
PROVEN SYSTEM
REDUCED MUD LOSS
INCREASED TRIP SPEEDS
CONSTANT RHEOLOGY TO 300°F (149°C)
SUPERIOR HOLE CLEANING

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International Petroleum News and Technology / www.ogjonline.com

Pipeline Economics

Embargo of '73 launched era of mutual adjustment
Midcontinent low-btu gas poses challenges
Supplemental offshore bonding calculations updated
Method determines injection to inhibit hydrates


Do more exploring collaborating
project leading technology leading industry leading
subsurface subsea subanywhere smiling geosteering
globe-trekking horizontal drilling ecothinking biking
creative thinking stress reducing playing family bonding
rock sampling rock climbing relaxing on the weekends
team building carbon capturing pushing the envelope
groundbreaking digital mapping remote sensing
mud logging well logging caring for our environment
life balancing parenting softball playing soccer playing
initiative grabbing challenging yourself here.

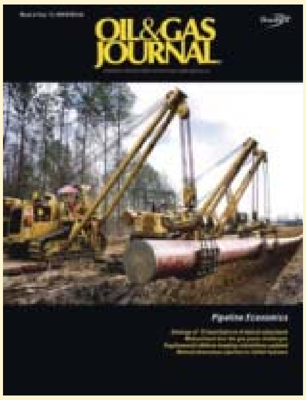
OIL&GAS JOURNAL
Sept. 14, 2009
Volume 107.34

Pipeline Economics

Regular Features

Cover

A work crew lowers in pipe on the Midcontinent Express Pipeline Project's Spread 4 constructed by Willbros Construction (US) LLC for Midcontinent Express Pipeline LLC, a joint venture of Kinder Morgan Energy Partners LP and Energy Transfer Partners LP. Work on the pipeline included laying the 42-in OD pipe shown here on Spread 4 near Sarepta, La. The entire 500-mile pipeline extends from Bennington, Okla., to Station 85, connecting production from the Barnett shale, Bossier sands, and other plays in the region to the eastern US. Oil & Gas Journal's special report on Pipeline Economics, which begins on p. 60, provides more information on similar projects, along with operational and financial data reported to the US Federal Energy Regulatory Commission for 2008-09. Photo from Willbros USA Inc. by Lindy King.



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Drilling & Production

Processing

Transportation

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Sept. 14, 2009

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General Interest — *Quick Takes*

EPA dissatisfied with Texas clean-air permitting

Key aspects of the Texas clean-air permitting program do not meet US Clean Air Act requirements, the Environmental Protection Agency said in a Sept. 8 news release from its Dallas office.

EPA proposes to disapprove parts of the Texas air permitting program. The CAA requires states develop permitting plans that are approved by EPA. Previously, Houston Mayor Bill White and others have pushed for stricter air pollution regulations for refineries and petrochemical plants along the Houston Ship Channel.

The federal agency's rejections are expected to become final next year following a 60-day public comment period. Meanwhile, EPA said it will work with the Texas Commission on Environmental Quality, industry, and environmental groups to identify and adopt changes in the state program.

"Texas' air-permitting program should be transparent and understandable to the communities we serve, protective of air quality, and establish clear and consistent requirements," said Lawrence Starfield, EPA acting regional administrator. "These notices make clear our view that significant changes are necessary for compliance with the Clean Air Act."

EPA proposes to reject Texas' flexible permits, which allow air polluters to exceed emission limits in certain areas provided that those areas achieve an overall emissions average. EPA also plans to reject Texas rules that allow air polluters to make certain changes at plants without having to schedule public hearings.

EPA cites Shell for second pollution violation

The US Environmental Protection Agency cited Shell Chemical Yabucoa Inc. in Puerto Rico on Sept. 3 for violating the federal Clean Water Act for the second time in a year.

EPA's Region 2 office in New York said that the refining and petrochemical plant improperly maintained deep ocean outfall equipment it operates under an EPA permit under the National Pollutant Discharge Elimination System (NPDES) and discharged unauthorized pollutants as a result. It issued a complaint, in which it has proposed a $153,057 penalty, and a compliance order.

Specifically, EPA said that the Shell Chemical affiliate violated the permit's terms by unlawfully discharging the pollutants into navigable waters for 14 days, and by not properly operating a multiport diffuser pipeline for 105 days.

According to the complaint, Shell Yabucoa admitted that a leak from its diffuser pipeline began on or about Feb. 25 and claimed that it stopped discharging from the pipe on Mar. 2. But the company later reported that it discharged through the pipeline during 14 days from Feb. 27 to Mar. 30, EPA said.

The federal environmental regulator's latest complaint against the firm followed a $1.025 million fine that Shell Chemical Yabucoa paid in May for similar violations. EPA said that fine stemmed from a Dec. 31, 2008, report indicated that two or three of Shell Chemical Yubacoa's diffuser ports were blocked by sand.

It said it accordingly issued an administrative compliance order (ACO) in March that required Shell Yabucoa to submit a plan to repair the leak and properly operate all ports of the diffuser. Despite the ACO, Shell failed to properly operate and maintain the diffuser from at least Dec. 31, 2008, to Apr. 15, 2009. That failure, in conjunction with the unauthorized discharges in February and March, led EPA to issue the most recent complaint, the agency said.

Shell Chemical bought the installation at Yabucoa from Sunoco Inc. in January 2002 to produce chemical feedstock for its plants in Norco, La., and Deer Park, Tex., as well as refined products for customers in Puerto Rico.

Clinton, others sued over Alberta Clipper oil line

Four environmental and Native American groups sued US Secretary of State Hillary R. Clinton and other federal officials on Sept. 3 to protest US Department of State approval of the proposed Alberta Clipper oil pipeline.

The Indigenous Environmental Network, Minnesota Center for Environmental Advocacy, National Wildlife Federation, and Sierra Club filed their 37-page complaint in the US District Court for Northern California. They are represented by the nonprofit law firm Earthjustice.

The groups said they might sue after the State Department's Aug. 24 approval for the 1,000-mile, 450,000 b/d line from Hardisty, Alta., to Superior, Wis., to cross the Canadian-US border. The project's sponsor, an Enbridge Energy Inc. subsidiary, said it hopes to have the system operating by mid-2010 after it receives other Canadian and US government permits.

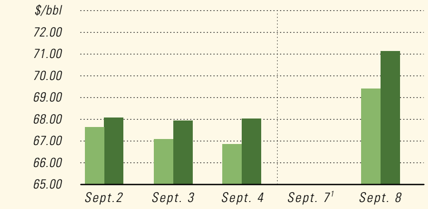
In their complaint, the groups said the State Department and US Army Corps of Engineers violated the National Environmental Policy Act by not adequately analyzing indirect and cumulative impacts of the proposed line.

They also said Congress has not fully relinquished its authority to regulate pipelines to the federal government's executive branch, and that an executive order issued by then-US President George W. Bush giving the secretary of state authority to issue permits to export and import oil, petroleum products, and other fuels at US borders did not include tar sands crude from Canada.

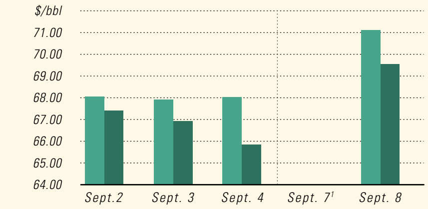
"This project will lock our nation into a dirty energy infrastructure for decades to come," said Sierra Club Executive Director Carl Pope. "Instead of increasing our reliance on oil and piping in pollution, the State Department should support clean, American energy and the jobs that come with it." ✦

Industry Scoreboard

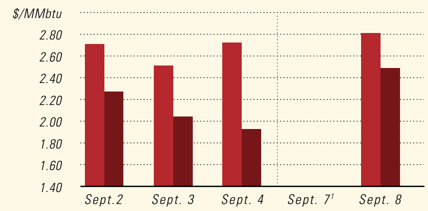
IPE BRENT / NYMEX LIGHT SWEET CRUDE



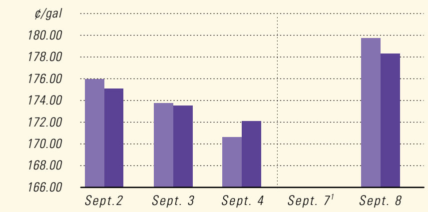
WTI CUSHING / BRENT SPOT



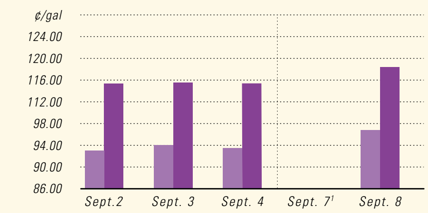
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



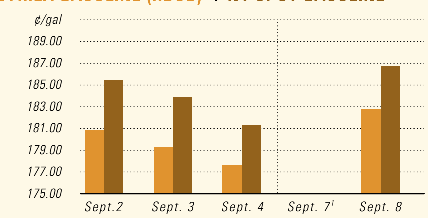
IPE GAS OIL / NYMEX HEATING OIL



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.

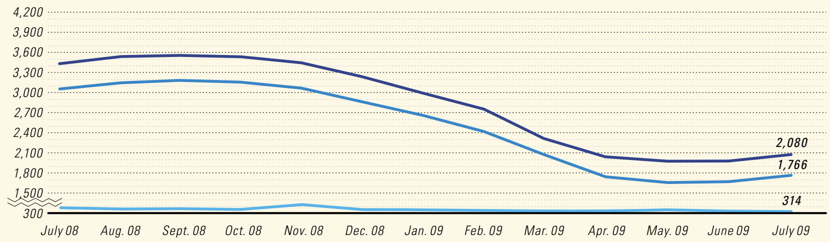
US INDUSTRY SCOREBOARD — 9/14

Latest week 8/28	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	9,185	9,135	0.5	9,000	9,062	–0.7
Distillate	3,393	3,660	–7.3	3,616	3,976	–9.1
Jet fuel	1,439	1,637	–12.1	1,390	1,591	–12.6
Residual	497	517	–3.9	581	636	–8.6
Other products	4,778	4,333	10.3	4,172	4,520	–7.7
TOTAL DEMAND	19,292	19,282	0.1	18,759	19,785	–5.2
Supply, 1,000 b/d						
Crude production	5,190	4,903	5.9	5,222	5,092	2.6
NGL production[2]	2,147	2,216	–3.1	1,994	2,151	–7.3
Crude imports	9,111	10,316	–11.7	9,270	9,899	–6.4
Product imports	2,325	2,800	–17.0	2,778	3,159	–12.1
Other supply[3]	1,691	1,503	12.5	1,720	1,543	11.5
TOTAL SUPPLY	20,464	21,738	–5.9	20,984	21,844	–3.9
Refining, 1,000 b/d						
Crude runs to stills	14,468	15,446	–6.3	14,468	14,697	–1.6
Input to crude stills	14,831	15,343	–3.3	14,831	15,038	–1.4
% utilization	84.0	87.1	—	84.0	85.4	—

Latest week 8/28	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	343,388	343,760	–372	303,862	39,526	13.0
Motor gasoline	205,085	208,054	–2,969	194,404	10,681	5.5
Distillate	163,563	162,384	1,179	131,712	31,851	24.2
Jet fuel–kerosine	45,755	45,450	305	42,081	3,674	8.7
Residual	33,892	34,442	–550	37,424	–3,532	–9.4
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.6	23.8	–0.8	20.3	16.3	
Motor gasoline	22.3	22.8	–2.2	20.6	8.3	
Distillate	48.2	48.1	0.2	30.9	56.0	
Propane	63.7	70.9	–10.2	54.4	17.1	
Futures prices[5] **9/4**			Change		Change	%
Light sweet crude ($/bbl)	68.41	72.62	–4.21	116.12	–47.71	–41.1
Natural gas, $/MMbtu	2.75	2.92	–0.17	8.10	–5.35	–66.0

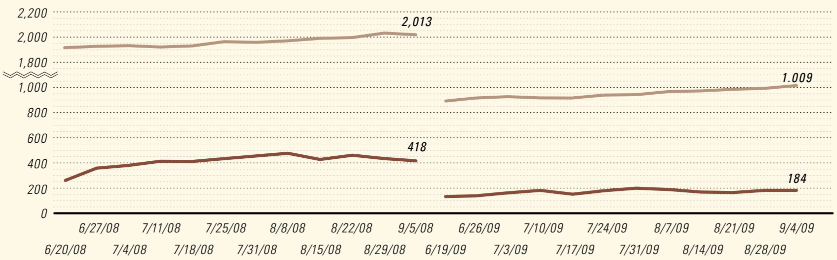
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

Exploration & Development — *Quick Takes*

Tests reveal high productivity of Guara presalt find

Flow tests, limited by equipment capacity, on the Guara presalt discovery well 1-SPS-55 (1-BRSA-594) drilled off Brazil produced at about 7,000 bo/d, according to Petroleo Brasileiro SA (Petrobras).

From these tests, the company estimates that the well initially could produce at about 50,000 bo/d and that the area contains about 1.1-2 billion bbl of recoverable 30° gravity oil.

The well, drilled in mid-2008, is on Block BM-S-9 in the Santos basin about 310 km off Sao Paulo state and 55 km southeast of the Tupi 1-RJS-628A (1-BRSA-369A) discovery well. Water depth is 2,141 m.

The operator Petrobras holds a 45% interest in the block. Companies holding the remaining interest in the block are BG Group 30% and Repsol YPF SA 25%.

Lundin finds Luno extension in Norwegian N. Sea

Lundin Petroleum AB found a gross 40 m oil-bearing column within a fractured basement on the Luno extension prospect in the Greater Luno Area of the Norwegian North Sea.

The complex reservoir requires further analysis to determine the resource potential and commerciality. Luno extension lies on Block 16/1, and is south of the Luno discovery made on the PL 338 license in 2007.

The company said the exploration well 16/1-12 did not encounter the same pre-Cretaceous reservoir of the Luno discovery.

"An extensive data acquisition program was carried out on this well, including coring and several mini drill-stem tests with the successful recovery of hydrocarbon samples," said Lundin Petroleum.

It used the Songa Dee semisubmersible drilling rig to reach a TVD of 2,030 m subsea in 107 m of water.

PL 338 was awarded in the Norwegian North Sea licensing round in 2004. Lundin Petroleum is the operator of PL338 with a 50% interest with partners Wintershall Norge ASA with 30% and RWE Dea Norge ASA with 20% interests.

Ashley Heppenstall, president and chief executive officer of Lundin Petroleum, said it was likely the Luno extension is not connected to the Luno field.

Drilling blocked in Colorado's San Luis area

A federal district court in Denver has blocked drilling at least temporarily in Colorado's San Luis Valley 30 miles north of Alamosa.

The court granted a motion by San Luis Valley Ecosystem Council for a preliminary injunction against the US Fish & Wildlife Service. FWS, surface owner of the Baca National Wildlife Refuge in Saguache County, had issued a finding of no significant impact for the proposed Baca gas drilling project (OGJ, Nov. 10, 2008, p. 44).

Lexam Explorations Inc., Toronto, said the decision prohibits drilling until a final ruling is reached in the litigation.

The FWS finding, which followed a 15-month review process, was the final approval needed for exploratory drilling in the nonproducing San Luis subbasin.

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

Drilling & Production — *Quick Takes*

ATP finds more sands, thicker pay at Mirage

ATP Oil & Gas Corp., Houston, said the No. 3 well at its Mirage field on Mississippi Canyon Block 941 in the deepwater Gulf of Mexico found thicker than expected sands and logged hydrocarbon-bearing sands that weren't present in the original wells.

Mirage, Morgus, and Telemark in the Atwater Valley and Mississippi Canyon areas are the three Telemark Hub fields that ATP plans to tie back to the ATP Titan drilling and production platform in MC 941.

ATP calls the Titan floating vessel, to be installed in October, a minimum deepwater operating concept. It has a production capacity of 25,000 b/d of oil and 50 MMcfd of gas (OGJ Online, May 12, 2009).

The MC 941-3 well, in 4,000 ft of water, logged more than 250 ft of net oil and gas pay, more than double predrill estimates. ATP set 7⅝-in. casing at 17,089 ft measured depth through the pay intervals.

Eight previously drilled wells had encountered 16 hydrocarbon-bearing sands, ATP said. Well depths are 20,000-24,000 ft at Telemark, where no oil-water contact was found, and 14,000-18,000 ft at Morgus and Mirage.

ATP previously tallied the project's proved and probable reserves at 42 million boe, 76% oil. The additional pay sands should lead to higher production and reserve estimates greater than currently booked, the company said. Production start is set for late 2009 or early 2010.

ATP is Telemark Hub project operator with 100% interest. ATP had invested $1 billion through June, including $554 million in the Titan, and expected to incur $500-600 million in further capital outlays through yearend 2010.

ATP's vendors have agreed to absorb 45-55% of project capex in exchange for a limited net profits interest.

The Titan will feed a 20-mile, 10-in. oil pipeline to the Shell Mars oil system on MC 718 and a 62-mile, 20-in. gas pipeline to the Discovery gas system in Grand Isle 115. The pipelines have been installed.

Tombua-Landana off Angola starts oil production

Cabinda Gulf Oil Co. Ltd. started oil production from the $3.8 billion Tombua-Landana project on Block 14 about 50 miles off Angola.


ConocoPhillips
cnooc

The Chevron Corp. subsidiary expects the two fields will reach peak production of 100,000 bo/d in 2011. Landana, discovered in 1998, and Tombua, discovered in 2001, contain 350 million bbl of recoverable oil, the company estimates.

The 46-well project includes a 1,554-ft compliant piled tower installed in 1,200 ft of water. The facility is designed for no produced water discharge and no routine gas flaring, CABGOC says.

The Angola Liquefied Natural Gas project, under construction at Soyo, will process the Tombua-Landana gas along with associated gas from other fields on Blocks 0, 14, 17, and 18. Completion of the Angola LNG projects is expected in 2012.

Early production from the Landana North-1 well began to the Benguela-Belize-Lobito-Tomboco compliant-piled tower in November 2006.

Operator Cabgoc holds a 31% percent interest in Block 14. Other interest owners are Sonangol P&P 20%, Eni Angola Exploration BV 20%, Total E&P Angola 20%, and GALP Energia 9%.

Another Kizomba satellite development contract let

Esso Exploration Angola (Block 15) Ltd. has awarded to GE Oil & Gas a contract for subsea equipment for its Kizomba satellite project in Block 15 off Angola.

The Kizomba satellites will produce to the existing Kizomba A and B field developments.

GE will supply subsea trees, manifolds, jumpers, and connectors; controls equipment; umbilical termination assemblies; subsea distribution units; and flying leads.

Topside equipment will be installed at the Kizomba A and B floating production, storage, and offloading vessels.

Previously Esso had let a tieback contract to Saipem SPA (OGJ Online, Aug. 3, 2009).

The ExxonMobil Corp. subsidiary expects production from the Mavacola and Clochas satellite fields to peak in 2010-12 at 125,000 b/d.

Petrominerales hikes Llanos basin production

Petrominerales Ltd., Bogota, said its Boa-1 exploration well, formerly B1, on the Corcel block in the Llanos basin is making more than 6,000 b/d of 19° gravity oil, hiking the company's output in Colombia above 25,000 b/d.

Boa-1, which reached a total depth of 12,875 ft on July 25, is producing the oil with less than 1% water cut from the Lower Sand 1 formation. Logs indicated 48 ft of net oil pay in the Lower Sand 1 and 2 formations, but Lower Sand 2 tests proved noncommercial.

Petrominerales, a 67% owned subsidiary of Petrobank Energy and Resources Ltd., Calgary, is drilling the Corcel-A2 sidetrack targeting the highest point of the Corcel A structure to reach bypassed Mirador and Guadalupe pay. The well is to be producing by the end of September, after which the rig will drill two wells on the Guatiquia block Percheron and Candelilla structures.

Meanwhile, the company plans to core the entire Mirador zone at Chiguiro Oeste-1, second of the 2009 three-well heavy oil exploration program in the Llanos basin. Coring and testing are to be finished by the end of September.

After Chiguiro Oeste-1, the rig will spud Rio Ariari-1 on the Rio Ariari block by early October.

Petrominerales shot and is interpreting 423 sq km of 3D seismic on the Castor, Mapache, Casanare Este, Casimena, and Rio Ariari blocks and a further 14 line-km of 2D data on Castor.

Company production averaged 20,679 b/d in August and has grown to more than 25,000 b/d including Boa-1 and excluding output of 1,300 b/d from Corcel-A4, which went offline Aug. 26 when the electric submersible pump failed. It is to be back on line within 10 days. Larger ESPs are to be run at Corcel-C1, Corcel-D2, Mapache-1, and Mirasol-1 by the end of October. ✦

Processing — *Quick Takes*

Valero shuts Delaware City coker, gasifier

Valero Energy Corp. is shutting down the coker and gasifier complex at the 210,000-b/cd refinery operated at Delaware City, Del., by its Premcor Refining Group Inc. subsidiary.

The move is the company's third major curtailment of operations this year.

"Both the coker and the gasifier complex at the Delaware City refinery have been unprofitable, a situation resulting from the economic recession, declining demand for refined products, and poor coking margins due to a decreased price differential between heavy sour and light sweet crude oils," the company said in a press release.

It also cited poor reliability and low operating rates of the gasifier complex, which it attributed to the facility's design and low gas prices.

"Regulatory issues and potentially significant capital expenditures contributed to the decision to shut down the gasifer complex," the company said.

Valero said the shutdown will reduce the Delaware City workforce by at least 150 employees and 100 contract workers.

It also said it expects to release more than 700 contract workers this month at its 235,000-b/d Aruba refinery, which it shut down in July and expects to remain idle "for an extended period."

Because of its configuration as a heavy crude oil upgrading facility, the Aruba refinery was losing money because of narrowing spreads between the prices of heavy sour and light sweet crudes.

Valero also said the Aruba refinery suffered from "looming local tax burdens," including a disputed tax on revenue and the expiration in December 2010 of a 20-year tax holiday.

In June the company shut down a coker and FCCU at its 315,000-b/d Corpus Christi, Tex., refinery. It also has trimmed coker utilization at other of its refineries.

Contract let for Suriname refinery expansion

Staatsolie, the state oil company of Suriname, has let a project management consultant contract to Aker Solutions US Inc. for a doubling of crude capacity of its refinery at Tout Lui Faut to 15,000 b/d.

When online in 2013, the expanded refinery will produce diesel, gasoline, fuel oil, bitumen, and sulfuric acid.

Glyn Rodgers, president of Aker Solutions US, said the expansion is "the largest single project in the country's history."

CB&I Lummus Inc. holds the contract for the third phase of front-end design work.

Vietnam urges quick repair of Dung Quat refinery

Vietnam has asked general contractor Technip to deal swiftly with the breakdown at the country's first refinery at Dung Quat so that operations can resume as soon as possible.

Operations at the 140,000-b/d plant were suspended on Aug. 16 for about 20 days due to a "technical repair" in the refinery's residue fluid catalytic cracking unit, according to a Petrovietnam official.

"There was a problem at the RFCC unit and repairs should take about 20 days, which means the plant will resume operation by Sept. 9 or 10," said a Petrovietnam official, who declined to be identified.

At the time, Technip director S.K. Singh said the consortium was working with suppliers and technical experts to determine the causes of the problem and find solutions so the refinery could resume operations.

The Dung Quat plant produced a combined 437,000 tons of products from the start of its trial run in April 2008 through Aug. 15.

In March, Vietnam's Petrovietnam Gas Corp., keen to reduce the nation's expenditures on imports, began construction of an LPG depot and a tank truck station at the Dung Quat facility.

The project, valued at 226.6 billion dongs ($13.32 million), includes two 1,000-tonne LPG rundown tanks, a system to deliver LPG from the rundown tanks to tank trucks, a firefighting system, and an industrial pipeline system (OGJ Online, Mar. 18, 2009). ✦

Transportation — *Quick Takes*

Second huge LNG train starts up in Qatar

Another megatrain of LNG production has begun service.

Earlier this week, Qatargas 2 partners Qatar Petroleum and ExxonMobil Corp. announced completion of the 7.8 million tonne/year Train 5. This follows start-up in the second quarter of Qatargas 2's other 7.8 million tpy Train 4. Each train is about 50% larger than any other liquefaction plant currently operating outside Qatar, said the announcement.

QP holds 65% of Train 5, ExxonMobil 18.3%, and Total SA 16.7%. Qatargas 2 Train 4 shareholder interest is QP 70% and ExxonMobil 30%.

Qatargas 2 links natural gas production, liquefaction, shipping, and regasification infrastructure into integrated LNG development and supply.

In addition to Trains 4 and 5, Qatargas 2 joint venture encompasses a fleet of carriers and the newly commissioned South Hook LNG terminal in Milford Haven, Wales (OGJ Online, Mar. 23, 2009; Apr. 6, 2009). The South Hook LNG Terminal Co. Ltd. is owned by QP 67.5%, ExxonMobil 24.15%, and Total 8.35%.

Qatargas 2 also has capacity to produce 0.85 million tpy of LPG and 140,000 b/d of condensate and employs three 145,000-cu m storage tanks.

Kuwait terminal receives first LNG

The Persian Gulf's first LNG regasification terminal, Kuwait's offshore Mina Al-Ahmadi GasPort, received its first cargo earlier this month.

The cargo arrived aboard the 150,900-cu m Express, a combined LNG carrier and regasification vessel owned and operated by Excelerate Energy LLC, The Woodlands, Tex.

According to an announcement from Excelerate's joint-venture partner RWE AG, the vessel regasified and delivered 130,000 cu m into the offshore port and directly into the country's gas grid. The LNG was loaded at Woodside's North West Shelf LNG plant in Australia.

The Mina Al-Ahmadi GasPort lies about 25 miles south of Kuwait City and was built by Excelerate for Kuwait National Petroleum Co. Construction started in 2008.

The terminal is intended as an interim solution to meet Kuwait's current gas needs, according to KPC, in advance of future development of domestic gas reserves to meet industrial and commercial demands.

One of Excelerate Energy's Energy Bridge regasification vessels (EBRV) will be stationed at the existing Mina Al-Ahmadi south jetty and can deliver regasified LNG at a baseload rate of up to 500 MMcfd, says KPC.

In addition, the terminal will incorporate a shuttle tanker berth that will provide for ship-to-ship LNG transfer and boil-off gas management capabilities between a conventional LNG carrier and the EBRV, according to the company.

Other sites served by Excelerate technology and vessels are the US (Texas and Massachusetts), the UK (Teesside), and Argentina (Bahia Blanca).

InterOil moves ahead with LNG project

InterOil Corp. is pushing ahead with its proposals for an LNG project in Papua New Guinea after submitting a project agreement to the Papua New Guinea government.

InterOil, along with partners Petromin PNG Holdings and Pacific LNG, submitted the agreement for the construction of the proposed plant.

Both Prime Minister Michael Somare and Minister for Petroleum and Energy William Duma have voiced their support for the $6 billion (Aus.), two-train LNG project that will have the capacity to produce 4 million tonnes/year of LNG.

InterOil says the project also is supported by other key Papua New Guinea government members.

According to InterOil, about 5,000 jobs will be created during the peak construction period at the plant site and economic returns are expected to fund public infrastructure and community services.

Although InterOil has yet to firm up sufficient reserves for the project, the company points to two separate independent resource evaluations that support the project agreement. It believes the likelihood of more successful gas and gas-condensate exploration has increased along with the potential for commercial oil discoveries.

InterOil has targeted first production from the project as end 2014 or early 2015. ✦

Letters

Green jobs

The Obama administration asserts that its big investments in "green energy" will create a large number of jobs. President Obama wants to "harness the power of alternative and renewable energy," to create "5 million new green jobs, good jobs that cannot be outsourced." The $58 billion on energy programs in the stimulus package is supposed by itself to foster over 450,000 new jobs.

The fact is that green energy subsidies lose as many jobs as they create. Spain is perhaps the most aggressive subsidizer of green energy of any country, especially on wind and solar. A new study from King Carlos University shows that for every green job created in Spain they lose 2.2 jobs in the industrial sector. That's mainly from increasing energy costs which cause energy intensive industries to move or close. Unemployment in Spain is nearing 20% despite its forests of towering turbines and acres of solar panels on the Costa del Sol.

The study notes that since 2000 Spain has spent $800,000 to create each green job.

US industry is developing renewable technology in solar, wind, algae biofuels, etc. with research support from the Department of Energy's National Renewable Energy Laboratory. We don't need additional billions to prematurely implement technology that isn't ready for production and needs large taxpayer subsidies to be competitive.

Proven and competitive nuclear power and domestic natural gas have the capacity to replace much of our coal-burning electric power while greatly reducing harmful emissions. They can also provide the needed additional megawatts as electricity powers more of our transportation. Investing in those cost-competitive energy sources will create jobs.

Rolf E. Westgard
St. Paul, Minn.

Calendar

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

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2009

SEPTEMBER

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/oilgas. 13-17.

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.

NPRA Environmental Conference, Denver, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 21-22.

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.

Canadian Offshore Resources Exhibition & Conference (CORE), Halifax, NS, (902) 425-4774, (902) 422-2332 (fax), e-mail: events@otans.com, website: www.otans.com. 5-8.

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

CO_2 transport guidelines

Christopher E. Smith
Pipeline Editor

Debate continues in scientific, political, financial, and environmental circles regarding the viability and cost of capturing and sequestering carbon dioxide as part of future energy policies. Some think it can't be done. Some think it shouldn't be done. Others see it as an absolute necessity.

Side-stepping this debate, however, Det Norske Veritas has issued the first guidelines setting out criteria for the development, design, construction, testing, operation, and maintenance of steel pipelines transporting CO_2. The guidelines, developed as a joint industry project (JIP) under DNV's carbon capture and storage section, apply to new offshore and onshore pipelines transporting fluids containing overwhelmingly CO_2, the conversion of existing pipelines, the pipeline transportation of CO_2 captured from hydrocarbon streams and anthropogenic CO_2, the pipeline transportation of natural sources for enhanced oil recovery, and other larger-scale transportation of CO_2. The guidelines include gaseous, liquid, and dense-phase operating conditions.

DNV started its JIP, CO2PIPETRANS, toward developing the guidelines roughly a year ago. Partners in the project were ArcelorMittal, BP PLC, Chevron Corp., Dong Energy, Gassco, Gassnova, ILF, Petroleo Brasileiro SA (Petrobras), Royal Dutch Shell PLC, StatoilHydro, and Vattenfall. Representatives of the Health and Safety Executive in the UK, the state supervision of mines in the Netherlands, and the Petroleum Safety Authority in Norway also participated.

Guidelines developed by the JIP supplement current pipeline standards such as ISO 13623, DNV OS-F101, and ASME B31.4, addressing specific CO_2 transportation issues for CCS developers, pipeline engineering and construction companies, pipeline operating companies, authorities, and certification companies.

DNV says it will issue a recommended practice based on the guidelines as soon as possible, and to that end has invited existing and new partners to join a second phase of the CO2PIPETRANS JIP, addressing knowledge gaps identified during Phase 1. Areas requiring additional research and development are:

- CO_2 release modeling validation data.
- Fracture arrest—full-scale crack arrest.
- Corrosion—investigation of corrosion rates at high partial-pressure CO_2.
- Material compatibility—polymers, elastomers.
- Effects of impurities.
- Hydrate formation.

DNV will distribute further information regarding participation in Phase 2 at 10 a.m. on the following dates: Sept. 16 at its Houston offices, Sept. 23 at the Calgary Marriott Hotel, and Sept. 30 at the Cumberland Hotel, London.

Grounding discussion

CO_2 has long been transported via pipeline as part of enhanced oil recovery operations. The prospect of shipping CO_2 through a potentially vast array of pipelines for the purpose of sequestration, however, has heightened interest in the topic, with competing interests in the CCS debate citing information often at odds with each other in an effort to advance their case.

CCS logistical risks range from capture and transportation to storage, and involve the commercial risks related to building a completely new value chain capable of establishing the appropriate risk-reward relationships for a variety of stakeholders with different backgrounds, objectives, and appetites for risk. The new CCS market must provide predictable long-term conditions for everyone, including a transparent decision basis and interfaces yet to be defined.

Norway plans to build its first full-scale CCS plant as early as 2012. Europe hopes to develop demonstration projects by 2015, followed by large-scale industry plants by 2020. North America and Australia are also active, and the global community is discussing how to incorporate CCS in a possible global greenhouse gas emission trading scheme, based on the goal of having a strong, global CO_2 price as one important incentive for the industry (OGJ, Aug. 17, 2009, p. 50).

The energy bill submitted in June by the US Senate Energy and Natural Resources Committee proposed a national indemnity program through the US Department of Energy for up to 10 commercial-scale CCS projects (OGJ Online, June 22, 2009), while a sequestration plant capable of storing CO_2 in deep formations beneath Barrow Island is a key component in advancing Chevron's Gorgon LNG project in western Australia (OGJ, July 20, 2009, p. 10).

DNV intends its recommended practice to help designers and operators manage uncertainties and risks related to pipeline transmission of CO_2. But in taking the lead on developing these recommended practices, DNV is also providing a foundation from which the scientific and economic questions surrounding CCS can be discussed.

The breadth of organizations participating in Phase 1 helps ensure inclusion of the views of a wide variety of stakeholders in the future of CCS. Adding participants for Phase 2 will only further the degree to which this is the case. ✦

Interests and credibility

By some ways of thinking, affiliation with the oil and gas industry discredits whatever a person might say on the subject of energy. When an industry representative comments on an energy issue, too many politicians and reporters too frequently reject the message as tainted by vested interest or worse. A measure of skepticism is of course appropriate when economic interests are at play. But interests of that type often accompany valuable expertise, especially with oil and gas, about which outsiders tend to be strikingly uninformed.

Anything beyond rudimentary understating of oil and gas, in fact, nearly always comes from someone with a financial interest in the subject, even if it's just a wage. Antagonists easily exploit the insularity: Don't listen to the oil and gas industry, they say; connection with the industry makes information unworthy of attention. This tactic, to the regrettable extent it succeeds in muffling the industry's political voice and expertise, exposes the US to costly mistakes on energy.

Industry protests

Last month Greenpeace tried to discredit by association an oil industry protest of the "cap-and-trade" bill passed by the House to limit greenhouse gas emissions. The activist group flaunted a leaked e-mail from American Petroleum Institute Pres. Jack N. Gerard to members of the trade association describing plans for rallies in 20 states. Among other things, Gerard asked member companies to encourage their employees to participate in the campaign, known as Energy Citizens.

Greenpeace tried to portray the initiative as sinister fraud. Mistakenly suggesting that API instigated the rallies alone, the group complained of an "astroturf campaign" to imply a departure from the "grassroots" real thing. With typical charm, it dismissed warnings about costs of the House bill as "lies."

To be sure, Greenpeace would want no one to believe a new study prepared for API by EnSys Energy of Lexington, Mass., on the cap-and-trade bill's effects on US refining. The study points out that the bill gives refiners the compliance obligation for 43% of covered emissions by making them responsible for not only their own emissions but also those associated with use of their products. Yet the bill allocates to refiners only 2.25% of the emission allowances to be available at no cost to industrial emitters of greenhouse gases at the start of the program. Emanating from so tilted a structure, expressed worries about cost, even from an industry with a vested interest, cannot be ignored as mere "lies."

According to EnSys, the bill would cut total US refinery throughput by as much as 4.4 million b/d by 2030 while increasing throughput outside the US by 3.3 million b/d. It would slash US refining investments by up to $89.7 billion/year—a decline of as much as 88%. And it would cut refinery utilization rates from 83.3% to as low as 63.4%. The broader economic effects, which the study didn't address, are easy to predict: lost US jobs and incomes and lower tax receipts by governments in refining centers, especially on the Gulf Coast and in California; rising imports of oil products; and higher prices for consumers.

Apparently more important to Greenpeace than warnings like these was that its friends see the August industry rallies as corporate manipulation of workforce pawns. In a press release, the group decried "the US oil industry's secret plans to have oil workers attend anti-US climate action rallies masquerading as concerned 'energy citizens.'"

Reason for concern

But who was masquerading? Oil and gas industry workers have good reason to call themselves energy citizens. They know more about energy than most fellow citizens writing legislation or news articles on the subject these days. And they have reason to be concerned. Ill-conceived energy legislation, if passed, would put their jobs in jeopardy.

No matter what Greenpeace says, oil workers have the right to protest an assault on their livelihoods and to expect their views to receive more than smirking attention. Indeed, policy-making would improve if politicians and newspeople began listening to what oil and gas professionals have to say about energy, whatever their vested interests. ✦

INTERNATIONAL PETROLEUM AGREEMENTS—2

Embargo of '73 launched era of mutual adjustment

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In October 1973, key Middle Eastern nations imposed an oil embargo against the US and other Western nations. Oil prices rose from less than \$3/bbl in 1973 to \$10/bbl in 1975 and then to \$13/bbl in 1978 (in dollars unadjusted for inflation). The Iranian revolution of 1979, followed by the commencement in 1980 of the 8-year Iraqi-Iranian war, increased the bargaining strength of other oil-exporting nations, especially those in the Organization of Petroleum Exporting Countries. The oil price peaked at \$37/bbl in 1981 (equivalent to over \$100/bbl in 2008 dollars).

For international petroleum agreements (IPAs), oil scarcity led to the demand by many oil-producing countries for the newer production sharing and risk service agreements or for a new concession agreement with so-called OPEC terms (OGJ, Sept. 7, 2009, p. 22). These terms consisted of high royalty rates (up to 20%) and taxation rates (up to 85%), coupled with majority state participation schemes.

In some cases, the new demands led to nationalization by the host country (HC).

In the low-price environment of the 1980s and 1990s, many host countries adopted policies to promote E&P investments in their territories by offering more-attractive terms and conditions to foreign investors.

State interest

One of the key objectives of OPEC and other producing countries in the early 1970s, prior to the 1973 oil embargo, was to obtain a high state participating interest in the existing concession agreements.

Minority state participation was already in force in several countries. Kuwait, for example, had negotiated a 15% participation rate in a concession with Aminoil in 1948 and a 20% participation option in case of discovery in a 1961 concession agreement. Other countries with minority state participation at that time were Iran, Egypt, Congo, Gabon, Algeria, and Nigeria.

The New York agreement of Oct. 5, 1972, signed between OPEC and a group of international oil companies (IOCs), provided for a 25% HC participation to begin on January 1973, increasing by steps to 51% in 1982. Indeed, a movement towards state majority participation or full nationalization took place in the 1970s in several major exporting countries. Among those countries were:

- Venezuela (100% HC participation with the nationalization of the oil industry in 1976 and the creation of Petroleo de Venezuela SA)
- Kuwait (100% since 1975 in its national oil company, Kuwait Oil Co.)
- Qatar (100% since 1975 in Qatar General Petroleum Corp., now Qatar Petroleum).
- The United Arab Emirates (60% since 1974 in various joint venture companies).
- Saudi Arabia (100% in Saudi Aramco since 1980).
- Oman (60% in its national oil company, Petroleum Development Oman, since January 1980).

