Week of Feb. 9, 2009/US$10.00

PennWell®

OIL&GAS JOURNAL®

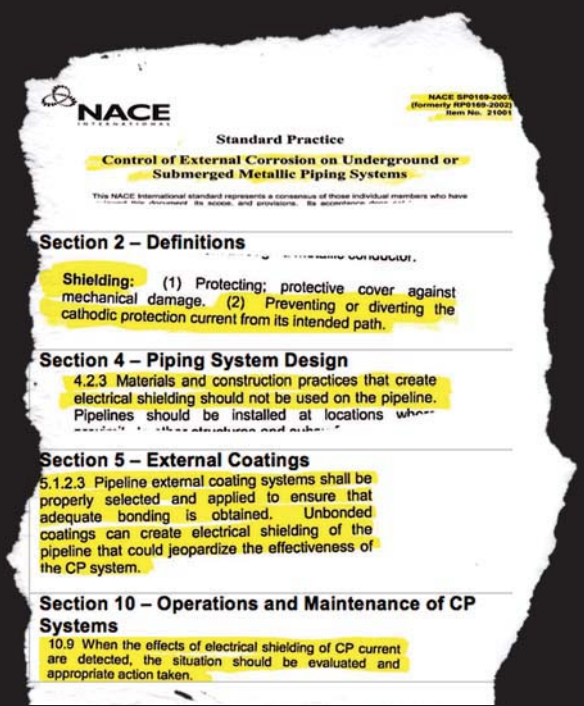
International Petroleum News and Technology / www.ogjonline.com

Worldwide Pipeline Construction

Global perspectives required for risk, opportunity analyses
Equation aids early estimation of gas field production potential
Kosmos, Tullow drill deepwater Cretaceous sands off Ghana
Gasoline-distillate price gap calls for refining investments

CAUTION CAUTION

Is your company ignoring this guidance?



NACE

NACE SP0169-2007 (formerly RP0169-2002) Item No. 21001

Standard Practice

Control of External Corrosion on Underground or Submerged Metallic Piping Systems

This NACE International standard represents a consensus of those individual members who have ... its scope, and provisions. ... conductor.

Section 2 – Definitions

Shielding: (1) Protecting; protective cover against mechanical damage. (2) Preventing or diverting the cathodic protection current from its intended path.

Section 4 – Piping System Design

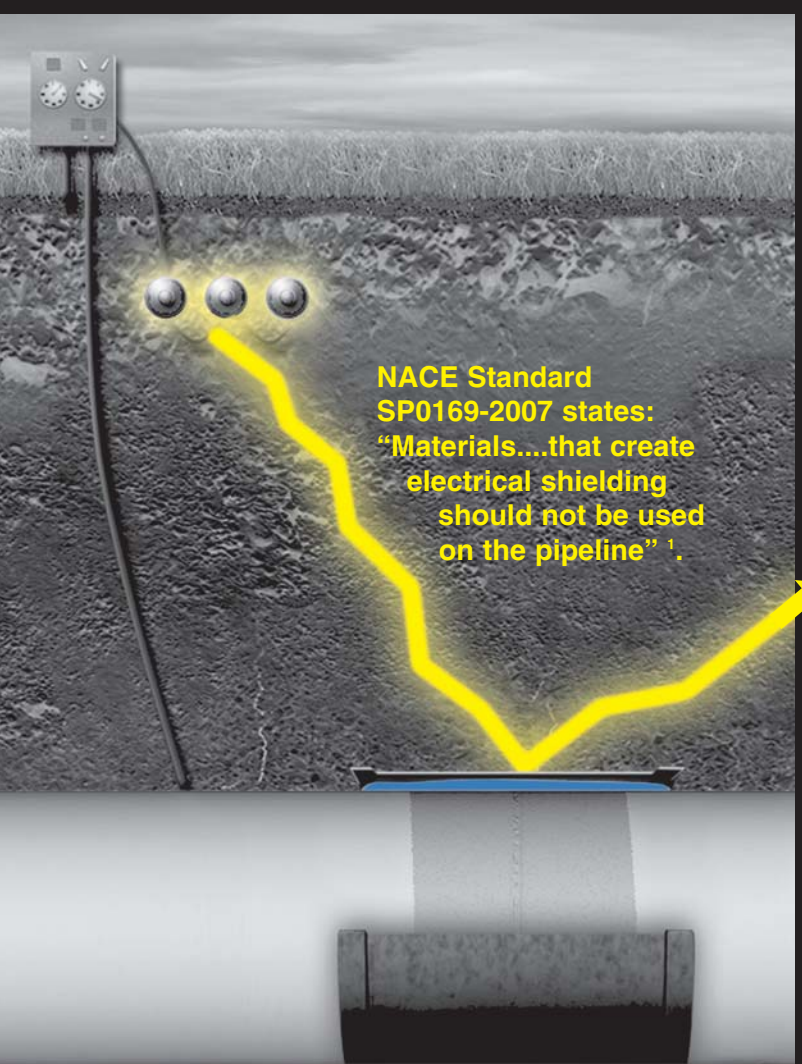
4.2.3 Materials and construction practices that create electrical shielding should not be used on the pipeline. Pipelines should be installed at locations ...

Section 5 – External Coatings

5.1.2.3 Pipeline external coating systems shall be properly selected and applied to ensure that adequate bonding is obtained. Unbonded coatings can create electrical shielding of the pipeline that could jeopardize the effectiveness of the CP system.

Section 10 – Operations and Maintenance of CP Systems

10.9 When the effects of electrical shielding of CP current are detected, the situation should be evaluated and appropriate action taken.



CONSIDER: If you use solid film backed corrosion coatings, you may be crippling your CP investment.

There is a common sense reason for this. CP systems protect pipelines by delivering electrical current to the steel surface. Solid film back corrosion coatings have the property of high dielectric strength, which means they block electrical current. This blocking effect is called cathodic shielding. Cathodic shielding has been the subject of dozens of technical papers since the mid 1980's.

Two corrosion coatings are proven to be non-shielding, and allow passage of protective CP currents. One of these coatings is FBE. The other is Polyguard RD-6.

If you are concerned that your organization is behind this curve, visit ***polyguardproducts.com/failsafecoating.htm*** and review the large body of information about shielding problems.

Polyguard

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- American Natl. Standards Institute
- Dutch Council for Certification
- Deutscher Akkreditierungs Rat

1. NACE Standard SP0169-2007
"Control of External Corrosion on Underground or Submerged Metallic Piping Systems".

OIL&GAS JOURNAL®

Feb. 9, 2009
Volume 107.6

WORLDWIDE PIPELINE CONSTRUCTION

REGULAR FEATURES

COVER

Saipem's Crawler completed tie-in of the 24-in. OD Medgaz pipeline between Algeria and Spain 1.6 km off Beni Saf, Algeria, in December 2008. Crawler raised the pipe left by Saipem's Castoro Sei in July 2008 and Saipem 7000 in November 2008, performed the final welds, and returned the completed structure to the bottom. Castoro Sei lay pipe from both coasts to a depth of 550 m, with Saipem 7000 completing the deepwater section of the lay (to 2,160 m) between the two shore-approach sections. Medgaz will complete hydraulic testing of the line by the end of March, with plans to put it into service in the second half. Medgaz will deliver 8 billion cu m/year of Algerian natural gas to Spain and Europe, adding both volume and diversity to European supplies. Oil & Gas Journal's special report on Worldwide Pipeline Construction, beginning on p. 52, provides information on construction trends and projects for both 2009 and into the future. Photograph from Medgaz SA.

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Drilling & Production

Processing

Transportation

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Feb. 9, 2009

International news for oil and gas professionals
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General Interest — Quick Takes

Indonesia places domestic gas sales over exports

Indonesian Vice-President Jusuf Kalla, on a state visit to Japan, has reaffirmed the need for his country to prioritize its domestic gas market over exports.

"I have spoken to the Japan Bank for International Cooperation (JBIC) that we will help Japan (meet their gas demand) as long as (the transactions) are under a win-win solution," Kalla said.

"We need gas for domestic consumption, but we also need to export gas for foreign exchange reserves," said Kalla who did not detail Indonesia's plans to export gas to Japan this year.

"We have abundant natural resources. Japan is dependent on us, particularly on energy," said Kalla, who hinted that Japan, via JBIC, would increase funding to Indonesia if it could secure gas supplies.

Kalla also said, "It is better for Japan to put its money into Indonesia" than to invest it domestically. Kulla explained that, "domestically, Japan will receive interest of only 0.1%, while it will get a 3% return from lending money to us."

