running over a weld seam.

This technique can acquire a wide range of UT data points, usually between 50,000 and 1.5 million UT readings/tank, depending on tank size and inspection strategy. These readings, taken throughout the tank, include the critical zone around the shell.

Manually reviewing this volume of data is not practical. Fig. 4 is the data analyst display providing the automated results of UT A-Scan—B-Scan analysis. An analyst can investigate minimum thickness thresholds detected by UT analysis software.

UT, EVA

Although 100% robotic inspection is possible in principle, it may be neither economical nor necessary. Most inspections measure thickness over a fraction of the floor and then estimate minimum floor thickness using extreme value analysis (EVA). This technique, used throughout the inspection industry, often is applied for inspection of pipelines, on which 100% coverage is impractical and unnecessary. Some tank owners also use EVA statistics when they evaluate out-of-service floor UT data following MFL scans.

In-service inspections seek to establish an acceptable time interval for the next internal floor inspection. Meeting this requires obtaining an accurate assessment of the deepest pitting. EVA statistics can make this estimate from inspection of only a small percent of the tank floor area and is widely used in many applications of corrosion monitoring. Using EVAs requires a number of assumptions, a discussion beyond the scope of this paper.[2,3]

Presuming the inspection plan meets requirements for application of EVA, data need to be collected from only a small percentage of the tank floor. Results of field tests and more than 20 independently monitored validation studies demonstrate that a small population sample of the tank floor can provide satisfactory results.[4]

The proper amount of tank scanning depends on the nature and amount of corrosion. The tank operator will consider these factors as well as risk tolerance when selecting the amount of scanning. For example, a quick preliminary robotic survey could determine the amount of coverage desired. Such surveys give a good qualitative indication of the general condition of the tank floor. Completing data analysis while the robot is still in the tank can identify and accommodate areas where supplementary data would be useful.

Defect identification

On stream inspections also seek to identify a range of plate defects in addition to plate thickness. Although a lack of sufficient clarity usually prohibits direct visual examination, topside and bottom-side corrosion can be indirectly classified, laminated plate identified, and coating failure detected.

Topside, bottom-side

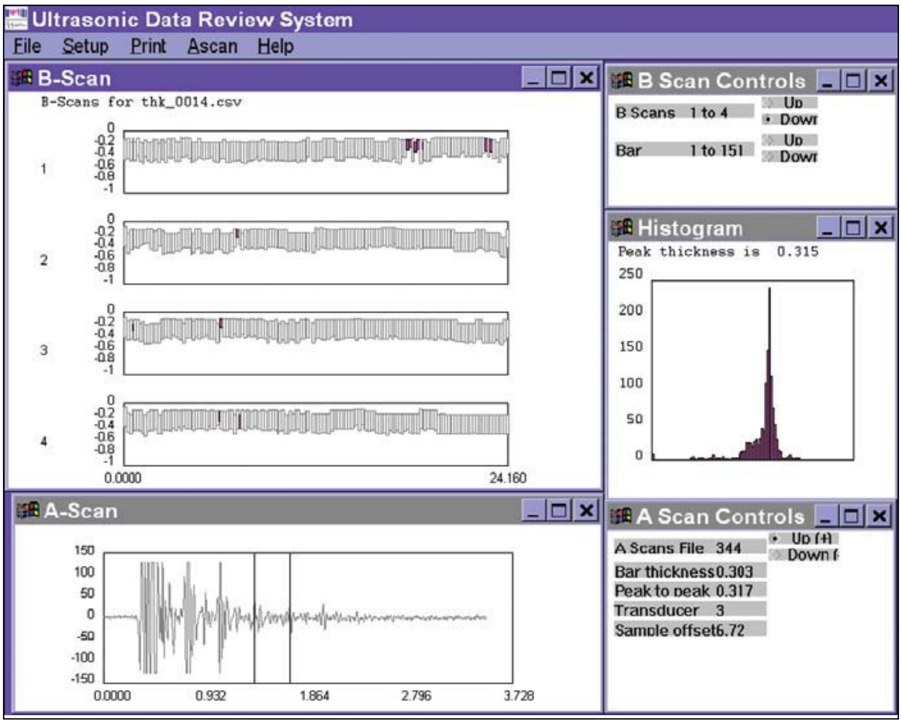
Examining the series of returns before and after the flagged return can discriminate topside from bottom-side corrosion. When the front face, the first discernable return from the plate, remains steady on the x-axes (time) while the second discernable return on the time axes moves toward the first return, the thinning is most likely due to bottom-side pitting. On the other hand, if the front return moves along the x-axes toward a fixed second return, then the thinning is probably due to topside pitting.

Measuring the distance between any two discernable peaks always determines the degree of thinning. Signal analysis software assists in classification. Noticeable dips on the top of the B scan UT display or gaps on the underside of the B-scan display show areas of possible topside or bottom-side pitting, respectively.