When HCs nationalized the oil industries, they usually entered into technical services agreements with the former foreign concessionaire for the provision of expertise or consulting services without any direct access to the production by the IOCs. For example, Kuwait, Qatar, Saudi Arabia, and Venezuela followed this course.

In OPEC countries where the concessionaires were not fully nationalized, such as Oman and the UAE), the concession agreements continued but were amended to achieve majority HC participation and increased taxes on the IOCs.

Most oil-producing countries followed this trend, even Western countries where petroleum reserves were found. For example, Norway created its own national oil company, Statoil, in 1972, which was granted an option for majority state participation in the event of commercial discovery.

Privatization of NOCs

In the 1980s, another "oil shock" occurred, but this time it was the shock of sharply falling oil prices. In 1986, the price of crude oil fell to about $8/bbl.

In this low-price environment, many HC governments sought to privatize their state-owned oil companies, led by governments in the Organization for Economic Cooperation and Development (OECD) countries. Privatization was first observed in the UK with British Petroleum, British Gas, and British National Oil Co., then in France with Elf and Total, Italy with Eni, Spain with Repsol/Hispanoil, and Canada with Petro-Canada.

The movement then spread to developing countries. For example, Argentina privatized its national oil company (NOC) in 1993, which was taken over by Repsol in 1999. Brazil partially privatized Petrobras, which, though still a state-controlled company, lost its 45-year monopoly over exploration and production (E&P) in 1998.

Since 1980, host countries and international oil companies have focused more attention on the environmental and social issues related to petroleum exploration and exploitation activities.

In Norway, Statoil was also partially privatized, but as in Brazil it remains a state-controlled company. In addition, Norway created a separate entity, Petoro, which is fully owned by the state for the purpose of independently managing Norwegian HC participation interests, known as the state's direct financial interests.

Following the break-up of the Soviet Union in 1991 and the creation of the Russian Federation and the Commonwealth of Independent States, the Russian Ministry of Fuels was reorganized to create many local state-owned companies, some of which were privatized. A similar movement toward minority privatization of NOCs is now occurring in China.

At the turn of the 21st Century, rising oil prices and profits have caused an opposite trend to the preceding softening of the terms in E&P contracts.

In tandem with the privatization of NOCs through the sale of shares to international investors, many countries opened E&P acreage to IOCs. This opening is another way for the HC to "privatize" domestic oil operations by entering into international petroleum agreements (IPAs) with IOCs. China, Russia, Azerbaijan, Kazakhstan, Turkmenistan, Romania, Ukraine, Hungary, and Poland have followed this course.

The same trend occurred on a large scale in Latin America, with licensing rounds open to foreign investors in Argentina, Bolivia, Brazil, Colombia, and Ecuador.

Venezuela also decided in the 1990s to reopen its E&P sector to IOCs, through the signing of 32 risk service contracts (contratos operativos) resulting from three licensing rounds organized between 1991 and 1997, as well as the signing of other types of agreements. These contracts included projects to reactivate mature fields under "operations contracts," to explore eight exploration blocks, and to develop extra-heavy oil reserves in the Orinoco Belt through four "strategic alliances" with IOCs.

Since 1995, Iran has signed over 20 risk service agreements with IOCs, the first with Total in 1995. Algeria, Angola, and Nigeria all increased the awards of blocks to IOCs.

However, four countries with major reserves and resources of interest to the IOCs remain closed to foreign direct investment:

- Mexico, except for operations under "multiple-service contracts" signed with Pemex for increasing gas production in selected areas.
- Kuwait, where the award of risk service agreements called "operations services agreements" has been under consideration for a long time.
- Saudi Arabia, except for natural gas development where Saudi Aramco's monopoly was ended by the signing of four "upstream agreements" with IOCs, awarding the IOCs a license for the exploration, development, and production (including transport of gas and related products) of gas from nonassociated gas reservoirs.
- Iraq, with the exception of a few PSAs and service contracts. However, Iraq is expected to promulgate a new petroleum law providing for IPAs with foreign companies and has begun negotiating agreements.

Easing terms

In the low-price environment of the 1980s and 1990s, many HCs, with the exception of the largest exporters, adopted policies to promote E&P investments in their territories by offering more-attractive terms and conditions to foreign investors and to interest these investors in more-costly ventures, such as deep offshore areas, deeper reservoirs, heavy oil, or natural gas.

As a striking example, the UK marginal government take, which peaked at over 90% in 1982, was gradually reduced to 65% for "old" fields developed before 1993 and reduced to a mere 30% for new fields developed after 1993. The UK government's objective was to maximize the benefits to the nation through the development of local industry and manpower rather than simply looking for tax revenues.

> *Flexibility is a key challenge in designing and negotiating international petroleum agreements because price volatility is likely to remain a notable feature of global oil and gas markets.*

The easing of fiscal terms in the UK and some other producing countries was noticed by other countries that were engaged in assessing their legislation and contract terms prior to organizing licensing rounds or preparing negotiations with IOCs.

The trend toward more favorable terms for private investors was implemented through new policies adopted by oil-importing countries which had domestic petroleum sources that supplemented imports from abroad. These new policies were designed to foster domestic E&P activities through reductions or waivers in royalty rates, lower HC participation, or lower income tax rates. The host countries and IOCs also mutually agreed to negotiate and adjust, usually at the IOCs' request, the terms of IPAs entered into before 1986 in the era of higher prices.

HCs wanted to encourage new investments, which would have been only marginally profitable under the original IPAs after prices dropped. Indeed, in the 1990s, many HCs were competing with each other to attract foreign capital in a period of reduced investments in E&P. This competition led to growing opportunities for investors to gain access to newly opened areas.

In addition to the award of E&P contracts to explore new fields, more countries provided incentives to invest in existing fields by offering agreements to extend the producing life of older fields, to carry out enhanced oil recovery projects, or to develop natural gas discoveries.

Also, since 1980, HCs and IOCs have focused more attention on the environmental and social issues related to petroleum exploration and exploitation activities. This new priority came to the fore, first, in the Western oil-producing countries of the OECD, which enacted extensive legislation to control air and water pollution, hazardous wastes, and land use, especially in sensitive coastal areas and in the Alaskan Arctic and the North Sea. These issues are now of increasing importance to all countries where petroleum development occurs.

NOC diversification

In the last decade, many NOCs that once operated only in their home countries have diversified into upstream investments abroad, taking advantage of E&P acreage openings in certain countries.

The move to invest abroad in the 1990s was taken in particular by Statoil; Petronas (Malaysia); Petrobras (Brazil); Kufpec (Kuwait); China National Petroleum Corp. and Sinopec (China); Oil & National Gas Corp. (India); Petro-Vietnam; Sonatrach (Algeria); the new Russian companies such as Lukoil, Gazprom, and Rosneft; and Iranian companies (such as Petropars).

> *The evolution in IPAs since World War II has been decidedly lopsided in favor of developing countries.*

The strategic objectives of these "going abroad" NOCs are to be recognized as global oil and gas companies that can perform according to the good practices of the industry, to become more efficient in their home operations, and to earn profits against investment criteria similar to those used by the Western IOCs.

Some NOCs from oil-importing countries like China and India may be willing to accept a higher degree of risk or lower profitability in order to gain access to production that can meet their countries' growing energy demands.

Changes after 2000

At the turn of the 21st century, rising oil prices and profits have caused an opposite trend to the preceding softening of the terms in E&P contracts.

With little surplus producing capacity available anywhere in the world until very recently, host countries took advantage of the new high-price environment to slow the licensing of new acreage. In particular, several OPEC countries refused to give access to the most promising exploration areas or to already producing fields.

At the same time, IOCs had surplus funds to invest from their own higher cash flows but faced a relative lack of attractive new opportunities in E&P. Therefore, spurred on by competition from NOCs going international, IOCs were forced to offer better terms in the post-2000 licensing rounds in countries like Libya and Angola, where acreage was opened to foreign investors. Thus, Libya, after the lifting of US sanctions against it in 2004, organized two successful licensing rounds in 2005 for production sharing agreements which attracted many IOCs and NOCs ready to offer highly advantageous terms to the country.

Many countries, including OECD countries, have recently introduced additional taxes on their own domestic production. For example, in 2002, the UK government introduced an additional income tax of 10%, rising to 20% in 2006, which led to a revised marginal government take of 75% (in "old" fields) and 50% (in "new" fields).

The state of Alaska adopted a new profit-based petroleum production tax in 2006 to replace royalty payments in the concession agreements.

Some major oil-exporting countries, such as Venezuela, Bolivia, and Ecuador, radically changed some of the conditions and terms under which foreign investors operated.

Will this trend to impose harsher tax rates and terms on investors in the petroleum business continue? Or will the IPAs and related petroleum legislation and regulations be robust enough to self-adjust to price volatility, so that there is a fair sharing of profits between HCs and investors over long-term business cycles?

The real issue is how production, profits, and the control of operations will be split between the risk-taking investor and the state as owner of the subsoil.

Such flexibility is a key challenge in designing and negotiating IPAs because price volatility is likely to remain a notable feature of global oil and gas markets.

Mutual adjustment

Early IPAs were the result of a certain political, economic, and technical climate. When these original factors gave way to new conditions, the IPAs and their terms were modified accordingly.

In this context, the bargaining power between HCs and IOCs is one of mutual adjustment in which each party acts to further its own best interests when it is in a stronger overall position and yields to necessity when in a weaker position.

Nevertheless, the evolution in IPAs since World War II has been decidedly lopsided in favor of developing countries. Once freed from colonial rule, these countries have successfully asserted their sovereignty over their natural resources, especially in an era of relative scarcity in petroleum supplies and high oil prices, like the 1970s.

From the mid-1980s to the turn of the 21st Century, relatively low oil prices led to the privatization of some national oil companies and the opening of acreage once closed to IOCs, as bargaining power shifted in favor of IOCs (except in the largest oil exporting countries of OPEC). With the oil price hikes through mid-2008, HCs

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were again in the driver's seat, able to capture a higher share of the profits.

All IPAs share many basic features and can be made to achieve the same economic results. In fact, at least 80% of the contents of most IPAs consist of the same clauses, irrespective of their label. The real issue is how production, profits, and the control of operations will be split between the risk-taking investor and the state as owner of the subsoil. All IPAs still aim, just as in Col. Drake's days, at the same goal: to make petroleum exploration and exploitation possible.

Acknowledgment

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Lower demand, prices crush 2Q, first-half earnings

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Average commodity prices and rig counts in this year's second quarter plummeted compared with second-quarter 2008, sending the financial results of producers, refiners, and service companies tumbling from a year earlier.

A sample of US operators recorded a combined 74% decline in earnings for the second quarter of 2009, and for the first half of this year, the group combined for a loss.

A group of producers and pipeline companies with headquarters in Canada similarly posted a collective decrease in second-quarter earnings from a year ago. This group's first-half 2009 earnings also were down sharply year-on-year.

Compared with a year earlier, a sample of service and supply companies reported a collective decline in earnings over the 3-month and 6-month periods as well.

In this year's second quarter, the front-month futures price of oil on the New York Mercantile Exchange averaged $59.79/bbl, down from $123.80/bbl a year earlier.

Meanwhile, the front-month gas futures contract during the second quarter was down 67% from a year earlier, averaging $3.81/MMbtu in the recent quarter.

The rig count in Canada for June fell to 125 units from 266 a year earlier, according to Baker Hughes Inc. And the US rig count in June averaged about 900, down from 1,902 a year earlier.

Results are in US dollars, unless indicated otherwise.

US producers

Thirty-seven of the 70 US-based oil and gas producers and independent refiners in a sample of firms reported a net loss for the recent quarter. And although the large, integrated companies reported solid results, earnings were down sharply from a year earlier due to much lower oil and gas prices.

With net income of $3.95 billion, ExxonMobil Corp. recorded a 66% slide in second-quarter earnings from a year earlier. Revenues slid 46% to $74.4 billion.

ExxonMobil reported that lower oil and gas price realizations reduced its second-quarter earnings by $6.1 billion. Production decreased about 3% from second quarter of 2008.

The company reported that its downstream earnings of $512 million were down $1 billion from the second quarter of 2008, as weaker refining margins more than offset stronger marketing margins. Petroleum product sales were down slightly from a year earlier, mainly reflecting asset sales and lower demand.

Marathon Oil Corp. reported a 47% decline in earnings for the second quarter to $413 million, as revenues slumped 40% to $13.358 million. Lower oil and gas price realizations pushed down E&P earnings to $220 million in the recent quarter from $822 million in the 2008 second quarter.

Weaker oil and gas prices also suppressed the earnings of Chevron Corp., which recorded a 71% decline in its second-quarter 2009 profit compared with a year earlier.

Many of the independent oil and gas producers swung to a loss for the 2009 second quarter vs. the second quarter of 2008, including Pioneer Natural Resources Co., which recorded a $92.1 million loss in the recent quarter due to a loss on derivatives.

Devon Energy Corp. reported net earnings of $314 million for the quarter ended June 30, down 76% from the 2008 second quarter. Production of oil, gas, and natural gas liquids increased 12% to a record 65.4 million boe in the recent quarter. Devon's gas production volumes in Canada climbed a bit due to lower government royalties. But the company's record production volumes were met with lower realized prices for all products, resulting in the decrease in quarterly net earnings.

Chesapeake Energy Corp. swung to a $237 million profit for the recent quarter, with results buoyed by a realized gas and oil hedging gain of $597 million.

Refiners

Most US-based refiners in the sample of companies posted a net loss for this year's second quarter, including Sunoco Inc., Tesoro Petroleum Corp., and Valero Energy Corp. Each of these companies incurred sharp declines in revenues from a year earlier as a result

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

	2nd quarter — Revenues		2nd quarter — Net income		Six months — Revenues		Six months — Net income	
	2009	2008	2009	2008	2009	2008	2009	2008
	Million $ (US)							
Anadarko Petroleum Corp.	1,745.0	2,786.0	(216.0)	28.0	3,340.0	5,764.0	(547.0)	314.0
Apache Corp.	2,093.4	3,900.2	444.7	1,445.2	3,727.2	7,087.9	(1,312.2)	2,466.7
Approach Resources Inc.	9.9	24.1	(0.7)	0.9	20.0	43.2	0.2	3.7
Atlas America Inc.	414.7	334.1	9.4	(7.8)	771.9	804.4	14.0	(1.3)
ATP Oil & Gas Corp.	81.1	192.5	(0.1)	(11.8)	163.2	420.6	3.5	35.1
Basic Earth Science Systems Inc.[1]	1.5	3.3	0.2	1.4	NA	NA	NA	NA
Berry Petroleum Co.	99.9	198.9	(13.0)	49.1	283.1	369.8	22.0	92.2
Bill Barrett Corp.	138.9	157.9	10.6	33.3	283.9	307.6	37.0	63.8
Brigham Exploration Co.	10.6	25.1	(7.0)	1.5	29.2	50.2	(126.0)	3.0
Cabot Oil & Gas Corp.	204.8	248.9	25.5	54.6	438.8	468.5	73.1	100.6
Carrizo Oil & Gas Inc.	31.2	53.7	(125.5)	(5.3)	NA	NA	NA	NA
Cheniere Energy Inc.	38.3	5.7	(13.1)	(136.5)	40.4	16.8	(95.8)	(191.2)
Chesapeake Energy Corp.	1,673.0	(455.0)	243.0	(1,592.0)	3,668.0	1,156.0	(5,498.0)	(1,722.0)
Chevron Corp.	40,200.0	82,989.0	1,745.0	5,975.0	76,335.0	148,935.0	3,582.0	11,143.0
Clayton Williams Energy Inc.	60.5	191.3	(38.2)	(21.0)	118.3	328.1	(59.5)	(13.7)
CNX Gas Corp.	161.6	205.8	33.0	64.3	340.0	366.4	87.9	114.2
Comstock Resources Inc.	64.9	172.2	(11.5)	82.6	133.3	300.1	(17.1)	123.7
ConocoPhillips	36,630.0	73,353.0	1,314.0	5,456.0	67,910.0	129,905.0	2,170.0	9,614.0
Continental Resouces Inc.	151.8	303.4	13.5	127.3	248.4	531.1	(13.1)	213.3
Credo Petroleum Corp.[2]	2.4	4.9	(4.7)	(0.8)	4.5	8.7	(14.6)	0.7
Delta Petroleum Corp.	23.1	84.5	(180.5)	(23.3)	82.4	150.8	(209.9)	(44.4)
Denbury Resources Inc.	217.4	417.9	(87.2)	114.1	391.2	735.3	(105.5)	187.1
Devon Energy Corp.	2,090.0	3,548.0	314.0	1,301.0	4,118.0	6,523.0	(3,645.0)	2,050.0
Dorchester Minerals LP	9.7	29.0	4.7	23.2	18.5	50.3	8.5	38.6
El Paso Corp.	973.0	1,153.0	89.0	191.0	2,457.0	2,422.0	(880.0)	410.0
Encore Acquisition Co.	163.5	357.3	(47.0)	(35.7)	277.8	630.2	(54.5)	(4.5)
EOG Resources Inc.	861.0	1,095.5	(16.7)	178.2	2,019.2	2,229.5	142.0	419.2
EQT Corp.	238.0	334.0	26.6	55.4	707.4	870.0	98.6	125.9
Exco Resources Inc.	159.2	455.7	(72.0)	(297.9)	348.4	788.4	(1,171.6)	(495.8)
ExxonMobil Corp.	74,457.0	138,072.0	3,950.0	11,680.0	138,485.0	254,926.0	8,500.0	22,570.0
Fidelity Exploration & Production Co.	104.8	215.2	20.8	71.7	210.9	384.8	(352.5)	122.3
Forest Oil Corp.	182.1	516.4	37.1	(68.0)	376.9	894.1	(1,140.6)	(72.8)
Frontier Oil Corp.	1,102.6	1,767.9	49.8	59.3	1,949.4	2,955.9	123.3	105.3
Gasco Energy Inc.	4.4	14.1	(3.9)	(0.8)	9.8	23.8	(47.7)	(5.2)
Helix Energy Solutions Group Inc.	494.6	530.1	100.5	90.5	1,065.6	971.9	207.7	164.5
Hess Corp.	6,755.0	11,729.0	102.0	911.0	13,627.0	22,429.0	85.0	1,663.0
HKN Inc.	3.4	7.1	(0.2)	2.3	6.1	13.4	(1.3)	3.5
Holly Corp.	1,038.5	1,747.6	21.6	11.9	1,691.5	3,231.2	45.5	21.4
Lucas Energy Inc.	441.5	13,238.0	(308.7)	1,390.0	NA	NA	NA	NA
Marathon Oil Corp.	13,358.0	22,202.0	413.0	774.0	23,635.0	40,223.0	695.0	1,505.0
Murphy Oil Corp.	4,555.8	8,344.2	158.8	619.2	8,001.4	14,853.7	329.9	1,028.2
Newfield Exploration Co.	287.0	691.0	(39.0)	(244.0)	549.0	1,207.0	(733.0)	(308.0)
Noble Energy Inc.	491.0	1,205.0	(57.0)	(144.0)	932.0	2,230.0	(245.0)	71.0
Occidental Petroleum Corp.	3,722.0	7,220.0	694.0	2,334.0	6,825.0	13,294.0	1,071.0	4,209.0
Parallel Petroleum Corp.	19.9	56.1	(9.6)	(29.2)	38.2	100.1	(30.0)	(31.9)
Penn Virginia Corp.	183.9	360.4	(22.2)	(4.5)	383.1	609.5	(29.4)	(1.4)
Petrohawk Energy Corp.	227.3	304.6	(22.0)	(92.8)	490.8	519.6	(1,021.8)	(148.4)
PetroQuest Energy Inc.	55.3	92.9	9.0	23.1	114.7	169.4	(56.6)	38.5
Pioneer Natural Resources Co.	459.3	646.8	(92.1)	162.9	837.7	1,215.6	(102.9)	291.6
Plains Exploration & Production Co.	278.7	732.7	43.6	202.9	507.2	1,355.8	48.8	366.4
Quest Resource Inc.	23.7	56.3	(30.5)	(97.7)	53.8	101.5	(109.6)	(139.5)
Questar Corp.	617.4	834.1	78.5	174.7	1,540.9	1,836.6	146.2	362.9
Quicksilver Resources Inc.	206.0	197.9	(20.5)	52.3	392.0	355.5	(587.8)	94.0
Range Resources Corp.	180.4	151.8	(39.9)	(32.4)	456.9	357.1	(7.3)	(27.5)
Rosetta Resources Inc.	73.6	154.8	4.0	39.3	153.1	283.4	(234.1)	66.8
Southwestern Energy Co.	477.5	604.4	121.1	136.8	1,018.3	1,128.5	(311.8)	245.9
St. Mary Land & Exploration Co.	205.3	357.0	(8.3)	32.5	404.5	719.2	(95.9)	127.4
Stone Energy Corp.	170.5	266.4	27.2	82.8	312.8	474.5	(198.7)	145.1
Sunoco Inc.	7,509.0	15,179.0	(55.0)	82.0	13,644.0	27,283.0	(43.0)	23.0
Swift Energy Co.	82.9	262.7	(2.3)	81.9	159.3	461.6	(61.4)	130.3
Tesoro Petroleum Corp.	4,183.0	8,888.0	(45.0)	4.0	7,464.0	15,496.0	6.0	(78.0)
Ultra Petroleum	130.3	308.2	(25.5)	116.9	298.3	579.4	(538.1)	200.2
Unit Corp.	164.1	370.1	32.0	94.1	365.1	691.5	(115.5)	171.2
VAALCO Energy Inc.	32.4	56.2	(0.0)	15.0	54.1	98.9	(12.0)	17.8
Valero Energy Corp.	17,925.0	36,640.0	(254.0)	734.0	31,749.0	64,585.0	55.0	995.0
W&T Offshore Inc.	150.4	461.0	(6.0)	134.6	267.9	817.5	(236.7)	214.4
Warren Resources Inc.	15.2	34.5	(9.2)	17.0	26.9	576.3	(15.7)	27.2
Whiting Petroleum Corp.	230.2	345.8	(93.2)	80.4	394.0	609.8	(136.9)	142.8
Williams Cos. Inc.	1,909.0	3,657.0	142.0	437.0	3,831.0	6,821.0	(30.0)	937.0
XTO Energy Inc.	2,273.0	1,936.0	496.0	575.0	4,434.0	3,609.0	982.0	1,040.0
Total	**233,329.4**	**452,624.2**	**8,796.9**	**33,559.7**	**435,031.3**	**799,756.0**	**(1,710.9)**	**61,333.9**

[1]First quarter. [2]Quarter ended Apr. 30.

of weak demand for petroleum products.

But as costs declined on lower crude prices, Holly Corp. reported a jump in second-quarter earnings to $21.6 million from $11.9 million in the second quarter of 2008. The Dallas-based company attributed the increase to a host of factors, including the effects of

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

	2nd quarter Revenues 2009	2nd quarter Revenues 2008	2nd quarter Net income 2009	2nd quarter Net income 2008	Six months Revenues 2009	Six months Revenues 2008	Six months Net income 2009	Six months Net income 2008
	Million $ (Canadian)							
Canadian Natural Resources Ltd.	2,538.0	4,424.0	162.0	(347.0)	4,525.0	7,942.0	467.0	380.0
Enbridge Inc.	2,867.6	3,871.5	394.7	659.4	6,650.2	7,839.3	954.5	912.4
EnCana Corp.	4,331.9	8,546.3	275.2	1,406.0	9,637.9	14,803.4	1,382.9	1,513.0
Gentry Resources Ltd.	35.6	39.9	(12.3)	5.4	76.7	75.4	(21.3)	6.4
Husky Energy Inc.	4,509.2	8,289.5	495.1	1,563.7	8,712.1	14,145.9	872.8	2,586.2
Imperial Oil Ltd.	5,303.0	8,859.0	209.0	1,148.0	9,973.0	16,122.0	498.0	1,829.0
Ivanhoe Energy Inc.	4.8	(3.2)	(11.4)	(21.7)	10.7	5.0	(23.7)	(30.3)
Nexen Inc.	1,282.0	2,105.0	22.0	381.0	2,587.0	4,197.0	160.0	1,012.0
Suncor Energy Inc.	5,058.0	7,959.0	(51.0)	829.0	9,872.0	13,947.0	(240.0)	1,537.0
Talisman Energy Inc.	1,603.0	3,022.0	63.0	426.0	3,176.0	5,029.0	518.0	892.0
TransCanada Corp.	2,127.0	2,017.0	314.0	324.0	4,507.0	4,150.0	648.0	773.0
Total	**29,660.1**	**49,130.0**	**1,860.3**	**6,373.8**	**59,727.6**	**88,256.1**	**5,216.2**	**11,410.8**

SERVICE-SUPPLY COMPANIES' SECOND QUARTER 2009 REVENUES, EARNINGS

	2nd quarter Revenues 2009	2nd quarter Revenues 2008	2nd quarter Net income 2009	2nd quarter Net income 2008	Six months Revenues 2009	Six months Revenues 2008	Six months Net income 2009	Six months Net income 2008
	Million $ (US)							
Baker Hughes Inc.	2,336.0	2,998.0	87.0	379.0	5,004.0	5,668.0	282.0	774.0
BJ Services Inc.*	786.9	1,328.2	(32.3)	141.8	3,273.2	3,896.5	159.9	441.3
Bronco Drilling Co. Inc.	27.5	68.3	(7.2)	4.3	78.1	135.3	(8.9)	12.5
Cameron International Corp.	1,270.0	1,480.6	138.6	148.8	2,527.1	2,819.9	253.2	271.8
Diamond Offshore Drilling Inc.	947.6	957.3	387.4	416.2	1,833.9	1,747.8	733.0	706.7
Dril-Quip Inc.	143.5	133.3	27.7	26.7	277.6	261.1	53.1	51.4
Foster Wheeler Ltd.	1,311.2	1,713.2	127.3	161.3	2,578.4	3,519.4	201.7	299.8
Gulfmark Offshore Inc.	104.7	82.2	34.9	46.8	213.6	165.8	49.1	79.0
Halliburton Co.	3,497.0	4,496.0	265.0	510.0	470.6	854.5	645.0	1,097.0
Hornbeck Offshore Services Inc.	98.0	104.7	0.2	25.2	207.7	203.2	27.3	47.9
Nabors Industries Ltd.	878.0	1,303.4	(193.0)	176.4	2,020.7	2,625.0	(67.8)	388.5
Noble Corp.	900.2	814.5	391.8	375.7	1,797.4	1,679.1	806.1	759.9
Oceaneering International Inc.	450.8	500.2	48.1	52.1	886.0	936.1	92.5	93.4
Parker Drilling Co.	222.0	217.1	4.4	21.9	396.2	390.7	6.5	45.1
Patterson-UTI Energy Inc.	161.0	526.8	(17.7)	81.4	457.1	1,031.7	(1.5)	158.8
Pioneer Drilling Co.	69.2	152.8	(6.3)	19.1	170.1	266.7	(5.6)	31.0
Pride International Inc.	501.2	546.5	124.1	187.4	1,052.1	1,094.0	283.0	427.3
Rowan Cos. Inc.	482.4	588.3	96.6	120.6	977.5	1,077.0	228.3	219.2
RPC Inc.	127.1	214.7	(11.6)	22.5	303.4	412.0	(7.2)	37.2
Schlumberger Ltd.	5,528.0	6,746.0	615.0	1,426.0	11,528.0	13,036.0	1,556.0	2,770.0
Smith International Inc.	1,945.0	2,494.9	63.3	252.7	4,356.9	4,866.8	207.5	498.8
Total	**21,787.3**	**27,467.0**	**2,143.3**	**4,595.9**	**40,409.6**	**46,686.6**	**5,493.2**	**9,210.6**

*Third quarter.

increased refining production, partially offset by an overall decrease in refinery gross margins.

Holly's overall refinery gross margins were down 14%, but refinery production levels increased 41% from a year earlier due to incremental production attributable to operations of the company's recently acquired Tulsa refinery and production gains resulting from capacity expansions at the Navajo and Woods Cross refineries.

Also contributing to Holly's year-over-year increase in second-quarter production levels were the effects of reduced production during the second quarter of 2008 as a result of a fluid catalytic cracking unit outage that forced a downtime at the Navajo refinery. Increased earnings attributable to the company's asphalt marketing business also contributed to the increased earnings in the recent quarter.

Canadian operators

A sample of Canadian-based producers and pipeline operators recorded a combined 71% decline in second-quarter earnings. For the first half, net income sank 54% from a year earlier, as most companies in the group reported poorer results.

Canadian Natural Resources Ltd. reported $162 million (Can.) in earnings in the recent quarter, compared with a $347 million (Can.) loss a year earlier. The company's oil production volumes climbed following a ramp-up in oil sands production at the Horizon project, which started up in this year's first quarter.

Despite swinging to a net profit, CNR reported that its adjusted net earnings were lower from the second quarter of 2008 due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, and higher interest expense, partially offset by the impact of higher realized risk management gains, lower royalty expense, and the impact of the weaker Canadian dollar relative to the US dollar.

Of the 11 companies in the sample

of Canadian firms, only TransCanada Corp. posted an increase in revenues in the second quarter of 2009 vs. a year earlier. TransCanada's revenues climbed 5.5% on the strength of both its electric power and pipeline segments, but earnings fell 3% from the second quarter of last year due in part to higher interest expenses.

Three of the companies posted a loss for the quarter, including Ivanhoe Energy Inc., Gentry Resources Ltd., and Suncor Energy Inc. Ivanhoe also recorded negative revenue for the recent quarter due to a derivative loss.

Service, supply firms

A decline in drilling activity, especially in North America, continued to suppress financial results for a group of service and supply firms.

Collectively, the sample of service and supply companies posted a 53% decline in net income in this year's second quarter. Revenues for the 21 firms declined 21%. Combined first-half earnings were down 40% from the group's first-half 2008 net income.

Six of the service and supply companies in the sample recorded a net loss for the quarter, and five of those also incurred a loss for the first 6 months of this year.

BJ Services Inc., which recently announced a merger agreement with Baker Hughes Inc. (OGJ Online, Aug. 31, 2009), recorded a second-quarter loss of $32.3 million on revenues of $787 million, and for the first half of 2009, the company earned $160 million.

BJ Services reported that the slide in earnings in the recent quarter was primarily a result of decreased demand and intense price competition for its products and services in pressure-pumping markets in the US and Canada.

Baker Hughes announced $87 million in earnings for the recent quarter, a decline of 77% from a year earlier. For the first half of 2009, Baker Hughes recorded a 64% drop in earnings from a year earlier to $282 million. ✦

Bain & Co.: Tough decisions loom on costs, investments

Tentative economic recovery and volatile oil prices will force managers of the oil and gas industry to make tough decisions soon, warns Bain & Co., Boston.

Price gains in the second quarter of 2009 restored oil company profits hurt by the slide in last year's second half. But they create hazards, the consultancy says: Further price increases might slow the global recovery and hurt efforts to lower costs.

The uncertainty complicates investment decisions by oil company managers.

"On the one hand, they must continue to cut costs without compromising on important areas like maintenance, technology, and people development," Bain says in its Midyear Review. "On the other, they must invest in large-scale capital projects to replace declining assets and increase future revenue growth."

Project and exploration delays resulting from the price slump might cut conventional production capacity worldwide from historic highs by 3-5 million b/d by the end of 2010, Bain says, pointing to unusual constraints on exploration and production investment.

In all industry slumps, operators delay or shelve production projects as expected returns fall. To those crimps on production, the current slump adds limits on capital availability and "price deflation after years of inflation."

Timing crucial

Opportunities exist for solid companies acting at the right time.

"Those companies that have built up reserves and have a strong projects pipeline will be in a prime position to capture new opportunities," Bain says. "Others will either watch from the sidelines or be swallowed up in the industry churn."

In the next few months, the consultancy says, industry managers must answer three questions:

- At what point do we switch the emphasis from cutting costs to ramping up investments for the future?
- In a volatile price environment, what should we assume about the future of oil prices to make investment decisions?
- If oil prices settle at $60-70/bbl for the rest of 2009, how should we deploy the additional gross revenues?

Bain estimates the oil and gas industry cut expenses by 20% during the first half of 2009 from their levels of 2008. The cuts came mostly from reducing activity, pressuring suppliers, and squeezing operational costs.

At an oil price of about $65/bbl, the firm says, "the industry's need to contain costs is overtaken by the desire to expand and grow."

If oil prices remain above $60/bbl during the next 2 quarters, the industry might have additional cash income exceeding $100 billion. In recent years, the industry has tended to return cash windfalls to shareholders through dividends and buybacks.

"The last 12 months," Bain says, "have made the decision on how to spend the money much more complex: invest for the long term, invest in a strategic acquisition, or abdicate the decision to shareholders." ✦

IHS CERA: World oil demand set to rise next year

Paula Dittrick
Senior Staff Writer

World oil demand is set to grow next year for the first time since 2007 and is expected to reach pre-recession levels by 2012, IHS Cambridge Energy Research Associates said in its quarterly World Oil Watch report.

IHS CERA expects oil demand growth to rise by 900,000 b/d in 2010 and resume its 2007 high of 86.5 million b/d by 2012, which would mark a 5-year turnaround.

Oil demand dropped by 2.8 million b/d to reach 83.8 million b/d in 2009. The last time that the world experienced such a severe decline in oil consumption was in the early 1980s, and it took 9 years for demand to return to the 1979 high.

"There are a lot of questions as to whether things will be different this time in terms of the recovery of oil demand," said IHS CERA Chairman Daniel Yergin. "While the answer is that it will be shorter, it is still going to take a substantial amount of time."

Jim Burkhard, IHS CERA global oil managing director, said key differences between the current recovery and that of the 1980s are accelerating oil demand growth from emerging markets and fewer options for substituting fuels on a global scale.

"In the 1980s, the largest area of the demand decline came from power generation, where oil was replaced by readily available substitutes like coal, gas, or nuclear," Burkhard said. "Today, global demand growth is coming from the transportation sector in emerging markets where there are fewer large-scale options for switching fuels."

Overall, emerging markets will drive the recovery of oil demand. IHS CERA expects oil demand to increase to 89.1 million b/d in 2014 from 83.8 million b/d in 2009. The report anticipates 83% of the oil demand growth will come from countries outside the Organization for Economic Cooperation and Development members.

"This near-stagnation of oil demand growth in the industrial countries of the OECD highlights several structural changes," Burkhard said. "Decreasing oil intensity associated with economic growth, higher fuel efficiency, the displacement of conventional oil with renewable energy sources, and a slower pace of growth in transportation fuel consumption—all these point to a leveling off of demand in the industrial world."

While the trajectory of oil demand seems certain, Burkhard said future events always can alter demand.

"While our base case suggests that 2012 will be the year that global oil demand recovers to 2007 levels, we continue to research the alternative scenarios that could alter the balance in the oil market," Burkhard said. ✦

Brazil unveils proposed offshore presalt legislation

Eric Watkins
Oil Diplomacy Editor

Brazil's President Luiz Inacio Lula da Silva has proposed new legislation aimed at governing the development of his country's potentially enormous reserves of oil in the offshore presalt layer, about 270 km off Brazil.

"The subsalt oil fields are a gift from God—wealth which, if properly managed, can drive major transformations in Brazil, improving living conditions for our people," Lula said while announcing the proposal.

Lula also reiterated that Brazil does not want to be a "mere exporter of crude oil" and that the plan also aims to establish a powerful petrochemical industry to refine the oil into derivatives in order to export value-added products like gasoline.

The development model, which must be ratified by Brazil's Congress, includes: a new production-sharing system for contracts; a new public company for presalt contract agreement and administration; and a new social fund for investment in education and mitigating poverty in Brazil.

Production-sharing system

The new development model involves Brazil's move from a concession model to a production-sharing system for the award of new contracts.

Brazil's Minister of Mines and Energy Edison Lobao said the proposed production-sharing system reflects a change in Brazil's standing from an oil importer to a self-sufficient global energy producer.

"With the discovery of the presalt oil fields in 2007, the realities of Brazil's energy reserves have changed profoundly as have the risk-reward ratios," Lobao said.

"In 1997, when Brazil adopted a concession model, the level of risk for exploration was much higher with much lower profitability than currently estimated for the presalt play," the minister said, adding, "As an oil importer, the country sought investments."

But the discovery of the presalt area has changed that outlook, not least due to the potentially high rewards and low risk associated with the presalt layer.

"For strategic reserves with low risk and high profitability, as is the case in the presalt area, the production-sharing system is more suitable," said Lobao.

Under the proposed system, Brazil's state-owned Petroleo Brasileiro SA (Petrobras) will be the operator of all contracts for E&P of the presalt layer, while interested parties can seek contracts through a partnership agreement.

The production-sharing system will apply to new contracts signed for fields in 72% of the presalt area, while previously awarded contracts, which involve 28% of the presalt region, will remain unchanged.

Public company, social fund

The government's new model also includes the creation of a public company responsible for controlling and monitoring the cost of E&P of presalt and the administration of sharing contracts.

This company will represent the country in the consortia and operating committees to be created for directly managing different sharing contracts and monitoring all activities in E&P.

The presalt development model will establish a social fund that will set up a means to direct revenues from presalt exploration toward investment in poverty reduction, in education and in science and technology.

The new social fund will take the form of a public savings account that receives income from various sources such as royalties, signature, bonuses, and commercial revenues from petroleum and gas, originated in production sharing, and resources from activities such as mining.

Reduced estimate

The announcement of the proposed legislation coincided with a report that Credit Suisse has reduced to 28.2 billion bbl from 50 billion bbl its estimate for presalt oil reserves in Brazil's Santos basin.

According to the report by Brazil's state news agency, the previous estimate was made when potential reserves of 8 billion and 4 billion bbl were announced respectively for the Tupi and Iara prospects.

In his assessment, analyst Emerson Leite considered a total of 19 blocks, located in Tupi or its immediate surroundings, known as the presalt fringe.

According to Leite, the revision was necessary because the region is becoming clearer as more wells are drilled. He noted that in July two wells, drilled respectively on BM-S-22 and BM-S-52 blocks, turned up dry.

"The market tends to get used to more dry wells in the subsalt, given that no exploratory area has a rate of 100% success," he said.

Although he hasn't raised estimates for any areas, Leite made positive comments about the Guara prospect, on BM-S-9 block. "We believe this is the most promising area in the block," he said. ✦

Minister sees 4% decline in Mexico's oil output in 2010

Eric Watkins
Oil Diplomacy Editor

Oil production by Mexico's state-owned Petroleos Mexicanos (Pemex) will average 2.5 million b/d in 2010, down 4% from levels in this year's first half and down 5.7% from previous estimates, according to Energy Secretary Georgina Kessel.