The Indonesian government recently urged gas producers in the country to maintain production or produce more gas to meet rising demand from domestic and overseas markets. Earlier, Indonesia's acting coordinating minister for the economy Sri Mulyani Indrawati said the government has put higher priority on the domestic market than on exports (OGJ Online, Jan. 25, 2009).

Inpex president upbeat about LNG developments

Inpex Pres. Naoki Kuroda, in an interview with Japan's Nikkei Business Daily, remains upbeat on his company's prospects regarding the development of two LNG projects despite the current economic downturn.

Kuroda said Inpex is making a huge investment in LNG at the moment because the lead time for natural resources development is long. "We cannot do anything if we look at only short-term trends."

He acknowledged that demand for resources is falling amid the economic slowdown but the Japanese firm nevertheless plans to start production in Australia in 2015 and in Indonesia the following year.

"We expect that the economy will have recovered and demand for LNG will have increased by then," he said, adding: "It's necessary to continue active investments from medium and long-term perspectives."

Kuroda noted that Inpex expects its two projects to produce 12-13 million tonnes/year, which accounts for about 20% of domestic demand. "The projects will contribute to a stable energy supply and become a major revenue source for us," he said.

Referring to the amount of investment for each project—$20 billion in Australia and $11.2 billion in Indonesia—Kuroda said Inpex will "sort out the details of the plants before finalizing the amounts."

In fact, Kuroda said the actual costs would be lower than the estimates because equipment prices are falling.

"We will also draw up the best combination of loans and bonds to procure funds," he said, adding: "We can make the projects profitable and keep our finances sound with cautious risk management."

Kuorda said Inpex has yet to start formal sales negotiations, but large-lot customers are showing strong interest. Since LNG releases less carbon dioxide than oil, it is attracting more demand.

Asked if Royal Dutch Shell Group is interested in participating in the Indonesian project, Kuroda said: "More than 10 companies have expressed interest, though we haven't entered into tie-up talks with any of them."

"We have a 100% stake in the project and may consider letting other companies take partial interests," he said.

However, Kuroda downplayed any talk of a shakeout among resource development companies.

"We have no plans for a merger," he said. "What's necessary for growth is to increase our stakes in overseas natural resource projects. We will consider tie-ups with Japanese and foreign competitors on large-scale oil and gas development projects that would be difficult to handle on our own."

Concluding, Kuroda expressed his company's goal, saying that, "Inpex has a daily output equivalent to 400,000 bbl of crude oil at present, and we aim to increase that figure to 800,000-to-1 million bbl and join the ranks of the semimajors in the future." ✦

Exploration & Development — Quick Takes

Brazil reports oil, gas finds in Potiguar basin

Brazil's Petroleo Brasileiro SA (Petrobras) told the country's hydrocarbons regulator Agencia Nacional do Petroleo (ANP) that it found traces of oil in test wells drilled at two exploration blocks in the Potiguar basin.

ANP said the discoveries were made at well 3-BRSA-695RN on Block POT-T-520, and at well 3-BRSA-700DRN on Block BT-POT-8, both off Brazil's Rio Grande do Norte state.

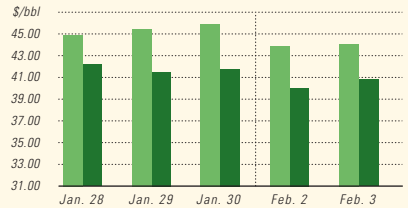
Petrobras, which reported the finds on Feb. 3, holds 100% stakes in both blocks.

The announcement coincided with earlier reports by ANP that Galp Energia and Petrobras also discovered signs of oil and gas in the Potiguar basin as well as the Sergipe-Alagoas basin.

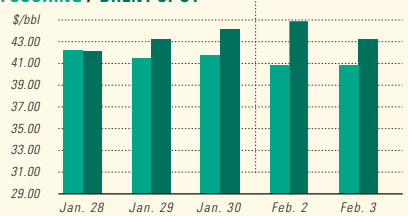
ANP Feb. 2 said that Galp Energia found traces of hydrocarbons

Industry Scoreboard

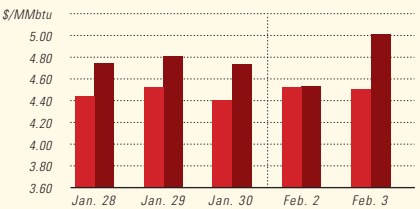
IPE BRENT / NYMEX LIGHT SWEET CRUDE



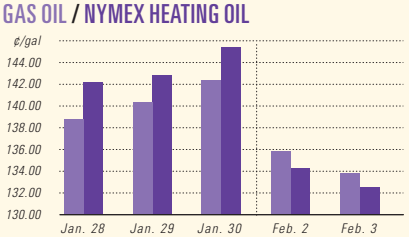
WTI CUSHING / BRENT SPOT



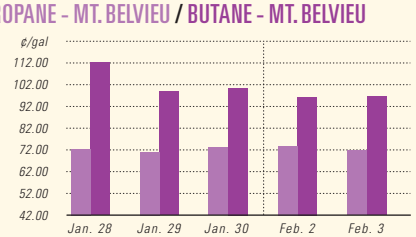
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



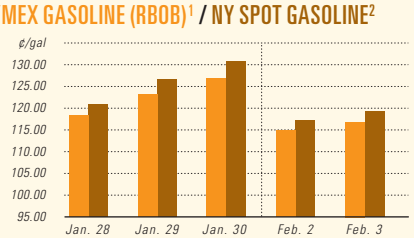
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Nonoxygenated regular unleaded.

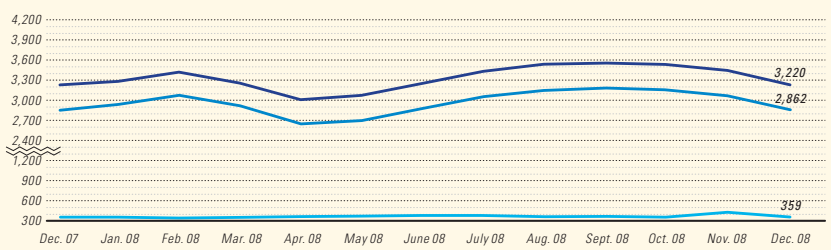
US INDUSTRY SCOREBOARD — 2/9

Latest week 1/23	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	8,760	8,908	–1.7	8,760	8,814	–0.6
Distillate	4,078	4,206	–3.0	4,078	4,209	–3.1
Jet fuel	1,396	1,558	–10.4	1,396	1,546	–9.7
Residual	611	671	–8.9	611	672	–9.1
Other products	4,586	4,901	–6.4	4,587	4,873	–5.9
TOTAL DEMAND	19,431	20,244	–4.0	19,431	20,114	–3.4
Supply, 1,000 b/d						
Crude production	4,987	5,085	–1.9	4,987	5,093	–2.1
NGL production[2]	2,103	2,196	–4.2	2,315	2,123	9.0
Crude imports	9,947	9,965	–0.2	9,947	10,000	–0.5
Product imports	3,380	3,394	–0.4	3,380	3,492	–3.2
Other supply[3]	1,649	1,415	16.5	1,334	1,056	26.3
TOTAL SUPPLY	22,066	22,055	0.0	21,962	21,765	0.9
Refining, 1,000 b/d						
Crude runs to stills	14,347	15,276	–6.1	14,347	14,799	–3.1
Input to crude stills	14,778	15,155	–2.5	14,778	15,086	–2.0
% utilization	83.9	86.3	—	83.9	85.8	—

Latest week 1/23	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	338,881	332,663	6,218	292,952	45,929	15.7
Motor gasoline	219,859	219,980	–121	223,899	–4,040	–1.8
Distillate	143,952	144,957	–1,005	127,004	16,948	13.3
Jet fuel–kerosine	38,401	38,429	–28	40,609	–2,208	–5.4
Residual	36,045	36,057	–12	35,531	514	1.4
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.6	23.2	1.7	19.4	21.6	
Motor gasoline	25.1	24.8	1.2	24.7	1.6	
Distillate	35.3	35.4	–0.3	29.9	18.1	
Propane	30.9	34.8	–11.2	24.7	25.1	
Futures prices[5] **1/30**			Change		Change	%
Light sweet crude ($/bbl)	42.52	43.11	–0.59	89.24	–46.72	–52.4
Natural gas, $/MMbtu	4.49	4.66	–0.16	7.77	–3.28	–42.2

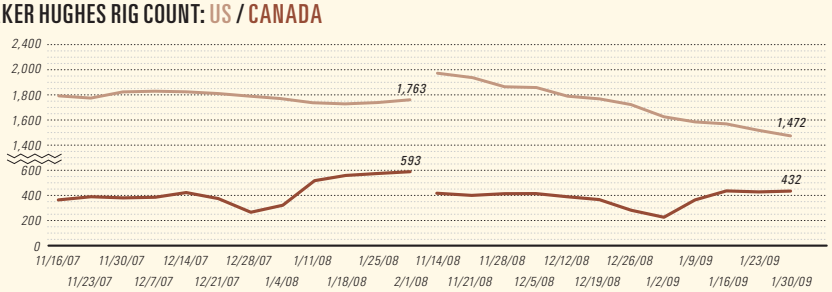
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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in onshore well 1-GALP-26RN on Potiguar's POT-T-354 Block in addition to signs of oil and gas in an onshore well on Sergipe-Alagoas' SEAL-T-412 Block. Galp operates both blocks with a 50% stake, while Petrobras holds the remaining 50%.