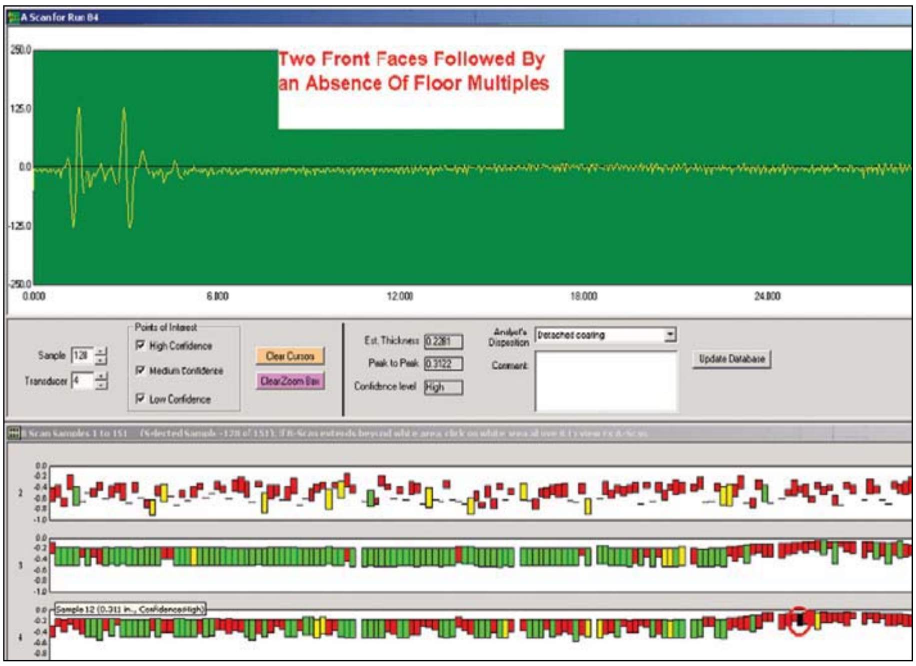
Lamination

Laminations are usually defects inherent in tank floor steel, created during fabrication. They usually appear mid-wall and are characterized as UT A scan returns measuring 50% of total peak-to-peak distance of the nominal plate. These mid-wall defects usually prove difficult to detect with qualitative scanning techniques but can be identified with high-density UT by the monitoring of abrupt changes from near nominal peak-to-peak values to values close to 50% of nominal.

Laminated areas can occupy anything from small plate areas (i.e., a few sq cm) to large plate areas (i.e., 1 sq m). Lamination is common but in most cases does not pose any serious tank-floor integrity threat unless found at a weld or in the critical zone adjacent to the shell-to-floor weld.



This data analyst interface shows both A-scan and B-scan data, providing a histogram to show metal loss found as part of a particular run (Fig. 4).



This analyst display shows the A-scan UT image of a coating failure. UT scanning is required unless the tank environment is clear enough to allow direct visual inspection (Fig. 5).

Coating failure

Unless the tank's contents allow for direct inspection of a surface via camera, the UT analyst must depend on knowledge of UT to detect separation between the steel and the coating. Coatings in this instance refer to a direct layer of epoxy or a thick material liner (such as fiberglass resin). When a coating failure occurs, UT returns (pulse-echo modes) are scattered, making thickness measurements impossible. Pockets of air or gas occupying the space between the lifted coating (or liner) and the steel floor usually cause these returns. When detected adjacent to plate characterized by clear UT returns, however, with sufficient signal-to-noise ratios for peak-to-peak measurements, they likely reflect areas of coating failure.

Fig. 5 shows an A-Scan image of coating failure.

Life calculations

The in-service inspection seeks to establish parameters quantitatively to set the next internal inspection. Documents such as API 653 typically use bottom condition, corrosion rate, and thinnest remaining steel as governing parameters. Robotic in-service inspection provides these data. Inspection and statistical data analysis also provide minimum remaining metal estimates, with the corrosion rate computed from this information.

The tank operator can also use inspection data to estimate how much longer the tank can remain in service before a bottom leak. Some codes and regulations may specify a non-zero minimum remaining bottom metal thickness for operations. The operator can use in-service data to make an informed, quantitative decision regarding the appropriate schedule for out-of-service inspection and repair. In-service floor UT data also improve the effectiveness of risk-based inspection programs.

The industry uses RBI programs to focus resources on important components in process facilities. An RBI analysis assesses both the probability and consequences of failure. Results can prioritize inspections within a plant and select appropriate inspection methods for the most probable modes of failure.

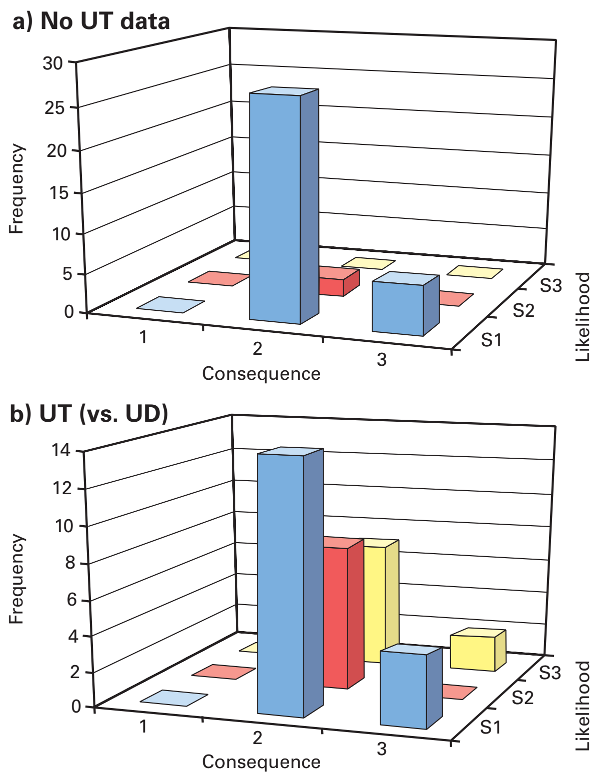
The important feature of RBI analysis as it relates to UT scanning of tank floors is the added level of confidence available for determining degrees of risk using accurate, quantifiable UT floor-thickness data, removing some of the ambiguity previously associated with risk-based assessments. Indirect, risk-based assessments of tank floor conditions can now be verified and augmented with reliable direct measurements.

Fig. 6 shows results of a 35-tank analysis, including RBI results with and without high-density tank floor UT data. The results support the benefits of using actual floor UT data in risk-based studies to improve forecasting of the appropriate next internal inspection interval.