Given the decline, Kessel said it is "very important" that the energy sector supports Pemex in expanding capacity, referring to proposed legislation by President Felipe Calderon that is aimed at opening Pemex to private investment and partnerships.

Kessel's remarks on production figures followed earlier statements by Pemex officials, who said that the decrease to 2.5 million b/d was a "preliminary estimate" by Pemex Chief Executive Officer Jesus Reyes Heroles in remarks published by Mexico's Reforma newspaper.

They said Pemex, which has an oil production goal of 2.65 million b/d for 2009, actually saw output fall by 7.8% to 2.561 million b/d in July compared to the same month in 2008.

They said 58.1% of Pemex's July production was heavy crude, 31.5% light crude, and the remainder super-light crude. They said 76.8% of its production came from marine regions, while 19.4% came from the southern region, and the rest from the north.

The amount of oil available for exports has been reduced by the decreased production figures as well as by increased domestic demand. Exports dropped by 14.8% to 1.2 million b/d during the first half, compared with 1.4 million b/d in first-half 2008.

Regardless of the exact figures, Pemex's reduced output is largely due to declining production at the aging Cantarell field, which saw a 35% decrease year-on-year in the first 7 months of 2009.

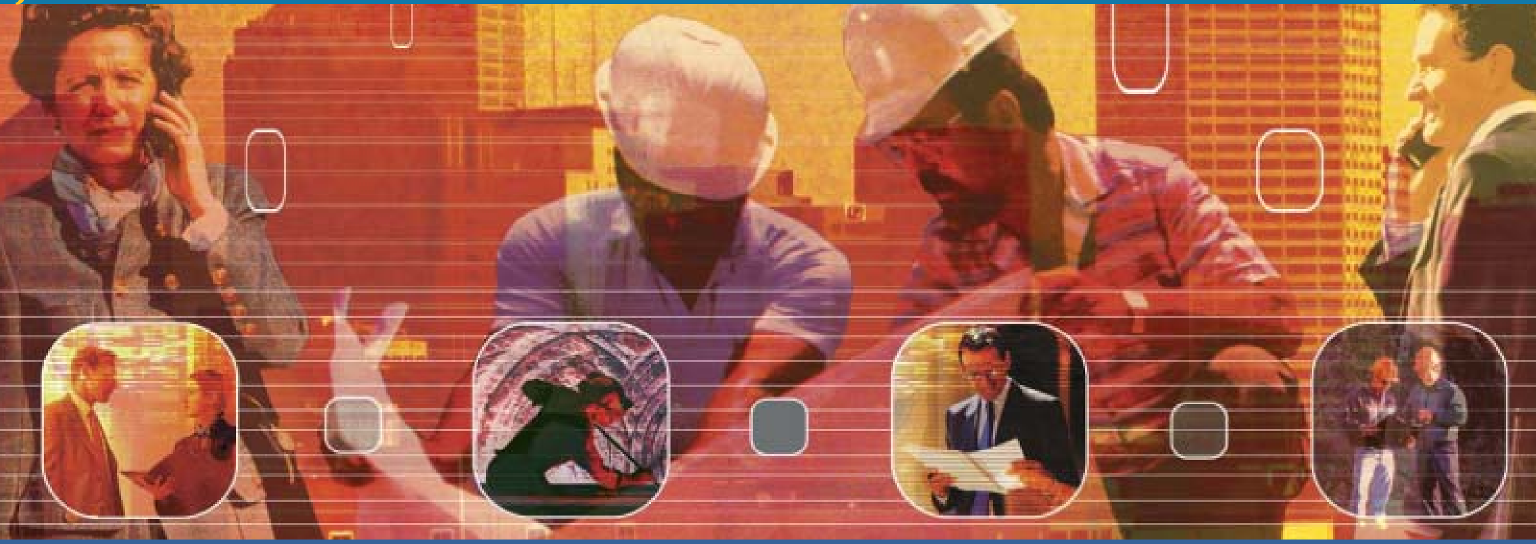
According to analyst IHS Global Insight, Cantarell field reached peak production of more than 2.1 million b/d in 2004, but its output has since plummeted "precipitously" to just 588,000 b/d in July 2009.

Pemex hopes to raise its overall oil production by seeking contractors to drill 200 oil wells in the country's southern district, with drilling scheduled to start in early October and last for 3 years.

On July 30, Pemex said it would keep to its target of nearly $20 billion in capital expenditures for 2009 despite the current oil price slump. In 2008, Pemex's total investments reached $18 billion, up from just $5.1 billion in 1998.

Last year's boost in spending clearly has not stabilized production, however, and analysts remain skeptical of the company's spending plans for 2009.

"Pemex intends to spend some $19.5 billion this year to find new fields in a bid to boost future production, but the overall output picture is likely to get worse before it gets better," said IHS Global Insight. ✦



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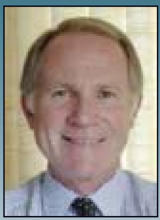

China urged to quit Myanmar

Activists have called on China to halt construction of controversial oil and gas pipelines through Myanmar, warning of instability and civil unrest if the country's ruling junta continues to starve its people of energy.

The Shwe Gas Movement (SGM), a group of Myanmar exiles in Bangladesh, India, and Thailand, also said the military's recent offensive against ethnic rebels near the pipeline route showed the regime had no concerns about providing stability for investors.

"People across [Myanmar] are facing severe energy shortages and this massive energy export will only fuel social unrest," SGM said in a Sept. 7 report.

"These resources belong to our people and should be used for the energy needs of our country," SGM said, claiming that fuel shortages triggered a series of protests in the country in 2007, leading to the deaths of 31 people in the bloodiest army crackdown since 1988.

Pipelines coming

China's largest oil and gas producer, China National Petroleum Corp., is due to start construction of nearly 4,000 km of duel pipelines from Myanmar's western Arakan state to China's Yunnan province.

The development is expected to provide the military, which has ruled the country since a 1962 coup, with at least $29 billion over 30 years. The pipelines will supply China with oil shipped from the Middle East and natural gas from Myanmar's vast offshore reserves in the Bay of Bengal.

How will the Chinese respond? Probably much like the South Koreans a few months ago when SGM and EarthRights International issued in June a joint report claiming that South Korea is failing to hold its corporations to account for abuses linked to gas development in Myanmar.

The report documents "conflicts of interest" within the government in Seoul and said South Korea is not upholding international guidelines.

Forced relocations

The report urged the Organization for Economic Cooperation and Development, which met in Paris at the time, to investigate a complaint on the issue that it said the South Korean government had dismissed.

"The Korean government is failing to hold Korean corporations accountable for abuses connected to natural gas development in military ruled [Myanmar]," the groups said in a statement.

The statement said the gas project "has already been linked to forced relocations and other human rights violations," adding, "Local people who criticized the project faced arbitrary arrest and detention."

Not much seemed to emerge from the criticism then, and even less is likely now. People are just not buying into the idea that oil and gas developments in Myanmar are responsible for the crimes being committed there.

Even less convincing is the activists' argument that exporting Myanmar's gas will lead to social unrest. The problems in Myanmar are well-known, and the military there bears much of the responsibility for them—not the oil and gas industry. ✦

Mexico to issue tender for ethanol production

Eric Watkins
Oil Diplomacy Editor

Mexico's state-owned Petroleos Mexicanos (Pemex) will invite tenders next month for a contract to produce 176 million l./year of ethanol, according to a senior government official.

Energy Secretary Georgina Kessel said the bidding round, which will be concluded in December, aims to promote ethanol as a transportation fuel as part of a wider plan by the government to reduce pollution and diversify the country's energy mix.

Kessel told delegates at a conference that the plan will help reduce the amount of pollutants released into the atmosphere while also guaranteeing the development of Mexico's food industry.

She said the project will first be carried out in the western state of Jalisco, with 65,000 ha of sugarcane to be used as feedstock in producing up to 176 million l./year of an ethanol-gasoline blend.

The project is being launched after a successful test-run last month in Monterrey, where 151,600 l. of sugarcane-based ethanol were added to gasoline at retail outlets, with 2.53 million l. of the blend sold to consumers.

According to Finance Secretary Agustin Carstens, the production of biofuels will not endanger ecosystems or food security in Mexico contrary to warnings issued by several nongovernmental organizations concerned over the use of corn—a dietary staple of the Latin American country—as feedstock.

"In Mexico, there's an agricultural zone potentially suited for the production of raw materials for ethanol production, especially sugarcane, sweet sorghum, and beets, with no risk to the country's food security or to jungles, forests, and the remaining natural ecosystems," Carstens said.

The finance secretary said other bid rounds will be announced before yearend for Monterrey and the Mexico City metropolitan area. Carstens said 126 million l./year of ethanol will be required to support those initiatives.

In 2008, Mexico enacted a law to promote and develop the use of biofuels, which also calls for production of ethanol from different sources, including algae, sugarcane, and corn.

In addition, the law also allows for the production of ethanol from waste leftover from sawmills, as well as agroindustrial and urban waste and traditional agriculture and forest residues.

Mexico hopes that biofuel production will enable Pemex to reduce its imports of gasoline which, in May, accounted for 39.2% of sales in the country during the second quarter compared with 40.5% year-on-year. In terms of volume, gasoline sales totaled 784,364 b/d compared with 798,249 b/d year-on-year. ✦

FERC expects Alaska gas line applications in 2010

Nick Snow
Washington Editor

The US Federal Energy Regulatory Commission expects to receive open season applications in 2010 from both groups proposing construction of a natural gas pipeline from Alaska's North Slope to the Lower 48 states.

TransCanada Alaska Co. LLC and Denali—a joint venture of BP PLC and ConocoPhillips—have announced their plans to conduct the formal process of obtaining shipper commitments on their respective proposed systems next year, FERC said Aug. 26 in its latest semiannual report to Congress.

FERC noted that it is required under Section 1810 of the 2005 Energy Policy Act to submit reports twice a year to federal lawmakers on progress made in constructing and licensing a gas pipeline from Alaska to markets in the Lower 48 and any related impediments.

FERC reported that since it submitted its last Alaska gas line report on Feb. 20, TC Alaska entered the commission's prefiling process for its project while Denali's prefiling process for its project continued. Other gas pipeline projects in Alaska which would not be subject to federal jurisdiction also continued to be developed, it said.

FERC noted that Denali plans to build a 48-in., 4 bcfd capacity gas line from ANS to the Alberta Hub to serve North America. TC Alaska, the licensee under the Alaska's Alaska Gasline Inducement Act (AGIA) program, plans to build and operate a 48-in., 5 bcfd throughput gas line from ANS to North America via the Alberta Hub, FERC said.

Denali activity

FERC noted that during 2009 its staff has worked closely with Denali project officials and the federal interagency team to exchange information and coordinate activities to ensure a timely and efficient application development and review.

FERC said it continues to execute its National Environmental Policy Act and Natural Gas Act certificate application responsibilities for Denali's proposal. It said its staff focused on producing an environmental impact statement (EIS) for the project on a timeline defined by the Alaska Natural Gas Pipeline Act.

Highlights since Feb. 20 included Argonne National Laboratory's selection on May 15 as third-party contractor for the EIS's preparation. FERC said its staff met in Calgary that day with officials from Denali, Argonne, and Canada's National Energy Board to review project efforts in Canada and how they are coordinated with field work in Alaska.

FERC staff traveled to Alaska in August to meet with agencies that are part of the federal interagency team, to conduct pipeline route reconnaissance, and to meet with Alaska's Department of Natural Resources. Discussions focused on the agencies' ability to review two projects simultaneously, the need for infrastructure improvements to support construction, and strategies for engaging Alaskan Natives in the project's review, FERC said.

FERC said that, since the previous report, Denali submitted several items to the commission as part of the prefiling process, including a public participation plan on Apr. 21 and its first monthly status report on May 1. In that status report, FERC said Denali reported that it had awarded an engineering contract for the project's mainline portion to Bechtel Corp. during the preliminary design phase.

Denali officials also met in June with the US Department of Transportation's Pipeline and Hazardous Materials Administration to provide a project update and discuss special permits it might seek. None of these permits would require PHMSA action until Denali completes its open season, where project officials plan to concentrate efforts while resuming more intensive environmental field surveys in 2010, FERC said.

TC Alaska activities

FERC reported that TC Alaska asked the commission to initiate the prefiling process for that gas line project on Apr. 23, and that FERC's energy projects office director approved the request on May 1. FERC's staff has been working with TC Alaska officials and the federal interagency team since that time, FERC said.

In TC Alaska's prefiling request, project officials reported that contracts have been awarded to develop plans and schedules for technical work leading up to a 2010 open season, and to perform preliminary engineering

Watching Government

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Surface owner notification

The US Bureau of Land Management quietly moved toward better relations with surface landholders in July as some of its state offices issued notices that those landholders' names and addresses will be required in expressions of interest (EOI) for future lease sales involving split estates.

"Once BLM gets the names and addresses from the party submitting the EOI, we intend to notify the surface owner of this, and send them a notice if the tract goes up for lease," said Robyn Shoop, the agency's acting senior mineral leasing specialist.

This will occur before the land goes up for lease and give all parties a chance to look at parcels and provide input, Shoop told OGJ on Sept. 4. "It's a courtesy on our part because the mineral estate is dominant, but it brings surface owners into the picture sooner," she said.

The notification's time frame could vary because each state office prepares its lease sales differently, Shoop said. The agency has asked each state office to issue two consecutive monthly oil and gas lease notices with this requirement stated, she said.

Roots in EPACT

The initiative started under the 2005 Energy Policy Act, which directed BLM to review its policies involving subsurface leases and surface owners, Shoop explained.

"After meeting with private surface owners, we concluded that they would like to be contacted sooner when BLM is leasing minerals underlying their property. Two state offices already had such a program, but we wanted to make sure it was consistent bureau-wide," she said.

Shoop said some smaller producers say the requirement could be an added burden because they may have to retrieve the name and address from paper tax records at a county courthouse. But the information in other states and counties is readily accessible online, she said.

"Surface owners appreciate this. It promotes better interaction between the subsurface lessee, the surface owner, and the BLM in the long run," Shoop said.

West Virginia concerns

Surface landholders in West Virginia, where split estates primarily involve private entities, also would like to be involved sooner, noted David McMahon, cofounder of the West Virginia Surface Rights Owners' Association. "The only notice a surface landowner gets now is when someone who wants to drill goes to get a permit from the state," he told OGJ.

McMahon conceded that many producers contact surface owners before coming onto the land, but added a requirement to do so earlier could accommodate surface uses before soil erosion, sediment control, and water protection studies are conducted. "Wells can be moved easily here because these are stratigraphic instead of structural traps," he said.

As it is, he said, the state requires a subsurface lessee to send a copy of the drilling permit application to the surface owner, who has 15 days to comment and no right to a hearing or appeal. "Surface owners feel they should have more than that," he said. ✦

studies and develop a preliminary cost estimate for the project, FERC said in its report. It said that TC Alaska also is setting up a spatial data management system and completing aerial photography of its proposed pipeline route. "Similar to Denali, TC Alaska conducted an infrastructure needs assessment to identify its requirements for highway system and air strip upgrades," it said.

FERC noted that on June 11, TransCanada Corp., TC Alaska's parent, announced that it had agreed with ExxonMobil Corp. affiliates to work together on an Alaska gas line.

TransCanada said TC Alaska remains the project's sponsor, that its responsibilities as the AGIA licensee with Alaska's state government won't be affected, and that it will continue as the project's primary contact point with government agencies and the public. But TransCanada added that it and ExxonMobil now are sharing some expenses to advance the project's technical, commercial, regulatory, and financial aspects.

FERC reported that in TC Alaska's first monthly status report on July 15, project officials said they were continuing their study of a preliminary route through Alaska that will be the basis of engineering and cost estimates to support its open season. TC Alaska also said in its report that it has begun to plan for a limited late summer geophysical program at specific locations along the study corridor, including work on the pipeline reliability model, further integrating strain capacity and strain demand elements, and frost heave testing.

FERC said TC Alaska also met in June with the Alaska AGIA State Pipeline Coordinator's office, the US Bureau of Land Management, and FERC to discuss regulatory requirements. Activities in Canada included more meetings with federal, territorial, and provincial regulators and with First Nation communities along the proposed project's route; construction planning; and conducting an environmental needs analysis and an environmental constraints review, it indicated.

Other projects

FERC noted that the Alaska Gasline Port Authority's proposed LNG export project would liquefy and load gas shipped from Prudhoe Bay to Valdez onto tankers for sale on the US West Coast, Mexico, Hawaii, elsewhere in Asia. It said TC Alaska has committed to include an option of transporting gas for this project within its open season for a line from ANS to Alberta. FERC said it would have jurisdiction over this or any other Alaskan LNG project.

FERC reported that Alaska's Natural Gas Development Authority is continuing to develop plans to develop intrastate gas pipelines, including a 460-mile system of various diameters from Beluga in southern Alaska to Fairbanks that would be used initially to transport gas from Cook Inlet, and then connect later to either the Denali or TC Alaska system to bring ANS gas to southern Alaska.

FERC said Alaska is using in-state data to consider four in-state gas delivery alternatives from ANS to Cook Inlet: a pipeline along the Parks Highway, a pipeline along the Richardson and Glenn highways, a spur from a main line to Alberta along the Parks Highway, and a similar main line spur along the Richardson and Glenn highways.

FERC said Alaska intends to identify the preferred alternative, develop the associated right-of-way, analyze costs, and facilitate discussions and agreements between gas producers and customers. "Once these efforts are complete, assuming the chosen project is economic, the state will provide the private sector the opportunity to purchase these assets and develop the project," FERC said.

It said the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects (OFC) continued work with the interagency to create a consolidated plan. OFC is preparing a plan for each proposed project, has completed the first phase of one for the Denali project, and is working on the first phase of one for the TC Alaska project, according to FERC.

It said that the US Department of Energy's program office for the federal loan guarantee process for a natural gas pipeline from Alaska monitored potential project's developments from Feb. 20 to Aug. 26. "When a more complete commercial project emerges from Denali, TC Alaska, or another sponsor, DOE will proceed with structuring the loan guarantee program," FERC said in its report to Congress. ✦

PWC: Oil, gas industry major contributor to US economy

Sam Fletcher
Senior Writer

The oil and natural gas industry supports more than 9 million US jobs while contributing to the national economy as both an employer and purchaser of US goods and services, according to a new study by PricewaterhouseCoopers (PWC) for the American Petroleum Institute.

The report said the oil and gas industry currently supplies more than 60% of the nation's total energy demands and more than 99% of the fuel used by US motorists in their cars and trucks, while 900 of the next 1,000 US electric power plants are projected to use natural gas.

The industry is one of the largest employers in the country, with millions of people in exploring, producing, processing, transporting, and marketing oil and natural gas. "Millions of jobs in other industries are supported by the oil and natural gas industry's purchases of intermediate inputs and capital goods from other US producers," the report said. "These businesses include equipment suppliers, construction services, management services, food services, and many other types of support services. These supporting businesses, in turn, purchase goods and services, spurring additional economic activities. Further, employees and business owners make personal purchases out of the additional income that is generated by this process, sending more new demands rippling through the economy."

At the national level, the study found each job in the oil and gas industry supported more than three jobs elsewhere in the US economy in 2007, the most recent year for which data are available. In terms of operational impact, it directly and indirectly contributed over 7.8 million full-time and part-time jobs to the national economy.

Further, the industry's capital investment contributed an additional 1.4 million jobs to the national economy. Combining both operational and capital investment impacts, the oil and natural gas industry's total employment contribution to the national economy amounted to 9.2 million full-time and part-time jobs in 2007, accounting for 5.2% of total US employment.

Associated labor income, including proprietors' income, was estimated at $558 billion, or 6.3% of total national labor income. The industry's total value-added contribution to the national economy topped $1 trillion, accounting for 7.5% of US gross domestic product for 2007.

"The economic impact of the oil and natural gas industry reaches all 50 states and the District of Columbia," PWC reported. The total number of jobs directly or indirectly attributable to the industry's operations ranged from a low of 12,815 (in the District of Columbia) to more than 1.7 million (in Texas). The top 15 states, in terms of the total number of jobs directly or indirectly attributable to the oil and natural gas industry's operations in 2007 were Texas, California, Oklahoma, Louisiana, New York, Pennsylvania, Florida, Illinois, Ohio, Colorado, Michigan, Georgia, North Carolina, Virginia, and New Jersey."

PWC said the industry accounted for 4% or more of total employment in another group of 15 states, including Wyoming (18.8%), Oklahoma (16.3%), Louisiana (13.4%), Texas (13.1%), Alaska (9.8%), New Mexico (8.1%), West Virginia (6.7%), Kansas (6.5%), Colorado (6%), North Dakota (5.7%), Mississippi (5.5%), Montana (5.3%), Utah (4.7%), Arkansas (4.4%), and Nebraska (4%).

As Congress debates greater domestic oil and gas access and higher energy taxes, legislators should keep in mind the oil and gas industry's importance to the US economy and in states well beyond traditional oil and gas-producing regions, said API President Jack Gerard. "Congress should remember that some of the energy tax and climate change legislation it has proposed would have a devastating impact on the industry and many of the 9.2 million American jobs it supports, as well as on the American economy and energy security," he said.

"The people in the US oil and natural gas industry are the backbone of our economy," Gerard said. "They provide most of the nation's energy, spurring growth and job creation across America. At a time of economic recession, the oil and natural gas industry is actually responsible for creating more jobs and generating more revenue to the economy. Irresponsible proposals to pile new taxes on the industry threaten these jobs and the nation's ability to produce more of its own energy. We should not put any jobs at risk, but especially not when millions of Americans already are unemployed and economic recovery remains uncertain." ✦

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Low-btu gas in the US Midcontinent: A challenge for geologists and engineers

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Considerable unexploited resources of natural gas in the US have been largely bypassed due to unacceptable levels of associated nitrogen (N_2), which lowers heat content.

Natural gas that is laden with other common impurities such carbon dioxide, hydrogen sulfide, and heavier hydrocarbons typically has less of a problem accessing local markets because of the relative ease in which these components can be removed.

Nitrogen separates from natural gas with more difficulty, but as a result many domestic production opportunities have been shunned by generations of producers.

One such fairway of bypassed low-btu gas (nominally, gas with heat content <950 btu/standard cu ft) is in central and southern Kansas. The authors' premise is that small-scale and mobile nitrogen-removal systems, when coupled with good resource evaluation, can reap considerable reward with only small investment.

Substantial geologic and well-test data from wells in this region indicate possible, probable, and proved reserves of heretofore unsellable low-btu gas that can be explored and produced with varying degrees of risk.

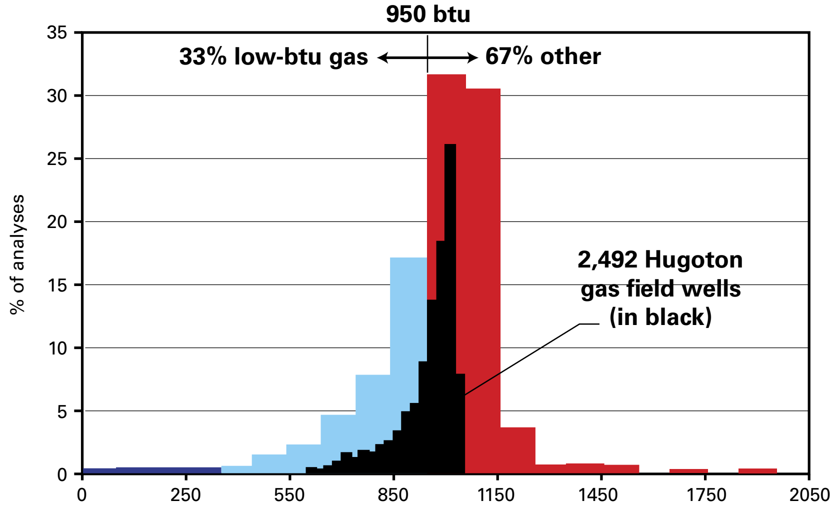
Low-btu gas can be an unrecognized resource. Some of it can be utilized at the wellsite for powering pumps that tap oil zones or for onsite or sales-to-grid electrical generation by microturbines, but much of it is left behind pipe if its relative flow rate prohibits it from being blended with a higher-btu gas.

A successful exploitation endeavor will require judicious adherence to "fiscal proportionality," whereby early-stage nitrogen removal will succeed only when project costs are in line with project revenues. Pressures and rates of production must be diligently quantified in order to select the type and size of upgrading asset.

Recent advances in small-scale nitrogen removal are now providing a means for upgrading low-btu gas in

DISTRIBUTION OF 1,253 KANSAS GAS BTU ANALYSES*

Fig. 1

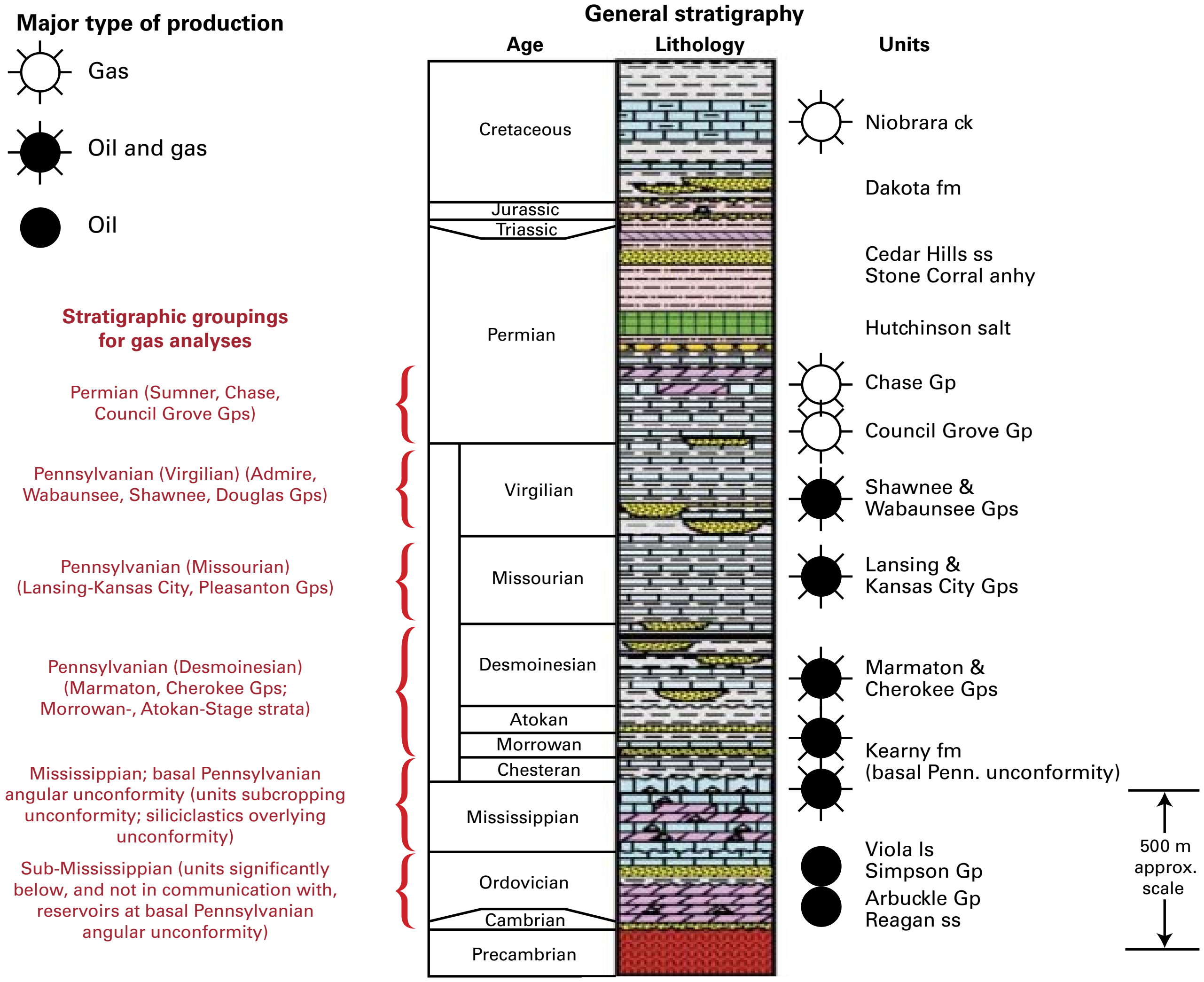


*33% of the values compiled are less than 950 btu/scf, an approximate cutoff imposed by most pipeline companies. Superimposed is a histogram (in black), with narrower class intervals, that depicts heating values for 2,492 Hugoton field wells. Both distributions are slightly skewed normal distributions.

Source: Compiled from 77 published and unpublished sources

KANSAS STRATIGRAPHIC COLUMN*

Fig. 2



*For mapping gas chemistry, strata are divided into six intervals roughly corresponding to age of the pay zone.

these areas of Kansas that have frustrated gas producers since the early days.

Trends in gas quality

Low-btu gas in Kansas is found in a variety of reservoirs of varying age and in fields ranging in size up to giant Hugoton gas field.

Kansas produces 36 million bbl/year of oil and 370 bcf/year of gas, mostly from Mesozoic and Paleozoic strata. Giant Hugoton gas field in southwestern Kansas accounts for 53% of the current gas production in the state. Significant gas production elsewhere in the state is also associated with strata immediately overlying and subcropping beneath the basal Pennsylvanian angular unconformity.

Low-btu gas in this part of the Midcontinent is primarily caused by high percentages of nitrogen and subsidiary helium. Argon and CO_2 can also be present, but they commonly compose less than 0.5% of the total gas.

Gas chemistry data are available from a variety of sources, including analyses published by the erstwhile US Bureau of Mines, scientific articles, and information occasionally reported on scout cards. A compilation of gas chemical analyses in Kansas from various sources shows that about one third of those record heating values of less than 950 btu/scf (Fig. 1).

The 950 btu/scf cutoff for low-btu gas is somewhat artificial, but this is a commonly specified minimum heat content necessary for sale of gas to large interstate pipelines. More often specific maximum percentages of individual nonhydrocarbon gases (nitrogen, CO_2, water vapor, etc.) are also specified.

Histograms that depict the heating values of gases in a given geological province are typically skewed distributions, with a tail extending into the lower-btu values. Heating values for giant Hugoton field show an asymmetric distribution similar to that for Kansas at large (Fig. 1). Low-btu gases are thus a flank to a larger distribution in gas quality in this part of the Midcontinent, rather than a separate population of gases.

Differentiation of gas-chemistry data by stratigraphic interval shows gas compositions change with age of the strata. A comparison is facilitated by dividing the stratigraphic column of the state into six broad interval (Fig. 2) roughly corresponding to age of the pay zone.

The interval that corresponds to the Mississippian/basal Pennsylvanian unconformity can include reservoirs as old as Precambrian, for several different ages of pay zone can subcrop beneath this angular unconformity. Its stratigraphic position is considered below younger Pennsylvanian pays, and above older pay zones that have not been breached by it or older unconformities.

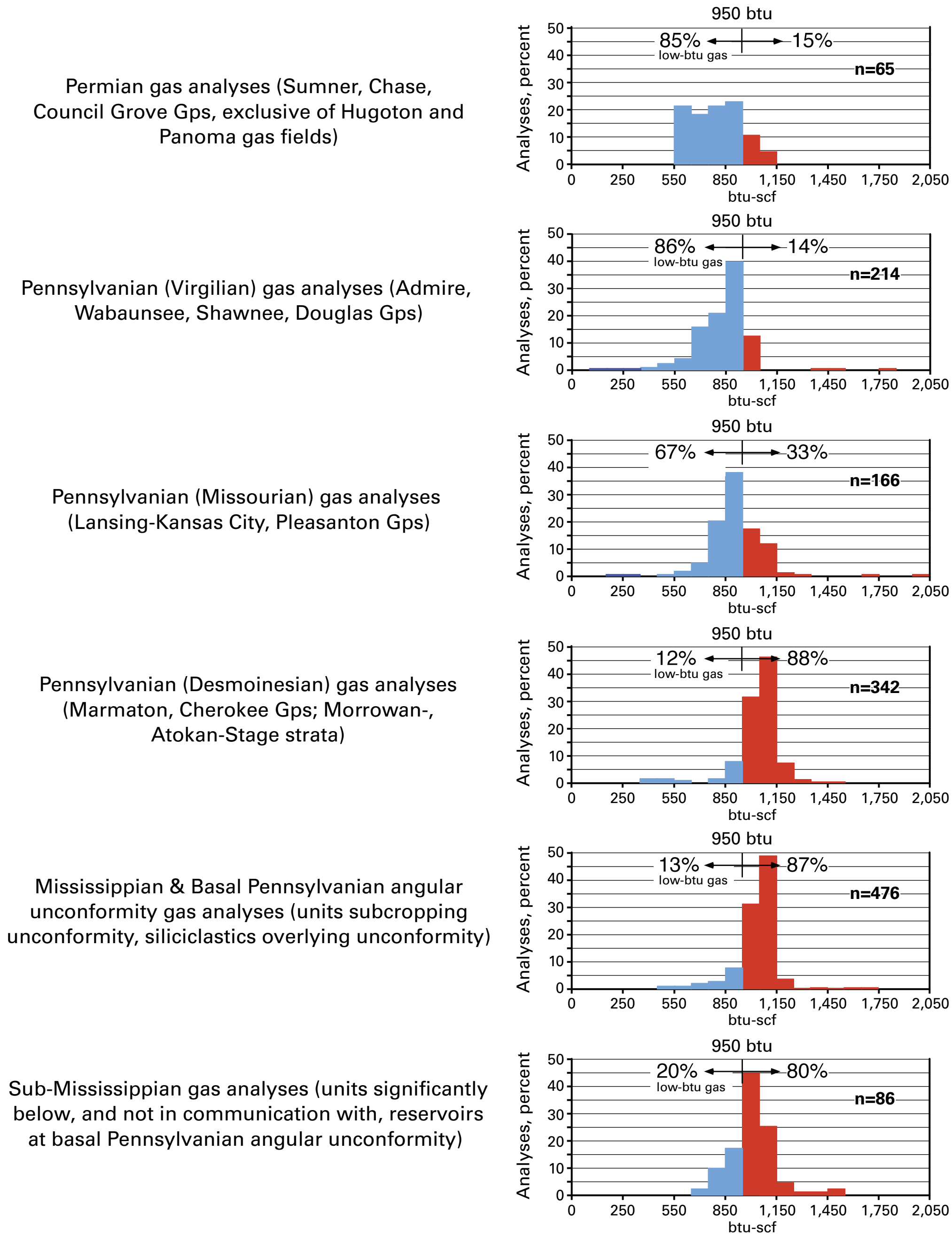
Comparison of the btu distributions (Fig. 3) according to stratigraphy shows that lower-btu gases are more common in younger pay zones in Permian and Upper Pennsylvanian rocks. Other chemical characteristics, such as the hydrocarbon wetness (a measure the ratio of higher-molecular-weight hydrocarbon gases to methane) decreases upward with younger strata.

Percentage of noncombustible gases and the nitrogen-to-helium ratio of gases increases overall (Fig. 4) with decreasing age of the producing formation.

Mapping of the chemical characteristics in a specific stratigraphic interval highlights areas where low-btu gas is commonly found and reveals trends in its quality. For example, low-btu gas is found along the perimeter of Hugoton gas field in southwestern Kansas (Fig. 5), and its distribution is relatively wide

HEATING VALUES BY KANSAS STRATA AGE*

Fig. 3



*Btu content generally decreases with decreasing age of the reservoir.

CHANGES IN GAS CHEMISTRY WITH AGE OF PAY ZONE*

Fig. 4

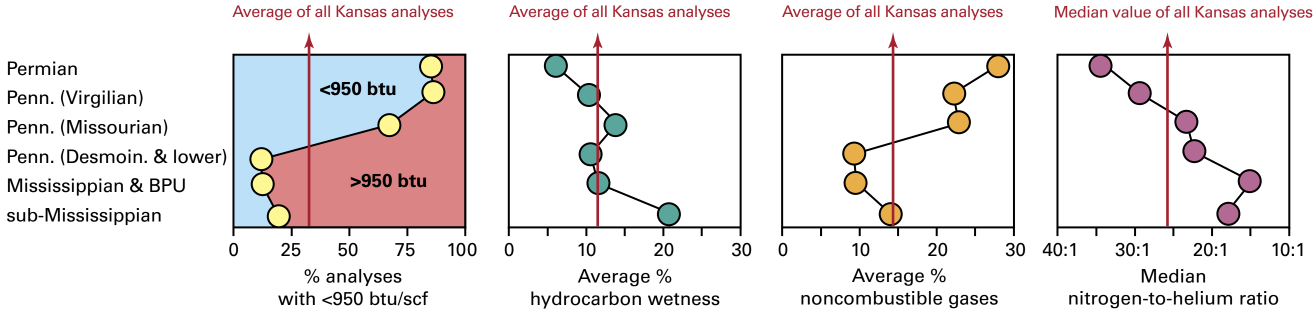
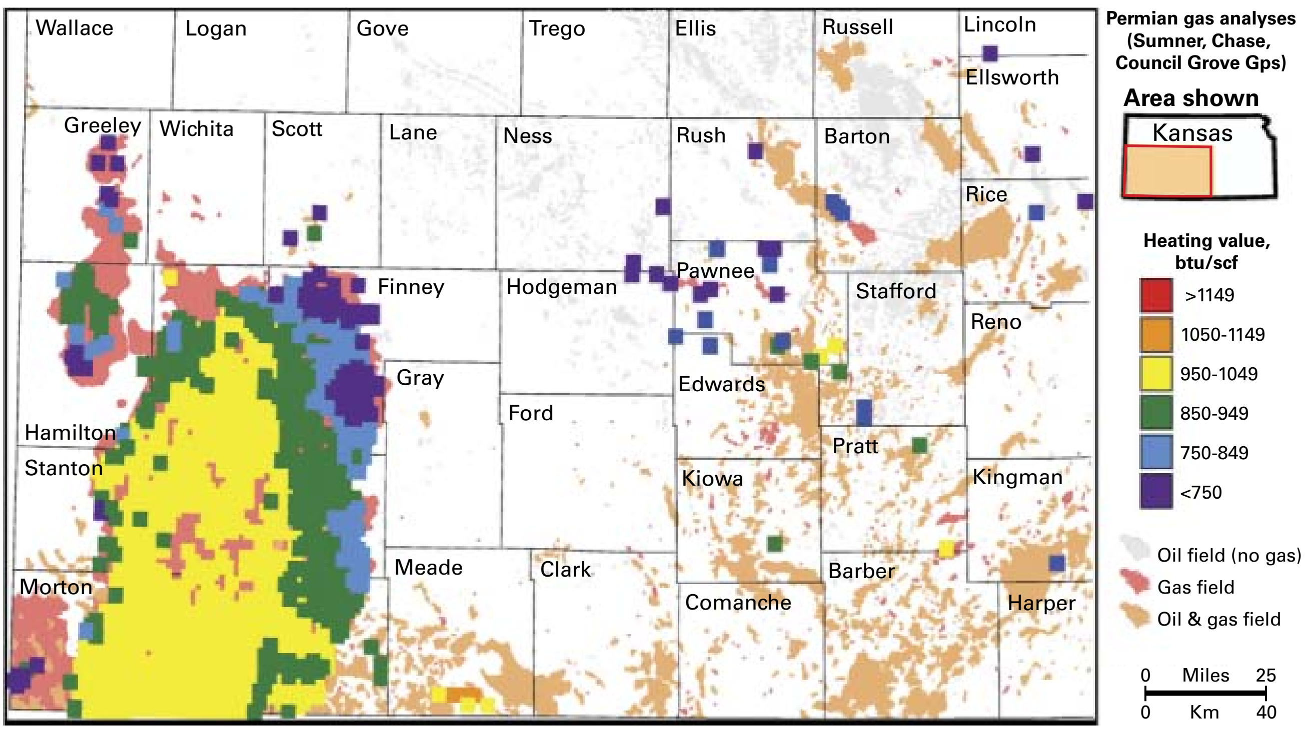


*Diagram at far left, which is a summary of the histograms presented in Fig. 3, shows changes in btu/scf. In general, heat content, hydrocarbon wetness, hydrocarbon percentage, and helium percentages and helium-to-nitrogen ratios decrease with decreasing age of the pay.