Last month, Petrobras and its partner Starfish Oil & Gas SA declared a natural gas find at Well 1-STAR-BRN on Block POT-T-794 onshore, also in the Potiguar basin.

Moosebar shale test drilling in British Columbia

Canada Energy Partners Inc., Vancouver, BC, spudded a horizontal exploration well to Lower Cretaceous Moosebar shale in northeast British Columbia.

The wellsite, near Hudson's Hope west of Dawson Creek, was chosen near the site of an unstimulated natural gas flow that occurred from the Moosebar shale during the drilling of a deeper well for coalbed methane in the Lower Cretaceous Gething formation (OGJ Online, Jan. 5, 2009). Canada Energy is drilling the well, expected to take 2 weeks, in a joint venture with GeoMet Inc., Houston. It is the first horizontal well to target the Moosebar shale on Canada Energy's 50,000-acre Peace River project. Under the joint venture agreement, Canada Energy is operator of the Moosebar shale rights.

In addition to the 50% working interest it already owns, Canada Energy has the right or option to earn an aggregate 75-87.5% interest in the Moosebar shale rights under the acreage subject to certain drilling obligations and elections by the joint venture partner.

BLM sale proceeds; eight tracts deferred

US Interior Secretary Ken Salazar on Feb. 2 ordered the Bureau of Land Management to remove eight tracts from a Feb. 3 oil and gas lease sale after Wyoming Gov. Dave Freudenthal expressed concerns about them.

Salazar said his decision was a response to Freudenthal's Feb. 2 letter to BLM Wyoming State Director Don Simpson concerning three parcels near Shoshone National Forest and five parcels adjacent to the Jack Morrow Hills Coordinated Activity Plan boundary.

The lease sale of 137 remaining parcels totaling 163,526.4 acres proceeded as planned, raising nearly $2.4 million from the sale of leasing rights and from rental fees on 112 parcels totaling 121,706.36 acres, BLM's Wyoming state office said on Feb. 3.

It said that 74.43% of the total acres and 81.75% of the total parcels offered were sold. Bids totaling nearly $2.2 million ranged from the federally mandated minimum of $2/acre to a high bid of $230/acre on one tract.

Successful bidders also pay a one-time administrative fee of $140/parcel and yearly rental of $1.50/acre for the first 5 years and $2/acre for the remaining 5 years of the 10-year leases, said the Wyoming BLM office.

It said its next oil and gas lease sale is scheduled for Apr. 7.

Petrohawk's Haynesville output hits 160 MMcfd

Petrohawk Energy Corp., Houston, is producing a gross 160 MMcfd of gas equivalent (MMcfed) from 16 operated Jurassic Haynesville shale wells in North Louisiana.

The company's budget is $690 million for Haynesville drilling in 2009, when it expects to average 12 rigs and complete 75-80 gross wells. Petrohawk is targeting laterals of 4,300-4,600 ft with as many as 15 frac stages spaced 325 ft apart to improve drainage and minimize the number of wells. While laterals at its first four completions averaged 3,339 ft with 10 frac stages, the last 12 completions averaged 3,958 ft and 12 stages except one well that had mechanical problems and only six frac stages.

The four wells turned to sales most recently are:

- Mack Hogan-4, in 3-16n-11w, Bossier Parish, initial rate of 13.4 MMcfed on a 24/64-in. choke with 6,350 psi flowing casing pressure.
- Osborne 8-3H, 8-16n-11w, Bossier, 18.8 MMcfed, 24/64-in. choke, 6,800 psi FCP.
- Roos A-5, 3-16n-11w, Bossier, 15.1 MMcfed, 24/64-in. choke, 6,100 psi FCP.
- Griffith 11-1, 11-13n-14w, DeSoto, 23.3 MMcfed, 28/64-in., 7,550 psi FCP. Griffith is a long southwest step-out.

Two wells, Sample 4-1 and R.E. Smith Jr. 32-1, had mechanical problems and lower than average production rates.

Of the 16 operated wells on production, 11 have been on production 30 days or more and averaged 15.2 MMcfed in their first 30 days. Eight have been on production 60 days or more and averaged 13.2 MMcfed in the first 60 days. The four wells on line more than 90 days have averaged 8.8 MMcfed in the first 90 days.

All operated wells to date have been produced utilizing similar production practices. Petrohawk will conduct a pilot program on certain wells in 2009 by altering practices to restrict production by using smaller chokes. It will monitor these wells for effects on decline rate and mechanical operation.

Gazprom to explore Algeria's El Assel license

Gazprom Netherlands BV has secured from Sonatrach the rights to explore the onshore El Assel concession in the Berkine basin in Algeria. Gazprom will have a 49% stake.

"According to provisional estimates, the recoverable oil reserves of the said area amount to some 30 million tons. El Assel includes three blocks covering a total of 3,083 sq km," Gazprom said.

This, the company's first project in Algeria, underpins its strategy to build a presence in Africa.

In 2006 Gazprom and Sonatrach pledged to cooperate under a memorandum of understanding in Algeria, Russia, and overseas on exploration, production, transportation, and asset swaps.

Algeria's proved natural gas reserves total 4.58 trillion cu m, with the majority of these in the central and eastern areas of the country. Its proved oil reserves amount to 1.58 billion tonnes. ✦

Drilling & Production — *Quick Takes*

Encore presses Bakken-Sanish drilling, refracs

Encore Acquisition Co., Fort Worth, plans to drill 9 operated and 19 nonoperated wells in 2009 in the Williston basin Bakken play, where it holds 300,000 net acres.

Encore participated in completions in 2008 with Continental Resources Inc., Newfield Exploration Co., Brigham Exploration

Corp., and XTO Energy Inc.

Encore has drilled 13 operated Middle Bakken wells and 6 operated Three Forks/Sanish wells to date. Average initial rates were 380 boe/d from the Middle Bakken and 524 boe/d from the Three Forks/Sanish.

One goal is to reduce average well cost to $4 million from $5 million, the company said Feb. 3.

Encore also plans four refracs in the Cherry and Bear Creek project areas of North Dakota. Several wells in Elm Coulee field in Montana sustained higher production after refrac, the company said. The 2008 refracs averaged 85 boe/d of incremental production and 80,000 boe of incremental reserves for an estimated $500,000/well.

Refracs are applied 9-18 months after initial production, and other operators are starting refrac programs, Encore said. ✦

Processing — *Quick Takes*

Lindsey refinery workers near job offers victory

Workers participating in an unofficial strike at Total UK Ltd.'s Lindsey refinery in England have been told there will be 102 jobs made available for British workers if they end their protest about the employment of foreign workers.

Union representatives will present the offer for staff to vote on Feb. 5 and if accepted will end the week-long dispute that gained sympathy walkouts at refineries and electric power stations all over the country.

This is a revised proposal after workers rejected a deal where only 60 jobs out of the 200 available would have been created for British employees. Total, the unions, and Acas, the employment mediation service, have been in talks for 3 days to resolve the issue that has been discussed in parliament and that triggered debates on xenophobia and antiprotectionism.

The British workers complained about discrimination after Total contracted Italian firm Irem SPA to build a diesel hydrodesulfurization unit (OGJ Online, Jan. 30, 2009). Total insisted that it has not and will not discriminate against British companies and workers.

Irem was using Italian and Portuguese employees and had provided a floating hotel as accommodation for them. According to the deal, none of them will lose their jobs.

Derek Simpson, joint secretary for Unite union, said: "The problem is not workers from other European countries working in the UK, nor is it about foreign contractors winning contracts in the UK. The problem is that employers are excluding UK workers from even applying for work on these contracts."

The issue of contracting foreign workers for major projects in the UK has led the Construction and Engineering Association to recommend that companies first always consider whether there are competent local workers. According to the guidelines published Feb. 4, if there are, non-UK contractors should consider any applications.

British Prime Minister Gordon Brown described them as "the common sense way of dealing in practical terms with the difficulties we face."