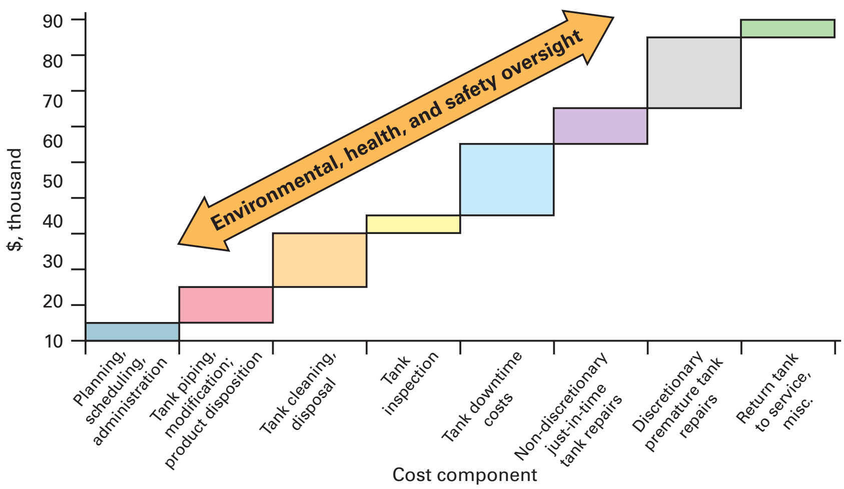
Robotic cleaning

Cleaning ASTs conventionally typically requires a great deal of manpower, equipment, and time out of service. In-service robotics reduce manpower

RISK-BASED INSPECTION TANK-FAILURE LIKELIHOOD Fig. 6

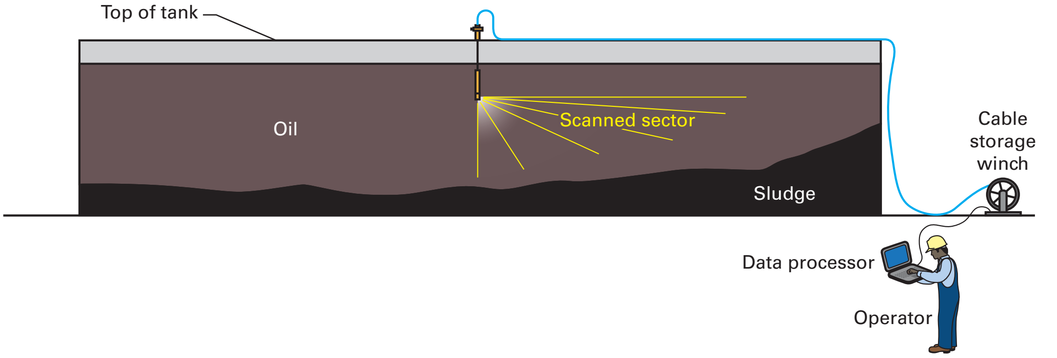


OUT-OF-SERVICE INSPECTION COST COMPONENTS Fig. 7



Tank sludge, acoustic measurement

Fig. 8



and equipment requirements and eliminate time out of service. The robotic system can use a variety of pumps to pump sludge and sediment into awaiting containers for disposal. Depending on the sediment level, inspection can occur during cleaning, eliminating the equipment needed for an out-of-service cleaning.

Economic effect

In addition to safety and environmental benefits, in-service tank inspections offer cost benefits compared with out-of-service methods. Out-of-service inspections have difficulty controlling both visible and hidden costs.

Visible costs consist of payments directly to contractors for cleaning, inspecting, waste disposal, and repair. Indirect, hidden costs, however, usually dwarf direct expenses. Traditional inspection methods require extensive planning by the operator and multiple contractors before scheduling, typically pulling time from internal resources involved in engineering, supply, scheduling, safety, and tank operations.

Product and vapor freeing the tank also has hidden costs. Owners frequently incur costs for transferring and downgrading product in preparation for cleaning, sometimes building temporary lines to move product from the tank. Tank-heel disposition often also results in hidden costs, as otherwise saleable product becomes intermingled with water and sludge.

Once a tank is out of service, the operator may also incur supply-related costs associated with downtime: higher shipping costs for smaller inbound lots, transportation costs for two-porting ships or rerouting trucks, and production effects due to reduced storage capacity.

At most companies the full cost of tank cleaning and inspection spans multiple cost centers and there is no one person who accounts for all of the costs associated with the entire process for even one tank. For example, engineers know the cost of inspecting the tank, but only traders know the costs of securing an alternative source of product. And while the operator is aware of incremental trucking costs incurred while the tank is down, only the engineer knows the true incremental cost for emergency versus competitively bid tank repairs.

Fig. 7 depicts the total system cost associated with the tank cleaning, inspection, and repair process. The industry standard process of opening, cleaning, and inspecting an AST is at times followed by hurried repairs to the AST. Repairing an AST on an emergency basis when it is already out-of-service is expensive and operationally disruptive to the facility.

Waiving the standard bidding process is typical to avoid lengthy out-of-service time for the tank. At the same time, vendors charge a premium to complete the work as quickly as possible. In addition to paying a premium for tank repair, most tank owners conduct tank repair work years before it is required to prevent taking the tank out of service again. Many repairs are also done earlier than warranted so that they can be completed while the tank is out of service, forcing the operator to accelerate deferrable costs into the current budget cycle.

In-service inspections allow tank operators to avoid emergency repairs during API 653 inspection by determining the scope of repairs before removing the tank from service and competitively bidding the work and ordering of required materials

By waiting until the optimal time for tank repairs, the operator also extends the asset's useful life and defers associated capital or expense dollars into a future year.

Sludge measurement

The acoustic inspection system measures the volume and topology of sludge sediments in the bottom of liquid storage tanks.

The system includes an ATEX inspection tool inserted into the tank through a suitable access hole in the roof until fully submerged in the liquid. The end of the tool has an angled phased array producing acoustic beams to scan a sector of the tank floor and wall (Fig. 8).

PC-based data acquisition produces a three-dimensional display of the sediment layer and calculates the volume of sediment using the known geometry of the tank. Sector data from multiple entry points can be combined to give 100% coverage of the tank floor. ✦

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Services/Suppliers

Transocean Ltd.,

Zug, Switzerland, has named Ihab Toma senior vice-president, marketing and planning. Based in Geneva, Toma will be responsible for marketing and planning for the company's fleet of 133 mobile offshore drilling units worldwide. He will also oversee Transocean Solutions, which offers clients a complete package for well construction and field development needs, and two company subsidiaries, Applied Drilling Technology Inc. and Challenger Minerals Inc. Previously, Toma served at Schlumberger, including product line president and various other oil field services assignments, with regional and global responsibilities in a number of countries. He has a bachelor's in electrical engineering from Cairo University.