LOW-BTU GAS AREAS ON HUGOTON EAST FLANK, AND EASTWARD AROUND PAWNEE COUNTY*

Fig. 5



*Farther east of Hugoton, low-btu Permian gas in a group of small fields centered around Pawnee County generally increases in quality eastward.

on the downdip eastern flank of the field. Hugoton field has produced 25.2 tcf since its discovery in 1922, and currently has 7,600 active wells. Its main pay zones are several porous carbonate beds in the Permian Chase Group.

Pay zones in the Permian Council Grove Group (underlying the Chase Group in Hugoton gas field) compose the giant Panoma gas field (3 tcf cumulative production since 1956, 2,400 active wells). Hugoton and Panoma gases are nearly similar in quality at any given locality. Low-btu gas is estimated to compose 15% of Hugoton field and 7% of Panoma field (M. Dubois, personal communication).

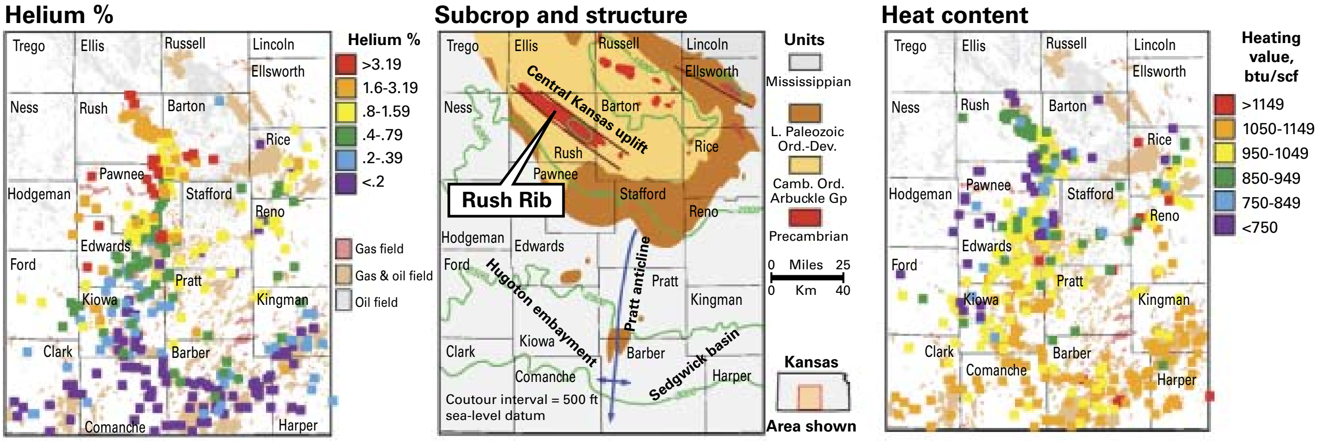
Quantity is its own quality in Hugoton field, thus most of its gas is upgraded in large cryogenic gas plants that also capture the helium. The nitrogen-to-helium ratio for Hugoton field is 40:1.[1]

Small Permian gas fields in central Kansas east of Hugoton field also produce low-btu gas from carbonates in the Chase Group (Fig. 5). Btu content of gas in these fields generally increases eastward. Their smaller reserves and geographic separation likely will require a different upgrading solution from Hugoton field.

The optimal type of upgrade pro-

GEOLOGY AND GAS CHEMISTRY ALONG BASAL PENN. ANGULAR UNCONFORMITY*

Fig. 6



*Fields paying from strata in subcropping and overlying the basal Pennsylvanian angular unconformity have a concentration of low-btu gas in central Kansas. Gas quality decreases northward, with the lowest-quality gases being present on a basement uplift called the Rush Rib in Rush County. Helium percentages increase northward and are at a maximum near the Rush Rib.

cessing will be determined by the rates, pressures, consistency of gas chemistry, and longevity of the individual wells. Pipeline logistics and the type of processing also need to be considered for either centralized or decentralized wellsite upgrading.

Smaller, isolated low-btu gas fields militate for on site processing. Skid-mounted upgrading units are an amenable solution, for these plants can be moved to other nearby localities when their gas source (a single or a few wells) is depleted.

Farther east in central Kansas, low-btu gas is present on the southern end of the Central Kansas uplift, particularly along a NW-SE trending faulted basement uplift called the Rush Rib, which straddles the Rush and Barton County lines (Fig. 6). Much of this low-btu gas is in reservoirs that subcrop and are directly above the basal Pennsylvanian unconformity. The quality of the gas degrades updip and northward onto the Central Kansas uplift (Fig. 6) due to an increasing percentage of noncombustible gas (mostly nitrogen).

As associated nitrogen is principally a value inhibitor to a natural gas, few studies focus on its source and migration. However, since nitrogen in natural gas is usually present in a nearly fixed ratio to helium,[1] a new set of economics comes in to play for producers willing to consider extraction and purification the helium in low-btu gas.

Ancillary income is possible from the capture and sale of helium. In general, helium-to-nitrogen ratios increase with increasing age of the reservoir in the Midcontinent (Fig. 3), and gas fields with the greatest percentage of helium are those that are dominated by low-btu gas (Fig. 5).

Helium is linked to nitrogen in an almost constant ratio of 8:1 for Mississippian and other reservoirs subjacent to the basal Pennsylvanian angular unconformity. Helium content increases northward and updip and exceeds 3% in reservoirs at the north end of the Rush Rib (Fig. 6).

The geological reasons for this are not completely understood, but the relatively low nitrogen-to-helium ratio of the many gas fields along the Rush Rib, in combination with the high percentage of nitrogen and helium, makes this region a potential target for gas upgrading through various engineering processes.

The spatial distribution of low-btu gas can be complex, with each stratigraphic horizon showing different trends (Fig. 7). In general, shallower and younger strata are exploration targets for low-btu gas. Once it is found, an economic success then depends on the engineering solution to the low-btu problem.

Engineering solutions

From an engineering standpoint, nitrogen is by far the most difficult and expensive of all natural gas separation endeavors.

Other problematic gases such as CO_2 and H_2S that are sometimes associated with natural gas can be removed in systems that utilize relatively simple chemical reactions. Other constituents, such as heavy hydrocarbons (propane, butane, etc.) can also be removed relatively simply with refrigeration units and at a reasonably low cost.

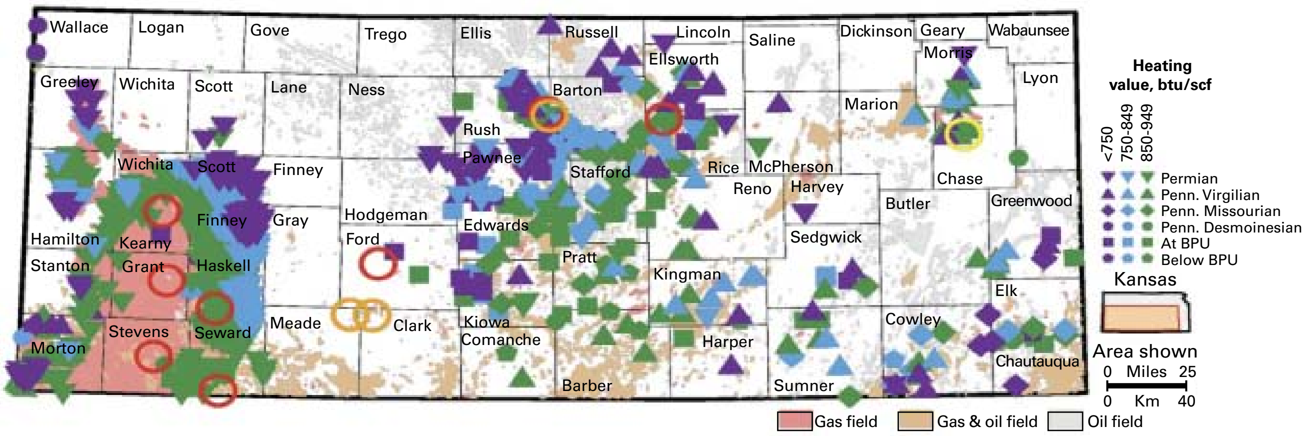
The shape and size of the nitrogen molecule is very similar to that of methane. For years upgrading of nitrogen-rich natural gases has focused on the respective boiling points of methane (–161° C.) and nitrogen (–196° C.), cryogenically liquefying the methane and venting the nitrogen through a system composed of compressors, heat exchangers, and pressure towers.

A similar procedure at even colder temperature can condense nitrogen and separate it from helium. Well-designed cryogenic systems work quite well, presuming these criteria: 1) high-pressure inlet gas (>600 psig), 2) large inlet volumes (>10 MMcfd), and 3) stable inlet volumes and gas composition.

In the early days, large cryogenic nitrogen-rejection plants were placed in geologic basins where nitrogen lev-

Low-btu gas analyses and plays in Kansas*

Fig. 7



*The Hugoton field perimeter and the southern end of the Central Kansas uplift are dominated by low-btu gas. Map also shows locations of large cryogenic-upgrade plants (red circles), IACX PSA plants (orange circles), and the PSA micro-rejection unit developed by American Energies Corp. and the Kansas Geological Survey (yellow circle).

els were most problematic. However, subsequent growth and integration of natural gas transmission systems across the country made it increasingly possible for lower-btu streams from one basin to be blended with higher-btu gas from another, mitigating the need for nitrogen removal.

One by one, large cryogenic plants fell off the map. The remaining plants in the US were relegated only to those basins where blending capacity was limited or unavailable, such as Hugoton field (Fig. 8).

From the mid-1980s forward, many have tried and (mostly) failed to design compact systems for noncryogenic nitrogen removal. Large and expensive nitrogen-rejection projects quickly become wildcat endeavors when they are placed on projects with even the smallest degree of reservoir risk.

Lower or uncertain volumes of natural gas cannot be economically accommodated by large, capital-intensive plants because process turndowns can yield enormous inefficiencies.

A handful of companies focus primarily on nitrogen rejection. BCCK Energy, Midland, Tex., utilizes proprietary cryogenic processes to extract nitrogen from higher-volume, higher-pressure gas streams, whereas IACX Energy of Dallas utilizes a proprietary process based on pressure swing adsorption (PSA), which allows smaller volumes of gas to be processed.

The PSA process involves exposing the raw natural gas to a specialized carbon material that traps (adsorbs) hydrocarbons, allowing for the undesired nitrogen to pass through the carbon unaffected. Once a carbon bed is fully loaded with adsorbed hydrocarbons, it is depressurized and pulled down with a vacuum causing the release of the hydrocarbon from the carbon adsorbent.

Molecular sieve technology can also separate nitrogen from methane. A membrane allows passage of one gas species through it, and the residual gas becomes richer is the retained species.

The economics for all processes vary drastically with differing operating conditions and gas composition.

If a producer has demonstrably higher and sustainable volumes of nitrogen-laden gas, then a larger-scale cryogenic plant will probably yield substantially lower processing cost per thousand cubic feet. If, on the other hand, a producer has gas reserves that are more questionable or that produce at lower volumes and pressures, then a modular or skid-mounted system is probably a better fit.

IACX Energy currently has 16 mobile nitrogen rejection units operating, five of which are in Kansas. Its process, "Nitrogen Sponge," utilizes PSA to remove nitrogen from natural gas streams at or near the wellhead. IACX Energy guarantees its systems have 95% methane recoveries, >99% C_{3+} recoveries, and 92% on stream time.

Throughout its existing fleet, inlet volumes range from 100 to 700 Mcfd with nitrogen levels ranging from 12% to 41%. Lower throughput volumes are possible, with commodity prices being the only significant limiting factor. IACX's fees represent an "all in" number, from dehydration, nitrogen removal, liquids removal (if needed), and compression into the sales line.

The company does not sell its units, but rather it owns and operates them on a lease/toll basis using a percentage of proceeds, or with joint-venture agreements. IACX Energy also captures and purifies associated helium gas, where feasible.

An even smaller nitrogen-rejection PSA system was developed in joint effort by the Kansas Geological Survey and American Energies Corp., Wichita, with aid of a grant from The Stripper Well Consortium at Penn State University. This experimental plant utilizes nonpatented technology and an adsorbent composed of porous activated charcoal made from coconut husks.

During the 6-month test of this prototype plant, inlet volumes averaged 150 Mcfd with nitrogen levels ranging

Nitrogen rejection alternatives in the Midcontinent range from the IACX Energy mobile unit at Otis, Kan., (top left) that uses nitrogen sponge technology to the smaller American Energies Corp. plant at Elmdale, Kan., developed with aid of a grant from the Stripper Well Consortium,[2] that uses the pressure swing adsorption method (top right) to BP American Production Co.'s cryogenic gas processing plant at Ulysses, Kan. (below). BP photo by John Charlton (Fig. 8).

from 32% to 40% (615 to 715 btu/scf). Feed-gas compositions, plumbing, valve timings, and vessel pressures were subject to experimentation, and problems with dead space in pressure vessels and blowout of carbon dust were addressed.

With fine-tuning, approximately 75% of the nitrogen was eliminated from the low-btu feedstock gas, 98% of the C_{2+} hydrocarbons were recovered, but methane recoveries were only 55% to 65%, depending on feed-gas composition. The lesser efficiency of methane recovery indicates that processing low-btu dry gas (i.e., hydrocarbon component dominated by methane) will have lesser economic feasibility with this system than low-btu wet gas (i.e., natural gas with substantial ethane and heavier hydrocarbon component gases).

On stream efficiency is difficult to determine with only one prototype, but AEC maintains this plant, once it was fine-tuned, profitably upgraded low-btu input feeds to a simple requisite minimum pipeline heat content of 950 btu/scf. This PSA unit, like those of IACX Energy, is mobile and can be moved to other wellsites at relatively low cost once the low-btu resource is locally depleted.

Summary

Several low-btu gas plays can be defined by mapping gas quality by geological horizon in the Midcontinent.

Some of the more inviting plays include Permian strata west of the Central Kansas uplift and on the eastern flank of Hugoton field and Mississippi chat and other pays that subcrop beneath (and directly overlie) the basal Pennsylvanian angular unconformity at the southern end of the Central Kansas uplift.

Successful development of these plays will require the cooperation of reservoir geologists and process engineers so that the gas can be economi-

cally upgraded and sold at a nominal pipeline quality of 950 btu/scf or greater.

Nitrogen is the major noncombustible contaminant in these gas fields, and various processes can be utilized to separate it from the hydrocarbon gases. Helium, which is usually found in percentages corresponding to nitrogen, is a possible ancillary sales product in this region. Its separation from the nitrogen, of course, requires additional processing.

The engineering solution for low-btu gas depends on the rates, volumes, and chemistry of the gas needing upgrading. Cryogenic methods of nitrogen removal are classically used for larger feed volumes, but smaller feed volumes characteristic of isolated, low-pressure gas fields can now be handled by available small-scale PSA technologies.

Operations of these PSA plants are now downscaled for upgrading stripper well gas production. Any nitrogen separation process should be sized, within reason, to match the anticipated flow rate. If the reservoir rock surprises to the upside, the modularity of the upgrading units is critical, for they can be stacked to meet higher volumes. If a reservoir disappoints (and some will), modularity allows the asset to be moved to another site without breaking the bank. ✦

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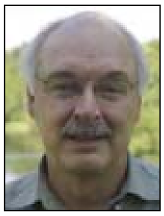
The authors



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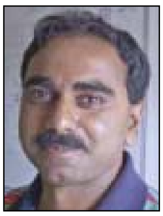

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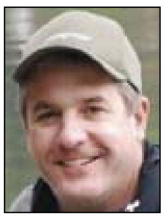


Scott Sears is chief executive officer and a director of IACX Corp., Dallas. His expertise is upstream exploration and production. He was previously vice-president at Oklahoma Oil Co. He has a BA in history and an MBA from Southern Methodist University.

Brunei

Tap Oil Ltd.'s Borneo subsidiary said it identified a contingent resource of 8 to 64 million boe in Brunei's undeveloped Belait oil and gas field onshore 65 km southwest of Bandar Seri Begawan.

Tap Energy (Borneo) Pty. Ltd. shot 118 sq km of 3D seismic and 60 line-km of 2D seismic over the field and adjacent areas on Block M, which covers 3,011 sq km in the Baram Delta. The balance of Brunei's largest onshore permit is underexplored.

The 3D seismic program, first in the Belait trend, is "designed to address the structural complexity of the field and identify deeper, higher impact targets," Tap Oil said. At least two wells are to be drilled starting in mid-2010.

Interests in Block M are Tap Energy (Borneo) 39%, Triton Borneo Ltd. 36%, China Sino Oil Co. Ltd. 21%, and Jana Corp. Sdn. Bhd. 4%.

Triton notes that Belait was discovered in 1913, and one well produced oil in 1924-31. A total of 18 wells have been drilled in the 122 sq km area.

India

Reliance Industries Ltd., Mumbai, has spud the first well on the D9 license in the Krishna-Godavari basin off eastern India.

The KG-D9-A1 well is to go to TD 4,820 m in 2,754 m of water using the Transocean Deepwater Expedition. Targets are early and middle Miocene slope fan sands. The well is the first in a four-well minimum work program on the 11,605-sq km block.

Reliance Industries is operator of the block, and Hardy Oil & Gas PLC holds 10% interest.

Russia

Crown Oil & Gas Inc., Bellingham, Wash., shot 779 line-km of high resolution 2D seismic on the 1,100 sq km Kikinsko-Gusikhinsky license in Russia's Saratov area.

Saratovneftegeophyzika interpreted the data and recommended drilling the Prirazlomny and Chernobulaksky prospects. Projected drilling depths are 2,230 m, with targeted pay zones starting with Upper Cretaceous at 700 m.

Drilling is likely in 2010, when more seismic is planned on five other leads.

DRILLING MARKET FOCUS

Contractors' earnings fall amid brighter deepwater forecasts

Paula Dittrick
Senior Staff Writer

Drilling

Offshore drilling contractors reported declines in second-quarter 2009 net earnings and continued stacking rigs, while oil companies coped with less cash flow to finance drilling during an economic downturn and slowing growth in world oil demand.

Drilling giant Transocean Ltd. of Geneva, Switzerland, reported seven rig leases were canceled or terminated as of early August and its rig utilization rates are down across all rig categories. Deepwater drilling remains the strongest.

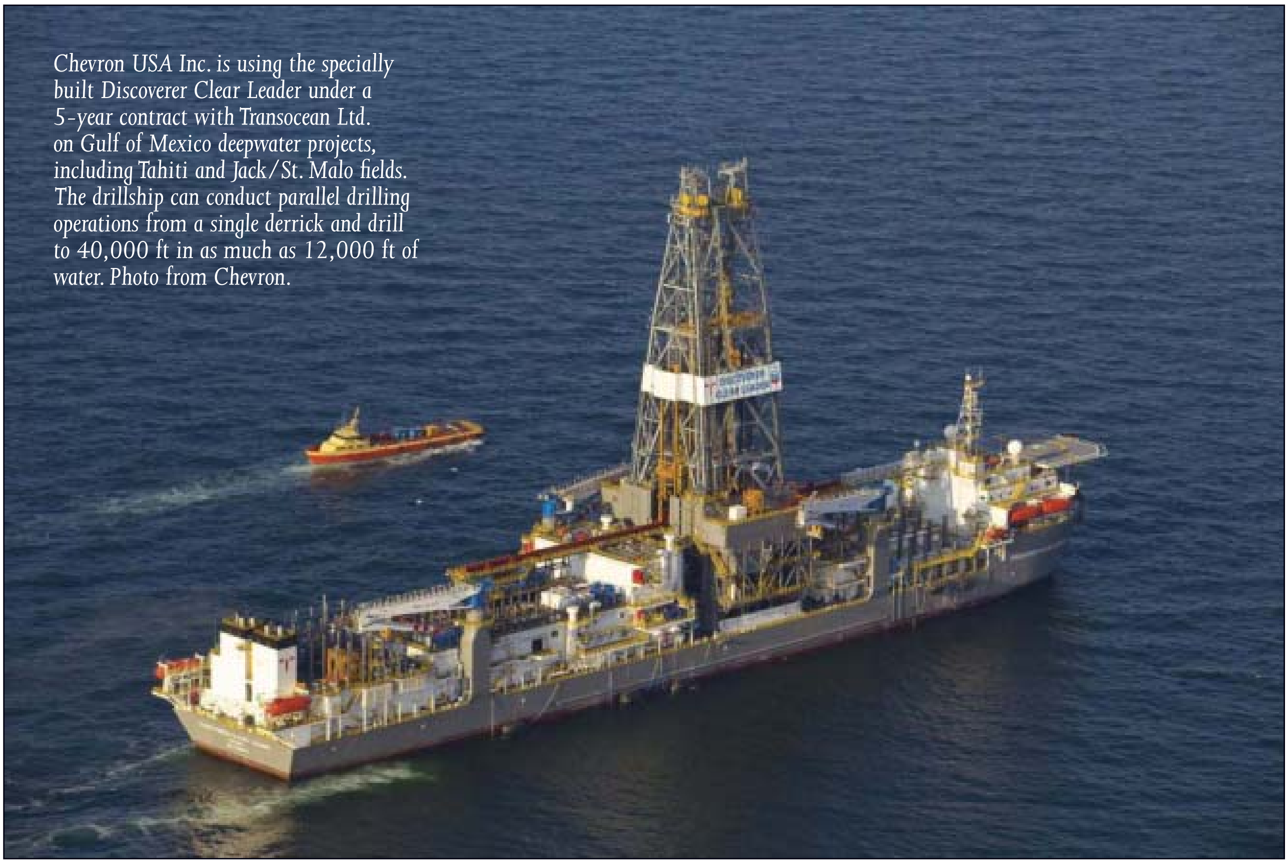
On Aug. 13, Chevron USA Inc. announced Transocean's Discoverer Clear Leader began operations in the Gulf of Mexico. The dynamically positioned, double-hulled Discoverer Clear Leader is the first of five Transocean ultra-deepwater Enterprise-class drillships scheduled to begin operating in 2009 and 2010 (OGJ, Mar. 6, 2006, Newsletter).

The drilling contractor is scheduled to commission a second drillship for Chevron, the Discoverer Inspiration, early next year.

Deepwater markets hold robust promise, according to reports issued this year by Douglas-Westwood Ltd. and Energyfiles, a forecasting service for oil and gas production, consumption, and drilling activity.

The reports are entitled "World Offshore Oil & Gas Production and Spend Forecast 2009-2013" published in August and "The World Offshore Drilling and Spend Forecast 2009-2013" published in April.

Analysts forecast overall lower offshore drilling expenditures during



Chevron USA Inc. is using the specially built Discoverer Clear Leader under a 5-year contract with Transocean Ltd. on Gulf of Mexico deepwater projects, including Tahiti and Jack/St. Malo fields. The drillship can conduct parallel drilling operations from a single derrick and drill to 40,000 ft in as much as 12,000 ft of water. Photo from Chevron.

WORLDWIDE RIG COUNT

2009	Latin America	Europe	Africa	Middle East	Far East	Canada	US	World
January	381	93	58	274	238	377	1,553	2,974
February	374	81	59	264	242	413	1,320	2,753
March	358	95	61	262	236	196	1,105	2,313
April	349	86	62	253	236	74	995	2,055
May	357	82	62	253	239	72	918	1,983
June	343	77	64	247	236	125	895	1,987
July	351	73	57	249	244	175	931	2,080

Source: Baker Hughes Inc.

2009-10 followed by a return to previous growth levels.

Total world offshore expenditures are expected to reach $330 billion in 2013 compared with $240 billion in 2008, forecasters said. During the last 5 years, an estimated average of $278 billion was spent on offshore drilling.

Offshore to rebound after 2010

Crude oil price volatility led to uncertainty and project delays resulting in what Michael R. Smith, chief executive of the UK-based Energyfiles, calls "across-the-board cost deflation" in 2009.

Global upstream oil and gas budgets for 2009 were cut by 21% with more than 20 planned large projects postponed, he said.

"By 2013, the [estimated annual global offshore drilling] market will be worth nearly $90 billion, having grown from $37 billion in 2004 and $72 billion in 2008," Smith said. Deepwater projects are expected to drive the biggest future growth.

He said development spending increased more rapidly than exploration spending since 2004, although the trend slowed in 2007-08. Smith expects the 2009 spending decline will mark the beginning of a permanent jump in the relative share of development spending in oil company budgets.

Separately, Baker Hughes Inc. reported the worldwide rig count for July 2009 was 2,080, up 93 from the 1,987 counted in June 2009 but still down 1,356 from the 3,436 counted in July 2008.

The July international rig count (outside the US and Canada) was 974, up 7 from the 967 counted in June 2009, and down 118 from the 1,092 counted in July 2008, Baker Hughes said. The international offshore rig count for July 2009 was 275, up 6 from the 269 counted in June 2009 and down 37 from the 312 counted in July 2008.

Smith of Energyfiles said new offshore oil supplies outside deep waters and the Persian Gulf are scarce, meaning the industry must explore and invest in far-flung, high-cost regions.

"Malaysia and Indonesia have significant ongoing deepwater projects, and India is developing deepwater gas fields off its eastern coast," Smith said. "The Asian market will return to strength by mid-2010 with a wide range of opportunities, especially as China, India, and Vietnam look to exploit their more-distance offshore shelves."

Western European offshore spending generally is expected to be lower through 2011, after a sharp decline in 2009. Prospects are expected to recover slightly upon tax relief and improving oil and gas prices, which is likely to boost commerciality of smaller projects, Smith said.

"Deepwater spending is modest due to a lack of prospective deepwater basins outside limited areas of Norway, the UK, and the Mediterranean," he said.

In Africa, progressive exploitation of deeper and deeper waters previously drove growth. "However, a dip occurred in Africa in 2008, and this is expected to be repeated in 2009 before steady growth returns up to 2013," he said.

The same pattern is expected in Latin America with Brazil and Mexico being the most active. The Middle East was the only region where drilling demand increased during 2008, but that has dipped this year.

"Growth is forecast to return through 2013 with low-cost drilling in field developments dominating in the Persian Gulf, and higher-cost deepwater or environmentally difficult wells dominating elsewhere," Smith said.

Diamond Offshore buys semi

Diamond Offshore Drilling Inc. completed its $460 million acquisition of the semisubmersible PetroRig I from Jurong Shipyard Pte Ltd., a subsidiary of Sembcorp Marine. The semi was renamed Ocean Courage.

Previously, PetroRig I was scheduled to work in the Gulf of Mexico for Petroleo Brasileiro SA. Those plans were scrapped, and the semi was sold after three Singapore subsidiaries belonging to Norwegian PetroMENA AS filed for reorganization under Chapter 11 bankruptcy protection in the US Southern District of New York.

Court records show PetroRig I had bond debt, and that PetroMENA struggled to arrange financing to complete the semi's construction. Reuters news service reported in late April that Sembcorp Marine said Jurong Shipyard terminated the rig-construction contract with PetroMENA for lack of a final payment.

Lawrence R. Dickerson, Diamond Offshore president and chief executive officer, reported Ocean Courage was acquired without any drill pipe. Several potential customers have inquired about Ocean Courage, which he expects to be available in 2010. As of Aug. 17, Ocean Courage had no drilling contract yet.

In response to questions during a conference call, Dickerson said he anticipates a day rate in the $400,000 range for this type of semi. Negotiations will hinge upon contract length and where the semi ends up working, he said.

Diamond Offshore reported second-quarter 2009 revenues of $946.4 million compared with $954.4 million for the same period a year ago. Dickerson noted 88% of the company's current revenues came from contracts signed more than 1 year ago.

Second-quarter profits were $387.4 million compared with $416.2 million for second-quarter 2008.

Contractors stacking rigs

Transocean's net income for the quarter ended June 30 was $806 million compared with net income of $1.065 billion for the same quarter a year ago. The latest second-quarter revenues were $2.88 billion compared with $3.1 billion for the same period last year.

Pritchard Capital Partners LLC analysts said Transocean had 18 idle jack ups, of which 15 are stacked. That compared with 9 idle jack ups that Transocean reported at the end of the first quarter and 3 idle jack ups as of yearend 2008.

Transocean executives expect to have stacked 25-26 jack ups by yearend 2009. Previously, the contractor estimated 15-20 jack ups stacked by year end. The company also told analysts that it's optimistic there will be long-term demand for deepwater floaters off Libya, Israel, and Mexico, Pritchard Capital said.

Chad C. Deaton, Baker Hughes chairman, president, and chief executive officer, said the decline in international rig activity appears less severe than the dipping US rig count.

"We were awarded new work or renewed international contracts in the second quarter for more than $1.5 billion," Deaton said. This included contracts for intelligent completions in Brazil and directional drilling off Nigeria.

He believes drilling activity in Russia and the Caspian region reached bottom and has started to rebound. Meanwhile he expects "activity in the Middle East, Asia-Pacific, and Latin America regions will increase modestly."

Baker Hughes reported second-quarter 2009 net income of $87 million compared with $379 million for the same quarter a year ago. Second-quarter 2009 revenue was $2.34 billion, down 22% compared with the same period a year ago. ✦

OFFSHORE BONDS— Conclusion

Risk-adjusted methods update supplemental bonding calculations

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Bernard J. Kruse III
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Production

Risk-adjusted methods provide alternative approaches for calculating supplemental bonding requirements for operators in the Gulf of Mexico.

Currently the US Mineral Management Service is assessing the need to update the formula for calculating bonding requirements that have been in place since the early 1990s.

This concluding part of a two-part series summarizes several proposed alternative calculation methods to determine adequate supplemental bonding levels. The first part (OGJ, Sept. 7, 2009, p. 37) provided an overview of the supplemental bonding industry in the gulf.

Supplemental bonding

Supplemental bonding protects the government from incurring costs associated with offshore lease abandonment. The MMS requires operators to post a supplemental bond if at least one record titleholder of the lease does not satisfy a minimum threshold financial capacity.

MMS has been using an empirically derived formula (Table 1) for computing end-of-lease liability. The formula has worked successfully but because the bonding formula is calibrated to projects performed in the early 1990s, there is an obvious need to update the formula to reflect current operating costs and technology.

A recent study presented updated risk-adjusted bonding levels and discussed the guidelines and tradeoffs in formula development.[1]

The present article summarizes these risk-adjusted alternatives.

Background

The US government sells the right to explore for hydrocarbons and develop tracks on the Outer Continental Shelf at periodic sealed-bid auctions. The bidding variable at these auctions is a cash payment, or bonus that the winning bidder must pay to the government before the lease becomes effective.

Operators buy the right to extract natural resources on federal lands subject to royalty and rental payments, a commitment to operate in an environmentally sound manner, and to remove facilities when the lease can no longer produce commercially.

The MMS is the primary federal agency responsible for ensuring that operators develop resources and maintain facilities in a safe and environmentally sound manner. Once production facilities reach the end of their useful lives, MMS has the obligation to ensure that decommissioning operations protect the safety of workers and environmental integrity, in accordance with federal regulations.[2]

From the operator's point of view, decommissioning represents a future cost to be incurred, while from the government's perspective, decommissioning represents a risk of noncompliance and potential financial liability.

The government requires operators to post a general bond on all leases based on the amount of activity on a lease to ensure compliance with rent, royalties, environmental damage, and clean-up activities not related to oil spills, abandonment, and site-clearance.

When the cost to meet lease obligations exceeds the amount of a general bond and the lessee cannot demonstrate the financial capability to meet these obligations, the regulations require a supplemental bond.

The accompanying box provides a definition of financial capacity.

Recently, the MMS issued NTL No. 2008-N07 to update and clarify the procedures and criteria used to determine when a supplemental bond is required to cover potential decommissioning liability.[3]

The MMS considers all lessees and operating-rights interest owners on a lease to be jointly and severally liable for all lease obligations. A company that sells its interest remains liable for

FINANCIAL STRENGTH, RELIABILITY LITMUS TEST

Table 1

For lessees with stockholders' equity or net worth of:	If the lessee's cumulative potential decommissioning liability is ≤25% of stockholder's equity or net worth, the lessee's debt to equity ratio (total liabilities/net worth) must be:	If the lessee's cumulative potential decommissioning liability is >25% but ≤50% of stockholder's equity or net worth, the lessee's debt-to-equity ratio (total liabilities/net worth) must be:
$65 million-$100 million	≤2.5	≤2.0
Greater than $100 million	≤3.0	≤2.5

Source: NTL No. 2008-N07

decommissioning if the current owners do not comply with the terms of the lease.

If a property has current or previous working interest owners who are not financially capable of performing their decommissioning obligations or if a property does not have any previous owners,the property will be put up for sale. If the property is of marginal value or decommissioning liability is greater than the expected value of production, it is unlikely that a buyer for the property will be found.

Decommissioning commitments nonetheless have to be fulfilled, which creates a potential problem because MMS is neither funded nor authorized to incur these obligations. If the cost of decommissioning is greater than the supplemental bond on the lease, the lessee has the obligation to pay the difference.

In the case of default, the US government, as the party of last resort, would have the obligation to pay the difference.

Each producing lease in the OCS has a different level of decommissioning risk to the government. Risk events may be triggered by occurrences specific to a few participants, such as a bankruptcy or blowout, or by events that affect several companies simultaneously, such as hurricane destruction.

Fortunately, the gulf has had a low default rate. During the past 2 decades, only two operators in the gulf have not met their decommissioning obligations, and in both cases, because a previous record titleholder was financially sound, the federal government did not incur any expense.

In recent years, however, as more properties mature and change hands and smaller operators hold larger portfolios of assets, there are concerns about the potential financial risk of decommissioning to the US government.

For all leases in the gulf for which the estimated lease liability exceeds a specified financial commitment for all owners, the operator must post a supplemental bond,

Financial strength, reliability

Federal regulations require a supplemental bond on a lease, right-of-use easement, or right-of-way, unless the government determines that at least one record title owner or holder of the RUE or ROW meets the following conditions that demonstrate financial strength and reliability:

1. Provides an independently audited calculation of net worth equal to or greater than $65 million, in accordance with US Generally Accepted Accounting Principles (US GAAP) or the International Financial Reporting Standards (IFRS).

2. Has a cumulative decommissioning liability of less than or equal to 50% of the most recent and independently audited calculation of net worth.

3. Demonstrates reliability as evidenced by:

- *Number of years of successful operations and production of oil and gas in the OCS or in the onshore oil and gas industry.*
- *Credit rating, trade references, and verified published sources.*
- *A record of compliance with current and previous governing laws, regulations, and lease terms.*
- *Other factors that indicate financial strength or reliability.*

4. Produces fluid hydrocarbons in excess of an average of 20,000 boe/d from OCS leases for which the lessee owns a record title interest.

5. Meets the criteria set forth in Table 1 by providing independently audited financial statements in accordance with US GAAP or the IFRS.

Source: NTL No. 2008-N07

MMS LEGACY FORMULA[1]

Table 2

Decommissioning stage	Water depth, ft	Estimated cost,[2] $1,000
Plug & abandon	All	100
Structure removal	<150	400
	151-200	600
	20-299	1,250
	>300	2,000+
Site clearance & verification	<150	300
	151-249	400
	>250	500

[1]The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate. [2]The plug-and-abandonment unit cost is per borehole, the structure removal cost is per structure, and the SC&V cost is per leasehold. Total lease liability is computed by summing the unit-cost elements for the number of wells and structures per leasehold.
Source: MMS, 1998

Bonding calculations

Historically, MMS's procedure for determining the value of the bond involves counting the number of unplugged wells and structures on the lease and then applying its formula, referred to as the legacy formula (Table 2).

The MMS adjusts the cost estimates when available information shows that the numbers are inaccurate.

An outline of an alternative approach described in the next section uses risk-adjusted cost estimates for decommissioning.

Baseline level

The approach sets the baseline bonding level for each of the three main stages of decommissioning—well plugging and abandonment, structure removal, and site clearance and verification—at the average historical cost for performing the activity.

The calculation uses the bonding levels for a p-year future time horizon based on data collected from a time no longer than p-years, and vice versa.

For example, if the only cost data available are from a 5-year horizon, then the calculation should use a bonding formula with a future horizon of no longer than 5 years.

Cost estimation assumptions

Plugging and abandonment

- *Considers all wellbores on a lease except for permanently plugged and abandoned wells. Wells include producing (active), idle (inactive, shut-in, temporarily abandoned), and service (disposal, injection) wells.*
- *Makes no distinction between wells based on age, production type (oil, gas, condensate), water depth, completion type (single or multiple), trajectory (vertical, deviated, horizontal), number of sidetracks, or other complexity measures.*
- *Determines costs based on the application of rig and rigless techniques, platform and lift boat jobs, day rate and turnkey contracts.*
- *Allows scale economies in wellbore plugging on a multiwell contract.*
- *Considers only normal operations and not P&A work for hurricane-destroyed structures or wells.*
- *Considers only surface systems or wells with a surface tree in less than 300-ft water depth. Hybrid wells and wet trees (subsea wells) in water depth greater than 300 ft require a separate assessment.*
- *Assumes P&A technology remains essentially unchanged during the time horizon under consideration and no significant changes in the regulatory framework during this time.*
- *Applies a 10%/year cost inflation.*

Structure removal

- *Assumes employment of conventional technology for all operations and the permitting of all possible disposition options, for instance, complete removal of platforms with all materials transported ashore for recycling or disposal, or reefing of the structures.*
- *Assumes removal technology remains essentially unchanged during the time horizon under consideration and no significant changes in the regulatory framework.*
- *Does not consider the impact of environmental mitigation cost; the cost to retain an agent; engineering, planning, permitting, and regulatory compliance; weather and general contingency factors; and abnormal market conditions.*
- *Considers only normal operations and not structures destroyed by man-made or natural catastrophe.*
- *Assumes no scale economies occur in operations, such as the grouping of structures in a multistructure removal package.*
- *Considers only fixed structures in less than 300-ft water depth in the Gulf of Mexico. Structures in water depth greater than 300 ft or residing outside of the gulf require a separate assessment.*
- *Considers and groups in the same category caissons and well protectors as defined by the MMS as similar structures for the purpose of removal. Fixed platforms comprise a separate category.*
- *Includes pipeline abandonment in the costs for removal of caissons and well protectors. Removal cost for fixed platforms includes structure preparation and pipeline abandonment.*
- *Does not inflate cost data.*

Site clearance and verification

- *Assumes site clearance performed with net trawling under day rate contracts.*
- *Limits water depth to 300 ft or less.*
- *Groups structural units and counts them in terms of caissons and all other jacketed structures (well protectors and fixed platforms) to match the clearance area requirements defined by the MMS.*
- *Does not inflate cost data.*

Formula duration

The approach sets bonding requirements at a specific time and it applies to current decommissioning operations as well as future activity. This creates a dilemma when setting bonding levels because costs may inflate and levels set at the current time may not represent future expenditures.