The controversy's political dimension is acute because the UK will require at least 60% of its power stations to be replaced, according to Unite's estimates. It is keen to see that British employees have a sizeable amount of work.

There also been have different responses from the ruling Labor party. John Mann, a Labor Member of Parliament, congratulated unions for "exposing this exploitation and the absence of equal opportunities to apply for all jobs." He called for primarily British labor to build new power stations. In contrast, Peter Mandelson, the business secretary, has warned that stopping foreign competition from participating in local industries would turn the recession into depression.

Brown's phrase 'British jobs for British workers,' which was used in 2007, has been a rallying cry for the strikers as fears about job losses intensify during the recession. During the Prime Minister's Question Time in parliament, Brown defended the remark despite accusations by David Cameron, leader of the Conservative party, of a grave error of judgment and pandering to protectionist fears.

Midor awards contract for coking unit

Middle East Oil Refinery has awarded a €43 million engineering, procurement, and construction contract to Technip for the expansion of the delayed coking unit at its refinery in Alexandria, Egypt.

The unit, which will have 30,000 b/d production capacity and will be based on ConocoPhillips's technology, is scheduled for completion by third quarter 2010.

California refinery temporarily shutting down

Big West LLC said its Flying J subsidiary, which filed for reorganizational bankruptcy last year, temporarily is shutting down its Bakersfield, Calif., refinery for lack of cash with which to buy oil.

Flying J, which is based in Ogden, Utah, filed for Chapter 11 bankruptcy on Dec. 22. The refinery, which has a 65,000 b/cd capacity, supplies diesel and gasoline to California. The closure will not affect Flying J's refinery in Salt Lake City, Utah, the company said. The Salt Lake refinery has a 30,000 b/cd capacity.

"For now, we will be winding down refining operations at the facility," Fred Greener, Big West executive vice-president, said of the Bakersfield refinery in a Jan. 28 news release. "We hope that this suspension will be short lived, and are working very hard to find a solution that will allow resumption of the operations. We cannot predict when that might occur."

He said Big West contacted the United Steelworkers Local 219 to begin discussions about the future of its contract with union employees at the Bakersfield refinery.

Total budgets Donges refinery upgrades

Total SA has earmarked €120 million for the scheduled 5-year turnaround of its 229,700 b/d Donges refinery near Saint Nazaire on the Loire estuary. Donges is the group's second largest refinery in France. Work will be carried out between Feb. 22 and Apr. 20, with 200 companies engaged on site.

Half the units will be shut down during the 2-month turn-

around, but the refinery's spokesperson told OGJ that products have been stored, and customers will be fully provided with all products during the down time.

The change of convection and radiation equipment of the three atmospheric distillation furnaces will involve the largest expenditure, €20 million. A further €60 million will provide a new amine unit for gas desulfurization, a new torch, construction of double lining for the troughs bordering the Loire River, and a laboratory.

In addition, €10 million will be spent for a thorough evaluation of the 30,000 km of pipes at the refinery. ✦

Transportation — *Quick Takes*

Putin says ESPO may have parallel gas line

Russian Prime Minister Vladimir Putin said a natural gas pipeline might be laid alongside the Eastern Siberia-Pacific Ocean (ESPO) oil pipeline and would carry gas toward China and the Pacific Ocean.

"The project for the first section of the ESPO [oil] pipeline system is in its final phase," Putin said, adding, "In the long term, a gas pipe may be laid in the direction of the Pacific Ocean and China parallel to the oil pipeline." Russia's state-owned pipeline monopoly OAO Transeft plans to commission the first section of the ESPO oil line in December. The section, with a throughput capacity of 30 million tonnes/year, will extend from Taishet in East Siberia to Skovorodino near the border with China.

The second section of the ESPO, which is scheduled to be completed by yearend 2013 or the beginning of 2014, will extend from Skovorodino to the port of Kozmino on Russia's Pacific coast.

Russia's transport Minister Igor Levitin said last month construction of the export terminal in Kozmino, as well as the port's approach railways, will be completed in 2010.

On completion of the ESPO's first section, up to 15 million tonnes of oil will be delivered by railway to the port of Kozmino for further shipment to Asia Pacific states, including Japan. An additional 50 million tonnes of crude will reach the port of Kozmino on completion of the ESPO's second section.

Meanwhile, Russia's subsoil use agency Rosnedra has set a starting bid price of $50.3 million at an auction for the rights to the East Talakan field in Eastern Siberia.

Russia's Vedomosti business daily reported that Surgutneftegaz, which is developing the adjacent Talakan field, is likely to get the rights to East Talakan, although Gazprom is also a leading candidate. The paper reported that East Talakan field holds proved and probable reserves of 9.9 million bbl of oil, 22.9 billion cu m of gas, and 0.2 million tonnes of gas condensate.

According to analyst BMI, future development of oil from the East Talakan field "is likely to contribute to planned throughput for the ESPO line." This year, BMI said, Surgutneftegaz is expecting to boost initial Talakan production to 40,000 b/d, with output expected to reach 120,000 b/d by 2015.

Tokyo Gas to build fourth LNG terminal in Japan

Tokyo Gas Co., which currently operates three LNG regasification terminals in Japan, has selected the coastal city of Hitachi in Ibaraki prefecture as the site for its fourth facility, the firm's first in 20 years.

Tokyo Gas, which operates two LNG receiving facilities in the Yokohama area and one in Sodegaura, will spend some 100 billion yen on the Hitachi facility, which will include docks for tankers, storage tanks, and regasification equipment.

The new terminal is scheduled to start operations in 2017-18, but the firm released no information on its size or its sources of supply.

Generally, the new terminal is expected to help meet the long-term growth in demand from industry as Tokyo Gas' industrial gas sales have been rising at an average of 7%/year since 2003-04 and now account for about 40% of all its gas sales.

More precisely, the decision—announced by Tokyo Gas president Mitsunori Torihara—follows earlier efforts by the firm to increase its supply of gas to the Hitachi region.

In 2007, Tokyo Gas said it would supply Hitachi Ltd.'s power station in the city with natural gas from July through a new satellite LNG terminal in Ibaraki prefecture—a move aimed at expanding the company's natural gas user base to include areas that lack gas pipelines. A Tokyo Gas spokesman said the firm would deliver LNG to the satellite terminal by truck from its main Sodegaura LNG terminal in adjacent Chiba prefecture before regasifying the LNG and selling it in Hitachi.

Tokyo Gas plans to provide 50,000 tonnes/year of gas to the power station and expects to double the volume by developing new customers in the area, the spokesman said.

The Ibaraki satellite terminal, which has a 2,400-kl tank and three 7.5-tonne/hr regasification units, is the company's second satellite LNG terminal—the first was also built in Ibaraki prefecture in April 2006, with two 400-kl tanks.

This week's announcement of the new regasification terminal at Hitachi comes despite figures announced by Tokyo Gas this month showing a slight dip in its recent sales of natural gas.

Total gas sales volume by Tokyo Gas for December 2008 came to about 1.169 billion cu m, down 112.08 million cu m from the same period last year.

Sales of residential gas totaled 326.9 million cu m, down 8.7% from December 2007 due to fewer counted days and higher temperatures, which caused a heating and boiling water demand decrease.

Commercial, public, and medical use volumes totaled 210.3 million cu m, down 7.4% from last year due to fewer counted days and higher temperature days from that of the previous year, which caused heating demand decrease.

Although industrial use represents a larger percentage of Tokyo Gas' sales, recent demand totaled about 442.95 million cu m, down 11.5% from last year as existing customers use less.

Volumes for wholesale supply to other gas companies totaled 189.3 million cu m, down 3.5% from last year. Wholesale gas suppliers sold less to high-volume customers.

On a cumulative basis, Tokyo Gas said, gas volumes from April through December 2008 totaled 986.2 million cu m, a decrease of 0.1% vs. the same period in 2007. ✦

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Letters

The case for hydrogen

This is a response to the letter from Thomas Wyman entitled "Hydrogen and thermodynamics" (OGJ, Jan. 19, 2009, p. 14).

Mr. Wyman bemoans the fact that it takes more energy to make hydrogen than is contained in that hydrogen. True, but what about other energy carriers? It's a good thing that this thinking didn't prevail in the 18th century when inventors were developing a new energy carrier that could transmit large quantities of energy nearly instantaneously over long distances. This new energy carrier could economically power homes, factories, and buildings without producing any pollution. But there was a major roadblock: It would take two to three times more energy to generate this carrier than it contained.