Toma

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

Weatherford International Ltd.,

Houston, has completed its purchase of Secure Drilling. This follows the Jan. 1 announcement that it had entered into a joint venture agreement with Impact Solutions Group Ltd. for a 50% stake in Secure Drilling. The merger combines Secure Drilling's patented Micro-Flux technology with Weatherford's managed pressure drilling systems.

Weatherford is one of the largest global providers of innovative mechanical solutions, technology, and services for the drilling and production sectors of the oil and gas industry.

Honeywell International,

Morris Township, NJ, has signed a definitive agreement valued at about $400 million to acquire Kassel, Germany-based RMG Group and its subsidiaries. The deal is subject to regulatory approvals. RMG will be integrated into Honeywell Process Solutions. The acquisition will build Honeywell's presence in the areas of natural gas transportation, storage, distribution, and industrial consumption.

RMG specializes in the design and manufacture of natural gas control, measurement, and analysis equipment, including flow metering technology, regulating products, and safety devices for oil and gas companies.

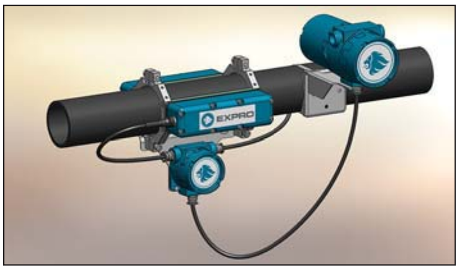
Honeywell Process Solutions is part of Honeywell's Automation and Control Solutions group, a global leader in product and service solutions that improve efficiency and profitability, support regulatory compliance, and maintain safe, comfortable environments in homes, buildings, and industry.

Aker Solutions ASA,

Oslo, has opened its modernized and expanded manufacturing facility for surface trees and wellheads in Batam, Indonesia. Aker invested $17 million in the project, designed to hike manufacturing capacity at Batam by more than 50%.

Aker is a leading global provider of engineering and construction services, technology products, and integrated solutions serving the oil and gas, refining and chemicals, mining and metals, and power generation industries.

Equipment/Software/Literature



Clamp-on meter designed for upstream flow operations

ActiveSONAR clamp-on sonar meters are specifically designed to address flow rates and heavy schedule piping in upstream operations.

The new meter uses pulsed-array sonar technology. The nonintrusive, clamp-on design enables units to be deployed on new or existing installations and inherently lowers technical risks and operating costs, the company says.

The combination of ActiveSONAR and PassiveSONAR technology provides clamp-on well flow surveillance specifically designed to address a range of wellhead production and injection surveillance applications.

Source: **Expro Meters, c/o Expro International Group Ltd.,** Davidson House, Forbury Square, Reading, RG1 3EU, UK.

24/7 physician access serves offshore health needs

InPlace Medical Solutions, an offshore medical service using video telemedicine, has secured physician staffing for 24/7/365 via video telemedicine for its clients.

The company says services are provided by emergency medicine and internal medicine physicians who are board certified by the American Board of Emergency Medicine or the American Board of Internal Medicine.

eCareGroup PLLC, an independent physician group based in Houston, has developed a team of physicians—all experienced in video telemedicine—to provide services to offshore and remote locations. The eCareGroup physicians provide offshore care through InPlace Medical Solutions' video telemedicine systems whenever needed regardless of time of day. To maximize availability, eCareGroup's doctors follow the premise of the nondistracted provider—meaning they have no other duties when providing this service. eCareGroup is exclusively providing this service to InPlace Medical Solutions.

The eCareGroup doctors are on duty and available 24/7 via live, two-way video conferencing for InPlace Medical Solutions clients. The company says that these doctors stand ready to see patients, diagnose their illness or injury, recommend care and treatment, and prescribe medications when required.

InPlace Medical Solutions' delivery model is designed to place resources on internet-enabled offshore rigs and remote facilities: specially qualified medics from the eCareGroup, advanced equipment, medical-quality video conferencing, and an electronic medical record system.

Source: **NuPhysicia LLC,** 4625 Southwest Freeway, Suite 1423, Houston, TX 77027.

Imports of crude and products

	Districts 1–4 7–24 2009	Districts 1–4 7–17 2009	District 5 7–24 2009	District 5 7–17 2009	Total US 7–24 2009	Total US 7–17 2009	Total US *7–25 2008
	1,000 b/d						
Total motor gasoline	963	1,015	28	11	991	1,026	965
Mo. gas. blending comp.	657	827	9	11	666	838	830
Distillate	254	252	0	0	254	252	121
Residual	118	221	44	53	162	274	386
Jet fuel–kerosine	48	74	20	19	68	93	119
Propane–propylene	156	86	6	3	162	89	76
Other	103	201	(13)	101	90	302	713
Total products	**2,299**	**2,676**	**94**	**198**	**2,393**	**2,874**	**3,210**
Total crude	**8,672**	**8,257**	**1,352**	**946**	**10,024**	**9,203**	**10,005**
Total imports	**10,971**	**10,933**	**1,446**	**1,144**	**12,417**	**12,077**	**13,215**

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

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

OIL&GAS JOURNAL online research center.