For formula durations that extend across a limited and short time horizon, one would expect this problem to be minimal.

To reduce the level of ambiguity and to encourage a regular review cycle, the recommendation is that the approach specify explicitly the formula duration.

Inflation factor

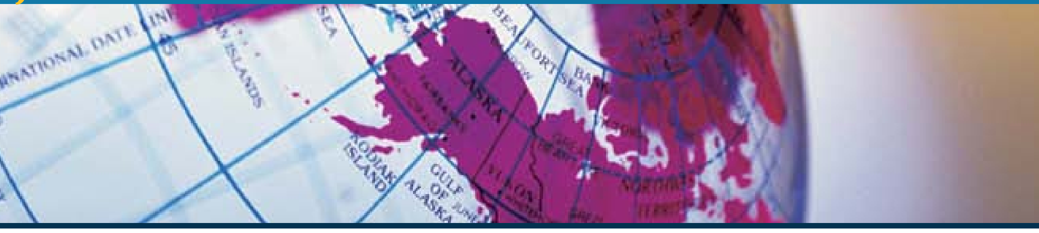
Cost indices are available for different segments of the oil and gas industry, but offshore decommissioning is a specialized sector without any good proxy measures for cost inflation that we believe are representative of the sector.

Activities that depend on support and construction vessels may require an inflationary adjustment, due to changes in labor rates, fuel, demand requirements, etc. or may be relatively immune to inflationary pressures.

Supply and demand conditions in the gulf determine market rates, and because the uncertainty and magnitude in market rates typically dominates inflation uncertainty, empirical data may not provide clear trends on the occurrence or absence of inflation effects.

Representative cost

Ideally, to estimate decommissioning



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The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

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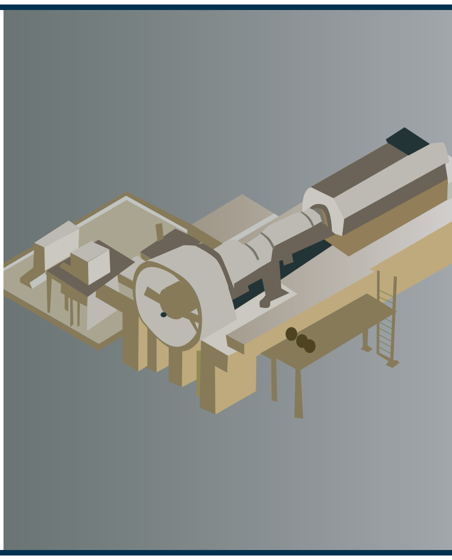
These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

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



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Unused GE D11 HP/IP turbine assembly and other miscellaneous parts including LP casings and 304-MW generator stator now available for immediate sale.

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

Solar Centaur 40 T4701S Turbine Generator Package with approximately 60,000 accumulated hours at 50% load. Package was in service from 1999 until August 2007. Engine is BACT compliant with OEM 25 ppm Nox/50 ppm CO guarantee. Operates off SAB-type Ideal generator rated at 3500 kW, 4375 kVA and 13,800 volts at 60 Hz. Miscellaneous equipment includes inlet air filtration and simple exhaust systems, and auxiliary control console with start/stop/sync/control.

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Example

A lease in 75 ft of water has an inventory of 5 producing wells, 18 idle wells, and 3 service wells; 2 caissons, 1 well protector, and 2 fixed platforms.

The supplemental bonding required on the lease if no working interest owner meets the minimum financial requirements of the MMS are as follows. First, enumerate the number of wells and structure count by type, and record the water depth of each entity:

- *Total well count: 26.*
- *Structure count by type: CAIS = 2, WP = 1, FP = 2.*
- *Water depth: 75 ft.*

Apply Tables 2-5 to determine bonding levels. For the average cost case, Table 2 yields:

- *P&A cost = 26 × $773,000 = $20.1 million.*
- *REM cost = 3 × $1,260,000 + 2 × $1,527,000 = $6.83 million.*
- *SC&V cost = 2 × $16,000 + 3 × $43,000 = $161,000.*

The total supplemental bond is $28.39 million for the lease. Table 7 shows the results for the risk-adjusted bonding levels.

cost, one would want to record detailed descriptions of the work activity. In this perfect world, one could easily calculate average costs, and if all operations were reported under well-defined accounting standards, no uncertainty would arise regarding the nature of the assessment and if it is representative of the industry.

In the real world, acquiring cost data that is representative of the industry is a more difficult task due to confidentiality concerns, the lack of industry interest, and the time and resource commitments required.

Real world data sets are neither complete nor representative and one must take care to ensure that analysis of the collected data includes the specific characteristics of the operations and operators.

In the real world, bias can result from sample selection problems. Cost statistics closely relate to the sample set and one cannot consider this representative by default. In almost all cases, the analysis needs additional processing.

Data balancing

To normalize or balance the sample data, the proposed approach employs an equal-weighted averaging scheme that first averages according to operator type and then equal-weights the averages by class.

This is based on user preference and the belief that if the federal government performed decommissioning activities in the gulf for any company, independent or major, its cost for services likely would be more similar to those of a major and not those of an independent.

The US government would need the services of a project management firm to manage the logistics and permitting process, would not realize the economics of scale economies, which would increase safety and environmental expenditures above the average costs.

The equal-weight class average attempts to balance the nature of operations with the availability of reliable data. Other balancing schemes are also possible.

Data uncertainty, risk tolerance

The risk-adjusted approach reflects the uncertainty associated with operational and market activity, cost estimation, and the risk tolerance level of the federal government.

One would not expect any of these factors to dominate every situation; therefore, one can view risk adjustment as a means to account for the combination of all data uncertainty and risk tolerance variation.

Risk adjustment

The approach adjusts upward the bonding level from the baseline (average) cost by 1, 2, and 3 standard deviation multiples. There is a trade-off in the selection of the risk adjustment because

High risk[1]

Table 3

Decommissioning stage	Water depth, ft	Estimated cost,[2] $1,000	
Plug & abandon	All	773	
		CAIS & WP	FP
Structure removal	0-100	1,260	1,527
	101-200	1,813	2,470
	201-300		3,090
		CAIS	WP & FP
Site clearance & verification	All	16	43

[1]2008-13, average cost. [2]Plug-and-abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit-cost elements for the number of wells and structures per leasehold.
Source: Reference 1

Moderate risk[1]

Table 4

Decommissioning stage	Water depth, ft	Estimated cost,[2] $1,000	
Plug & abandon	All	1,383	
		CAIS & WP	FP
Structure removal	0-100	1,731	2,580
	101-200	2,750	3,503
	201-300		5,199
		CAIS	WP & FP
Site clearance & verification	All	26	67

[1]2008-13, average cost + 1 standard deviation. [2]Plug-and-abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit-cost elements for the number of wells and structures per leasehold.
Source: Reference 1

Low risk[1]

Table 5

Decommissioning stage	Water depth, ft	Estimated cost,[2] $1,000	
Plug & abandon	All	1,993	
		CAIS & WP	FP
Structure removal	0-100	2,200	3,633
	101-200	3,687	4,836
	201-300		7,307
		CAIS	WP & FP
Site clearance & verification	All	36	91

[1]2008-13, average cost + 2 standard deviation. [2]Plug-and-abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit-cost elements for the number of wells and structures per leasehold.
Source: Reference 1

Very low risk[1]

Table 6

Decommissioning stage	Water depth, ft	Estimated cost,[2] $1,000	
Plug & abandon	All	2,603	
		CAIS & WP	FP
Structure removal	0-100	2,673	4,686
	101-200	4,624	6,169
	201-300		8,416
		CAIS	WP & FP
Site clearance & verification	All	46	115

[1]2008-13, average cost + 3 standard deviation. [2]Plug-and-abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit-cost elements for the number of wells and structures per leasehold.
Source: Reference 1

any increase above average cost will impose a greater financial burden on operators while holding bonding levels at average cost will transfer a greater portion of decommissioning exposure to the government.

Each stage of decommissioning has one of the following four bonding levels:

1. Average Cost: C (high risk).
2. Risk-adjusted cost I: C + 1SD (moderate risk).
3. Risk-adjusted cost II: C + 2SD (low risk).
4. Risk-adjusted cost III: C + 3SD (very low risk).

The approach assigns qualitative risk indicators of high, moderate, low, and very low to each category based on the frequency in which actual costs likely will exceed the average costs under normal conditions.

The indicators are subjective and meant to be interpreted in a relative sense. It is difficult to establish quantitatively the correspondence between risk and decommissioning exposure, but by incorporating one or more standard deviation terms, the government likely has less exposure to liabilities arising from inadequate bonding levels.

Average cost represents the base case or the high-risk category. The addition of one or two standard deviation multiples to the base case lowers the risks that the risk-adjusted cost of decommissioning will exceed the posted bonds.

Supplemental bond requirements

Table 7

Stage	C	C + 1×SD	C + 2×SD	C + 3×SD
	Risk-adjusted cost level, $ million			
P&A	20.10	35.96	51.82	67.68
REM	6.83	10.35	13.87	17.39
SC&V	0.161	0.253	0.345	0.437
Total	**28.39**	**46.56**	**66.04**	**85.51**

Supplemental bonding tableau

The accompanying box shows the assumptions used in updating the MMS supplemental bonding legacy formula with a risk-adjusted mechanism across each of the main stages of decommissioning.

Table 3 shows the average, no risk-adjustment, and cost of decommissioning, while Tables 4-6 show the three risk-adjusted levels using standard deviation as a proxy for the risk-adjustment factor.

The updated formula maintains the same structure as the legacy formula but is only directly comparable across the P&A category, where since the early 1990s the average well bonding levels have increased roughly sevenfold.

In the structure removal category, bonding levels have increased two to four times above the legacy formula.

The box shows an example calculation with the updated formula, and Table 7 shows the risk-adjusted calculation. ✦

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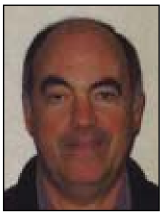
2. Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Decommissioning Activities; Final Rule, 30 CFR Parts 250, 256,. 67 (96):35398-35412, 2002.

3. Supplemental Bond Procedures, Notice to Lessees and Operators—NTL No. 2008-N07, Minerals Management Service, Aug. 28, 2008.

The authors



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Mark J. Kaiser's biography and photo were published in the first installment of this series (OGJ, Sept. 7, 2009, p. 37).

Here's a quick means to determine MeOH injection to inhibit hydrates

Mahmood Moshfeghian
John M. Campbell & Co.
Norman, Okla.

Roohallah Taraf
Pars Oil & Gas Co.
Tehran

This article proposes a set of reference charts developed by the authors for determining required methanol concentrations in the aqueous phase (rich solution) and total lean inhibitor's flow rate for a desired depression in hydrate formation temperature of a wet natural gas.

The charts were generated for 100 wt % MeOH and pressures of 3 MPa (about 435 psi), 5 MPa, 7 MPa, and 9 MPa based on ProMax and for a natural gas mixture with relative density of 0.6 but are extended to gases with relative densities up to 0.8 by use of two correction factors. A simple equation extends the charts' use to other lean MeOH concentrations.

Results obtained by these charts are compared here with results of other methods for a practical case; good agreement is obtained. The authors also suggest that linear interpolation can be used for pressures between 3, 5, 7, and 9 MPa.

Based on a presentation to the 88th Annual Gas Processors Association Convention, Mar 8-11, 2009, San Antonio.

Hydrates in operations

Formation of hydrates in natural gas processing units and pipelines can cause shutdowns and even destruction of valuable equipment. Because of these often costly consequences, methods have been applied to prevent hydrate development in gas streams.

Conditions that tend to promote hydrate formation include low temperature, high pressure, and a gas at or below its water dewpoint temperature with "free" water present. Formation of hydrates can be prevented by any of the following techniques:

- Adjusting the temperature above and pressure below the hydrate formation condition, which may not be practically possible for economic or operational reasons.
- Dehydrating a gas stream with solid desiccant or glycol dehydration to prevent a free-water phase.
- Impeding hydrate formation in the free-water phase by injection of an inhibitor.

The most common inhibitors are methanol, monoethylene glycol,

Known data, results

Flowing gas temperature = 40° C.
Hydrate-formation temperature = 17° C.
Flowing gas pressure = 8 MPa
Density (specific gravity) = 0.60
Inhibitor = 100 wt % MeOH
Minimum flowing temperature = 5° C.
HFT depression = HFT – MFT = 17 – 5 = 12° C.

Equations

$$S = \frac{(\text{specific gravity} - 0.65)}{0.05} \quad (1)$$

$$\Delta W = W_1 + W_2 \quad (2)$$

$$Wt_r = Wt_{fig} - \Delta W \quad (3)$$

$$\text{Flow rate} = \text{flow rate}_{fig} + F \times FLC \quad (4)$$

$$F = \frac{(\text{specific gravity} - 0.60)}{0.05} \quad (5)$$

$$\text{Rate}_{\text{lean-new solution}} = \frac{\text{wt \%}_{\text{rich-chart}} \times \text{rate}_{\text{lean-chart}}}{\text{wt \%}_{\text{lean-new solution}} - \text{wt \%}_{\text{rich-chart}}}\left(\frac{\text{wt \%}_{\text{lean-chart}}}{\text{wt \%}_{\text{rich-chart}}} - 1\right) \quad (6)$$

Where:
$\text{Rate}_{\text{lean-new solution}}$ = required injection rate for new lean concentration
$\text{wt \%}_{\text{lean-new solution}}$ = concentration of inhibitor in the new lean solution
$\text{wt \%}_{\text{rich-chart}}$ = required concentration in the rich solution
$\text{Rate}_{\text{lean-chart}}$ = required injection rate
$\text{wt \%}_{\text{lean-chart}}$ = specified lean concentration (100 wt % for MeOH)

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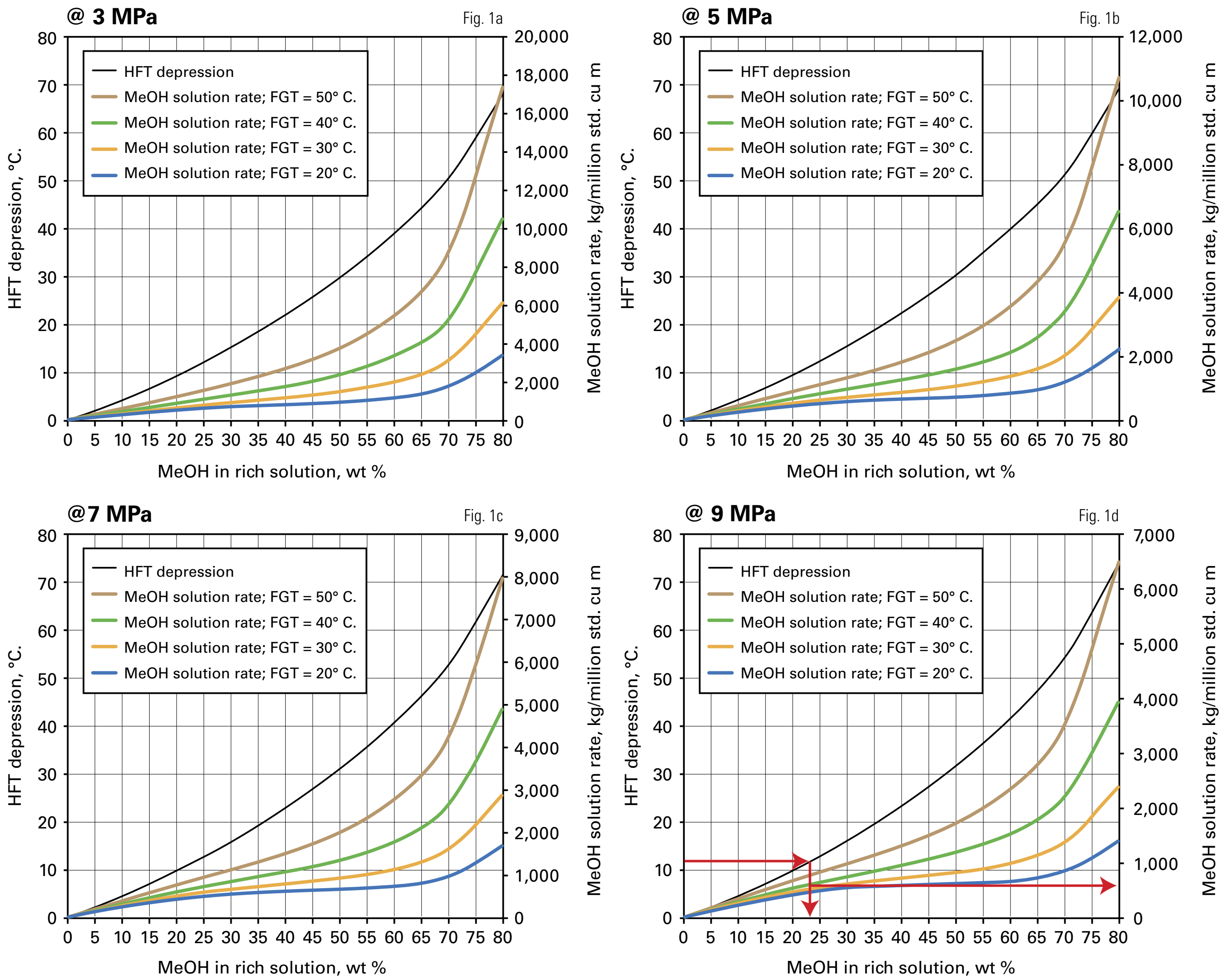
DETERMINING MeOH CONCENTRATION, INJECTION RATE*

Fig. 1



*Using 100 wt % MeOH lean solution; FGT = feed-gas temperature.

and diethylene glycol. Typically, MeOH is used in a nonregenerable system, while MEG and DEG are used in regenerable processes.

The injected inhibitor may distribute into three possible phases:

1. Vapor hydrocarbon phase.
2. Liquid hydrocarbon phase.
3. Aqueous phase, in which hydrate inhibition occurs, and the inhibitor affects the hydrate-formation condition. Therefore, calculating the inhibitor concentration in aqueous phase and total lean inhibitor injection rate are important.

Models

There are several models for predicting hydrate formation in the presence of an inhibitor. Correlations developed by Hammerschmidt, Nielsen and Bucklin, Carroll, and Moshfeghian-Maddox[1-4] predict concentration of inhibitors in an aqueous solution and lower the hydrate-formation temperature.

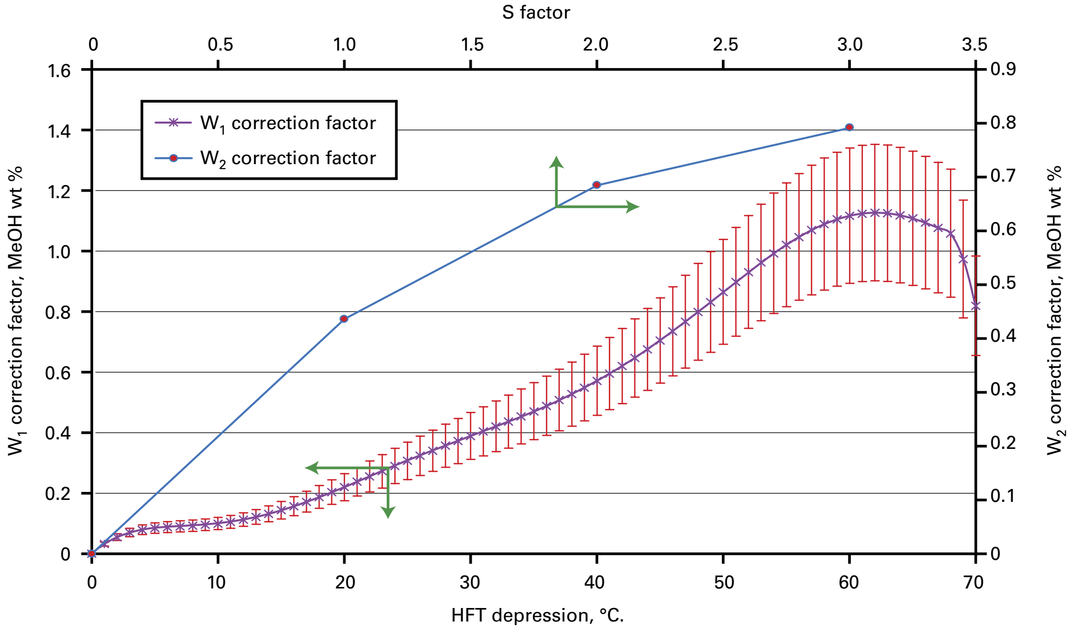
Portability and simplicity are advantages of these correlations because they are applicable even with a simple calculator, and the results are in good agreement with the experimental data.[1-4] It is to be noted that simulation packages such as ProMax,[5] HYSYS,[6] and GCAP[7] are available for predicting the effect of inhibitors on hydrate formation.

The injection rate is a function of feed-gas temperature, pressure, relative density, hydrate formation temperature depression, and lean solution concentration. Recently, the authors proposed a shortcut, graphical method to predict the required MEG or MeOH weight percent and flow rate for a desired depression in hydrate temperature of natural gas mixtures.[8 9]

This article will demonstrate how the diagrams can be used to determine the concentration of MeOH in the rich solution and the required total injection

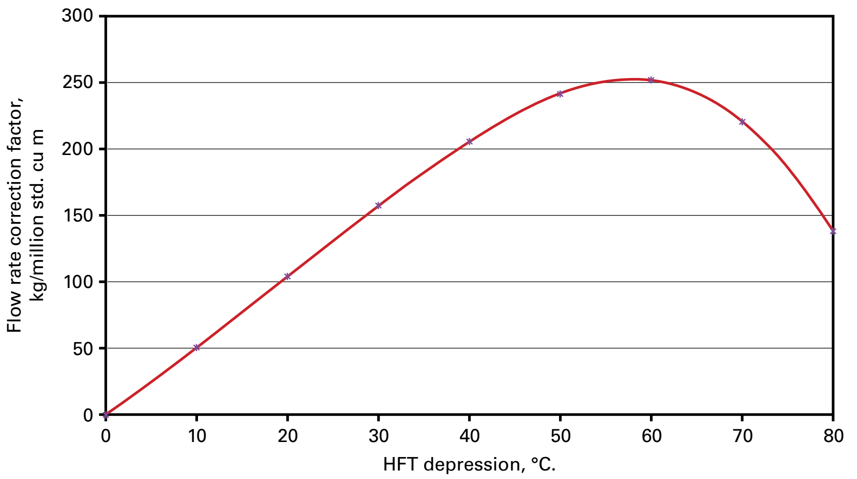
MeOH CORRECTION FACTORS

Fig. 2



OBTAINING FLOW RATE CORRECTION FACTOR

Fig. 3



rate for a desired depression of hydrate-formation temperature.

The graphs in Fig. 1 apply for any wet natural gas mixture with specific gravity of 0.6. Note that the right hand y-axis represents the total injection rate of MeOH that may distribute into gas phase, liquid hydrocarbon phase, and rich solution phase.

Extending the application of these charts to gas mixtures with other specific gravities requires two correction factors W_1 and W_2. These factors are used to correct the inhibitor concentration in the rich solution for other relative densities (0.65-0.80) that appear in Fig. 2.

W_1 is the correction factor due to the difference of inhibitor concentration in the rich solution in different hydrate-formation temperature depression. This factor is applicable for gas with specific gravities greater than 0.6.

W_2 is the correction factor due to the difference in inhibitor concentration in the rich solution due to the difference in gas specific gravities. To determine W_2, the S-factor is defined as shown in Equation 1 in the accompanying box.

Calculating the S-factor allows W_2 to be easily read from Fig. 2. This correction factor is applicable for gas with specific gravities of 0.65 and greater.

Using W_1 and W_2 in Equations 2 and 3 corrects the obtained weight percent from the charts in Fig. 1 (Wt_{fig}).

Using the flow rate correction factor (FLC) found in Fig. 3 corrects the obtained flow rate from charts (Fig. 1). The correction factor can be applied as shown in Equations 4 and 5.

With these correction factors, the charts are applicable for natural wet gases with specific gravities of 0.6-0.8 saturated at temperature of 20, 30, 40, and 50° C. and pressures of 3, 5, 7 and 9 MPa.

As mentioned earlier, the inhibitor in the aqueous phase (rich solution) affects the hydrate-formation condition and is independent of the inhibitor weight percent in the lean solution. The same hydrate temperature depression is achieved when there is a similar inhibitor weight percent in the rich solution. However, the injection rate is a function of both lean and rich stream concentration.

Therefore, a simple material balance gives Equation 6.

Case study

A demonstration of the proposed charts employs Example 6.6 from

CASE STUDY RESULTS*

Table 1

	Required wt % in rich solution	Required injection rate, kg/million std. cu m
@ 7 MPa pressure using Fig. 1c	23.7	694.5
@ 9 MPa pressure using Fig. 1d	23.4	635.1
@ 8 MPa pressure using linear interpolation	23.5	664.8

*Based on Example 6.6, in Reference 10.

RESULTS COMPARISON

Table 2

Method	Required wt % in rich solution	Required injection rate, kg/day
Hammerschmidt equation[1]	23.0	2,330
ProMax[2]	24.4	2,391
HYSYS[3]	24.0	2,091
GCAP[4]	22.8	2,105
This work	23.5	2,327

[1]References 1 and 10. [2]Reference 5. [3]Reference 6. [4]Reference 7.

Campbell's Gas Conditioning and Processing.[10]

This example states that 3.5 million std. cu m/day of natural gas leaves an offshore platform at 40° C. and 8,000 kPa. The hydrate temperature of the gas is 17° C. The gas arrives ashore at 5° C. and 6,500 kPa. The associated condensate production is 60 cu m/1 million std. cu m. The amount of methanol required to prevent hydrate formation in the pipeline is to be estimated.

It should be noted that in this example the composition (or relative density) of natural gas is not given. To demonstrating the use of these charts, therefore, one assumes a relative density of 0.6. With the feed-gas pressure at 8 MPa, a linear interpolation between 7MPa (Fig. 1c) and 9 MPa (Fig. 1d) is applied.

The summary of known data appears in the accompanying box on p. 54.

The presence of uncertainties in all inhibitor injection calculation methods prompts a safety factor to be applied to the hydrate-formation temperature depression. For example, this case has the HFTD set to the minimum flowing temperature. In practical situations, a design factor such as 2.8° C. (5° F.) below the MFT is used to ensure any errors in the estimation method are covered and also to ensure that the minimum temperature includes any upset process condition.

As an example, Fig. 1d shows the location of HFTD, required weight percent, and the total injection rate of MeOH for pressure of 9 MPa for this example. The results are tabulated in Table 1, and Table 2 compares the results of this work with those based on the Hammerschmidt[1] equation, ProMax, HYSYS, and GCAP.

As can be seen from Table 2, agreement between the graphical method and ProMax is quite good. The methanol injection rates as estimated by HYSYS are significantly lower than the other methods, and caution should be applied in using HYSYS for inhibitor injection estimates. It is likely that the differences in the natural gas water dewpoint predictions are the result of this discrepancy.

Also note for modeling methanol liquid systems in process simulators, a polar equation-of-state package for the vapor phase and a polar model for the liquid phases must be selected to obtain accurate results. ✦

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Pipeline profits, capacity expansion plans grow despite increased costs

Christopher E. Smith
Pipeline Editor

Natural gas pipeline operators saw their profits reach new highs in 2008, rising by more than 7% compared with 2007, despite a 9% drop in revenues year over year. Net profits totaled $5.1 billion against revenues of $19.8 billion.

The resulting earnings as a portion of revenues—25.78%—was the highest figure yet recorded by Oil & Gas Journal for the industry.

Oil pipeline profit growth also outstripped revenue growth: 4.67% vs. 2.75%.

Natural gas profits continued to be funneled into infrastructure, with additions to gas plant totaling nearly $12.2 billion, a roughly 89% increase from 2007 levels.

Operators also increased planned capacity expansions. Proposed mileage increased by more than 242%. Compression plans followed a similar pattern, rising more than 270% to total 664,755 hp.

The greater quantity of proposed pipeline projects came despite continued upward momentum in material costs. Estimated pipeline costs rose 10.25% to more than $3.7 million/mile. Pipeline labor prices maintained their premium to material and miscellaneous costs as the single most expensive per-mile item but this gap shrunk, with

IN THIS REPORT . . .

material costs rising more than 25% to more than $1.3 million/mile.

Higher-cost labor meanwhile affected the balance between estimated and actual costs for both pipeline and compressor projects completed in the 12 months ending June 30, 2009. Actual land pipeline costs exceeded projected costs by more than $300,000/mile, with a $360,000/mile difference in labor costs more than compensating for lower than predicted material and miscellaneous costs.

Higher than anticipated labor costs contributed the entire difference between estimated and actual compressor costs, with projects completed by June 30, 2009, running $137/hp more expensive than had been predicted and actual costs for both material and miscellaneous expenses lower than estimated costs.

The difference between estimated and actual costs was even sharper for offshore projects, with actual costs running nearly $2.2 million/mile higher than estimates.

US pipeline data

At the end of this article, two large tables (beginning on p. 73) offer a variety of data for US oil and gas pipeline companies: revenue, income, volumes transported, miles operated, and investments in physical plants. These data are gathered from annual reports filed with the Federal Energy Regulatory Commission by regulated oil and natural gas pipeline companies for the previous calendar year.

Data are also gathered from periodic filings with FERC by those regulated natural gas pipeline companies seeking FERC approval to expand capacity. OGJ keeps a record of these filings for each 12-month period ending June 30.

Combined, these data enable an analysis of the US regulated interstate pipeline system.

• *Annual reports.* Companies that, in FERC's determination, are involved in the interstate movement of oil or natural gas for a fee are jurisdictional to FERC, must apply to FERC for approval of transportation rates, and therefore must file a FERC annual report: Form 2 or 2A, respectively, for major or nonmajor natural gas pipelines; Form 6 for oil (crude or product) pipelines.

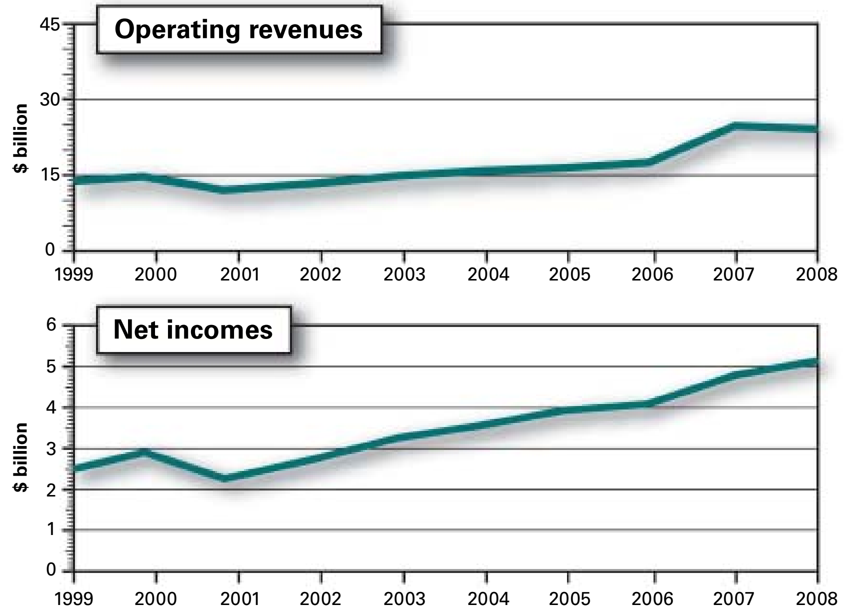
The distinction between "major" and "nonmajor" is defined by FERC and appears as a note at the end of the table listing all FERC-regulated natural gas pipeline companies for 2008 at the end of this article (p. 77).

The deadline to file these reports each year is Apr. 1. For a variety of reasons, a number of companies miss that deadline and apply for extensions, but eventually file an annual report. That deadline and the numerous delayed filings explain why publication of this OGJ report on pipeline economics occurs in the third quarter of each year. Earlier publication would exclude many companies' information.

• *Periodic reports.* When a FERC-regulated natural gas pipeline company

Natural gas pipeline performance trends

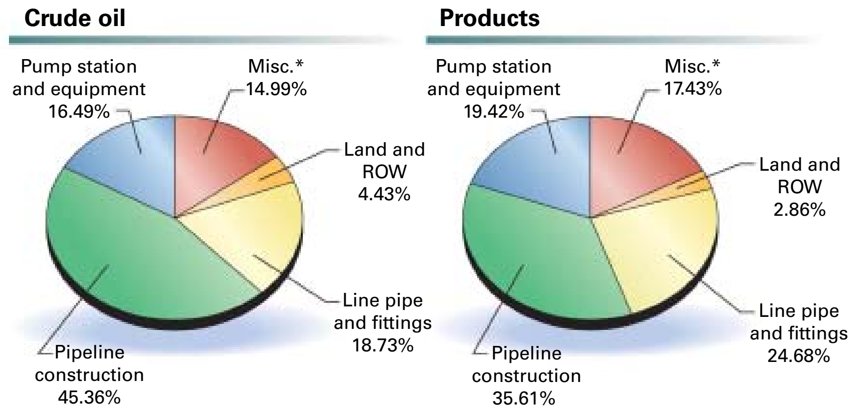
Fig. 1



Source: US FERC Forms 2 and 2A, gas pipeline company reports

Oil pipeline investment

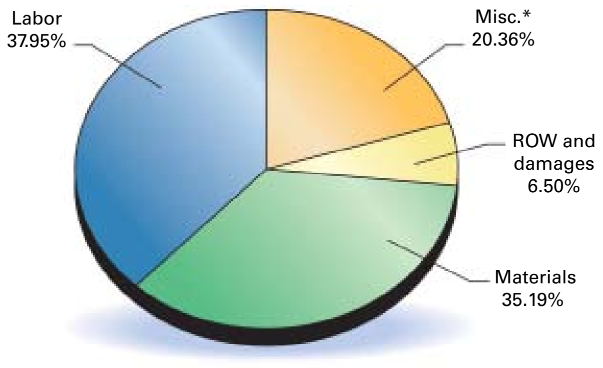
Fig. 2



*Generally includes delivery systems, communications, office furniture and equipment, vehicles and other work equipment, and other property.
Source: US oil pipeline company annual reports (Form 6) to FERC for 2008

PIPELINE CONSTRUCTION COSTS–ESTIMATED

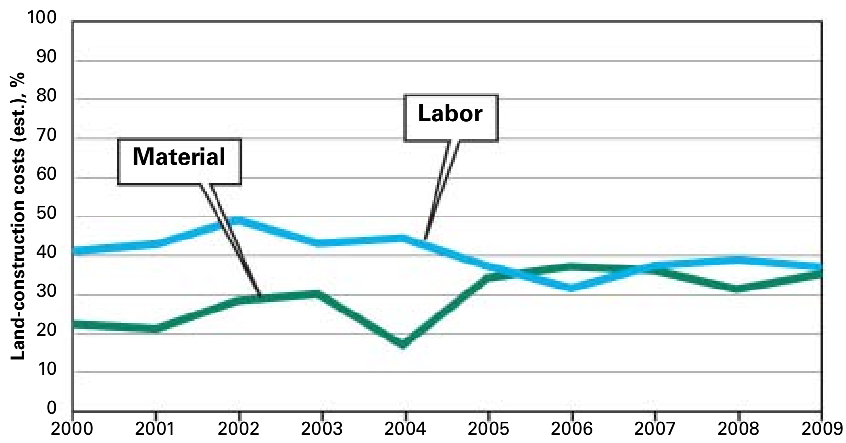
Fig. 3



*Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies and allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC construction-permit filings, July 1, 2008, to June 30, 2009

MAJOR COST COMPONENTS—10 YEARS

Fig. 4



Source: US FERC

wants to modify its system, it must apply for a "certificate of public convenience and necessity." This filing must explain in detail the planned construction, justify it, and—except in certain instances—specify what the company estimates construction will cost.

Not all applications are approved. Not all that are approved are built. But, assuming a company receives its certificate and builds its facilities, it must—again, with some exceptions—report back to FERC how its original cost estimates compared with what it actually spent.

OGJ spends the year July 1 to June 30 monitoring these filings, collecting them, and analyzing their numbers.

OGJ's exclusive, annual Pipeline Economics Report began tracking volumes of gas transported for a fee by major interstate pipelines in 1987 (OGJ, Nov. 28, 1988, p. 33) as pipelines moved gradually after 1984 from owning the gas they moved to mostly providing transportation services.

Volumes of natural gas sold by pipelines have been steadily declining, so that, beginning with 2001 data in the 2002 report, the table only lists volumes transported for others.