Fortunately, the likes of Faraday, Tesla, Edison, Westinghouse, et al. were not impeded by this take on thermodynamics as they developed electricity as a practical energy carrier. Today a coal plant might produce electricity at 36% efficiency. Adding 8% loss in transmission, the overall efficiency might be 33%. Thus it takes over 300 MJ of coal to make 100 MJ of electricity. Advanced natural gas combined cycle power plants might reach 60% efficiency for a net 55% system efficiency, but it still takes more energy to make electricity than is embodied in that electricity. Is this justification to renounce electricity?

Hydrogen is routinely produced by reforming natural gas at 75% efficiency. It takes 133 MJ of natural gas to make 100 MJ of hydrogen. Given that a fuel cell vehicle burning hydrogen is at least twice as efficient as a conventional car burning natural gas, 100 MJ of natural gas converted to hydrogen will propel a fuel cell car 50% farther than that same 100 MJ of natural gas in a conventional car. Furthermore, the fuel cell vehicle will produce no urban air pollution, and hydrogen, like electricity, can be made from virtually any fuel.

C. E. (Sandy) Thomas, PhD
President
H_2Gen Innovations Inc.
Alexandria, Va.

Calendar

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

OIL&GAS JOURNAL online

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

2009

FEBRUARY

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 9-12.

CERAWeek, Houston, (617) 966-5992, e-mail: info@cera.com, website: www.cera.com. 9-13.

SPE Unconventional Fields Conference, Margarita Island, Venezuela, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Pipe Line Contractors Association Annual Conference (PLCA), Carlsbad, Calif., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 11-15.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

Annual Petroleum Coke Conference, San Francisco, (832) 351-7828, e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 13-14.

International Petrochemicals Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 16-17.

IP Week, London, +44 (0)20 8561 6030, +44 (0)20 8561-0131 (fax), e-mail: events@energyinst.org.uk, website: www.energyinst.org.uk. 16-19.

Calendar

EnerCom's The Oil & Services Conference, San Francisco, (303) 296-8834, e-mail: kgrover@enercominc.com, website: www.theoilandservicesconference.com/index.html. 18-19.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 18-19.

ASEG/PESA International Geophysical Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au, website: www.sapro.com.au/aseg.htm. 22-25.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-2248, (405) 325-7164 (fax), e-mail: bettyk@ou.edu, website: www.engr.outreach.ou.edu. 22-25.

Nitrogen + Syngas International Conference and Exhibition, Rome, +44 20 7903 2167, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: http://crugroup.com. 22-25.

CERI Natural Gas Conference, Calgary, (403) 282-1231, (403) 284-4181 (fax), e-mail: conference@ceri.ca, website: www.ceri.ca. 23-24.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 23-26.

MARCH

EAGE North African/Mediterranean Petroleum and Geosciences Conference & Exhibition, Tunis, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 2-4.

SPE Research & Development Conference, Lisbon, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-4.

APPEX Prospect and Property Expo, London, (918) 560-2616, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 3-5.

Subsea Tieback Forum & Exhibition, San Antonio, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Doha Natural Gas Conference & Exhibition, Doha, e-mail: gascon@qp.com.qa, website: www.dohagascon.com.qa. 9-12.

ARTC Annual Meeting, Kuala Lumpur, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 10-12.

European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 10-12.

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 10-12.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

Purvin & Gertz Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 17-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

Offshore Mediterranean Conference & Exhibition (OMC), Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc2009.it. 25-27.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 29-31.

Petroleum Geology Conference, London, +44 (0)20 7434 9944, +44 (0)20 7494 0579 (fax), e-mail: georgina.worrall@geolsoc.org.uk, website: www.geolsoc.org.uk. Mar. 30-Apr. 2.

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 1.

Offshore Asia/Multiphase Pumping & Technologies Conference & Exhibition, Bangkok, 918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOA@pennwell.com, website: www.offshoreasiaevent.com. Mar. 31-Apr. 2.

APRIL

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-3.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-8.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 7-8.

ATYRAU Regional Oil & Gas Exhibition & OilTech Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 7-9.

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 14-16.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 16.

Middle East Petroleum & Gas Conference, Dubai, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 19-21.

ERTC Coking & Gasification Conference, Budapest, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Hannover Messe Pipeline Technology Conference, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), website: www.hannovermesse.de. 20-24.

IADC Drilling HSE Middle East Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21-22.

API Pipeline Conference, Fort Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-22.

Pipeline Transport Conference & Exhibition, Moscow, +43 1 230 85 35 33, website: www.expopipeline.com. 21-23.

Base Oils and Lubricants in Russia & CIS Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-23.

Instrumentation Systems Automation Show & Conference, (ISA), Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 22-23.

CPS/SEG International Geophysical Conference & Exposition, Beijing, (918) 497-5500, (918) 497-5557 (fax), e-mail: semery@seg.org, website: www.seg.org. 24-27.

AIChE Spring National Meeting, Tampa, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 26-30.

API Spring Refining and Equipment Standards Meeting, Denver, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

EAGE European Symposium on Improved Oil Recovery, Paris, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 27-29.

ENTELEC Conference & Expo, Houston, (972) 929-3169, (972) 915-6040 (fax), e-mail: blaine@entelec.org, website: www.entelec.org. Apr. 29-May 1.

MAY

EAGE International Petroleum Conference & Exhibition, Shiraz, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 4-6.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 4-7.

GPA Permian Basin Annual Meeting, Austin, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 5.

Interstate Oil and Gas Compact Commission Midyear Meeting (IOGCC), Anchorage, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 10-12.

ERTC Asset Maximisation Conference, Prague, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

IADC Environmental Conference & Exhibition, Stavanger, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

North American Unconventional Oil & Gas Conference & Exposition, Denver, (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-13.

NPRA National Safety Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 12-14.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 12-14.

NPRA Reliability & Maintenance Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 19-22.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21.

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

APPEA Conference & Exhibition, Darwin, +61 7 3802 2208, e-mail: jhood@appea.com.au. website: www.appea2009.com.au. May 31-Jun. 3.

Journally Speaking

National, local, and back

Christopher E. Smith
Pipeline Editor

US President Barack H. Obama's affect on the country's oil and gas pipeline industry is still in the earliest stages of being defined. As part of his administration's Comprehensive New Energy for America plan, Obama has prioritized construction of a natural gas pipeline from Alaska, at least in part to help create the jobs needed to fuel an economic recovery (OGJ, Jan. 26, 2008, p. 20).

This same economic downturn, however, has also placed pressures on the project that could little have been imagined as recently as last summer, when Alaskan Gov. Sarah Palin, while campaigning as the Republican nominee for vice-president, trumpeted the line's construction as one of her crowning achievements. The capital needed for a project of this scale is simply harder to access now than it was even 8 months ago.

The economic pressures on an Alaskan gas line become even more acute when combined with sharply lower energy prices, surging shale gas production in the Lower 48, and underused capacity for importing LNG into the US. But proponents, including TransCanada Pres. Russ Girling, note that the long timelines of an Alaskan gas pipeline project coincide well with the still-upward sloping demand curve projected through at least 2030. TransCanada was awarded a license to build the project by the state of Alaska in December 2008.

Obama's cabinet

The president's cabinet also has so far had scant opportunity to influence oil and gas pipelines. New Transportation Secretary Ray LaHood, a former 14-year Republican representative from Illinois, didn't comment directly on pipelines during his confirmation hearing, but did stress the need for his department to increase the safety of all modes of transportation.

As a US representative, LaHood voted "Yes" on the Renewable Energy and Energy Conservation Tax Act, voted "Yes" on criminalizing oil cartels like the Organization of Petroleum Exporting Countries, and "No" on retaining the moratorium on OCS drilling. He did, however, also vote to remove oil and gas exploration subsidies.

New Department of Homeland Security Secretary Janet Napolitano also is responsible for the security of US pipelines as part of the country's critical infrastructure.

Napolitano issued five action directives in her first official day in the position, all of which have potential effects on the pipeline industry. The directives sought to update the status of:

- Critical infrastructure protection, including plans to enhance both the protection itself and private sector participation in the protection.
- Risk analysis, including enhancing risk management as the basis of decision-making.
- State and local intelligence-sharing.
- Transportation security (encompassing air, surface, and maritime transportation).
- State, local, and tribal integration, designed to more fully integrate these governmental levels into the security process and including an acceleration of the input process from these levels.

Local

These federal initiatives come at the same time that local resistance to new pipeline projects is emerging, particularly in areas surrounding the Barnett and Haynesville shales. Republican legislators in Texas—one from Burleson, just south of Fort Worth, and the other from Houston—have introduced two bills increasing landowner rights when faced by condemnation for a pipeline right of way.

The city council of Lewisville, Tex., also in the Dallas-Fort Worth area, is one of 30 Texas municipalities, including Fort Worth itself, to have passed a resolution asking the Texas legislature to give cities more authority in pipeline matters.