OGJ crack spread

	*7–31–09	*8–1–08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	75.44	133.81	–58.37	–43.6
Brent crude	68.32	125.34	–57.02	–45.5
Crack spread	7.12	8.47	–1.35	–15.9
FUTURES MARKET PRICES				
One month				
Product value	78.62	135.90	–57.28	–42.1
Light sweet crude	67.07	124.57	–57.50	–46.2
Crack spread	11.55	11.33	0.22	2.0
Six month				
Product value	78.23	138.05	–59.82	–43.3
Light sweet crude	72.97	126.13	–53.16	–42.1
Crack spread	5.26	11.92	–6.66	–55.9

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

Purvin & Gertz LNG netbacks—July 31, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	6.04	3.84	5.26	3.74	4.60	5.19
Everett	2.73	0.96	2.46	1.06	1.46	2.99
Isle of Grain	2.41	0.62	1.91	0.53	1.11	1.93
Lake Charles	1.00	–0.66	0.82	–0.51	–0.33	1.50
Sodegaura	4.17	5.87	4.42	5.59	4.92	3.56
Zeebrugge	4.69	2.85	4.19	2.74	3.40	4.23

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

Crude and product stocks

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	14,834	56,059	39,136	11,947	67,704	14,144	3,515
PADD 2	83,389	52,559	25,215	7,510	33,455	1,150	27,730
PADD 3	182,586	70,016	37,978	15,695	45,029	14,512	34,254
PADD 4	15,976	6,109	2,107	624	3,431	224	[1]1,642
PADD 5	51,055	28,333	22,996	9,473	12,998	4,691	—
July 24, 2009	**347,840**	**213,076**	**127,432**	**45,249**	**162,617**	**34,721**	**67,141**
July 17, 2009	**342,688**	**215,391**	**129,581**	**44,089**	**160,509**	**36,485**	**66,429**
July 25, 2008[2]	**295,249**	**213,560**	**108,044**	**41,745**	**130,505**	**38,029**	**45,769**

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

Refinery report—July 24, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,395	1,361	2,416	96	447	100	57
PADD 2	3,251	3,232	2,176	232	833	48	274
PADD 3	7,197	7,043	2,630	725	1,977	291	680
PADD 4	587	578	330	31	200	12	[1]56
PADD 5	2,516	2,394	1,425	406	530	139	—
July 24, 2009	**14,946**	**14,608**	**8,977**	**1,490**	**3,987**	**590**	**1,067**
July 17, 2009	**15,169**	**14,779**	**9,236**	**1,458**	**4,052**	**604**	**1,090**
July 25, 2008[2]	**15,336**	**15,162**	**9,045**	**1,592**	**4,724**	**567**	**1,145**
	17,672 Operable capacity		**84.6% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 7-29-09	Pump price* 7-29-09	Pump price 7-30-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	193.5	240.0	403.3
Baltimore	195.6	237.5	394.3
Boston	201.1	243.0	397.3
Buffalo	192.6	253.5	406.9
Miami	206.4	258.0	405.8
Newark	196.4	229.0	387.3
New York	185.2	246.1	399.9
Norfolk	195.6	234.0	386.3
Philadelphia	198.3	249.0	395.6
Pittsburgh	196.3	247.0	393.3
Wash., DC	211.6	250.0	397.9
PAD I avg	197.5	244.3	397.1
Chicago	197.9	262.3	420.2
Cleveland	198.3	244.7	387.1
Des Moines	195.3	235.7	382.1
Detroit	201.3	260.7	397.0
Indianapolis	188.3	247.7	387.0
Kansas City	180.7	216.7	378.1
Louisville	201.8	242.7	390.8
Memphis	180.9	220.7	379.3
Milwaukee	199.1	250.4	396.7
Minn.-St. Paul	194.7	238.7	388.0
Oklahoma City	175.3	210.7	372.2
Omaha	171.4	216.7	385.0
St. Louis	178.7	214.7	381.6
Tulsa	171.3	206.7	370.5
Wichita	176.3	219.7	373.9
PAD II avg	187.4	232.6	386.0
Albuquerque	190.6	227.0	383.0
Birmingham	189.4	228.7	389.7
Dallas-Fort Worth	193.3	231.7	391.8
Houston	190.3	228.7	389.8
Little Rock	186.5	226.7	389.4
New Orleans	193.2	231.6	389.3
San Antonio	196.8	235.2	386.2
PAD III avg	191.4	229.9	388.5
Cheyenne	211.9	244.3	385.9
Denver	210.9	251.3	410.2
Salt Lake City	204.4	247.3	407.3
PAD IV avg	209.1	247.6	401.1
Los Angeles	213.3	280.4	435.4
Phoenix	204.0	241.4	402.4
Portland	219.0	262.4	410.4
San Diego	215.3	282.4	433.5
San Francisco	223.3	290.4	443.2
Seattle	220.5	276.4	419.4
PAD V avg	215.9	272.2	424.0
Week's avg.	**196.4**	**242.0**	**395.8**
July avg.	**205.6**	**251.2**	**405.7**
June avg.	**214.6**	**260.2**	**404.2**
2009 to date	**169.3**	**214.9**	—
2008 to date	**306.2**	**350.0**	—

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

REFINED PRODUCT PRICES

Spot market product prices

	7-24-09 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	186.60
Gulf Coast	183.73
Los Angeles	195.60
Amsterdam-Rotterdam-Antwerp (ARA)	182.01
Singapore	185.10
Motor gasoline (Reformulated-regular)	
New York Harbor	194.48
Gulf Coast	188.35
Los Angeles	205.60

	7-24-09 ¢/gal
Heating oil No. 2	
New York Harbor	177.35
Gulf Coast	175.66
Gas oil	
ARA	180.81
Singapore	180.24
Residual fuel oil	
New York Harbor	152.90
Gulf Coast	155.07
Los Angeles	167.73
ARA	151.86
Singapore	157.98

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

BAKER HUGHES RIG COUNT

	7-31-09	8-1-08
Alabama	2	3
Alaska	5	5
Arkansas	45	56
California	21	43
Land	21	43
Offshore	0	0
Colorado	44	114
Florida	1	2
Illinois	1	1
Indiana	3	2
Kansas	19	13
Kentucky	9	12
Louisiana	140	189
N. Land	87	78
S. Inland waters	8	25
S. Land	13	29
Offshore	32	57
Maryland	0	1
Michigan	0	2
Mississippi	15	12
Montana	0	11
Nebraska	0	0
New Mexico	44	80
New York	2	6
North Dakota	41	71
Ohio	8	13
Oklahoma	75	207
Pennsylvania	46	24
South Dakota	1	2
Texas	347	920
Offshore	2	7
Inland waters	0	1
Dist. 1	14	16
Dist. 2	14	31
Dist. 3	32	66
Dist. 4	25	89
Dist. 5	76	178
Dist. 6	40	128
Dist. 7B	14	31
Dist. 7C	16	72
Dist. 8	55	137
Dist. 8A	13	31
Dist. 9	17	43
Dist. 10	29	90
Utah	17	48
West Virginia	21	26
Wyoming	34	76
Others—HI-1; NV-1; VA-5	7	12
Total US	**948**	**1,951**
Total Canada	**200**	**451**
Grand total	**1,148**	**2,402**
US Oil rigs	261	392
US Gas rigs	677	1,550
Total US offshore	35	67
Total US cum. avg. YTD	**1,105**	**1,836**