The company tables also reflect as-

US INTERSTATE PIPELINE MILEAGE

Table 1

Year	Miles Gas[1,2]	Oil	Total[1]
1999	180,489	155,904	336,393
2000	186,151	152,823	338,974
2001	180,961	154,877	335,838
2002	190,899	149,619	340,518
2003	188,178	139,901	328,079
2004	190,117	142,200	332,317
2005	188,847	131,334	320,181
2006	189,012	140,407	329,419
2007	192,189	147,235	339,424
2008	192,384	146,822	339,206

[1]FERC-defined major gas pipelines only; transmission mileage. See GAS COMPANIES table for definition of major and nonmajor companies and details of companies reporting mileage for 2008. [2]Totals revised from initial publication.
Source: US FERC annual reports: Form 6, oil pipelines; Form 2, gas pipelines

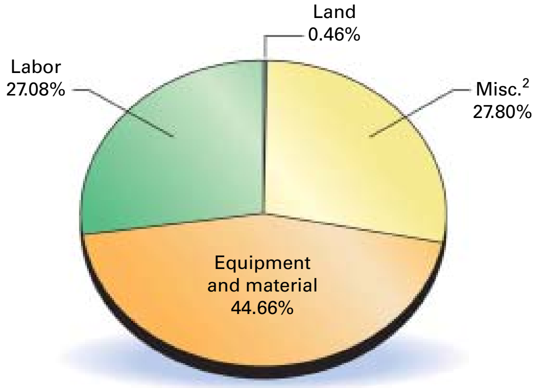
TOP 10 US INTERSTATE OIL PIPELINE COMPANIES—2008

	Company	Mileage	Company	Trunkline traffic, million bbl-miles	Company	Income, $1,000
1	Magellan Pipeline Co. LP	8,658	Colonial Pipeline Co.	686,727	Kinder Morgan Operating LP "A"	734,163
2	Mid-America Pipeline Co.	7,833	Enbridge Energy LP	432,111	Whiting Oil & Gas Corp.	258,509
3	Plains Pipeline LP	7,575	Marathon Pipeline LLC	161,240	Enbridge Energy LP	247,973
4	ConocoPhillips Pipe Line Co.	6,694	Explorer Pipeline Co.	120,529	Shell Pipeline Co. LP	225,126
5	Sunoco Pipeline LP	5,904	Plains Pipeline LP	114,624	Colonial Pipeline Co.	193,144
6	Colonial Pipeline Co.	5,593	TE Products Pipeline Co. LP	108,217	NuStar Logistics LP	164,279
7	TE Products Pipeline Co. LP	4,676	Mid-America Pipeline Co. LLC	106,665	Mid-America Pipeline Co. LLC	159,119
8	ExxonMobil Pipeline Co.	4,557	Plantation Pipe Line Co.	105,577	Plains Pipeline LP	150,616
9	TEPPCO Crude Pipeline LP	3,967	ConocoPhillips Transportation Alaska Inc.	78,991	Marathon Pipeline LLC	142,638
10	BP Pipelines North America Inc.	3,776	ExxonMobil Pipeline Co.	73,491	Sunoco Pipeline LP	141,640
	Total	**59,233**	**Total**	**1,988,172**	**Total**	**$2,417,207**
	Part of all companies	**40.34%**		**57.84%**		**61.48%**
	Top 10 total—2007	59,448		2,058,820		$2,131,461

Source: US FERC Form 6: Annual Report of Oil Pipeline Companies, Dec. 31, 2008

Compressor construction costs—estimated[1]

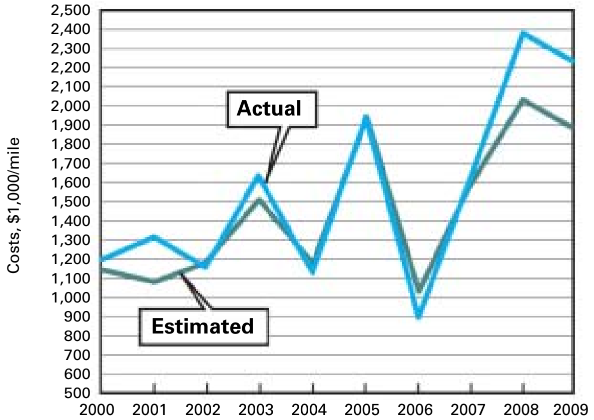
Fig. 5



[1]Onshore only. [2]Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies and allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC construction-permit filings, July 1, 2008, to June 30, 2009

Estimated, actual cost trends—10 years*

Fig. 6



*Land and offshore pipeline construction as of June 30 of each year for the previous 12 months.
Source: US FERC

set consolidation and merger activity among companies in their efforts to improve transportation efficiencies and bottom lines.

Reporting changes

The number of companies required to file annual reports with FERC may change from year to year, with some companies becoming jurisdictional, others nonjurisdictional, and still others merging or being consolidated out of existence.

Such changes require that care be taken in comparing annual US petroleum and natural gas pipeline statistics.

Institution by FERC of the two-tiered (2 and 2A) classification system for natural gas pipeline companies after 1984 further complicated comparisons (OGJ, Nov. 25, 1985, p. 55).

Only major gas pipelines are required to file miles operated in a given year. The other companies may indicate miles operated but are not specifically required to do so.

For several years after 1984, many

Pipeline company revenues, incomes

Table 2

	Gas		Oil	
	Operating revenues, $1,000	Net income, $1,000	Operating revenues, $1,000	Net income, $1,000
1999	14,616,949	2,545,043	7,219,500	2,928,460
2000	14,980,925	2,910,835	7,483,100	2,705,463
2001	14,407,467	2,246,109	7,729,972	3,006,898
2002	14,015,308	2,734,182	7,811,951	3,408,753
2003	15,082,011	3,260,797	7,703,998	3,469,996
2004	15,781,445	3,588,344	8,019,554	3,322,738
2005	16,375,921	3,863,331	7,917,176	3,076,476
2006	$17,122,586	$4,015,253	$8,516,563	$3,743,115
2007	$21,736,725	$4,765,815	$8,996,329	$3,756,749
2008	$19,797,663	$5,104,772	$9,243,677	$3,931,602

Source: US FERC annual reports (Forms 2, 2A, and 6) by regulated interstate natural gas and oil pipeline companies

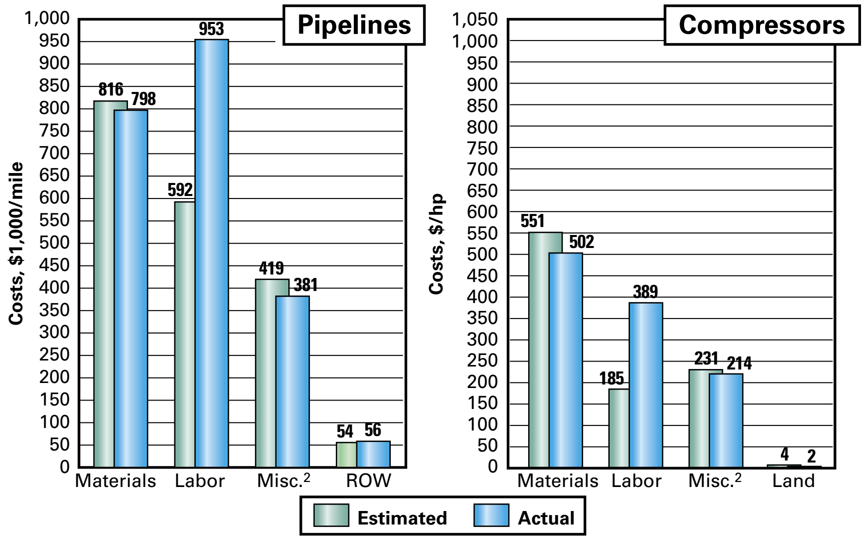
Top 10 US interstate gas pipeline companies—2008

	Company*	Transmission mileage	Company*	Volumes moved for fee, MMcf	Company*	Net income, $1,000
1	Northern Natural Gas Co.	15,018	Transcontinental Gas Pipe Line Corp.	2,577,642	Natural Gas Pipeline Co. of America	384,621
2	Tennessee Gas Pipeline Co.	14,463	ANR Pipeline Co.	1,982,666	Northern Natural Gas Co.	250,798
3	Columbia Gas Transmission Corp.	11,531	Natural Gas Pipeline Co. of America	1,925,335	Distrigas of Massachusetts LLC	248,473
4	El Paso Natural Gas Co.	10,237	Columbia Gulf Tranmission Co.	1,910,403	Transcontinental Gas Pipe Line Co.	235,164
5	Transcontinental Gas Pipe Line Corp.	9,972	Tennessee Gas Pipeline Co.	1,801,283	Texas Eastern Transmission Corp.	207,298
6	ANR Pipeline Co.	9,580	El Paso Natural Gas Co.	1,740,860	Dominion Transmission Inc.	203,114
7	Texas Eastern Transmission LP	9,202	Texas Eastern Transmission Corp.	1,432,742	Columbia Gas Transmission Corp.	193,276
8	Natural Gas Pipeline Co. of America	9,008	CenterPoint Energy Gas Transmission Co.	1,252,757	Gas Transmission Northwest Corp.	177,659
9	Southern Natural Gas Co.	7,593	Northern Natural Gas Co.	1,143,582	Panhandle Eastern Pipe Line Co.	174,456
10	Gulf South Pipeline Co. LP	6,466	Gulf South Pipeline Co. LP	1,048,042	Southern Natural Gas Co.	149,176
	Total 2008	**103,070**	**Total 2008**	**16,815,312**	**Total 2008**	**$2,224,035**
	Part of majors	**53.58%**		**43.99%**		**44.24%**
	Part of all companies	**52.05%**		**43.36%**		**43.57%**
	Total—2007 Top 10	102,736		16,387,585		$2,147,348

*All FERC-classified as "major."
Source: US FERC Form 2: annual reports for natural gas companies, Dec. 31, 2008

COMPONENT COSTS: ESTIMATED VS. ACTUAL[1]

Fig. 7



[1]Onshore only. For construction cost filings made before July 1, 2009. [2]Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies, allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC

nonmajors did not describe their systems. But filing descriptions of their systems has become standard, and most provide miles operated.

Reports for 2008 show an increase in FERC-defined major gas pipeline companies: 83 companies of 130 filing for 2008, from 77 of 121 for 2007.

The FERC made an additional change to reporting requirements for 1995 for both crude oil and petroleum products pipelines. Exempt from requirements to prepare and file a Form 6 were those pipelines with operating revenues at or less than $350,000 for each of the 3 preceding calendar years. These companies must now file only an "Annual Cost of Service Based Analysis Schedule," which provides only total annual cost of service, actual operating revenues, and total throughput in both deliveries and barrel-miles.

In 1996 major natural gas pipeline

INVESTMENT IN OIL PIPELINES—2008

Table 3

	Company and investment, $						
	A	B	C	D	E	Total, $	%
CRUDE PIPELINES							
Land	9,225,344	141,938	292,544	2,571,029	5,001,716	17,232,571	0.37
Right of way	163,911,717	955,277	316,592	8,732,873	13,323,396	187,239,855	4.06
Line pipe	659,531,533	23,386,168	11,353,060	36,088,373	49,101,314	779,460,448	16.90
Line pipe fittings	37,584,164	1,241,348	6,627,550	20,681,840	18,160,077	84,294,979	1.83
Pipeline construction	1,766,888,912	32,833,851	21,291,693	92,702,395	177,815,519	2,091,532,370	45.36
Buildings	92,478,912	4,002,648	3,608,637	10,211,758	14,456,912	124,758,867	2.71
Boilers	—	—	—	—	—	—	0.00
Pumping equipment	104,121,526	4,857,290	10,011,613	18,128,672	15,661,339	152,780,440	3.31
Machine tools and machinery	—	—	—	32,353	—	32,353	0.00
Other station equipment	407,134,491	23,118,717	13,144,673	114,232,958	50,008,725	607,639,564	13.18
Oil tanks	110,615,054	5,914,184	10,245,378	41,032,329	41,995,744	209,802,689	4.55
Delivery facilities	—	14,454	22,596,660	533,821	—	23,144,935	0.50
Communication systems	6,163,066	1,761,020	16,773	1,817,876	1,325,901	11,084,636	0.24
Office furniture and equipment	17,495,820	674,672	1,410,489	684,658	249,206	20,514,845	0.44
Vehicles and other work equip.	26,589,891	873,753	656,084	1,951,023	—	30,070,751	0.65
Other property	11,543,727	2,247,971	—	254,305,559	3,454,243	271,551,500	5.89
Total investment—2008	**$3,413,284,157**	**$102,023,291**	**$101,571,746**	**$603,707,517**	**$390,554,092**	**$4,611,140,803**	**100.00**
Total carrier property—2008	**$4,245,156,930**	**$101,959,893**	**$106,234,500**	**$710,128,049**	**$496,389,719**		
Total investment—2007	**$2,074,526,281**	**$98,876,969**	**$98,188,236**	**$572,191,295**	**$362,841,344**	**$3,206,624,125**	
PRODUCT PIPELINES							
Land	6,314,074	9,530,971	1,118,694	4,435,818	7,296,823	28,696,380	0.46
Right of way	—	22,023,235	29,556,155	11,701,291	86,762,837	150,043,518	2.40
Line pipe	399,882,739	81,804,634	501,186,097	92,554,942	180,984,510	1,256,412,922	20.11
Line pipe fittings	127,091,346	58,179,087	52,425,519	4,740,695	42,954,210	285,390,857	4.57
Pipeline construction	1,086,089,016	193,681,105	434,786,070	133,397,332	376,873,269	2,224,826,792	35.61
Buildings	39,626,179	15,792,946	11,642,200	19,811,671	38,052,424	124,925,420	2.00
Boilers	—	—	—	—	—	—	0.00
Pumping equipment	79,801,324	39,746,061	70,051,394	40,494,643	56,552,227	286,645,649	4.59
Machine tools and machinery	—	—	—	—	—	—	0.00
Other station equipment	293,113,724	155,853,320	117,826,711	106,794,432	252,803,751	926,391,938	14.83
Oil tanks	178,520,722	89,209,208	8,736,548	41,049,518	130,299,411	447,815,407	7.17
Delivery facilities	—	—	12,157,770	32,614,746	131,020,391	175,792,907	2.81
Communication systems	9,641,110	1,586,923	3,400,030	14,485,315	24,237,014	53,350,392	0.85
Office furniture and equipment	45,405,489	1,974,207	34,622,204	6,260,498	3,651,190	91,913,588	1.47
Vehicles and other work equip.	22,372,872	3,734,934	12,137,298	16,292,267	3,197,298	57,734,669	0.92
Other property	106,606,208	—	29,155,751	—	2,565,504	138,327,463	2.21
Total investment—2008	**$2,394,464,803**	**$673,116,631**	**$1,318,802,441**	**$524,633,168**	**$1,337,250,859**	**$6,248,267,902**	**100.00**
Total carrier property—2008	**$2,408,948,543**	**$698,507,430**	**$1,333,040,112**	**$526,445,929**	**$1,371,477,411**		
Total investment—2007	**$2,320,564,521**	**$659,163,685**	**$1,239,778,892**	**$520,036,640**	**$1,274,647,129**	**$6,014,190,867**	

Sources: US FERC Forms 6, Annual Report of Oil Pipeline Companies, Dec. 31, 2008

US PIPELINE COSTS, ESTIMATED

Table 4

Size, in.	Location[1]	Length, miles	$ Material	Labor	Misc.[2]	ROW & damages	Total	$/mile
LAND PIPELINES								
6	Pennsylvania	8.00	963,492	2,820,777	2,810,169	449,800	7,044,238	880,530
16	Pennsylvania (lat.)	3.42	1,429,216	5,064,768	2,006,260	774,687	9,274,931	2,711,968
20	New Jersey	0.83	939,954	2,785,452	1,034,516	1,488,354	6,248,276	7,528,043
20	Connecticut (lat.)	1.13	735,173	2,349,198	2,395,166	988,710	6,468,247	5,724,112
20	West Virginia	27.71	22,680,000	54,000,000	28,060,000	2,400,000	107,140,000	3,866,474
24	Oregon (lat.)	3.80	3,952,000	2,174,000	1,351,000	1,538,000	9,015,000	2,372,368
24	Oregon (lat.)	9.50	7,022,775	9,806,464	14,336,881	1,130,579	32,296,699	3,399,653
24	Colorado	27.40	10,600,000	32,209,000	11,306,000	—	54,115,000	1,975,000
30	Wisconsin (L)	8.90	7,626,572	17,980,386	7,097,586	2,159,105	34,863,649	3,917,264
30	Colorado-Wyoming	15.50	10,367,000	19,708,000	2,243,000	6,431,000	38,749,000	2,499,935
30	Wyoming-North Dakota	302.00	186,000,000	260,100,000	27,635,148	116,900,000	590,635,148	1,955,746
30, 36	Georgia	42.10	43,593,768	56,275,234	26,452,080	5,751,226	132,072,308	3,137,109
36	Mississippi-Alabama	19.7	19,909,315	28,965,109	13,420,360	2,409,963	64,704,747	3,284,505
36	Oregon	105.70	119,730,000	128,900,000	53,416,000	72,252,000	374,298,000	3,541,135
36	Oregon	111.20	125,150,000	127,519,000	58,789,000	88,898,000	400,356,000	3,600,324
36	Oregon	121.00	122,517,421	102,407,595	193,513,177	15,000,000	433,438,193	3,582,134
36, 42	Mississippi-Alabama	19.5	25,733,630	39,696,004	16,471,331	2,445,683	84,346,648	4,325,469
20-42	Alabama-Florida	483.2	560,100,000	734,300,000	574,835,327	137,600,000	2,006,835,327	4,153,219
42	Pennsylvania (L)	9.42	3,500,000	15,500,000	11,608,516	1,100,000	31,708,516	3,366,085
42	Arkansas-Mississippi	185.00	491,592,970	518,303,208	206,200,496	30,650,245	1,246,746,919	6,739,173
42	Wyoming-Utah-Nevada-Oregon	675.20	1,093,264,635	923,766,582	399,268,400	37,970,600	2,454,270,217	3,634,879
Total projects—land		**2,176.79**	**$2,855,978,705**	**$3,079,566,009**	**$1,652,244,153**	**$527,563,265**	**$8,115,352,132**	**$3,728,128**
Total land—2008 report		898.66	$939,860,184	$1,208,148,741	$752,399,633	$139,049,185	$3,038,758,314	$3,381,433
Total—all projects		**2,176.79**	**$2,855,978,705**	**$3,079,566,009**	**$1,652,244,153**	**$527,563,265**	**$8,115,352,132**	**$3,728,128**
2008—report total, all projects		898.66	$939,860,184	$1,208,148,741	$752,399,633	$139,049,185	$3,038,758,314	$3,381,433

[1]L = loop; lat. = lateral; R = replacement. [2]Generally includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees.
Source: US FERC construction-permit applications, July 1, 2008, to June 30, 2009

companies were no longer required to report miles of gathering and storage systems separately from transmission. Thus, total miles operated for gas pipelines consist almost entirely of transmission mileage.

FERC-regulated major natural pipeline mileage edged higher in 2008, reaching its highest level since 1995 (Table 1). Final data show an increase of 195 miles, or 0.1%.

Rankings; activity

Natural gas pipeline companies in 2008 saw operating revenues drop by more than $1.9 billion, or nearly 9% from 2007. Net incomes, however, continued to rise, leading to a rebound in earnings as a percent of revenue to 25.78%, the highest level OGJ has yet recorded.

Oil pipelines saw much the same dynamic at work, with earnings rising 4.67% despite slower growth in revenues.

Liquids deliveries for 2008 via pipeline dropped more than 960 million bbl, or 6.9%, led by a more than 11% fall in product deliveries. Throughput measured in million bbl-miles (bbl-mile: 1 bbl moving 1 mile) fell roughly 0.6%, by more than 21.6 billion bbl-miles, with a products throughput drop of nearly 152 billion bbl-miles, or 7.6%, more than erasing gains in crude throughput.

OGJ uses FERC annual report data to rank the top 10 pipeline companies in three categories (miles operated, trunkline traffic, and operating income) for oil-pipeline companies and three categories (miles operated, gas transported for others, and net income) for natural gas pipeline companies.

Positions in these rankings shift year to year, reflecting normal fluctuations in companies' activities and fortunes. But also, because these companies comprise such a large portion of their respective groups, the listings provide snapshots of overall industry trends and events.

For instance, the growth in liquids pipeline earnings was driven by the top 10 companies in the segment, which grew their share of total earnings to 61.48%, led by an 87.1% jump in earnings at the highest-income company, Kinder Morgan Operating LP "A."

Company financial data for all companies provide a view of the ongoing condition of the oil and gas pipeline industries (Fig. 1; Table 2).

For all natural gas pipeline companies, for example, net income as a portion of operating revenues rebounded to 25.78% in 2008, more than erasing recent declines and setting a new record for the figure.

The percentage of income as operating revenues for oil pipelines also rebounded in 2008, reaching 42.53%

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US COMPRESSOR-CONSTRUCTION COSTS, ESTIMATED

Table 5

Location	Horsepower	Equipment material	Labor	Land	Misc.[1]	Total	$/hp
		$					
Utah[2]	3,980	3,354,000	2,261,000	—	2,357,000	7,972,000	2,003
Wyoming	4,630	7,500,000	7,100,000	—	—	14,600,000	3,153
Pennsylvania	5,325	9,752,385	7,700,000	2,075,000	8,231,402	27,758,787	5,213
Mississippi[2]	6,135	8,577,424	7,400,268	—	5,618,910	21,596,602	3,520
Texas[2]	6,135	9,646,555	7,778,268	—	5,454,707	22,879,530	3,729
Georgia[2]	7,000	10,907,700	2,300,000	—	7,041,292	20,248,992	2,893
Alabama	9,470	14,276,710	11,111,658	800,000	10,715,567	36,903,935	3,897
New York	10,310	9,785,000	6,173,000	—	6,568,000	22,526,000	2,185
Mississippi[2]	10,310	16,618,165	3,806,500	—	9,826,985	30,251,650	2,934
Mississippi	12,500	18,255,000	10,059,000	—	20,414,000	48,728,000	3,898
Louisiana[2]	15,000	13,991,298	7,178,051	4,208	10,758,993	31,932,550	2,129
Louisiana[2]	15,000	14,194,720	11,421,472	31,720	8,644,314	34,292,226	2,286
Louisiana[2]	15,000	14,194,720	10,971,472	31,720	8,488,367	33,686,279	2,246
Mississippi[2]	15,000	14,429,304	6,864,124	4,208	10,848,129	32,145,765	2,143
Wyoming	16,000	11,976,000	793,000	5,000	13,720,000	26,494,000	1,656
Wyoming[2]	16,000	8,818,000	232,400	—	6,287,600	15,338,000	959
Texas[2]	16,360	17,330,190	10,466,064	—	7,973,702	35,769,956	2,186
Wyoming[2]	17,500	14,480,251	8,624,224	—	24,349,554	47,454,029	2,712
Colorado[2]	20,500	12,978,250	7,866,310	—	9,896,911	30,741,471	1,500
West Virginia[2]	20,500	16,514,000	11,279,000	—	5,867,000	33,660,000	1,642
Oregon	28,000	27,000,000	10,500,000	295,000	27,962,478	65,757,478	2,348
Wyoming-Utah-Nevada	160,500	114,152,200	68,339,800	800,000	31,912,136	215,204,136	1,341
Alabama-Florida[2]	213,600	156,906,000	110,600,000	1,613,000	96,779,404	365,898,404	1,713
Total, land projects	**644,755**	**$545,637,872**	**$330,825,611**	**$5,659,856**	**$339,716,451**	**$1,221,839,790**	**$1,895**
2008—report total,land projects	238,500	$239,901,653	$122,711,966	$2,586,633	$87,618,219	$452,818,471	$1,899
Total, all projects	**644,755**	**$545,637,872**	**$330,825,611**	**$5,659,856**	**$339,716,451**	**$1,221,839,790**	**$1,895**
2008—report total, all projects	238,500	$239,901,653	$122,711,966	$2,586,633	$87,618,219	$452,818,471	$1,899

[1]Generally includes surveys, engineering, supervision, interest, administration, freight, taxes, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees. [2]Addition.
Source: US FERC construction-permit applications, July 1, 2008, to June 30, 2009

after falling to 41.76% in 2007 from nearly 44% in 2006.

Net income as a portion of gas-plant investment countered the increases seen in income as a portion of revenue for natural gas pipelines, slipping to 4.83% after having risen to 4.99% in 2007. Even so, it remained above the 4.7% level seen in 1998.

For oil pipelines, net income as a portion of investment in carrier property in 2008 fell to 10.5%, continuing a drop from the 11.5% reached 2006. Income as part of investment in carrier property in 2004 stood at 11.4%, having risen steadily toward that level from 6.8% in 1998.

Major and nonmajor natural gas pipelines in 2008 reported an industry gas-plant investment of nearly $105.8 billion, the highest level ever, up from more than $95.5 billion in 2007, $88.3 billion in 2006, $84 billion in 2005, more than $83 billion in 2004, nearly $78 billion in 2003, $74.2 billion in 2002, almost $71 billion in 2001, and $68 billion in 2000.

Investment in oil pipeline carrier property also continued to rise in 2008, reaching $39.1 billion, after hitting almost $35.9 billion in 2007, which in turned followed a rebound to $32.7 billion in 2006 from the lowest level seen since at least 1997, $29.5 billion in 2005.

OGJ for many years has tracked carrier-property investment by five crude oil pipeline and five products pipeline companies chosen as representative in terms of physical systems and expenditures (Table 3). In 2003, we added the base carrier-property investment to allow for comparisons among the anonymous companies.

The five crude oil pipeline companies in 2008 increased their overall investment in carrier property by more than $1.4 billion, or nearly 44%; the same grouping of companies increased overall investment in carrier property in 2007 by just $40.2 million, or 1.3%. All of the companies in the group increased their investment, but the bulk of the increase came as a result of increased construction expenditures at the largest company.

The five products pipeline companies, by contrast, increased overall investment in carrier property by $234 million, or 3.89%, down from the $463 million (8.35%) increase of 2007. As with the crude oil lines, all companies in the products pipeline group increased investment in 2008.

Comparisons of data in Table 2 with previous years' must be done with caution: In 2004, a major crude oil pipeline company listed there sold significant assets, making comparisons with previous years' data difficult.

Investment by the five product pipeline companies in 2008 was more than $6.2 billion, continuing a return to growth started in 2003 when investment of more than $4.7 billion was up from 2002's $4.5 billion level.

Fig. 2 illustrates the investment split in the crude oil and products pipeline companies.

Construction surges

Applications to FERC by regulated interstate natural gas pipeline companies to modify certain systems must,

10 YEARS OF LAND CONSTRUCTION COSTS[1]

Table 6

Size	Year	Average cost, $/mile ROW	Material	Labor	Misc.	Total	Range, $/mile Low	High
8 in.	2009	—	—	—	—	—	—	—
	2008	17,438	378,698	199,342	114,617	[2]710,095	—	—
	2007	—	—	—	—	—	—	—
	2006	—	—	—	—	—	—	—
	2005	—	—	—	—	—	—	—
	2004	239,860	84,651	599,280	591,276	1,515,068	1,507,694	1,518,017
	2003	206,313	72,270	280,847	207,362	766,793	390,870	10,712,500
	2002	25,302	31,809	88,400	81,165	[2]206,675	—	—
	2001	21,910	39,548	59,400	47,676	[2]168,533	—	—
	2000	20,099	51,065	385,845	137,789	594,797	909,727	4,003,300
12 in.	2009	—	—	—	—	—	—	—
	2008	178,757	195,406	566,193	466,159	1,406,515	541,392	4,186,636
	2007	—	—	—	—	—	—	—
	2006	45,944	160,618	243,104	174,207	623,873	515,091	1,159,683
	2005	—	—	—	—	—	—	—
	2004	559,684	212,495	1,740,003	691,419	3,203,601	222,012	4,628,800
	2003	10,941	119,813	196,100	75,363	402,217	158,194	646,240
	2002	15,470	88,398	180,110	39,168	323,146	160,116	524,417
	2001	88,592	83,940	481,060	267,073	920,665	820,179	925,452
	2000	30,721	83,069	264,461	163,653	541,894	190,731	885,051
16 in.	2009	226,517	417,899	1,480,926	586,626	[2]2,711,968	—	—
	2008	421,484	1,182,666	1,689,992	1,552,542	[2]4,646,684	—	—
	2007	—	—	—	—	—	—	—
	2006	181,184	192,998	398,048	111,888	884,118	601,274	948,857
	2005	88,312	144,768	238,056	181,419	652,555	396,660	1,728,247
	2004	246,628	141,315	849,567	386,050	1,623,560	353,528	2,529,399
	2003	24,549	93,299	172,599	73,049	363,497	210,023	1,377,297
	2002	11,756	88,358	135,606	71,383	307,104	201,614	1,796,507
	2001	30,964	146,191	592,557	464,233	1,233,953	822,866	3,619,607
	2000	132,500	121,675	374,154	359,815	988,143	241,877	3,612,208
20 in.	2009	164,377	820,867	1,993,079	1,061,331	4,039,654	3,866,474	7,528,043
	2008	23,219	869,178	941,096	491932	[2]2,325,425	—	—
	2007	—	—	—	—	—	—	—
	2006	99,125	233,125	796,688	478,406	[2]1,607,344	—	—
	2005	28,999	191,553	385,889	187,486	793,927	502,795	1,254,420
	2004	17,254	134,986	999,273	295,479	1,446,991	1,016,598	1,942,989
	2003	68,940	215,322	448,600	193,029	925,890	626,622	4,077,000
	2002	129,877	177,985	460,622	348,899	1,117,383	537,001	1,701,544
	2001	71,108	169,648	509,417	183,938	934,111	371,817	1,492,528
	2000	175,788	227,202	506,423	318,035	1,227,447	548,727	1,928,926
24 in.	2009	65,567	530,093	1,085,736	663,240	2,344,636	1,975,000	3,399,653
	2008	—	—	—	—	—	—	—
	2007	25,467	351,083	324,023	453,737	1,155,030	830,872	4,301,932
	2006	126,822	263,200	584,428	577,136	1,551,586	1,248,916	4,883,022
	2005	99,492	324,099	553,603	289,991	1,267,185	701,664	8,153,531
	2004	1,554,828	409,165	2,913,257	1,165,957	[2]6,043,208	—	—
	2003	197,476	323,116	1,124,623	728,855	2,374,070	923,400	9,236,061
	2002	43,494	233,583	641,094	305,899	1,224,069	754,046	7,021,087
	2001	130,504	241,517	540,604	281,141	1,193,767	532,645	5,029,640
	2000	119,147	238,555	461,141	327,696	1,146,538	402,515	2,168,000
30 in.	2009	384,467	624,980	912,342	113,283	2,035,073	1,955,746	3,917,264
	2008	83,016	1,091,147	356,539	472,278	2,002,981	1,684,461	2,264,167
	2007	156,303	1,371,819	1,328,831	922,647	3,779,600	1,546,833	4,715,909
	2006	135,337	589,703	960,760	650,255	2,336,055	1,131,419	6,791,954
	2005	108,418	580,031	1,296,166	639,103	2,623,718	1,333,438	4,082,365
	2004	150,549	448,125	634,490	371,734	1,604,899	1,447,235	2,264,492
	2003	40,472	389,806	476,194	205,405	1,111,877	732,468	[3]36,333,333
	2002	51,157	385,485	613,322	298,134	1,348,098	952,210	2,559,292
	2001	203,491	354,127	797,432	565,989	1,921,040	1,360,178	5,008,770
	2000	138,324	389,249	639,270	463,670	1,630,514	985,036	4,457,536
36 in.	2009	499,329	1,083,073	1,084,429	892,446	3,559,276	3,284,505	3,600,324
	2008	170,489	994,375	1,098,096	511,589	2,774,549	2,427,457	9,013,608
	2007	97,746	869,995	628,204	893,293	2,489,238	1,857,468	4,056,369
	2006	233,258	844,583	1,141,388	1,349,079	3,568,308	1,900,376	8,066,157
	2005	161,665	819,178	929,436	633,630	2,543,909	1,424,610	4,798,806
	2004	150,070	426,999	352,594	565,474	[2]1,495,137	—	—
	2003	137,857	716,743	696,259	547,675	[2]2,098,532	—	—
	2002	53,571	475,832	762,214	212,008	1,503,625	1,127,089	3,616,470
	2001	58,344	420,420	491,155	323,870	1,293,789	966,841	3,217,182
	2000	195,848	454,764	779,527	442,122	1,874,260	1,256,079	10,708,278

[1]Estimates; based on FERC land construction-permit applications for a 12-month period ending June 30 of each year. [2]Only one project proposed during this period for this diameter. [3]Involves river, stream, or channel crossing.

except in certain instances, provide estimated costs of these modifications in varying degrees of details.

Tracking the mileage and compression horsepower applied for and the estimated costs can indicate levels of construction activity over 2-4 years. OGJ has been doing that since this report began more than 50 years ago.

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US PIPELINE COSTS: ESTIMATED VS. ACTUAL, 2008-09[1]

Table 7

Size, in.	Location	Length, miles	Materials ($)	Labor ($)	Misc.[2] ($)	ROW & damages ($)	Total ($)	$/mile
Land pipelines								
8	North Dakota	1.21						
	Estimated		458,225	162,954	216,936	21,100	859,215	710,095
	Actual		425,601	126,655	460,981	20,435	1,033,672	854,274
12	Colorado (lat.)	41.40						
	Estimated		7,915,818	10,086,700	8,631,698	2,701,000	29,335,216	708,580
	Actual		9,226,133	20,266,903	7,102,270	3,297,496	39,892,802	963,594
12	West Virginia (lat.)	4.99						
	Estimated		515,600	1,752,000	803,000	128,500	3,199,100	641,102
	Actual		1,028,400	3,278,100	1,162,000	128,000	5,596,500	1,121,543
24	Utah-Wyoming (lat.)	129.30						
	Estimated		42,701,834	52,963,723	15,582,569	2,252,800	113,500,926	877,811
	Actual		41,996,860	92,412,992	20,875,385	2,743,840	158,029,077	1,222,189
24	Virginia (R)	33.10						
	Estimated		14,509,000	21,816,000	23,608,000	2,267,000	62,200,000	1,879,154
	Actual		10,793,734	38,949,319	19,199,722	1,072,896	70,015,671	2,115,277
36	Florida (L)	32.60						
	Estimated		24,109,645	14,395,526	19,895,254	3,325,690	61,726,115	1,893,439
	Actual		25,652,352	20,482,504	13,646,915	2,747,189	62,528,960	1,918,066
36	Louisiana	4.43						
	Estimated		3,142,750	4,239,260	3,051,819	576,000	11,009,829	2,485,289
	Actual		5,324,915	11,848,790	3,231,009	549,015	20,953,729	4,729,961
36, 42	Texas-Mississippi	243.60						
	Estimated		264,315,000	230,907,000	101,250,000	21,939,000	618,411,000	2,538,633
	Actual		239,759,000	348,915,000	136,037,000	29,385,000	754,096,000	3,095,632
42	Colorado-Missouri	713.00						
	Estimated		822,241,399	416,902,472	333,696,702	36,584,331	1,609,424,904	2,257,258
	Actual		808,418,568	812,514,986	272,889,144	40,016,378	1,933,839,076	2,712,257
42	Louisiana	153.00						
	Estimated		156,547,000	255,347,688	144,464,730	22,532,907	578,892,325	3,783,610
	Actual		146,313,745	252,214,673	161,949,233	22,710,533	583,188,184	3,811,687
Total land, miles		**1,314.02**						
	Estimated		**1,072,141,271**	**777,666,323**	**549,950,708**	**70,389,328**	**2,470,147,630**	**$1,879,840**
	Actual		**1,049,180,308**	**1,252,094,922**	**500,516,659**	**73,285,782**	**2,875,077,671**	**$2,188,001**
Offshore pipelines								
20	Florida	17.74						
	Estimated		7,607,414	32,364,669	13,902,510	2,374,760	56,249,353	3,170,764
	Actual		9,835,248	67,269,674	17,096,897	1,018,314	95,220,133	5,367,539
Total offshore, miles		**17.74**						
	Estimated		**$7,607,414**	**$32,364,669**	**$13,902,510**	**$2,374,760**	**$56,249,353**	**$3,170,764**
	Actual		**$9,835,248**	**$67,269,674**	**$17,096,897**	**$1,018,314**	**$95,220,133**	**$5,367,539**
Total, miles		**1,331.76**						
	Estimated		**$1,079,748,685**	**$810,030,992**	**$563,853,218**	**$72,764,088**	**$2,526,396,983**	**$1,897,036**
	Actual		**$1,059,015,556**	**$1,319,364,596**	**$517,613,556**	**$74,304,096**	**$2,970,297,804**	**$2,230,355**

[1]Actual cost data must be filed within 6 months following final hydrostatic test of pipeline. Not all projects proposed (estimated costs) are built (actual costs). L = loop; lat. = lateral; R = replacement. [2]Generally includes surveys, engr., supervision, interest, administration and overheads, contingencies, allowances for funds used during construction (AFUDC), and regulatory fees.
Source: US FERC; for completed-project costs filed between July 1, 2008, and June 30, 2009, under CFR Section 157.20(c)(4)

Tables 4 and 5 show companies' estimates during the period July 1, 2008, to June 30, 2009, for what it will cost to construct a pipeline or install new or additional compression.

These tables cover a variety of locations, pipeline sizes, and compressor-horsepower ratings.

Not all projects proposed are approved. And not all projects approved are eventually built.

Applications filed in the 12 months ending June 30, 2009, surged after falling sharply the previous year.

- More than 2,176 miles of pipeline were proposed for land construction, and no new offshore work. The land level is up from the roughly 900 miles of pipeline proposed for construction in 2008, reaching its highest level since the more than 2,700 miles proposed in 1998.
- New or additional compression proposed by the end of June 2009 measured 644,755 hp, up substantially from the 238,400 hp proposed in 2008 but still short of the 713,000 hp reached in 2007.