The resolution urges the legislature to revisit the continued appropriateness of preempting municipalities from regulating the practices of midstream gas utilities and requests it confer additional authority upon municipalities to "safeguard the interests of the public and the long-term economic viability of private property."

From the president down to the city council of 95,000 person towns like Lewisville, everyone is trying to make sure domestic energy development doesn't just happen, but happens in a way congruent with the country's overall needs and wants.

A large circle is formed. The development of the Barnett shale near Fort Worth is one of the factors weighing against prompt development of a pipeline to bring gas from Alaska to the Lower 48. At the same time, efforts to restrict pipeline infrastructure inside and from the Barnett shale may slow its growth, refocusing attention on the need to develop as many different resources as possible.

Obama, his cabinet, and the pipeline industry itself all have their work cut out for them. ✦

E d i t o r i a l

Deepwater investment

Oil and gas producers should expect a political fight after a US appeals court ruled in their favor about royalties from deepwater leases. They also should prepare for wild claims about associated "costs."

Deepwater royalty relief, one of the most effective energy programs in US history, elicited outrage in 2006 when the New York Times reported that the federal budget lacked estimates of royalty income for deepwater Gulf of Mexico leases issued in 1998 and 1999. The leases didn't reinstate royalty, as did those issued in similarly administered years, when oil and gas prices exceeded statutory "thresholds."

Courts, meanwhile, have been addressing the question whether the Department of the Interior's Minerals Management Service had authority to limit royalty relief on the basis of price for leases issued in the five years from 1996 through 2000. So far, the consistent answer is no.

In a case filed in 2006 by the former Kerr-McGee Oil & Gas Corp., now part of Anadarko Petroleum Corp., a federal appeals court on Jan. 12 unanimously upheld a lower-court ruling that Congress did not empower Interior to impose price thresholds during the years in question (OGJ, Jan. 19, 2009, p. 39). The Deep Water Royalty Relief Act of 1995, according to the courts, stipulated volume but not price limits for leases issued in 1996-2000.

Now, therefore, the federal government might receive no royalty payments, until volume thresholds are met, from deepwater leases of that vintage. It also might have to repay $1.5 billion collected from leases in which MMS improperly inserted price thresholds. To a heavily indebted government thinking it must spend feverishly to stimulate economic activity, both prospects will seem unbearable.

Economic perspective

If nothing else, this issue illuminates the power of economic perspective. In the 1995 law, Congress yielded future royalty revenue in order to start a business promising national benefits. At the time, oil and gas prices were depressed. Royalty relief looked like a promising investment in domestic energy supply, technology, jobs, and nonroyalty government revenue. By 2006, oil and gas prices were high and rising, and the forgone royalty came to be viewed solely as cost.

About that, politicians soon will have much to say. In 2006, the government was said to be facing a $60 billion "loss" if it lost the Kerr-McGee-Anadarko case. That number came from a 2004 MMS estimate subsequently found to have been based on overestimated production.

Since then, the Government Accountability Office has made two estimates of the value of forgone royalty on future production from deepwater leases. These estimates naturally vary with oil and gas prices. In fact, GAO published its second estimate last June to accommodate its forecasts to the unprecedented prices prevailing at the time. Since then, off course, crude has lost two thirds of its value.

The GAO estimates provide a framework against which to gauge "cost" complaints likely soon to emanate from Congress. For the threshold-free 1998 and 1999 leases, GAO estimates the total value of forgone future royalty at $4.3-14.7 billion, depending on commodity prices and production. The price ranges assumed for these years are $50-100/bbl for oil and $6.50-8/Mcf for natural gas. To project forgone future royalty for leases issued in 1996-97 and 2000, GAO uses a different price range: $70-100/bbl for oil and $6.50-8/Mcf for gas. It estimates forgone royalty from these leases at $15.1-38.3 billion.

Royalties in flux

Depending on future prices and production, then, the value of royalty relief for future production from deepwater leases issued in 1996-2000 could be as low as $19.4 billion or as high as $53 billion. These are totals spread over production lives assumed by GAO to be about 25 years. Over a quarter-century, these "costs" aren't extreme.

Against the 1 million b/d of oil and nearly 3.5 bcfd of gas now produced in deep water by an industry that would be nowhere close to its current level of development without past royalty relief, the cost, which involves no real expenditure of public money, looks a lot like investment. Some might even call it stimulus. ✦

Global perspectives required for risk, opportunity analyses

David Wood
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The world has always held risks for upstream oil and gas companies, and it certainly shows no signs of becoming less risky in the near future. In fact, many would argue quite the reverse based on the prevailing dynamic environment of political tensions, price volatility, fiscal instability, resource nationalism, strong competition from cash-rich national companies and sovereign wealth funds, and risk-averse financial institutions.

Without a healthy tolerance for risk and the vision to see the substantial resource opportunities that exist internationally in the oil and gas business, few companies venture far into international exploration and development activities. International oil companies (IOCs) have accepted this fact for many decades, and for the past decade, so have some of the less resource-rich national oil companies (NOCs).

Opportunity and risk, which go hand-in-hand, are two facets of uncertainty. There are good reasons why oil and gas companies more rigorously evaluate and, where possible, quantify the risks to which their operations, physical assets, and financial resources are exposed.

They also are keen to calculate their potential financial exposure to extreme risk events that occur infrequently but could have devastating effects. This recognition and pressure from tightening regulation have together prompted companies to develop enterprise risk management (ERM) systems to integrate such issues rigorously and systematically.

Quantitative analysis

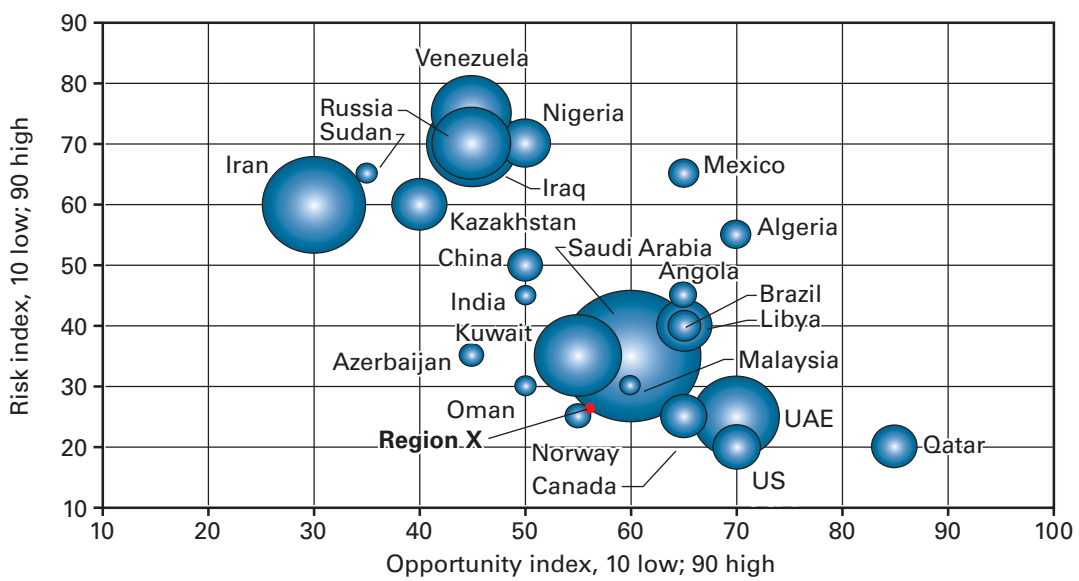
It is difficult to estimate accurately the likelihood of extreme events' occurring. Normal and lognormal distributions of historical data are only adequate in relatively static environments when estimating the probable occurrence of future extreme events.

In dynamic, rapidly changing environments, such forecasting methods often underestimate levels of uncertainty, as capital markets and many major international oil and gas companies have learned to their project cost detriment.