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

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

SMITH RIG COUNT

Proposed depth, ft	7-31-09 Rig count	7-31-09 Percent footage*	8-1-08 Rig count	8-1-08 Percent footage*
0–2,500	42	9.5	89	3.3
2,501-5,000	64	67.1	140	45.7
5,001-7,500	119	25.2	245	13.0
7,501-10,000	202	5.4	472	3.1
10,001-12,500	186	9.6	476	2.3
12,501-15,000	130	—	341	—
15,001-17,500	124	—	139	—
17,501-20,000	48	—	92	—
20,001-over	36	—	36	—
Total	**951**	**11.1**	**2,030**	**6.1**
INLAND	13		31	
LAND	899		1,944	
OFFSHORE	39		55	

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

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

OGJ PRODUCTION REPORT

	[1]7-31-09	[2]8-1-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	20
Alaska	649	621
California	638	649
Colorado	60	66
Florida	6	6
Illinois	28	27
Kansas	100	104
Louisiana	1,379	1,323
Michigan	15	16
Mississippi	60	60
Montana	89	84
New Mexico	164	164
North Dakota	182	174
Oklahoma	173	171
Texas	1,296	1,320
Utah	57	61
Wyoming	149	144
All others	65	74
Total	**5,129**	**5,084**

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

US CRUDE PRICES

	7-31-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	69.75
California-Kern River 13°	60.90
Lost Hills 30°	66.70
Wyoming Sweet	58.95
East Texas Sweet	65.50
West Texas Sour 34°	60.00
West Texas Intermediate	66.00
Oklahoma Sweet	66.00
Texas Upper Gulf Coast	59.00
Michigan Sour	58.00
Kansas Common	65.00
North Dakota Sweet	53.00

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

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

WORLD CRUDE PRICES

$/bbl[1]	7-24-09
United Kingdom-Brent 38°	65.67
Russia-Urals 32°	65.12
Saudi Light 34°	64.75
Dubai Fateh 32°	64.30
Algeria Saharan 44°	65.89
Nigeria-Bonny Light 37°	66.95
Indonesia-Minas 34°	68.01
Venezuela-Tia Juana Light 31°	64.34
Mexico-Isthmus 33°	64.23
OPEC basket	65.25
Total OPEC[2]	65.27
Total non-OPEC[2]	63.81
Total world[2]	64.63
US imports[3]	62.44

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

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

US NATURAL GAS STORAGE[1]

	7-24-09	7-17-09	7-24-08	Change, %
	bcf			
Producing region	1,059	1,043	752	**40.8**
Consuming region east	1,523	1,467	1,355	**12.4**
Consuming region west	441	442	345	**27.8**
Total US	**3,023**	**2,952**	**2,452**	**23.3**
	Apr. 09	**Apr. 08**	**Change, %**	
Total US[2]	**1,903**	**1,436**	**32.5**	