Putting the upturn in US gas pipeline construction in perspective, Table 4 lists 21 land-pipeline "spreads," or mileage segments, and no marine proj-

US COMPRESSOR-STATION COSTS: ESTIMATED VS. ACTUAL, 2008-09[1]

Table 8

Location	Size, hp	Cost, $ Materials	Labor	Misc.[2]	Land	Total	$/hp
North Dakota[3]	1,590						
Estimated		1,903,000	270,100	711,095	—	2,884,195	1,814
Actual		1,951,144	100,144	1,104,827	—	3,156,115	1,985
North Dakota	1,750						
Estimated		2,386,084	410,340	767,383	100,000	3,663,807	2,094
Actual		2,284,999	278,375	731,038	45,000	3,339,412	1,908
Kentucky[3]	3,548						
Estimated		6,187,170	2,377,910	2,625,990	—	11,191,070	3,154
Actual		9,037,446	7,942,589	6,009,626	900	22,990,561	6,480
Louisiana[3]	6,200						
Estimated		7,844,631	1,962,790	3,851,585	—	13,659,006	2,203
Actual		6,995,364	5,788,240	2,938,149	—	15,721,753	2,536
Louisiana[3]	7,800						
Estimated		8,286,880	1,893,426	3,899,367	—	14,079,673	1,805
Actual		6,964,191	8,061,687	4,256,656	—	19,282,534	2,472
Arizona	8,290						
Estimated		11,837,400	7,096,600	4,655,700	310,000	23,899,700	2,883
Actual		12,494,182	12,798,147	2,874,058	990,906	29,157,293	3,517
Texas[3]	10,000						
Estimated		6,021,942	2,409,808	2,850,444	—	11,282,194	1,128
Actual		7,930,273	11,559,840	4,908,587	—	24,398,700	2,440
Colorado	10,310						
Estimated		7,585,200	7,206,800	5,502,200	—	20,294,200	1,968
Actual		8,558,328	7,231,211	2,669,222	7,882	18,466,643	1,791
Texas[3]	11,000						
Estimated		7,808,862	3,454,605	4,091,131	—	15,354,598	1,396
Actual		6,782,043	5,692,519	2,598,392	—	15,072,954	1,370
Kentucky[3]	13,338						
Estimated		9,813,200	2,544,340	3,702,590	—	16,060,130	1,204
Actual		9,547,280	3,378,577	4,784,109	—	17,709,966	1,328
Alabama[3]	15,000						
Estimated		11,714,440	2,826,940	6,505,620	—	21,047,000	1,403
Actual		11,851,503	9,498,696	6,759,714	14,526	28,124,439	1,875
Louisiana	15,000						
Estimated		11,453,135	5,400,250	6,806,898	342,000	24,002,283	1,600
Actual		8,831,175	8,589,703	3,325,777	—	20,746,655	1,383
Texas[3]	15,000						
Estimated		8,273,557	3,636,250	5,432,790	192,000	17,534,597	1,169
Actual		8,145,974	6,470,087	1,573,986	—	16,190,047	1,079
Wyoming[3]	15,400						
Estimated		11,570,919	5,222,199	5,417,457	10,000	22,220,575	1,443
Actual		11,030,279	10,667,746	3,403,041	12,741	25,113,807	1,631
Wyoming[3]	24,930						
Estimated		18,174,300	7,298,400	6,475,800	125,000	32,073,500	1,287
Actual		18,318,683	18,768,127	4,332,673	42,363	41,461,846	1,663
Louisiana	26,000						
Estimated		30,461,000	7,519,000	9,332,000	616,000	47,928,000	1,843
Actual		18,247,000	12,965,000	8,598,770	181,000	39,991,770	1,538
Florida	30,000						
Estimated		21,083,000	5,002,500	9,121,500	—	35,207,000	1,174
Actual		24,918,994	18,593,250	9,850,151	319,049	53,681,444	1,789
Louisiana[3]	40,000						
Estimated		36,552,000	9,834,000	12,203,000	616,000	59,205,000	1,480
Actual		23,785,000	15,653,000	8,568,360	103,000	48,109,360	1,203
Texas[3]	40,000						
Estimated		32,156,000	9,353,000	11,550,000	75,000	53,134,000	1,328
Actual		23,367,000	13,587,000	10,945,830	16,000	47,915,830	1,198
Total	**295,156**						
Estimated		**$162,643,387**	**$54,524,048**	**$68,055,137**	**$1,158,000**	**$286,380,572**	**$970**
Actual		**$148,096,826**	**$114,902,137**	**$63,258,876**	**$503,720**	**$326,761,559**	**$1,107**

[1]Actual cost data must be filed within 6 months following commissioning of installed compression equipment. Not all projects proposed (estimated costs) are built (actual costs). [2]Generally includes surveys, engr., supervision, interest, administration and overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees. [3]Addition.
Source: US FERC; for completed-project costs filed between July 1, 2008, and June 30, 2009, under CFR Section 157.20(c)(4)

ects, compared with:

- 19 land and 0 marine projects (OGJ, Sept. 1, 2008, p. 58).
- 25 land and 1 marine project (OGJ, Sept. 3, 2007, p. 51)
- 42 land and 1 marine project (OGJ, Sept. 11, 2006, p. 46).
- 56 land and 4 marine projects (OGJ, Sept. 12, 2005, p. 50).
- 15 land and 0 marine projects (OGJ, Aug. 23, 2004, p. 60).
- 37 land and 3 marine projects (OGJ, Sept. 8, 2003, p. 60).
- 83 land and 3 marine projects (OGJ, Sept. 16, 2002, p. 52).
- 49 land and 2 marine projects (OGJ, Sept. 3, 2001, p. 66).
- 115 land and 6 marine projects (OGJ, Sept. 4, 2000, p. 68).

The disparity between the mileage growth and spread growth in 2009 shows that many of the newly proposed projects are big, with 7 of the 21 measuring 100 miles or more and 3 measuring more than 300 miles.

For the 12 months ending June 30, 2009, the 21 land projects would cost just more than $8.1 billion as compared with the $3 billion planned for 19 projects a year earlier.

The larger number and scale of these filings indicate the need to move newly developed natural gas resources to consuming centers, despite current softness in demand.

Projects' cost projections indicate much about where companies believe unit construction costs ($/mile) are headed. Estimated $/mile costs for the new projects continued to rise.

For proposed US gas pipeline projects 2008-09 the average land cost was $3.7 million/mile; in 2007-08, the average land cost was $3.3 million/mile; in 2006-07, the average land cost was $2.7 million/mile; for 2005-06, the average land cost was $1.95 million/mile; for 2004-05 the average land cost was $2.2 million/mile; and for 2003-04 the average land cost was $1.7 million/mile.

Cost components

Variations over time in the four major categories of pipeline construction costs—material, labor, miscellaneous, and right-of-way—can also suggest trends within each group.

Materials can include line pipe, pipe coating, and cathodic protection.

"Miscellaneous" costs generally cover surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

ROW costs include obtaining rights-of-way and allowing for damages.

For the 21 land spreads filed for in 2008-09, costs-per-mile projections for three of the four categories showed increases, with only miscellaneous charges easing:

- Material—$1,312,014/mile, up from $1,045,846/mile for 2007-08.
- Labor—$1,414,728/mile, up from $1,344,389/mile for 2007-08.
- Miscellaneous—$759,028/mile, down from $837,246/mile for 2007-08.
- ROW and damages—$242,358/mile, up from $154,729/mile for 2007-08.

Table 4 lists proposed pipelines in order of increasing size (OD) and increasing lengths within each size.

The average cost-per-mile for the projects rarely shows clear trends related to either length or geographic area. In general, however, the cost-per-mile within a given diameter decreases as the number of miles rises. Lines built nearer populated areas also tend to have higher unit costs.

Additionally, road, highway, river, or channel crossings and marshy or rocky terrain each strongly affect pipeline construction costs.

Fig. 3, derived from Table 4, shows the major cost-component splits for pipeline construction costs.

Despite the increases in other categories, labor remained the single largest portion of land construction costs. Labor's portion of estimated costs for land pipelines, however, shrank to 37.95% in 2009, from 39.76% in 2008, 37.93% in 2007, and 32.35% in 2006. Material costs for land pipelines continued to rise in absolute terms and took much of the percentage share surrendered by labor, making up 35.19% of total costs in 2009 as compared with 30.93% in 2008, 36.44% in 2007 and 38.17% in 2006.

Fig. 4 plots a 10-year comparison of land-construction unit costs for the two major components, material and labor.

Fig. 5 shows the cost split for land compressor stations based on data in Table 5.

Table 6 lists 10 years of unit land-construction costs for natural gas pipeline with diameters ranging from 8 to 36 in. The table's data consist of estimated costs filed under CP dockets with FERC, the same data shown in Tables 4 and 5.

Table 6 shows that the average cost per mile for any given diameter may fluctuate year to year as projects' costs are affected by geographic location, terrain, population density, or other factors.

Completed projects' costs

In most instances, a natural gas pipeline company must file with FERC what it has actually spent on an approved and built project. This filing must occur within 6 months after the pipeline's successful hydrostatic testing or the compressor's being put in service.

Fig. 6 shows 10 years of estimated vs. actual costs on cost-per-mile bases for project totals.

Tables 7 and 8 show such actual costs for pipeline and compressor projects reported to FERC during the 12 months ending June 30, 2009. Fig. 7, for the same period, depicts how total actual costs ($/mile) for each category compare with estimated costs.

Per-mile pipeline construction costs for completed projects fell by nearly 6.4%, after jumping nearly 51% a year earlier and more than 86% the year before that. Sharply lower $/mile costs for offshore work in the 12 months

Special Report

ending June 30, 2009, balanced continued incremental increases in $/mile costs of both material and labor for land pipeline projects.

Even so, actual costs were 17.6% higher than projected costs for the 12 months ending June 30, 2009, with the price of labor running nearly 63% higher than had been anticipated.

Some of these projects may have been proposed and even approved much earlier than the 1-year survey period. Others may have been filed for, approved, and built during the survey period.

If a project was reported in construction spreads in its initial filing, that's how projects are broken out in Table 4. Completed projects' cost data, however, are typically reported to FERC for an entire filing, usually but not always separating pipeline from compressor-station (or metering site) costs and lumping several diameters together.

The 12 months ending June 30, 2009, saw more than 295,000 hp of new or additional compression completed, continuing the increases seen the year before when the 196,000 hp completed reversed previous declines; 96,000 hp having been completed in 2007, 106,000 hp completed in 2006, and 153,000 hp of new or additional compression completed in 2005 vs. 468,000 hp in 2004.

More than half of the 2008-09 horsepower came from five projects.

Actual compression costs ran $137/hp higher than estimates, with labor costs more than double initial estimates overwhelming lower-than-expected costs in the other categories (Table 8). Despite the year-on-year widening of the gap between estimated and actual costs, however, $/hp actual costs dropped by 34% from 2008. ✦

Company	Miles of pipeline: Gathering	Trunk: Crude	Trunk: Products	Total	Deliveries, 1,000 bbl: Crude	Products	Total	Total trunkline traffic, million bbl-miles: Crude	Products	Total	Fiscal data, $1,000: Carrier property	Property change	Operating revenue	Income
Alpine Transportation Co.	—	—	—	—	39,854	—	39,854	1,370	—	1,370	105,962	4,746	28,772	12,405
Amoco Capline Pipeline Co.	—	667	—	667	30,587	—	30,587	10,355	—	10,355	—	—	16,259	4,339
Apache GOM Pipeline Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Arrowhead Louisiana Gathering LLC	25	—	—	25	2,202	—	2,202	—	—	—	6,940	4,708	3,857	3,246
Baton Rouge Pipeline LLC	—	—	30	30	—	13,561	13,561	—	407	407	14,900	—	1,424	95
Belle Fourche Pipeline Co.	630	160	80	870	29,928	1,029	30,957	214	79	293	46,365	7,123	16,575	7,206
Belle Rose NGL Pipeline LLC	—	—	48	48	—	3,297	3,297	—	158	158	31,439	1,602	1,097	–370
Bengal Pipeline Co.	—	—	158	158	—	169,460	169,460	—	9,756	9,756	164,067	4,344	37,370	15,643
Black Lake Pipeline Co.	—	—	313	313	—	6,609	6,609	—	1,226	1,226	34,048	506	6,534	977
Blue Dolphin Pipe Line Co.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BP Oil Pipeline Co.	—	978	—	978	28,093	—	28,093	17,235	—	17,235	12,170	–117	20,607	26,351
BP Pipelines (Alaska) Inc.*	—	800	—	800	85,418	—	85,418	65,689	—	65,689	—	—	14,490	–289,598
BP Pipelines North America Inc.	—	2,342	1,434	3,776	174,416	73,698	248,114	27,720	4,202	31,922	496,390	37,309	106,363	93,061
BP Transportation (Alaska) Inc.	—	42	—	42	11,437	—	11,437	196	—	196	154,007	624	24,703	1,827
Bridger Lake LLC (new)	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Bridger Pipeline LLC	386	271	—	657	20,536	—	20,536	1,219	—	1,219	63,398	25,348	19,425	13,825
Buckeye NGL Pipe Lines LLC	440	—	369	809	—	7,664	7,664	—	2,820	2,820	87,116	78	13,136	3,601
Buckeye Pipe Line Co. LP	—	—	2,651	2,651	—	287,284	287,284	—	38,378	38,378	701,290	17,990	238,746	87,854
Buckeye Pipe Line Transportation LLC	—	—	572	572	—	23,809	23,809	—	3,398	3,398	157,901	1,519	20,923	6,143
Burlington Resources Trading Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Butte Pipe Line Co.	—	373	—	373	36,791	—	36,791	9,590	—	9,590	25,697	470	20,149	4,785
Caillou Boca Gathering LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Calnev Pipe Line Co.	—	—	561	561	—	47,281	47,281	—	10,791	10,791	311,975	10,405	57,235	40,537
CCPS Transportation LLC	—	658	—	658	40,135	—	40,135	26,349	—	26,349	277,699	68,119	51,641	18,148
Cenex Pipeline LLC	—	—	703	703	—	16,158	16,158	—	4,643	4,643	65,232	57	25,587	15,084
Centennial Pipeline LLC	—	—	797	797	—	41,016	41,016	—	27,713	27,713	300,873	627	39,109	–4,818
Centurion Pipeline LP	1,276	2,316	—	3,592	85,239	—	85,239	19,453	—	19,453	469,420	115,697	77,606	–6,736
Chaparral Pipeline Co. LLC	—	—	845	845	—	9,395	9,395	—	5,541	5,541	120,384	3,774	35,829	11,002
Chevron Pipe Line Co.	157	1,919	1,546	3,622	147,522	43,602	191,124	8,497	8,664	17,161	730,641	13,031	142,503	–46,877
Chicap Pipe Line Co.	—	235	—	235	42,090	—	42,090	4,277	—	4,277	59,438	1,668	12,991	2,877
Chisholm Pipeline Co.	—	—	185	185	—	10,795	10,795	—	1,992	1,992	21,166	102	4,720	1,454
Chunchula Pipeline Co. LLC	—	—	144	144	—	1,055	1,055	—	152	152	18,083	148	1,247	–372
Citgo Pipeline Co.	5	128	—	133	130,832	9,662	140,494	1,982	10	1,992	31,957	–95	10,679	301
Citgo Products Pipeline Co.	—	—	358	358	—	13,901	13,901	—	1,763	1,763	41,790	248	15,577	7,289
Coffeyville Resources Crude Transportation LLC	—	—	—	—	—	—	—	949	—	949	13,511	293	8,608	—
Collins Pipeline Co.	—	—	124	124	—	40,529	40,529	—	5,048	5,048	24,484	3,052	10,092	1,897
Colonial Pipeline Co.	—	—	5,593	5,593	—	821,447	821,447	—	686,727	686,727	2,408,949	76,129	802,070	193,144
Conoco Offshore Pipe Line Co.	183	—	—	183	2,239	—	2,239	226	—	226	—	—	1,466	411
ConocoPhillips Pipe Line Co.	534	2,190	3,970	6,694	290,311	239,592	529,903	21,677	37,581	59,258	986,913	–6,487	320,123	112,599
ConocoPhillips Transportation Alaska Inc.*	—	818	—	818	100,055	—	100,055	78,991	—	78,991	3,127,690	14,260	464,986	–204,882
Cottonwood Creek Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Cypress Pipe Line Co. LLC	—	57	—	57	11,983	—	11,983	683	—	683	2,665	–8,971	6,101	4,026
Devon Energy Offshore Pipeline Co.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Devon Energy Petroleum Pipeline Co.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dixie Pipeline Co.	—	—	1,404	1,404	—	38,588	38,588	—	19,413	19,413	121,034	13,810	52,589	12,137
Dome Pipeline Corp.	—	—	—	—	—	5,278	5,278	—	318	318	28,592	672	3,291	1,272
DryTrails Midstream Energy LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Ellwood Pipeline Inc.	11	26	—	37	3,649	—	3,649	—	—	—	1,722	–142	5,452	6,027
Enbridge Energy LP	—	3,665	—	3,665	615,142	—	615,142	432,111	—	432,111	4,245,157	980,977	640,012	247,973
Enbridge Pipelines (North Dakota) LLC	307	637	—	944	38,421	—	38,421	15,285	—	15,285	195,596	47,030	62,665	26,543
Enbridge Pipelines (Ozark) LLC	—	480	—	480	84,417	—	84,417	30,631	—	30,631	126,918	13,207	50,190	26,345
Enbridge Pipelines (Patoka) LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Enbridge Pipelines (Toledo) Inc.	—	88	—	88	26,230	—	26,230	2,247	—	2,247	55,659	980	16,987	3,475
Encore Clear Fork Pipeline LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Endicott Pipeline Co.	—	26	—	26	14,156	—	14,156	368	—	368	60,875	289	7,337	–380
Energy Development Corp. (HIPS) Inc	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Enterprise Lou-Tex NGL Pipeline LP	—	—	205	205	—	17,104	17,104	—	3,506	3,506	100,787	640	21,749	12,480
EPL Pipeline LLC	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Explorer Pipeline Co.	—	—	1,879	1,879	—	168,514	168,514	—	120,529	120,529	698,507	43,204	235,301	41,961
Express Pipeline LLC	—	513	—	513	71,440	—	71,440	33,907	—	33,907	408,871	2,950	89,567	28,408
ExxonMobil Pipeline Co.*	605	1,051	2,901	4,557	376,249	300,185	676,434	63,987	9,504	73,491	594,621	12,229	160,365	128,119
Frontier Pipeline Co.	—	290	—	290	12,093	—	12,093	3,506	—	3,506	76,323	6,766	9,191	4,018
Genesis Pipeline USA LP	131	228	—	359	14,170	—	14,170	862	—	862	53,976	678	20,191	9,213
Heartland Pipeline Co.	—	—	49	49	—	8,521	8,521	—	2,718	2,718	12,081	–96	7,123	3,058
Holly Energy Partners—Operating LP	647	183	1,477	2,307	25,452	39,462	64,914	339	8,391	8,730	130,423	92,413	58,507	42,864
Inland Corp.	—	—	610	610	—	46,567	46,567	—	3,570	3,570	35,856	1,468	24,071	5,139

Company	Gathering	Trunk Crude	Trunk Products	Total miles	Deliveries Crude	Deliveries Products	Deliveries Total	Traffic Crude	Traffic Products	Traffic Total	Carrier property	Property change	Operating revenue	Income
	Miles of pipeline				Deliveries, 1,000 bbl			Total trunkline traffic, million bbl-miles			Fiscal data, $1,000			
Interstate Storage & Pipe Line Corp.	23	—	—	23	2,191	—	2,191	—	—	—	5,967	540	2,278	–2
IMTT-Pipeline	—	—	10	10	—	27,263	27,263	—	189	189	21,521	124	1,611	–1,023
Jayhawk Pipeline LLC	4	724	—	728	31,702	—	31,702	4,980	—	4,980	75,434	14,086	23,743	6,414
Kenai Pipe Line Co.	—	—	46	46	15,039	9,788	24,827	346	225	571	38,505	11,221	6,400	–299
Keystone Pipeline Co. LLC	—	—	—	—	—	2,900	2,900	—	731	731	—	—	3,009	–1
Kiantone Pipeline Corp.	—	156	—	156	—	—	—	—	—	—	16,070	585	4,623	1,703
Kinder Morgan Cochin LLC	—	—	1,236	1,236	—	11,156	11,156	—	6,991	6,991	144,444	2,515	37,767	3,298
Kinder Morgan Operating LP "A"	—	—	104	104	—	16,064	16,064	—	1,671	1,671	42,043	2,299	6,951	734,163
Kinder Morgan Wink Pipeline LLC	—	425	—	425	43,673	—	43,673	10,915	—	10,915	94,263	3,237	38,193	21,606
Koch Alaska Pipeline Co. LLC*	—	819	—	819	10,739	—	10,739	5,691	—	5,691	—	—	19,231	–9,660
Koch Pipeline Co. LP	—	591	11	602	17,985	4,242	22,227	9,574	46	9,620	191,110	747	34,585	37,493
Kuparuk Transportation Co.	—	—	—	—	104,891	—	104,891	3,453	—	3,453	153,478	17,853	21,089	7,451
Laclede Pipeline Co.	—	—	40	40	—	5,016	5,016	—	109	109	6,287	74	1,582	650
LDH Energy Hastings LLC	—	—	36	36	—	6,027	6,027	—	217	217	18,495	—	2,412	1,269
LOCAP LLC	—	57	—	57	345,386	—	345,386	19,766	—	19,766	153,302	3,035	30,681	9,969
Longhorn Partners Pipeline LP	—	—	761	761	—	23,225	23,225	—	15,614	15,614	548,160	34,369	96,059	29,872
Magellan Pipeline Co. LP	—	—	8,658	8,658	—	297,940	297,940	—	72,266	72,266	1,371,477	58,307	401,691	97,317
Marathon Offshore Pipeline LLC	—	294	—	294	6,912	—	6,912	620	—	620	32,463	–621	8,366	1,516
Marathon Pipe Line LLC	—	1,815	1,277	3,092	510,163	311,169	821,332	140,770	20,470	161,240	710,128	90,656	327,766	142,638
MarkWest Michigan Pipeline Co. LLC	85	152	—	237	—	—	—	738	—	738	23,699	852	4,709	354
Mars Oil Pipeline Co.	—	121	—	121	—	—	—	—	—	—	146,895	–105	110,987	75,115
Mid-America Pipeline Co. LLC	2,030	—	5,803	7,833	—	306,259	306,259	—	106,665	106,665	1,333,040	113,676	353,539	159,119
Mid-Valley Pipeline Co.	—	1,087	—	1,087	92,575	—	92,575	65,968	—	65,968	101,960	5,038	63,001	16,567
Milne Point Pipeline LLC	—	11	—	11	11,801	—	11,801	130	—	130	53,049	31	17,016	7,220
Minnesota Pipe Line Co. LLC	—	979	—	979	104,016	—	104,016	26,885	—	26,885	630,636	750,836	57,972	4,376
Mobil Eugene Island Pipeline Co.	—	—	—	—	2,277	—	2,277	157	—	157	20,153	–1,175	3,659	55
Mobil Pipe Line Co.	94	951	208	1,253	130,677	67,011	197,688	14,889	5,958	20,847	155,248	–14,214	55,139	86,209
MOEM Pipeline LLC	—	56	—	56	21,612	—	21,612	1,244	—	1,244	25,021	–314	7,314	2,978
Muskegon Pipeline LLC	—	—	170	170	—	10,290	10,290	—	1,746	1,746	28,316	194	5,660	3,387
Mustang Pipe Line LLC	—	211	—	211	32,888	—	32,888	6,412	—	6,412	57,518	–1,242	39,958	29,815
Navajo Nation Oil & Gas Co. Inc.	—	—	—	–	—	—	—	9	—	9	4,301	1,309	3,647	634
Navajo Pipeline Co. (final)	—	—	—	—	5,538	—	5,538	100	—	100	—	–19,190	3,028	1,980
NORCO Pipe Line Co. LLC	—	—	419	419	—	15,984	15,984	—	1,214	1,214	78,928	5,671	8,453	–4,016
Nova Chemicals Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NuStar Logistics LP	—	814	2,932	3,746	150,204	151,283	301,487	13,435	25,037	38,472	572,098	9,642	168,486	164,279
NuStar Pipeline Operating Partnership LP (new)	—	—	2,330	2,330	—	68,253	68,253	—	19,862	19,862	550,886	11,367	104,847	95,960
Ohio Oil Gathering Corp. II	137	—	—	137	1,525	—	1,525	—	—	—	9,538	–97	4,931	–799
Ohio River Pipe Line LLC	—	—	549	549	—	41,873	41,873	—	3,281	3,281	201,770	1,627	38,860	19,705
Olympic Pipe Line Co.	—	—	414	414	—	105,295	105,295	—	18,672	18,672	222,025	7,506	78,143	13,464
ONEOK NGL Pipeline LLC	—	—	2,577	2,577	—	123,241	123,241	—	36,181	36,181	551,995	—	87,573	23,133
ONEOK North System LLC	—	—	1,630	1,630	—	32,814	32,814	—	8,709	8,709	260,987	252,565	53,988	22,877
Osage Pipe Line Co. LLC	—	135	—	135	41,478	—	41,478	5,600	—	5,600	21,711	578	14,430	9,457
Overland Pass Pipeline LLC (new)	—	—	750	750	—	1,899	1,899	—	1,545	1,545	739,051	438,720	2,397	10,192
Phillips Texas Pipeline Co. Ltd.	491	607	635	1,733	69,435	4,670	74,105	13,121	7,109	20,230	190,558	6,140	113,882	55,493
Pioneer Natural Resources USA Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Pioneer Pipe Line Co.	—	—	563	563	—	22,627	22,627	—	4,739	4,739	91,727	1,443	23,003	6,708
Plains LPG Services LP	—	—	63	63	—	—	—	—	—	—	11,675	—	603	10,390
Plains Pipeline LP	1,739	5,575	261	7,575	750,383	18,614	768,997	112,276	2,348	114,624	970,680	8,834	331,750	150,616
Plantation Pipe Line Co.	—	—	3,123	3,123	—	175,805	175,805	—	105,577	105,577	526,446	5,728	186,279	27,219
Platte Pipe Line Co.	—	936	—	936	78,568	—	78,568	44,410	—	44,410	250,789	2,406	61,381	1,891
PMI Services North America Inc.	—	—	17	17	—	8,778	8,778	—	9	9	45,044	29,819	10,192	3,793
Point Arguello Pipeline Co.	—	28	—	28	2,661	—	2,661	75	—	75	289,057	241	5,379	–8,672
Portland Pipe Line Corp.	10	332	—	342	123,588	—	123,588	20,516	—	20,516	106,235	8,457	66,352	11,691
Premcor Pipeline Co.	—	71	116	187	32,814	68,099	100,913	755	646	1,401	129,501	24,313	19,095	–12,755
Questar Gas Management (new)	56	—	—	56	1,933	—	1,933	—	—	—	9,153	37	1,124	81,521
Razorback LLC	67	—	—	67	—	2,033	2,033	—	—	—	21,903	—	3,357	1,205
Red Butte Pipe Line Co.	67	736	—	803	14,253	—	14,253	1,445	—	1,445	21,342	638	14,577	224
Regency Liquids Pipeline LLC	—	—	40	40	—	—	—	—	—	—	5,925	354	1,423	536
Rio Grande Pipeline Co.	—	—	249	249	—	5,896	5,896	—	1,274	1,274	46,738	541	9,272	4,261
Rocky Mountain Pipeline System LLC	329	1,805	546	2,680	79,183	21,715	100,898	8,786	2,584	11,370	656,783	165,917	79,673	19,367
Salmon Resources Ltd.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Sanders Pipeline Co.	—	—	9	9	—	2,915	2,915	—	27	27	1,934	—	2,457	107
San Pedro Bay Pipeline Co.	18	—	—	18	—	—	—	—	—	—	5,290	1,094	1,590	–38
Seaway Crude Pipeline Co.	—	—	—	—	153,114	—	153,114	40,326	—	40,326	336,353	4,902	81,595	46,083
Seaway Products Pipeline Co.	—	—	520	520	—	2,805	2,805	—	1,357	1,357	69,155	297	1,755	–13,039
Seminole Pipeline Co.	97	—	1,229	1,326	—	104,330	104,330	—	60,422	60,422	425,359	6,177	81,944	5,717

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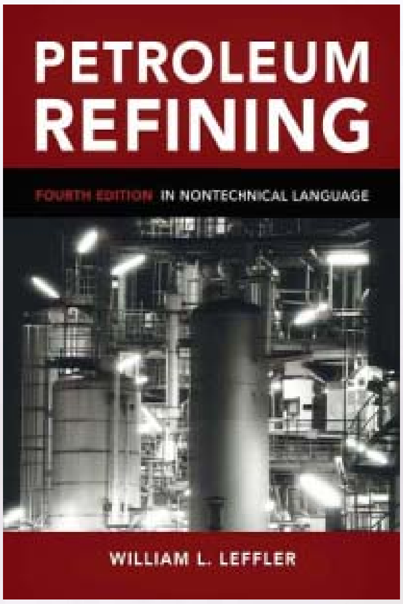

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OIL PIPELINES (CONTINUED)

Company	Miles of pipeline: Gathering	Trunk: Crude	Trunk: Products	Total	Deliveries, 1,000 bbl: Crude	Products	Total	Total trunkline traffic, million bbl-miles: Crude	Products	Total	Fiscal data, $1,000: Carrier property	Property change	Operating revenue	Income
SemPipe LP	—	—	—	—	—	—	—	—	—	—	—	—	—	—
SFPP LP	—	—	2,612	2,612	—	407,114	407,114	—	64,641	64,641	1,807,265	–47,394	271,379	120,062
Shamrock Pipe Line Corp.	198	25	—	223	6,786	—	6,786	357	—	357	4,384	362	1,913	1,096
Shell Pipeline Co. LP	10	1,600	414	2,024	518,679	151,416	670,095	37,953	760	38,713	588,982	16,036	204,231	225,126
Ship Shoal Pipeline Co.	—	121	—	121	66,182	—	66,182	206	—	206	42,720	71	15,946	6,870
Sinclair Pipeline Co. LLC	—	—	15	15	—	9,411	9,411	—	—	—	3,701	—	6,546	1,775
Skelly-Belvieu Pipeline Co. LLC	—	—	571	571	—	9,133	9,133	—	5,219	5,219	71,710	1,876	12,115	–608
Sorrento Pipeline Co LLC	—	—	484	484	—	17,484	17,484	—	914	914	127,484	4,738	11,388	15,173
Southcap Pipe Line Co.	—	638	—	638	5,952	—	5,952	3,251	—	3,251	—	—	7,026	102
SouthTex 66 Pipeline Co. Ltd.	—	—	755	755	—	72,994	72,994	—	13,354	13,354	171,984	1,057	72,203	44,913
St. Louis Pipeline Corp.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Suncor Energy (USA) Pipeline Co.	—	313	—	313	24,524	—	24,524	3,429	—	3,429	59,343	18,207	17,099	4,522
Sunoco Pipeline LP	515	3,317	2,072	5,904	236,832	219,049	455,881	20,088	23,712	43,800	1,120,778	252,997	266,653	141,640
Targa NGL Pipeline Co. LLC	—	—	183	183	—	—	—	—	964	964	36,588	5,362	5,591	2,111
TE Products Pipeline Co. LP	—	—	4,676	4,676	—	172,840	172,840	—	108,217	108,217	1,524,975	276,517	289,142	39,989
TEPPCO Crude Pipeline LLC	—	3,967	—	3,967	158,902	—	158,902	8,985	—	8,985	452,619	71,210	101,717	32,464
Tesoro High Plains Pipeline Co.	228	547	—	775	20,034	—	20,034	5,131	—	5,131	94,629	1,218	21,190	5,388
Total Petrochemicals Pipeline USA Inc.	—	14	—	14	—	—	—	—	—	—	361	—	1,335	1,373
TransMontaigne Product Services Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Trans Mountain Pipeline (Puget Sound) LLC	—	64	—	64	42,470	—	42,470	1,344	—	1,344	45,614	50,961	12,776	10,194
Tri-States NGL Pipeline LLC	—	—	165	165	—	16,965	16,965	—	2,566	2,566	90,738	322	16,993	8,265
Unocal Pipeline Co.*	93	1,179	—	1,272	7,115	—	7,115	3,732	—	3,732	21,562	2,159	15,646	–8,825
Valero MKS Logistics LLC (new)	—	53	—	53	44,443	—	44,443	1,454	—	1,454	40,671	538	5,289	–585
Valero Terminaling & Distribution Co.	—	—	521	521	—	2,554	2,554	—	224	224	1,375	21	1,025	2,531
Wesco Pipline LLC (new)	—	—	—	—	422	—	422	4	—	4	—	—	—	—
WesPac Pipelines—Memphis LLC (new)	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Western Refining Pipeline Co. (new)	—	424	—	424	1,430	—	1,430	—	—	—	66,787	3,347	10,923	–4,771
West Shore Pipe Line Co.	—	3	649	652	38,986	125,848	164,834	134	12,582	12,716	84,559	397	54,643	12,267
WestTex 66 Pipeline Co.	—	—	707	707	—	11,543	11,543	—	2,587	2,587	27,512	1,470	6,625	7,310
West Texas Gulf Pipe Line Co.	—	579	—	579	102,269	—	102,269	42,080	—	42,080	57,855	3,916	30,791	10,545
West Texas LPG Pipeline LP	—	—	2,295	2,295	—	84,271	84,271	—	35,512	35,512	210,745	69,955	63,983	16,568
Whiting Oil & Gas Corp.	66	13	—	79	2,688	—	2,688	37	—	37	5,326	—	2,286	258,509
WILPRISE Pipeline Co. LLC	—	—	30	30	—	11,147	11,147	—	334	334	24,468	—	3,270	1,420
Wolverine Pipe Line Co.	—	—	742	742	—	107,837	107,837	—	11,702	11,702	145,605	–6,148	55,274	8,188
Wood River Pipe Lines LLC.	—	—	995	995	—	74,665	74,665	—	12,598	12,598	389,031	1,922	36,499	8,135
Yellowstone Pipe Line Co.	—	—	690	690	—	37,519	37,519	—	7,745	7,745	64,742	3,351	26,535	5,976
2008 total	**11,694**	**50,214**	**84,914**	**146,822**	**6,858,005**	**6,114,132**	**12,972,137**	**1,581,492**	**1,856,120**	**3,437,612**	**$39,069,290**	**$4,419,490**	**$9,243,677**	**$3,931,602**
2007 total	14,911	46,658	85,666	147,235	7,038,083	6,895,723	13,933,806	1,451,245	2,008,042	3,459,287	$35,862,833	$4,062,114	$8,996,329	$3,756,749

*Crude and total mileages represent 818 miles of Trans-Alaska Pipeline, operated by Alyeska Pipeline Service Co., Anchorage. This figure is included in column total only once to avoid duplication.
NR = not reported.
Sources: US FERC Form No. 6: Annual Report of Oil Pipelines, Dec. 31, 2008

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Company	Transmission system, miles	Total compression stations: Transmission	Other	Total	Volumes trans. for others, MMcf	Fiscal data, $1,000: Gas plant	Additions	Operating & maintenance expenses	Operating revenue	Net income
Algonquin Gas Transmission LLC*	1,121	7	—	7	351,104	1,752,158	313,321	77,998	228,117	46,074
Alliance Pipeline LP*	888	7	—	7	640,863	1,871,066	2,833	66,315	295,246	85,229
ANR Pipeline Co.*	9,580	46	22	68	1,982,666	3,782,105	147,796	292,042	564,981	85,199
ANR Storage Co.*	24	—	3	3	—	139,741	390	7,307	31,131	22,168
Bear Creek Storage Co.*	—	—	1	1	—	161,462	857	7,865	39,937	15,318
Black Marlin Pipeline Co.	67	—	—	—	516	22,837	2,293	2,020	478	–8,852
Blue Lake Gas Storage Co.	—	—	1	1	—	102,843	–9	2,428	24,847	9,523
Bluewater Gas Storage LLC (new)	—	—	—	—	—	—	—	—	—	—
Bobcat Gas Storage* (new)	—	—	—	—	—	—	—	—	—	—
Caledonia Energy Partners LLC (new)	—	—	—	—	—	—	—	—	—	—
Canyon Creek Compression Co.	—	1	—	1	—	—	—	523	—	–1,725
Carolina Gas Transmission Corp.*	1,481	3	—	3	107,963	280,242	12,705	21,586	49,107	8,265
CenterPoint Energy Gas Transmissiion Co.*	6,320	60	3	63	1,252,757	1,983,242	166,939	240,922	553,113	142,405
CenterPoint Energy Mississippi River Transmission Corp.*	1,572	14	2	16	387,067	556,061	23,110	69,806	110,608	15,085
Centra Pipelines Minnesota Inc.	66	—	—	—	12,421	4,960	168	820	924	–40
Central Kentucky Transmission	29	—	—	—	5,084	742	—	80	181	46
Chandeleur Pipe Line Co.*	117	—	—	—	29,554	46,432	9	3,007	3,423	–1,415
Cheniere Creole Trail Pipeline LP* (new)	96	—	—	—	6,175	581,114	580,994	2,977	1,025	–3,729
Cheyenne Plains Gas Pipeline Co. LLC*	413	3	—	3	328,598	429,593	19,829	18,579	115,121	36,354
Cimarron River Pipeline LLC* (new)	530	20	—	20	22,801	79,407	79,407	3,186	3,495	–1,521
Clear Creek Storage Co. LLC	15	—	2	2	—	20,572	127	1,213	1,463	–656
Colorado Interstate Gas Co.*	4,108	31	6	37	814,300	1,323,465	46,008	119,508	325,358	97,040
Colorado Natural Gas Inc. (new)	6	—	—	—	—	68,973	12,913	7,414	14,017	2,026
Columbia Gas Transmission LLC*	11,531	68	24	92	1,910,403	3,915,059	114,756	264,560	724,200	193,276
Columbia Gulf Transmission Co.*	3,562	15	—	15	993,349	1,174,565	30,970	58,643	136,845	24,133
Crossroads Pipeline Co.	202	1	—	1	36,198	37,831	143	1,412	4,484	975
Dauphin Island Gathering Partners*	120	1	—	1	59,670	124,065	46	8,030	13,546	–10,377
Destin Pipeline Co. LLC*	271	2	—	2	284,717	504,729	619	20,178	59,773	8,751
Discovery Gas Transmission LLC*	197	—	—	—	257,070	210,743	1,816	5,384	14,183	8,104
Distrigas of Massachusetts LLC*	—	—	—	—	—	298,258	—	1,503,506	1,698,331	248,473
Dominion Cove Point LNG LP*	90	2	—	2	72,359	498,605	80,590	24,762	101,168	32,525
Dominion South Pipeline Co. LP	—	—	—	—	18,383	2,068	–45	227	963	392
Dominion Transmission Inc.*	3,466	59	46	105	620,055	3,248,295	356,889	392,254	879,260	203,114
East Tennessee Natural Gas LLC*	1,506	21		21	227,880	884,074	75,901	31,567	108,640	29,376
Eastern Shore Natural Gas Co.	308	—	—	—	22,946	134,416	11,693	7,738	23,776	5,545
El Paso Natural Gas Co.*	10,237	57	1	58	1,740,860	3,314,447	212,301	223,714	590,547	136,393
Empire Pipeline Inc.*	—	—	—	—	5,878	—	—	—	—	—
Enbridge Offshore Pipelines (UTOS) LLC*	30	—	—	—	47,311	64,282	1,073	4,403	2,599	–2,034
Enbridge Pipelines (AlaTenn) LLC	295	2	—	2	15,498	28,906	686	3,100	2,276	–2,840
Enbridge Pipelines (MidLa) LLC	412	1	—	1	36,241	44,213	698	4,113	7,871	1,314
Energy West Development	46	—	1	1	—	800	44	91	337	109
Equitrans LP*	588	5	25	30	73,889	642,710	242,039	37,486	83,557	17,201
Florida Gas Transmission Co. LLC*	4,872	26	1	27	785,975	3,183,709	259,291	93,532	513,682	148,269
Freebird Gas Storage LLC	—	—	—	—	—	—	—	—	—	—
Garden Banks Gas Pipeline LLC*	50	—	—	—	58,234	100,592	123	3,916	5,980	–3,108
Gas Transmission Northwest Corp.*	1,356	13	—	13	797,807	1,688,640	12,852	51,022	218,019	177,659
Granite State Gas Transmission Inc.	87	—	—	—	25,838	24,045	907	1,548	2,833	13
Great Lakes Gas Transmission LP*	2,115	14	—	14	789,616	2,047,046	18,184	46,276	287,130	79,126
Guardian Pipeline LLC*	262	1	—	1	54,397	535,846	247,089	11,274	34,980	14,625
Gulf South Pipeline Co. LP*	6,466	32	5	37	1,048,042	3,043,485	1,187,546	148,122	415,923	94,403
Gulf States Tranmission Corp. (new)	10	—	—	—	41,988	2,885	—	267	843	252
Gulfstream Natural Gas System LLC*	742	1	—	1	297,821	1,907,410	204,353	18,269	206,658	71,543
Hampshire Gas Co.	18	—	1	1	—	23,530	199	2,227	4,910	776
Hardy Storage Co.	—	—	1	—	—	169,244	—	2,985	23,588	5,009
High Island Offshore System LLC*	212	1	—	1	108,286	395,637	3,397	25,074	22,553	–3,857
Honeoye Storage Corp.	11	—	1	1	—	12,728	311	1,947	4,705	1,557
Horizon Pipeline Co. LLC	28	1	—	1	28,767	91,970	170	3,161	12,089	1,797
Iroquois Gas Transmission Systems LP (IPOC agent)*	416	6	—	6	381,221	1,177,615	81,287	27,608	169,855	40,105
Jackson Prairie Underground Storage Project	—	—	—	—	—	57,281	98	2,247	—	–2,247
Kern River Gas Transmission Co.*	1,680	12	—	12	802,385	2,369,351	40,429	36,577	443,062	148,663
Kinder Morgan Illinois Pipeline LLC	3	—	—	—	7,048	19,111	891	1,438	3,283	589
Kinder Morgan Interstate Gas Transmission LLC*	5,265	25	2	27	219,884	752,347	47,175	89,067	199,516	52,433
KO Transmission Co.	92	—	—	—	45,332	16,621	–34	413	1,679	702