Complex mathematical models, such as many of the value at risk (VAR) models popularized in financial circles, are now being used widely in the energy industry to justify risk exposure of both traded and physical asset portfolios. They claim to identify and quantify risk exposures, but these models themselves pose a major threat to the quality of decision-making for two main reasons:

First, such approaches lead

TOP 24 OIL[1] RESERVES NATIONS AS FUNCTION OF IOC RISK, OPPORTUNITY[2] Fig. 1



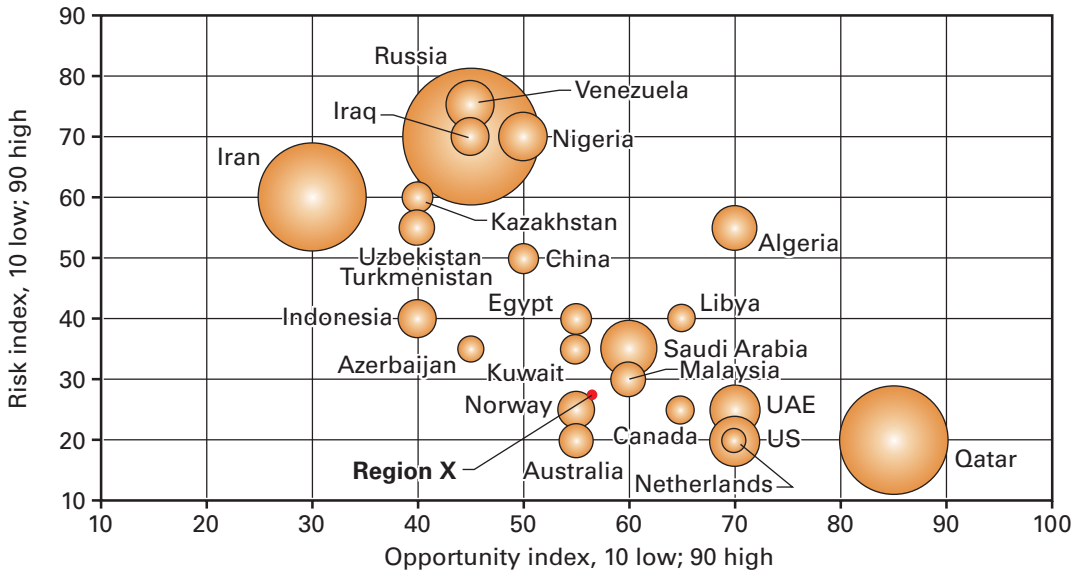
[1]Conventional oil. [2]July 2008 assessment. Opportunity indices evaluated for the top proved crude oil reserves-holding nations. Bubble diameters are proportional to proved crude oil reserve holdings as reported by BP Statistical Review (June 2008).
Sources: David Wood & Associates, BP Statistical Review (2008)

companies and their decision-makers to believe they can quantify their risks with unrealistic levels of precision, which often leads to overconfidence in their ability to manage risk and to exposures being underestimated.

Secondly, and the main point of this article, is that it encourages decision-makers to focus too much of their attention exclusively on the downside risks at the expense of considering and trying to identify and exploit the opportunities that are associated with many uncertain situations.

TOP 24 GAS[1] RESERVES NATIONS AS FUNCTION OF IOC RISK, OPPORTUNITY[2]

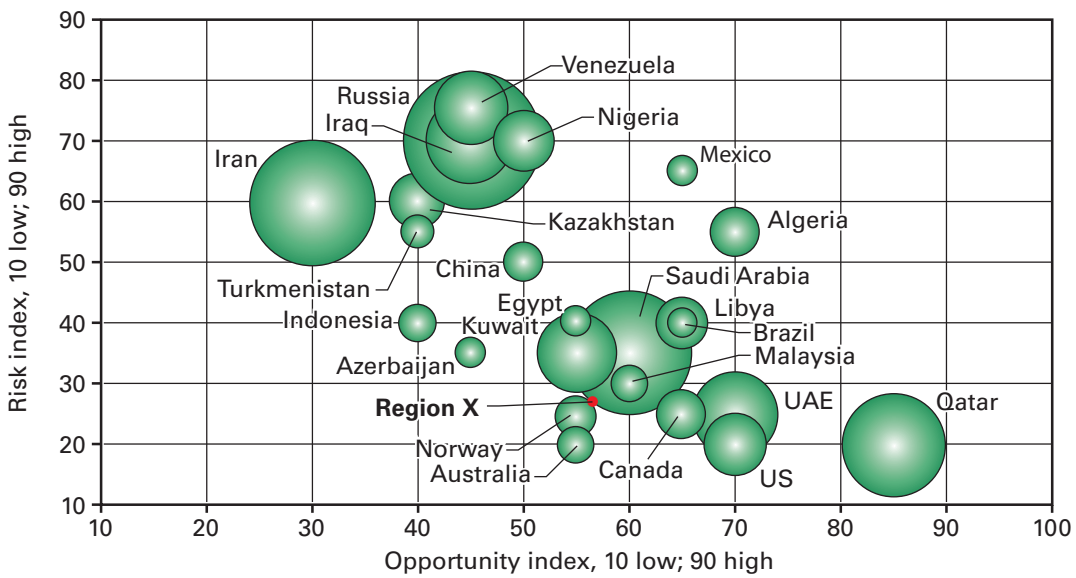
Fig. 2



[1]Conventional gas. [2]July 2008 assessment. Risk opportunity indices evaluated for the top natural gas proved reserves-holding nations. Bubble diameters are proportional to proved gas reserve holdings as reported by BP Statistical Review (June 2008).
Sources: David Wood & Associates, BP Statistical Review (2008)

TOP 24 OIL AND GAS RESERVES NATIONS AS FUNCTION OF IOC RISK, OPPORTUNITY*

Fig. 3



*Assessment conducted July 2008. Risk-opportunity indices evaluated for the top crude oil plus natural gas (boe) proved reserves-holding nations. Bubble diameters are proportional to proved crude oil plus proved gas reserve holdings as reported by BP Statistical Review (June 2008).
Sources: David Wood & Associates, BP Statistical Review (2008)

The bigger picture

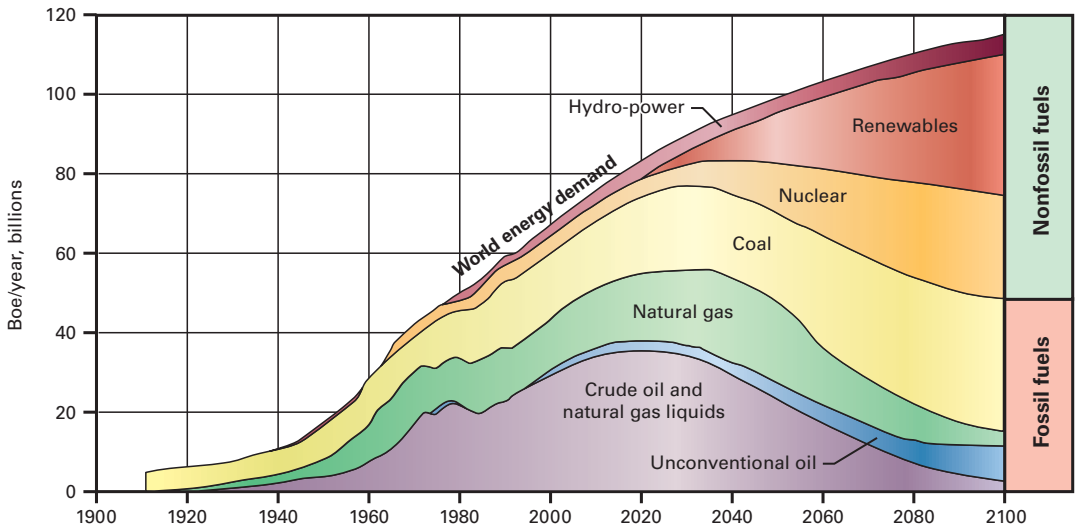
Opportunities, like risks, require careful identification and evaluation and rarely manifest themselves without efforts being made to seek them out and establish innovative approaches to exploit them.

Risk managers with a downside mitigation mentality are rarely equipped or have the vision or time to recognize and manipulate opportunities into projects that are considered achievable. This article does not recommend ignoring risk analysis and replacing it with an unconstrained search for opportunity. Quite the contrary; much valuable insight emerges from quantitative risk analysis techniques (e.g, Monte Carlo simulation, real options valuations, and VAR and its derivative techniques) even if the numerical calculations involved rarely provide an accurate value or unequivocal decision criteria. Such analysis is clearly required, but not necessarily at the earliest stages of project definition or strategy formation.

Placing a project, asset, portfolio, or nation into an energy industry context using qualitative or semiquantitative

FORECAST OF FUTURE FOSSIL FUEL SUPPLY PROFILES*

Fig. 4



*From the perspective of the low oil and low gas price environment of the mid-1990s. Expected potential for unconventional petroleum resources is severely limited. Energy demand forecast is influenced by the UN world population forecast of about 6 billion in 2000, 9 billion in 2050, and 11 billion in 2100.
Sources: David Wood & Associates, Edwards AAPG, August 1997

techniques to estimate its risks and opportunities in an integrated way is often a more useful starting point from which to approach the first hurdles of the decision-making process.

Such an approach facilitates a global mindset and encourages companies to seek out or recognize from a helicopter view just where opportunities might reside. Adopting such an approach is more likely to enable a risk analyst to conduct the more detailed quantitative analysis. It would focus on upside and downside scenarios that encompass the most probable outcomes and the rare, extreme, but realistically possible outcomes at both ends of the spectrum.