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

Statistics

Worldwide crude oil and gas production

	May 2009	Apr 2009	5 month average production 2009	2008	Change vs. previous year Volume	%	May 2009	Apr. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	615	620	622	597	25	4.2	122.5	118.2	586.44
Bolivia	40	40	40	40	—	–1.2	42.0	41.0	205.00
Brazil	1,955	1,940	1,927	1,782	145	8.1	32.0	28.0	148.00
Canada	2,374	2,506	2,562	2,548	14	0.5	399.1	408.9	2,246.95
Colombia	652	649	642	565	77	13.6	22.0	21.0	108.00
Ecuador[1]	480	480	480	500	–20	–4.0	2.0	2.0	10.00
Mexico	2,609	2,642	2,650	2,860	–209	–7.3	217.1	208.9	1,057.60
Peru	99	97	103	69	35	50.4	10.0	8.6	45.20
Trinidad	112	110	110	113	–3	–2.6	119.9	114.4	568.25
United States	5,346	5,228	5,270	5,118	151	3.0	1,865.0	1,819.0	9,147.00
Venezuela[1]	2,120	2,120	2,124	2,376	–252	–10.6	70.0	68.0	338.00
Other Latin America	83	83	83	83	—	–0.4	5.5	5.4	27.21
Western Hemisphere	**16,486**	**16,515**	**16,613**	**16,651**	**–38**	**–0.2**	**2,907.1**	**2,843.5**	**14,487.64**
Austria	19	19	19	17	2	9.7	5.0	4.9	23.47
Denmark	260	273	273	291	–17	–5.9	22.1	22.2	114.75
France	18	18	18	20	–2	–9.1	2.8	2.7	13.90
Germany	56	57	58	61	–4	–5.9	41.9	43.5	223.75
Italy	80	87	85	105	–21	–19.5	24.0	22.0	117.00
Netherlands	25	28	28	39	–11	–29.2	140.0	150.0	1,300.00
Norway	1,890	2,072	2,131	2,184	–53	–2.4	278.8	309.0	1,639.46
Turkey	46	46	43	40	3	8.2	—	—	—
United Kingdom	1,381	1,476	1,443	1,493	–49	–3.3	201.3	200.7	1,042.87
Other Western Europe	3	3	3	4	–1	–25.8	0.6	0.5	8.68
Western Europe	**3,778**	**4,079**	**4,101**	**4,253**	**–153**	**–3.6**	**716.5**	**755.6**	**4,483.88**
Azerbaijan	1,100	1,100	1,004	939	65	6.9	35.0	30.0	165.00
Croatia	14	14	14	15	–1	–6.6	5.4	5.2	26.35
Hungary	14	14	14	15	–1	–4.2	6.1	6.9	37.14
Kazakhstan	1,200	1,230	1,226	1,190	36	3.0	100.0	100.0	500.00
Romania	90	90	90	95	–5	–5.3	19.0	18.0	92.00
Russia	9,840	9,840	9,784	9,738	46	0.5	1,300.0	1,500.0	7,900.00
Other FSU	500	500	460	400	60	15.0	250.0	350.0	1,700.00
Other Eastern Europe	44	44	44	50	–6	–11.2	18.9	17.7	99.57
Eastern Europe and FSU	**12,802**	**12,832**	**12,636**	**12,442**	**195**	**1.6**	**1,734.4**	**2,027.9**	**10,520.05**
Algeria[1]	1,250	1,250	1,248	1,386	–138	–10.0	255.0	245.0	1,240.00
Angola[1]	1,780	1,700	1,726	1,910	–184	–9.6	6.0	4.0	23.00
Cameroon	70	68	74	87	–13	–15.1	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	640	650	662	–12	–1.8	125.0	120.0	615.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.30
Gabon	220	220	220	228	–8	–3.5	0.3	0.3	1.51
Libya[1]	1,540	1,520	1,562	1,754	–192	–10.9	38.0	35.0	185.00
Nigeria[1]	1,800	1,780	1,804	1,954	–150	–7.7	90.0	85.0	433.00
Sudan	500	500	500	480	20	4.2	—	—	—
Tunisia	81	86	86	80	6	7.2	8.0	8.6	41.42
Other Africa	221	221	221	221	—	—	9.1	8.3	43.90
Africa	**8,688**	**8,570**	**8,676**	**9,348**	**–671**	**–7.2**	**531.4**	**506.2**	**2,583.13**
Bahrain	168	168	169	170	—	–0.3	27.0	26.2	123.82
Iran[1]	3,720	3,750	3,722	3,948	–226	–5.7	290.0	285.0	1,430.00
Iraq[1]	2,410	2,370	2,326	2,409	–83	–3.4	20.0	18.0	95.00
Kuwait[1,2]	2,250	2,250	2,302	2,597	–295	–11.4	37.0	36.0	185.00
Oman	780	780	786	722	64	8.9	57.0	55.0	286.00
Qatar[1]	760	780	762	844	–82	–9.7	222.0	220.0	1,112.00
Saudi Arabia[1,2]	8,060	7,860	7,980	8,993	–1,013	–11.3	218.0	205.0	1,063.00
Syria	370	380	380	386	–6	–1.6	18.0	17.0	87.00
United Arab Emirates[1]	2,250	2,250	2,272	2,636	–364	–13.8	132.0	128.0	647.00
Yemen	270	280	280	314	–34	–10.8	—	—	—
Other Middle East	—	—	—	—	—	95.6	7.0	6.1	39.27
Middle East	**21,038**	**20,869**	**20,979**	**23,019**	**–2,039**	**–8.9**	**1,028.0**	**996.3**	**5,068.10**
Australia	405	483	465	429	36	8.4	118.9	122.9	582.87
Brunei	140	140	150	166	–17	–10.1	33.0	32.0	172.36
China	3,786	3,805	3,685	3,779	–94	–2.5	237.4	242.8	1,222.21
India	668	655	652	682	–30	–4.3	106.1	91.0	441.30
Indonesia	850	840	854	860	–6	–0.7	200.0	190.0	990.00
Japan	13	15	17	18	–1	–5.6	8.6	9.7	54.11
Malaysia	730	730	736	766	–30	–3.9	140.0	135.0	685.00
New Zealand	48	50	46	62	–16	–26.0	12.0	12.0	58.90
Pakistan	63	64	64	67	–3	–4.1	124.8	121.6	614.64
Papua New Guinea	35	40	39	43	–4	–9.3	1.0	0.9	4.80
Thailand	239	238	244	221	23	10.3	33.0	31.5	167.34
Vietnam	300	300	300	294	6	2.0	15.0	14.5	73.00
Other Asia–Pacific	35	35	35	39	–5	–11.8	94.5	88.5	467.50
Asia–Pacific	**7,310**	**7,394**	**7,286**	**7,426**	**–140**	**–1.9**	**1,124.3**	**1,092.4**	**5,534.02**
TOTAL WORLD	**70,101**	**70,258**	**70,292**	**73,139**	**–2,847**	**–3.9**	**8,041.8**	**8,221.9**	**42,676.82**
OPEC	28,420	28,110	28,308	32,167	–3,859	–12.0	1,380.0	1,331.0	8,861.00
North Sea	3,551	3,841	3,868	3,985	–116	–2.9	544.1	576.8	3,186.34

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

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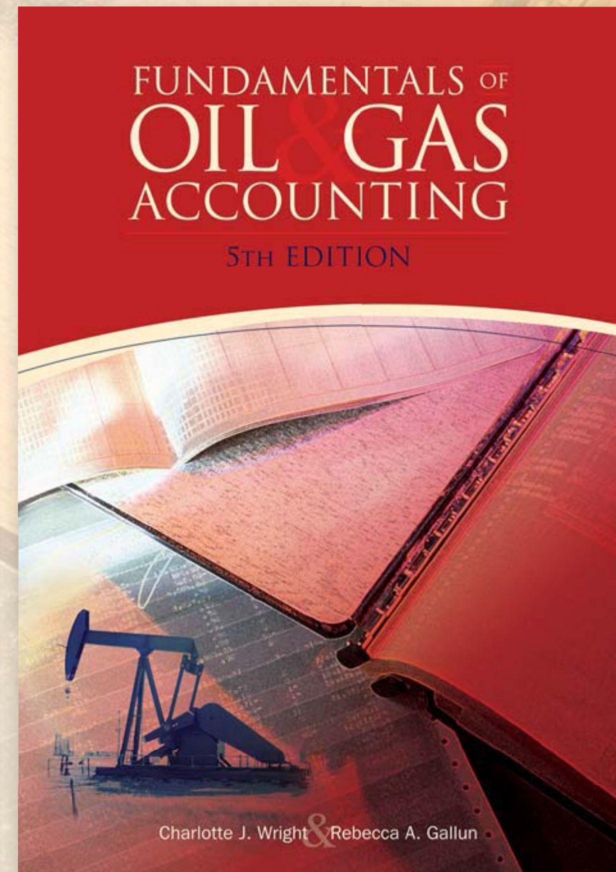

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From the Subscribers Only area of OIL&GAS JOURNAL online www.ogjonline.com

With profits down, lawmakers find new oil-price menace

When oil-company profits surged last year, Congress staged a two-ring circus. So what happens now that profits are crashing?