Company	Transmission system, miles	Total compression stations: Transmission	Other	Total	Volumes trans. for others, MMcf	Fiscal data, $1,000: Gas plant	Additions	Operating & maintenance expenses	Operating revenue	Net income
Liberty Gas Storage LLC	—	—	—	—	—	—	—	—	—	—
Maritimes & Northeast Pipeline LLC*	343	2	—	2	173,547	873,425	300	13,367	123,640	54,978
MarkWest New Mexico LP*	8	—	—	—	24,335	2,969	30	246	1,126	422
Midwest Energy Inc.* (new)	53	—	—	—	—	59,673	2,837	49,880	173,301	9,776
Midwestern Gas Transmission Co.*	399	7	—	7	139,627	213,312	79,675	10,079	25,093	3,897
MIGC Inc.*	264	5	—	5	61,470	50,638	462	4,759	19,809	6,896
Millennium Pipeline Co. LLC*	182	1	—	1	813	1,049,942	1,049,942	112	3,064	15,992
Mississippi Canyon Gas Pipeline LLC*	45	—	—	—	160,453	57,227	342	3,351	15,884	5,498
MoGas Pipeline LLC (new)	—	—	—	—	22,504	88,963	7,474	2,512	11,771	2,327
Mojave Pipeline Co.*	445	1	—	1	127,743	246,371	112	8,470	21,242	16,313
National Fuel Gas Supply Corp.*	1,458	16	3	19	312,943	792,403	16,786	64,777	184,859	45,482
National Grid LNG LP (new)	—	—	—	—	—	47,937	99	3,139	7,948	1,755
Natural Gas Pipeline Co. of America*	9,008	51	14	65	1,925,335	3,703,874	198,869	599,021	1,284,695	384,621
Nautilus Pipeline Co. LLC*	101	—	—	—	63,049	120,575	22	5,991	3,853	–5,462
NGO Transmission Inc.	—	—	—	—	8,879	21,164	1,211	2,276	4,320	377
North Baja Pipeline LLC*	80	1	—	1	104,723	198,233	43,759	3,690	32,909	10,457
Northern Border Pipeline Co.*	1,399	17	—	17	848,893	2,487,099	11,350	52,005	293,105	81,568
Northern Natural Gas Co.*	15,018	64	6	70	1,143,582	3,131,811	207,461	260,722	770,795	250,798
Northwest Pipeline GP*	3,882	43	1	44	883,612	2,766,938	121,212	133,165	434,854	100,752
ONEOK Gas Transportation LLC*	2,505	4	—	4	298,959	320,005	11,430	31,172	73,851	13,154
Ozark Gas Transmission LLC*	565	4	—	4	168,329	234,484	20,125	6,122	54,206	26,160
Paiute Pipeline Co.	856	6	—	6	41,044	173,156	3,938	13,502	30,990	6,561
Panhandle Eastern Pipe Line Co. LP*	6,049	24	—	24	701,616	1,611,294	261,693	161,150	367,098	174,456
Panther Interstate Pipeline Energy LLC	55	1	—	1	4,034	23,012	—	890	732	–258
Petal Gas Storage LLC*	59	1	2	3	100,181	286,578	66,203	9,864	46,442	15,938
Pine Needle LNG Co. LLC	—	—	—	—	—	108,837	78	4,355	18,654	4,927
Point Arguello Natural Gas Line Co.	—	—	—	—	504	141,980	66	1,489	13,481	11,484
Portland Natural Gas Transmission System*	296	—	—	—	49,150	492,245	210	9,718	54,916	74,468
Quest Pipelines (KPC)	1,121	3	—	3	9,450	80,786	1,072	9,638	19,795	3,890
Questar Overthrust Pipeline Co.*	215	2	—	2	342,288	325,170	199,301	2,612	42,417	13,799
Questar Pipeline Co.*	1,748	17	6	23	425,464	867,584	33,399	59,706	177,901	58,019
Questar Southern Trails Pipeline Co.	488	4	—	4	27,892	117,914	732	7,221	12,178	–3,092
Raton Gas Transmission Co. Inc.	22	—	—	—	1,125	1,033	34	1,178	1,233	34
Rockies Express Pipeline LLC*	1,049	10	—	10	570,159	2,588,761	1,915,525	105,317	433,967	104,192
Sabine Pipe Line LLC*	140	5	—	5	250,187	66,629	6,201	13,480	16,721	1,291
Saltville Gas Storage Co. LLC	7	—	1	1	—	117,089	29,583	7,543	14,638	3,120
Sea Robin Pipeline Co. LLC*	418	2	—	2	126,293	292,587	27,988	14,297	17,727	–607
Southeast Supply Header LLC* (new)	288	3	2	5	64,117	1,177,368	1,177,368	2,361	22,739	41,813
Southern LNG Inc.*	—	—	—	—	—	390,933	2,472	25,431	71,597	28,872
Southern Natural Gas Co.*	7,593	43	—	43	879,172	3,448,766	228,741	184,947	539,031	149,176
Southern Star Central Gas Pipeline Inc.*	5,721	33	7	40	414,254	1,165,220	83,346	87,638	196,788	31,902
Southwest Gas Storage Co.	—	—	4	4	—	183,540	6,821	22,057	45,943	9,480
Southwest Gas Transmission Co. LP	9	—	—	—	32,260	2,156	441	106	466	154
Steuben Gas Storage Co.	15	—	1	1	—	31,654	36	1,351	6,716	1,785
Stingray Pipeline Co. LLC*	379	—	2	2	—	302,012	13,021	11,306	11,854	–1,068
Tennessee Gas Pipeline Co.*	14,463	72	1	73	1,801,283	6,831,863	566,195	412,888	916,763	132,015
Texas Eastern Transmission LP*	9,202	71	—	71	1,432,742	5,729,201	193,108	397,165	915,783	207,298
Texas Gas Transmission LLC.*	5,595	26	7	33	867,664	1,945,457	301,030	105,696	297,072	133,722
Trailblazer Pipeline Co.*	439	3	—	3	324,680	333,338	2,158	29,957	73,716	21,207
TransColorado Gas Transmission Co.*	305	8	—	8	263,592	419,145	65,365	10,348	63,450	24,714
Transcontinental Gas Pipe Line Co. LLC*	9,972	48	16	64	2,577,642	7,573,559	221,878	542,623	1,202,290	235,164
Transwestern Pipeline Co. LLC*	2,392	30	—	30	650,417	1,252,918	116,790	69,321	244,224	95,037
Trunkline Gas Co. LLC*	3,598	19	1	20	643,316	1,637,889	140,008	69,052	204,340	55,428
Trunkline LNG Co. LLC*	—	—	—	—	—	741,827	845	30,679	129,070	75,234
Tuscarora Gas Transmission Co.	240	3	1	4	30,933	202,715	20,259	4,177	31,553	9,650
Valero Natural Gas Pipeline Co.	3	—	—	—	9,055	1,157	—	186	252	3
Vector Pipeline LP*	333	4	—	4	491,325	798,807	9,842	10,101	100,523	18,221
Venice Gathering System LLC*	190	—	—	—	22,560	95,294	4,535	10,449	592	–13,572
Viking Gas Transmission Co.*	674	8	—	8	145,749	176,897	1,823	11,319	31,624	8,502
West Texas Gas Inc.	650	—	—	—	11,006	146,609	9,397	227,944	235,369	8,652
Western Gas Interstate Co.	264	—	—	—	4,416	13,906	689	721	1,874	1,998
WestGas InterState Inc.	12	—	—	—	3,513	667	—	47	177	75
White River Hub LLC* (new)	11	—	—	—	18,012	46,828	46,828	48	763	807
Williston Basin Interstate Pipeline Co.*	3,367	22	10	32	137,858	423,759	25,467	43,112	95,590	18,366
WTG Hugoton LP (new)	184	1	14	15	47,033	115,126	613	6,798	9,228	–1,126

GAS PIPELINES (CONTINUED)

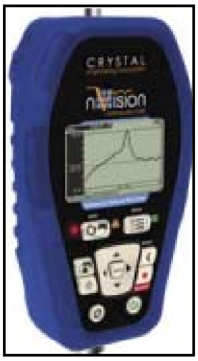
Company	Transmission system, miles	Total compression stations: Transmission	Other	Total	Volumes trans. for others, MMcf	Fiscal data, $1,000: Gas plant	Additions	Operating & maintenance expenses	Operating revenue	Net income
Wyoming Interstate Co. Ltd.*	849	9	—	9	930,587	836,414	90,047	45,562	144,515	46,341
Young Gas Storage Co. Ltd.	11	1	—	1	—	47,340	1,025	3,098	8,330	1,406
2008 total—majors (83)	**192,384**	**1,228**	**219**	**1,447**	**38,228,678**	**$103,234,920**	**$12,179,025**	**$7,779,398**	**$19,186,468**	**$5,027,305**
2007 total—majors (77)	192,189	1,189	213	1,402	36,466,881	$93,250,209	$6,446,799	$7,645,118	$21,279,633	$4,659,406
2008 total—all	**198,016**	**1,253**	**247**	**1,499**	**38,778,586**	**$105,788,237**	**$12,293,846**	**$8,147,038**	**$19,797,663**	**$5,104,772**
2007 total—all	198,318	1,216	226	1,442	37,113,408	$95,540,534	$6,550,226	$7,865,327	$21,736,725	$4,765,815

*Major natural gas pipeline companies as defined above (and in FERC Accounting and Reporting Requirements for Natural Gas Companies, para. 20-011, effective Feb. 2, 1985, beginning with 1984 reporting year). Beginning with 1996, major companies were required to file mileage for transmission systems only. NR = not reported.
Source: FERC Forms 2 and 2A for major and nonmajor natural gas pipeline companies. Under criteria established for the 1984 reporting year (OGJ, Nov. 25, 1985, p. 80), major pipeline companies are those whose combined gas sold for resale and gas transported for a fee exceeded 50 bcf at 14.73 psi (60° F.) in each of the 3 previous calendar years. Nonmajors are natural gas pipeline companies not classified as majors and whose total gas sales of volume transactions exceeded 200 MMcf at l4.73 psi (60° F.) in each of the 3 previous calendar years.

Equipment/Software/Literature

New reference pressure recorder

Here's nVision, a new type of field pressure calibrator that can be configured to measure and record 200,000 pressure, temperature, current, and voltage measurements.



It can display the recorded data graphically, or graph the measurements as they are being recorded on its high resolution screen.

Stored data, or data being recorded, can be displayed graphically where you can easily zoom into and magnify specific events or zoom out to get a big picture of your test.

The intrinsically safe tool promises accurate data under field conditions. Pressure measurement accuracy is up to 0.025% of reading, throughout the entire operating temperature range of –20° to +50° C.

The nVision is also capable of recording any parameter at a rate of 10/sec, suiting it for high speed measurements, e.g., pressure safety valve testing. The graphical display makes it easy to view valve characteristics such as response time and repeatability, and the recorded data can become part of a permanent test record.

The unit is shock and vibration resistant, includes threaded mounting points, and is certified waterproof to IP67 (submersion in water to 1 m for as long as 30 min).

Source: **Crystal Engineering Corp.,** 708 Fiero Lane, Suite 9, San Luis Obispo, CA 93401.

Drillbit designed for directional control

The new SideWinder PDC drillbit is designed to provide directional performance in steerable motors and rotary steerable operations.

The design of the bit eliminates the gauge pads entirely in favor of making the cutting structure as active in the lateral aspect as it is in the vertical. Additionally, the cutting structure blends smoothly and uninterrupted into the flank of the bit and even upwards into the relief back to the shank. This upwards component allows the SideWinder to be pulled while rotating through tight curves, similar to a keyseat mill, and to ream the upper side of the curve to enlarge the radius as much as possible for casing clearance.

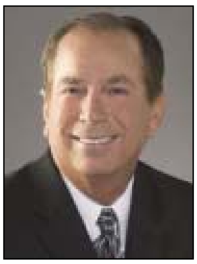
The design can be incorporated into any standard profile PDC bit, which allows drillers to match the bit to geologic formations and still have optimal directional control, the firm points out

Source: **Encore Bits LLC,** 14902 Sommermeyer St., Suite 100, Houston, TX 77041.

Services/Suppliers

Knight Oil Tools,

Houston, has selected Gary Davis to broaden its business development efforts globally. With more than 25 years of experience in the rental tool industry, with a focus on fishing tools, Davis was chosen to guide Knight's international sales initiatives and to investigate new opportunities to expand Knight's global reach. Davis previously served as international sales manager and has been involved with new product development. Davis is a member of the National Oil Equipment Manufacturers and Delegates Society.



Davis

Knight Oil Tools is the largest privately held rental and fishing tools business in the oil and gas industry

Viking Moorings,

Aberdeen, has announced its acquisition by HSBC Private Equity (UK) from Inflexion Private Equity. Terms of the deal aren't disclosed. Inflexion and its management both will retain a significant investment in Viking.

Viking Moorings is a market leader in the design, rental, and sale of mooring solutions for semisubmersible drilling rigs, floating accommodation units, and other key assets. It also has offices in Norway, Singapore, and Australia.

HSBC PE, part of the HSBC Group, invests in transactions with equity requirements of more than £10 million and enterprise value of £20-300 million.

Inflexion is a leading independent private equity house based in London that invests in small- to mid-market growth businesses.

InterMoor Inc.,

Houston, has named Randy Giroir health, safety, and environment coordinator for the company's Fourchon, La., facility. Prior to joining InterMoor, Giroir was the HSE adviser for Oceaneering International's diving division. He will be responsible for all HSE concerns at the Fourchon facility.

InterMoor, an Acteon Group Ltd. company, is a leading supplier of mooring technology, providing solutions for rig moves, mooring services, and subsea foundations, including engineering and design, survey and positioning, fabrication, and subsea services.

Acteon, Norwich, UK, is a group of specialist engineering companies serving the global oil and gas industry.

Honeywell International,

Morris Township, NJ, has completed its acquisition of Kassel, Germany-based RMG Group (OGJ Online, Aug. 10, 2009). RMG will be part of Honeywell Process Solutions.

RMG specializes in the design and manufacture of natural gas control, measurement, and analysis equipment.

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.

Imports of crude and products

	Districts 1-4 8-28 2009	Districts 1-4 8-21 2009	District 5 8-28 2009	District 5 8-21 2009	Total US 8-28 2009	Total US 8-21 2009	Total US *8-29 2008
	1,000 b/d						
Total motor gasoline	875	1,042	3	60	878	1,102	883
Mo. gas. blending comp.	547	705	3	19	550	724	640
Distillate	156	132	0	0	156	132	93
Residual	131	212	4	134	135	346	356
Jet fuel–kerosine	51	41	61	57	112	98	50
Propane–propylene	81	64	4	4	85	68	251
Other	250	82	52	42	302	124	531
Total products	**2,091**	**2,278**	**127**	**316**	**2,218**	**2,594**	**2,804**
Total crude	**8,545**	**8,216**	**1,031**	**1,009**	**9,576**	**9,225**	**9,830**
Total imports	**10,636**	**10,494**	**1,158**	**1,325**	**11,794**	**11,819**	**12,634**

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

Purvin & Gertz LNG netbacks—Sept. 4, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant — $/MMbtu					
Barcelona	5.82	3.72	5.02	3.62	4.28	4.95
Everett	2.03	0.11	1.71	0.21	0.61	2.27
Isle of Grain	3.04	1.15	2.54	1.06	1.67	2.55
Lake Charles	0.32	–1.21	0.12	–1.17	–1.05	0.83
Sodegaura	4.91	6.26	5.17	5.97	6.11	4.27
Zeebrugge	5.02	3.00	4.46	2.88	3.56	4.50

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
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

	*9-4-09	*9-5-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	74.82	123.45	–48.63	–39.4
Brent crude	67.15	104.67	–37.52	–35.8
Crack spread	7.67	18.78	–11.11	–59.2
FUTURES MARKET PRICES				
One month				
Product value	75.48	119.91	–44.43	–37.1
Light sweet crude	68.41	108.30	–39.89	–36.8
Crack spread	7.07	11.61	–4.54	–39.1
Six month				
Product value	78.11	121.83	–43.72	–35.9
Light sweet crude	71.43	110.84	–39.41	–35.6
Crack spread	6.68	10.99	–4.31	–39.2

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

Crude and product stocks

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	13,061	53,465	34,977	12,563	70,182	13,694	4,413
PADD 2	82,959	49,900	24,647	7,652	32,651	1,068	29,452
PADD 3	176,793	68,918	37,776	15,874	46,982	14,201	33,814
PADD 4	15,647	5,771	1,712	475	2,704	224	[1]1,962
PADD 5	54,928	27,031	21,454	9,191	11,044	4,705	—
Aug. 28, 2009	**343,388**	**205,085**	**120,566**	**45,755**	**163,563**	**33,892**	**69,641**
Aug. 21, 2009	**343,760**	**208,054**	**122,566**	**45,450**	**162,384**	**34,442**	**70,658**
Aug. 29, 2008[2]	**303,862**	**194,404**	**98,636**	**42,081**	**131,712**	**37,424**	**52,908**

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

Refinery report—Aug. 28, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,339	1,235	2,504	68	405	105	52
PADD 2	3,309	3,291	2,094	203	915	52	263
PADD 3	7,832	7,609	2,663	747	2,195	263	713
PADD 4	573	565	342	30	179	12	[1]52
PADD 5	2,324	2,251	1,554	355	426	149	—
Aug. 28, 2009	**15,377**	**14,951**	**9,157**	**1,403**	**4,120**	**581**	**1,080**
Aug 21, 2009	**14,861**	**14,483**	**9,019**	**1,299**	**4,001**	**569**	**1,038**
Aug. 29, 2008[2]	**15,617**	**15,258**	**9,446**	**1,505**	**4,518**	**502**	**1,014**
	17,644 Operable capacity		**87.2% 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 9-2-09	Pump price* 9-2-09	Pump price 9-3-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	213.3	259.8	368.2
Baltimore	217.2	259.1	371.4
Boston	220.4	262.3	369.1
Buffalo	213.3	274.2	364.2
Miami	226.7	278.3	365.2
Newark	217.6	250.2	358.1
New York	207.4	268.3	368.0
Norfolk	216.8	255.2	363.0
Philadelphia	218.6	269.3	371.0
Pittsburgh	218.4	269.1	367.0
Wash., DC	230.9	269.3	366.2
PAD I avg	218.2	265.0	366.5
Chicago	216.5	280.9	396.5
Cleveland	218.4	264.8	361.5
Des Moines	215.0	255.4	355.5
Detroit	221.9	281.3	372.4
Indianapolis	207.5	266.9	361.5
Kansas City	202.3	238.3	355.5
Louisville	222.0	262.9	365.5
Memphis	202.0	241.8	354.5
Milwaukee	215.6	266.9	370.5
Minn.-St. Paul	217.3	261.3	362.5
Oklahoma City	195.4	230.8	350.5
Omaha	191.5	236.8	365.5
St. Louis	198.8	234.8	356.5
Tulsa	191.9	227.3	349.4
Wichita	196.6	240.0	351.5
PAD II avg	207.5	252.7	362.0
Albuquerque	208.2	244.6	359.0
Birmingham	211.2	250.5	359.3
Dallas-Fort Worth	213.2	251.6	346.7
Houston	209.1	247.5	343.7
Little Rock	204.4	244.6	358.3
New Orleans	212.1	250.5	361.2
San Antonio	214.8	253.2	357.3
PAD III avg	210.4	248.9	355.1
Cheyenne	223.7	256.1	363.7
Denver	224.7	265.1	393.5
Salt Lake City	215.8	258.7	389.8
PAD IV avg	221.4	260.0	382.4
Los Angeles	235.4	302.5	403.7
Phoenix	224.2	261.6	371.6
Portland	241.1	284.5	377.8
San Diego	237.4	304.5	401.7
San Francisco	244.4	311.5	413.6
Seattle	242.6	298.5	389.5
PAD V avg	237.5	293.9	393.0
Week's avg.	**216.1**	**261.7**	**367.9**
Aug. avg.	**209.9**	**255.5**	**375.3**
July avg.	**205.6**	**251.2**	**405.7**
2009 to date	**175.2**	**220.8**	—
2008 to date	**309.4**	**353.3**	—

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

REFINED PRODUCT PRICES

	8-28-09 ¢/gal		8-28-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	193.08	New York Harbor	184.85
Gulf Coast	187.78	Gulf Coast	184.10
Los Angeles	197.78	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	190.08	ARA	188.01
Singapore	195.36	Singapore	188.69
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	213.08	New York Harbor	161.24
Gulf Coast	183.78	Gulf Coast	165.40
Los Angeles	212.78	Los Angeles	177.15
		ARA	164.23
		Singapore	169.55

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

BAKER HUGHES RIG COUNT

	9-4-09	9-5-08
Alabama	3	6
Alaska	8	10
Arkansas	42	59
California	20	50
Land	19	48
Offshore	1	2
Colorado	45	119
Florida	2	3
Illinois	2	0
Indiana	1	2
Kansas	24	10
Kentucky	9	12
Louisiana	139	182
N. Land	89	81
S. Inland waters	6	21
S. Land	18	25
Offshore	26	55
Maryland	0	0
Michigan	0	2
Mississippi	12	14
Montana	1	10
Nebraska	0	1
New Mexico	46	92
New York	2	7
North Dakota	47	75
Ohio	8	10
Oklahoma	79	219
Pennsylvania	53	27
South Dakota	1	1
Texas	388	938
Offshore	4	9
Inland waters	0	1
Dist. 1	17	27
Dist. 2	11	35
Dist. 3	38	65
Dist. 4	35	92
Dist. 5	69	188
Dist. 6	51	123
Dist. 7B	8	31
Dist. 7C	20	72
Dist. 8	73	135
Dist. 8A	10	26
Dist. 9	24	37
Dist. 10	28	97
Utah	14	47
West Virginia	19	28
Wyoming	34	77
Others—HI-1; NV-4; VA-5	10	12
Total US	**1,009**	**2,013**
Total Canada	**184**	**418**
Grand total	**1,193**	**2,431**
US Oil rigs	295	416
US Gas rigs	701	1,586
Total US offshore	33	72
Total US cum. avg. YTD	**1,089**	**1,859**

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	9-4-09 Rig count	9-4-09 Percent footage*	9-5-08 Rig count	9-5-08 Percent footage*
0-2,500	48	6.2	84	3.5
2,501-5,000	65	72.3	135	50.3
5,001-7,500	110	20.9	254	15.7
7,501-10,000	205	8.2	489	2.6
10,001-12,500	206	11.6	465	1.7
12,501-15,000	137	—	372	—
15,001-17,500	129	—	140	—
17,501-20,000	53	—	86	—
20,001-over	32	—	17	—
Total	**985**	**11.5**	**2,042**	**6.4**
INLAND	12		31	
LAND	941		1,972	
OFFSHORE	32		39	

*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]9-4-09	[2]9-5-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	19
Alaska	650	578
California	649	658
Colorado	64	65
Florida	6	5
Illinois	28	26
Kansas	108	112
Louisiana	1,396	993
Michigan	17	17
Mississippi	62	59
Montana	87	85
New Mexico	161	161
North Dakota	191	183
Oklahoma	180	144
Texas	1,365	1,269
Utah	60	62
Wyoming	148	145
All others	67	74
Total	**5,259**	**4,655**

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

US CRUDE PRICES

	9-4-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	69.75
California-Kern River 13°	59.40
Lost Hills 30°	67.90
Wyoming Sweet	58.52
East Texas Sweet	64.00
West Texas Sour 34°	59.50
West Texas Intermediate	64.50
Oklahoma Sweet	64.50
Texas Upper Gulf Coast	57.50
Michigan Sour	56.50
Kansas Common	63.50
North Dakota Sweet	54.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	8-21-09
United Kingdom-Brent 38°	71.42
Russia-Urals 32°	70.67
Saudi Light 34°	70.64
Dubai Fateh 32°	70.60
Algeria Saharan 44°	71.84
Nigeria-Bonny Light 37°	73.24
Indonesia-Minas 34°	75.34
Venezuela-Tia Juana Light 31°	70.06
Mexico-Isthmus 33°	69.95
OPEC basket	71.28
Total OPEC[2]	71.04
Total non-OPEC[2]	69.98
Total world[2]	70.58
US imports[3]	68.52

[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]

	8-28-09	8-21-09	8-28-08	Change, %
	bcf			
Producing region	1,086	1,079	791	**37.3**
Consuming region east	1,776	1,724	1,666	**6.6**
Consuming region west	461	455	377	**22.3**
Total US	**3,323**	**3,258**	**2,834**	**17.3**
	June 09	**June 08**	**Change, %**	
Total US[2]	**2,752**	**2,171**	**26.8**	

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

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Statistics

Worldwide crude oil and gas production

	June 2009	May 2009	6 month average production 2009	6 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	June 2009	May 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	602	615	618	594	24	4.1	123.4	122.5	709.86
Bolivia	40	40	40	40	0	–1.0	40.0	42.0	245.00
Brazil	1,918	1,955	1,926	1,790	136	7.6	27.0	32.0	175.00
Canada	2,530	2,376	2,553	2,538	15	0.6	383.3	397.3	2,629.10
Colombia	660	652	645	568	78	13.7	22.0	22.0	130.00
Ecuador	480	480	480	500	–20	–4.0	2.0	2.0	12.00
Mexico	2,519	2,609	2,628	2,856	–228	–8.0	213.6	217.1	1,271.23
Peru	97	99	102	70	33	46.7	10.8	10.0	56.00
Trinidad	110	112	110	113	–2	–2.2	113.5	119.9	681.75
United States	5,238	5,283	5,243	5,115	128	2.5	1,815.0	1,868.0	10,968.00
Venezuela[1]	2,120	2,120	2,123	2,373	–250	–10.5	68.0	70.0	406.00
Other Latin America	83	83	83	83	—	–0.3	5.4	5.5	32.65
Western Hemisphere	**16,396**	**16,425**	**16,552**	**16,641**	**–89**	**–0.5**	**2,824.1**	**2,908.3**	**17,316.59**
Austria	19	19	19	17	2	10.1	4.8	5.0	28.27
Denmark	256	260	271	291	–20	–7.0	16.9	22.1	131.68
France	19	18	19	20	–2	–8.3	2.5	2.8	16.40
Germany	55	56	57	61	–4	–6.3	39.1	41.9	262.81
Italy	73	85	84	104	–20	–19.5	20.0	24.5	137.50
Netherlands	26	25	27	36	–9	–23.7	140.0	140.0	1,440.00
Norway	1,850	1,890	2,084	2,157	–73	–3.4	258.5	278.8	1,897.93
Turkey	46	46	43	40	3	8.4	—	—	—
United Kingdom	1,378	1,377	1,432	1,474	–42	–2.9	182.3	204.2	1,228.40
Other Western Europe	3	3	3	4	–1	–25.3	0.2	0.2	8.45
Western Europe	**3,725**	**3,779**	**4,039**	**4,204**	**–165**	**–3.9**	**664.3**	**719.4**	**5,151.45**
Azerbaijan	1,150	1,100	1,028	949	79	8.3	40.0	35.0	205.00
Croatia	14	14	14	15	–1	–6.5	4.9	5.4	31.22
Hungary	14	14	14	15	–1	–5.3	5.6	6.1	42.73
Kazakhstan	1,300	1,200	1,238	1,192	47	3.9	100.0	100.0	600.00
Romania	90	90	90	95	–5	–5.3	18.0	19.0	110.00
Russia	9,860	9,840	9,797	9,735	62	0.6	1,200.0	1,300.0	9,100.00
Other FSU	400	500	450	400	50	12.5	250.0	250.0	1,950.00
Other Eastern Europe	44	44	45	50	–5	–10.6	18.8	17.9	117.30
Eastern Europe and FSU	**12,872**	**12,802**	**12,676**	**12,451**	**225**	**1.8**	**1,637.2**	**1,733.4**	**12,156.26**
Algeria[1]	1,250	1,250	1,248	1,385	–137	–9.9	245.0	255.0	1,485.00
Angola[1]	1,750	1,780	1,730	1,919	–189	–9.9	5.0	6.0	28.00
Cameroon	70	70	74	87	–13	–15.4	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	640	648	665	–17	–2.5	120.0	125.0	735.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.36
Gabon	220	220	220	230	–10	–4.3	0.3	0.3	1.81
Libya[1]	1,540	1,540	1,558	1,750	–192	–11.0	36.0	38.0	221.00
Nigeria[1]	1,720	1,800	1,790	1,933	–143	–7.4	83.0	90.0	516.00
Sudan	500	500	500	480	20	4.2	—	—	—
Tunisia	80	81	85	82	3	4.1	7.5	8.0	48.92
Other Africa	221	221	221	221	—	—	8.3	9.1	52.20
Africa	**8,576**	**8,688**	**8,660**	**9,337**	**–678**	**–7.3**	**505.2**	**531.4**	**3,088.29**
Bahrain	170	168	169	170	—	–0.2	26.0	27.0	149.82
Iran[1]	3,800	3,720	3,735	3,948	–213	–5.4	285.0	290.0	1,715.00
Iraq[1]	2,430	2,410	2,343	2,429	–86	–3.5	20.0	20.0	115.00
Kuwait[1,2]	2,240	2,250	2,292	2,603	–312	–12.0	35.0	37.0	220.00
Oman	790	800	790	722	68	9.5	55.0	57.0	341.00
Qatar[1]	780	760	765	850	–85	–10.0	220.0	222.0	1,332.00
Saudi Arabia[1,2]	8,210	8,060	8,018	9,055	–1,037	–11.4	215.0	218.0	1,278.00
Syria	370	370	378	385	–7	–1.7	17.0	18.0	104.00
United Arab Emirates[1]	2,250	2,250	2,268	2,642	–373	–14.1	128.0	132.0	775.00
Yemen	265	270	278	312	–34	–11.0	—	—	—
Other Middle East	—	—	—	—	—	71.7	9.1	7.0	48.34
Middle East	**21,305**	**21,058**	**21,037**	**23,115**	**–2,079**	**–9.0**	**1,010.1**	**1,028.0**	**6,078.17**
Australia	457	405	464	433	30	7.0	138.5	118.9	721.40
Brunei	140	140	148	163	–15	–9.0	32.0	33.0	204.36
China	3,834	3,786	3,710	3,799	–89	–2.3	241.1	237.4	1,463.30
India	661	668	654	674	–20	–3.0	111.5	106.1	552.80
Indonesia[1]	870	850	857	860	–3	–0.3	200.0	200.0	1,190.00
Japan	14	13	16	18	–1	–6.6	8.7	8.6	62.79
Malaysia	730	730	735	758	–23	–3.1	135.0	140.0	820.00
New Zealand	44	48	45	61	–15	–25.1	12.0	13.0	71.90
Pakistan	62	63	64	67	–3	–5.0	121.3	124.8	735.89
Papua New Guinea	35	35	38	43	–4	–9.8	0.9	1.0	5.70
Thailand	242	239	244	224	20	8.7	32.0	33.0	199.34
Vietnam	300	300	300	292	8	2.9	14.5	15.0	87.50
Other Asia-Pacific	35	35	35	39	–4	–11.4	88.5	94.5	556.00
Asia-Pacific	**7,423**	**7,310**	**7,309**	**7,429**	**–120**	**–1.6**	**1,136.0**	**1,125.3**	**6,670.98**
TOTAL WORLD	**70,298**	**70,061**	**70,272**	**73,177**	**–2,905**	**–4.0**	**7,776.8**	**8,045.9**	**50,461.73**
OPEC	28,570	28,420	28,352	32,248	–3,896	–12.1	1,342.0	1,380.0	10,203.00
North Sea	3,502	3,547	3,807	3,940	–133	–3.4	499.6	546.9	3,689.08

[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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Employment woes puncture hope for green energy jobs

The latest failure of liberal employment remedies should encourage the oil and gas industry.

According to liberal theory, governments create jobs by spending money. History suggests otherwise.

When governments spend money to create jobs they move funds and workers into activities with limited or no ability to create wealth. Whatever economic goodness comes about proves unsustainable.

The Editor's Perspective

by Bob Tippee, Editor

Governments must raise taxes to pay for the increased spending. Businesses, anticipating the new burden, trim spending. Then employment suffers as economic activity slows, and governments face new fiscal pressures. While governments can employ many people, they can't create jobs. New jobs require new wealth, which requires profits. Governments don't generate profits. They employ people with money taxed away from profitable activities in the private sector. They don't expand the workforce; they nationalize part of it.

In the latest demonstration of these effects, stimulus spending by the US government has failed spectacularly to create jobs.

As Rea S. Hederman Jr. and James Sherk of the Heritage Foundation point out in a Sept. 4 report, new job numbers refute promises by the Obama administration that spending would halt unemployment and lead to labor-market recovery by the third quarter.

According to the Bureau of Labor Statistics, the unemployment rate rose to 9.7% in August from 9.4% in July—well above the administration's prediction of an 8% peak. The number of workers employed fell by 216,000. BLS data further debunk recent administration claims about 500,000-1 million jobs created by stimulus spending. In fact, the share of the workforce represented by newly hired workers fell to 2.9% in June from 3.2% when Congress approved the spending spree in February, which was down from 3.8% before the recession began.

These failures do more than discredit liberal assumptions about governments and job creation. They also discolor those green jobs the administration touts in support of its state-centered energy program.

As a job creator, federal money channeled to noncommercial energy can be no better than broad stimulus spending. An important difference is the way hollow promises for green jobs become proposals for big tax hikes on oil and gas.

(Online Sept. 4, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Deutsche Bank closing exchange traded note

Citing new limitations on the New York Mercantile Exchange, Deutsche Bank AG said in early September it would close and redeem its popular $425 million PowerShares DB Crude Oil Double Long Exchange Traded Note (DXO)—one of the largest leveraged commodity products in the US.

"We expect the Commodity Futures Trading Commission and US commodity exchanges are on the brink of imposing a more stringent interpretation of accountability levels and position limits," explained Michael Lewis, head of commodities research at Deutsche Bank in London. On Sept. 2, there was the first joint meeting ever of the CFTC and of the Securities and Exchange Commission to discuss how best to "harmonize" financial regulations to protect the American public.

DXO "is likely only the first head to roll; we'll have to wait and see what other funds are affected by the new CFTC limits," said analysts in the Houston office of Raymond James & Associates Inc. The process of Deutsche Bank unwinding its long oil positions "could put some serious short-term downward pressure on oil prices," they said. Deutsche Bank will continue to roll out commodity-linked products within the new guidelines. Lewis said, "Although we do not believe this will have an impact on other exchange traded funds or exchange traded notes in the marketplace, we believe it has sent a minor shock wave through commodity markets." The bank—Germany's largest—quit issuing new shares on DXO in mid-August.

Redeeming the fund could have implications for commodity prices, forward curves, and volatility. "For example, assets under management of the DXO fund stand at roughly $400 million as of Sept. 2. Since the ETN has a two-for-one exposure in the oil market, it has approximately $800 million invested in the West Texas Intermediate July 2010 futures contract," Lewis said, adding, "Assuming an oil price of $68/bbl, this is equivalent to 11,750 futures contracts and consequently exceeds the position accountability levels governing the WTI sweet crude oil futures contract listed on NYMEX."

Government control

Governments have a history of trying to control energy and agricultural prices. "Not only do these commodities constitute a large share of consumer spending baskets, particularly in the developing world, but swings in gasoline and food prices can have a significant effect on headline inflation and consequently aggravate monetary policy objectives of the central bank," Lewis acknowledged.

So he's not surprised the administration of President Barack Obama is focusing on weeding speculators from the agricultural and energy markets. "In contrast, the precious metals and industrial metals markets have so far not been a priority for regulators and, in our view, may be offering a place of refuge for investors in the current environment," he said. In the wheat market, already regulated by the CFTC, there has been a growing dislocation between cash and futures prices. US authorities blame much of this distortion on an increase in futures trading via indices as a result of hedging exemptions. In recent months, Deutsche Bank has been close to the center of the CFTC's push to curb speculation in commodity markets. In August, CFTC revoked exemptions that allowed the bank to exceed federal speculative limits on agricultural futures contracts. It gave the bank until the end of October to reduce its corn and wheat holdings to within federal limits.

Until now comparable data on index trading in nonagricultural markets such as oil and natural gas have not been reported by the CFTC, but that is likely to change with improved data collection. However, Lewis said, "An examination of the basis in other commodity markets suggests the experience of the wheat market is unique. Indeed, one could argue that a much larger increase in crude oil futures trading has occurred over the past few years, yet the basis in this market has not moved to the same degree as that for wheat."

Still, he said, "We doubt the absence of a dislocation between cash and futures prices in energy markets will deter regulators from exploring steps to curb what they believe is an excessive increase in investment activity in these markets."

Lewis noted, "If this tightening in regulation occurs, we expect the appeal of investing in physical commodity exposure will be enhanced, particularly for commodities that are cheap and easy to store such as gold. Ironically we believe the CFTC's steps may therefore increase the appeal for investors to take delivery of commodities. As a result, what has tended to be a financial exposure to commodities becomes more physical with, in our view, a more direct impact on commodity prices."

(Online Sept. 7, 2009; author's e-mail: samf@ogjonline.com)

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