The circus played first on Apr. 1 in the House Select Committee on Energy Independence and Global Warming. Chairman Edward J. Markey (D-Mass.) summoned executives of five major oil companies to parry questions that were really political barbs aimed at Republican President George W. Bush.

The Editor's Perspective

by Bob Tippee, Editor

"Big Oil's profits have more than quadrupled over the last 6 years," Markey complained. The price of oil was less than $20/bbl when Bush took office but had risen above $100/bbl, he pointed out, not bothering to mention the contrasting market strains at work during those points in time.

Markey was, of course, simply exploiting oil-price restiveness to discredit an opposition-party president through association with an unpopular industry

The circus performed next in the Senate Judiciary Committee, where Chairman Patrick J. Leahy (D-Vt.) asked the same five executives "how all of you can justify such exorbitant profits on the backs of the middle class and hard-working families."

Again, the target was Bush.

"The president once boasted that with his pals in the oil industry, he would be able to keep prices low and consumers would benefit," Leahy said. "Instead, it appears to be his friends in the oil industry who have benefited."

Like Markey's, Leahy's hearing favored insinuation over insight.

It shouldn't require a congressional hearing to establish that oil company profits rise when oil prices increase.

What the likes of Markey and Leahy won't acknowledge is the reverse case.

With oil and gas prices this year down from year-earlier levels, oil company profits are plummeting.

For the record, here are the just-reported second quarter-to-second quarter earnings declines for the companies used as congressional stage props last year: Shell 67%, ConocoPhillips 76%, Chevron 79%, BP 53%, and ExxonMobil 66%.

Markey and Leahy won't hold any grateful hearings about this retreat from supposed exorbitance and what it means for hard-working families, of course.

Congress has found a new class of oil-price menace onto which to heave bombastic scorn. Now "speculators" are in the ring.

(Online July 31, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

KBC: Index funds lift oil prices

A growing market force is floating crude prices above levels justified by the simple fundamentals of supply and demand, said analysts at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK.

In an Aug. 3 report, KBC analysts asked, "How can it be that $60/bbl was justified when supply was trailing demand in the period 2004-06 and [is again] justified today when supply is so greatly exceeding demand?" As they astutely pointed out, "Something has clearly changed in the energy market." The primary change they see is "the rapid inflow of cash from index funds that, beginning in 2004, have greatly increased their energy market exposure." KBC analysts said, "This cash is coming from passive index funds that now dominate, but do not entirely dictate, global energy prices."

Index funds are not among the speculators now being damned before Congress for jacking up oil prices for fun and profit. Administrators of index funds "care little for the absolute price of oil; professional money managers seek only the benefits that the commodity energy market offers in terms of their overall portfolio of investments," the analysts explained. However, they said, "Through their dominant size, and because they are always net buyers, all of the petroleum commodity instruments have moved higher in price to accommodate the significant incremental demand for oil represented by these index funds."

Assuming current oil market fundamentals justify a crude price of $30-40/bbl, KBC analysts estimate the market impact of index funds, together with more active participation in oil futures markets by the large hedge funds, may add $30/bbl.

"We believe that the activity of financial investors has exerted a strong upward bias on crude oil prices that is essentially permanent—provided they remain in the market," said KBC analysts. "Furthermore, the 'long' only nature of the index position leads to a strong 'contango' bias time curve. The fact that these investors are required to indefinitely roll their positions by selling near term and buying further out has not escaped notice. The 'zero sum' nature of the market is only too willing to profit from these monthly costs for just as long as the index investors are willing to pay for that privilege." The indices put similar upward pressure on prices in the gasoline and heating oil markets.

CFTC hearings

Responding to changing political winds, a new proactive administration, and the consequences of high energy prices in 2007, the Commodity Futures Trading Commission has clearly signaled its intent to review and revise market regulations. KBC analysts said, "As Congress and the CFTC begin this period of comment and likely change to commodity regulations, we suggest a measured response. It is unlikely there will be any meaningful change to a very significant inflow of index funds without a change in position limits. However, that is precisely what the chairman [Gary Gensler] is focusing on." The CFTC had hearings July 28-29 concerning the roles of a variety of participants in various commodity markets. The third and last hearing was scheduled Aug. 5. In the earlier hearings, witnesses warned adoption of too strict regulations could damage the futures markets. Some participants said speculation should not be blamed for the big changes in energy prices.

"We have not seen empirical evidence that index funds and speculators distort prices, as has been widely alleged, nor is there any proof that putting position limits on these market participants will have any positive effect," said Craig Donohue, chief executive of CME Group, the parent company of the New York Mercantile Exchange, the Chicago Mercantile Exchange, and the Chicago Board of Trade. "We are deeply concerned that inappropriate regulation of these markets will cause participants to move to dark pools and other unregulated markets, causing irrevocable harm to the entire US economy" (OGJ Online, July 28, 2009).

Testifying for the Air Transport Association of America, Ben Hirst, senior vice-president and general counsel for Delta Airlines, said, "The objective should be to allow sufficient speculation to provide sufficient liquidity to enable the market to function efficiently, and no more. While it may not be possible to determine this limit with scientific precision, a reasonable surrogate might be the level of speculative activity on regulated exchanges 10 or more years ago, before the recent explosion of speculation in commodities."

Steven Strongin, managing director of Goldman Sachs, told an earlier Senate committee hearing attempts to regulate market price volatility "have rarely if ever succeeded." But such attempts "often have unintended and significant consequences," he said.

(Online Aug. 3, 2009; author's e-mail: samf@ogjonline.com)

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