A global context

What is important in the first strategic stages of analysis is that risks and opportunities are initially considered together, with an integrated, systematic, and rigorous approach grounded and presented in a global perspective relevant to the industry. There are several ways this can be done.

The following approach grounds the analysis in the context of proved reserves at the national level, statistics that are readily available. The quality of the proved reserves volumes at the national level varies by region, and confidence in such numbers is rightly questioned for unverifiable numbers presented by several resource-rich nations. However they are useful for distinguishing the resource endowments on the order of magnitude scale that is required.

Other useful global statistics that could be used include oil or gas production volumes, export volumes, and consumption statistics, depending upon the strategy being evaluated or pursued. Reserves are used here because many IOC and NOC upstream companies are seeking, as a strategic priority, new international opportunities to increase and diversify their resource bases.

Insightful quick look

Assigning a score to five factors broadly evaluating country risk and to another five factors broadly evaluating country opportunity provides a fast and effective way to systematically evaluate a large number of countries in a superficial but rigorous manner.

The five attributes proposed to evaluate for scoping risk analysis focus mainly on political, business, and fiscal risks:

- Expropriation or political instability.
- Corruption.
- High administrative burden (in cost and time).
- Community-labor disputes.
- Regressive and inflexible fiscal terms.

The five attributes proposed to evaluate for scoping opportunity analysis are focused mainly on technical, operational, and financial risks:

- Access to large reserves.
- Low finding and development costs.
- Ease of operation.
- Access to equity-debt funding.
- Access to infrastructure-markets.

Applying a simple scoring system makes the evaluation process quicker and more transparent. Here is a 1-5 scale applied to both risk and opportunity, but extending in different directions from a zero point (an impossible score implying an attribute with no uncertainty-risk or opportunity):

RISK OPPORTUNITY
5 4 3 2 1 0 1 2 3 4 5
← →
High Medium Low Low Medium High

An alternative is to use negative numbers for risk and positive numbers for opportunity. The proposed semi-quantitative scheme has the advantage of distancing points of high opportunity from those of high risk when cross-plotted graphically. It helps to have a clear verbal description of each score to reduce ambiguity and improve rigor. Thus a more precise definition of

each number could be:

1-very low (minimal).
2-low.
3-moderate.
4-high.
5-very high (extreme).

If a score of 1-5 is assigned to each attribute and the scores of all five attributes of opportunity and risk are added separately to yield two scores, those scores can vary between 5 and 25.

By subtracting 5 from the sum of the five attribute scores and multiplying that sum by 5, the total risk and opportunity scores are simply manipulated into an index scale of 0-100, which is relatively easy to interpret and contrast among nations (Fig. 1). Clearly detailed knowledge and understanding of the petroleum industry in the nation being evaluated is required by the analyst to assign a reliable score to each attribute.

To ground this simplistic analysis in a global context, the risk-opportunity indices for a spectrum of major resource holders can be evaluated and presented graphically with respect to their resource volumes. To illustrate this point Figs. 1-3 show such analysis for the top proved reserves-holding countries (yearend 2007 volumes, BP Statistical Review, June 2008) for oil, gas, and gas plus oil (expressed as barrels of oil equivalent using 6,000 cu ft/bbl).

The figures illustrate the same risk-

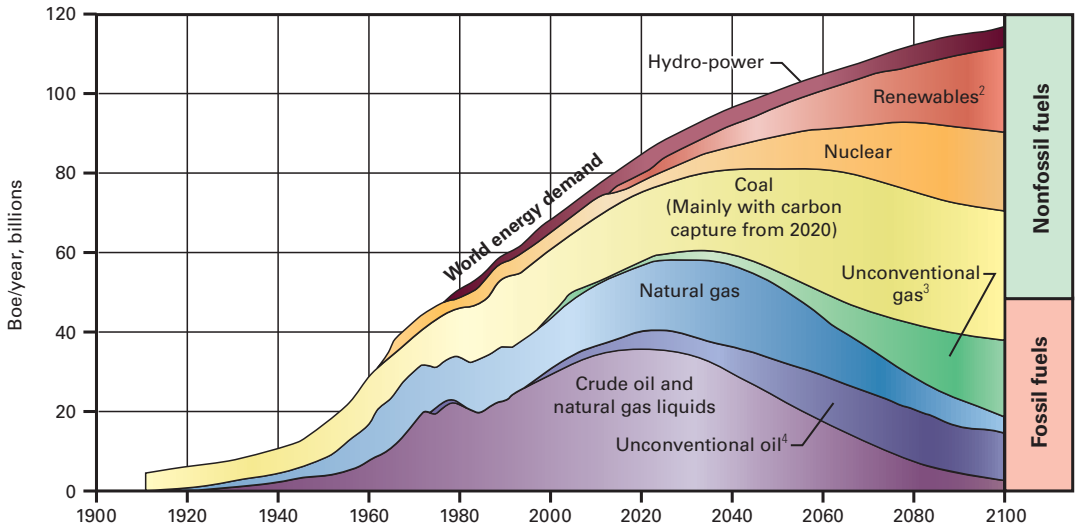
IOC RISK, OPPORTUNITY IN TOP 20 BOE PROVED RESERVES COUNTRIES*

Country	Overall risk score (0-100)	Opportunity score (0-100)	Proved gas reserves, tcf	Proved oil reserves, billion bbl	Proved reserves, billion boe
Russia	70	45	1,576.8	79.43	342.22
Saudi Arabia	35	60	253.0	264.21	306.38
Iran	60	30	981.7	138.40	302.02
Qatar	20	85	904.1	27.44	178.11
Iraq	70	45	111.9	115.00	133.66
UAE	25	70	215.1	97.80	133.64
Venezuela	75	45	181.9	87.04	117.35
Kuwait	35	55	63.0	101.50	112.00
Nigeria	70	50	187.0	36.22	67.39
US	20	70	211.1	29.44	64.62
Kazakhstan	60	40	67.2	39.83	51.03
Libya	40	65	52.8	41.46	50.26
Algeria	55	70	159.4	12.27	38.84
Canada	25	65	57.5	27.66	37.26
China	50	50	66.5	15.49	26.58
Norway	25	55	104.6	8.17	25.60
Indonesia	40	40	105.9	4.37	22.03
Malaysia	30	60	87.4	5.36	19.92
Australia	20	55	88.6	4.16	18.93
Turkmenistan	55	40	94.2	0.60	16.30

*International oil companies' risk, opportunities in countries ranked in descending order of 2007 proved oil plus gas boe reserves holdings.
Source: BP Statistical Review, June 2008

FUTURE FOSSIL FUEL SUPPLY PROFILES BASED ON 2008 PRICES[1]

Fig. 5



[1]Forecast is from the perspective of the high oil and high gas price environment of 2008. It suggests that a fatter tail to the petroleum resource distributions could materialize. Expected potential for unconventional petroleum resources is now high, and these resources are now receiving massive investment driven by technical, commercial, political, and security-of-supply opportunities. [2]Renewables include biomass, wind, solar, geothermal wave, and biofuels. [3]Unconventional gas includes coalbed methane, shale gas, and gas hydrates. [4]Unconventional oil includes bitumen, tar sands, oil shale, and ultraheavy crude oil.
Source: David Wood & Associates

opportunity evaluation—based on my own perceptions—with an IOC perspective in mind in mid-2008. Other analysts might disagree with these based on their own experience or perceptions, or on analyzing from an NOC perspective.

The point of the simple scales proposed is that they can be adjusted and updated easily and regularly in response to events, different opinions, or changing environments, or reassessed from different perspectives (e.g., NOC vs. IOC) in a transparent and rigorous manner.

Depending on whether the analysis is presented in relation to oil, gas, or boe reserves provides different global frameworks. Each framework may be more relevant to certain companies, portfolio strategies, or situations.

After producing the framework, it is relatively easy to highlight the analysis of a region or a country of specific interest in relation to that framework (e.g., Region X highlighted in Figs. 1-3). More usefully, the analysis of the region of interest and the analysis of the global framework nations can be updated as required.

Fig. 2 illustrates the impact of placing the analysis of a region of interest in a natural gas global framework rather than crude oil. Fig. 3 changes the framework again to combined oil and gas proved reserves, but maintains the integrated risk analysis results the same as for Figs. 1 and 2.

These risk-opportunity analysis results can also be expressed in summary tabular form as illustrated in the table or in more detailed form providing the scores assigned to each attribute. As already stated, this approach is simplistic and can only provide a scoping assessment. In many instances, the early stages of the decision-making process can benefit from the insight such analysis can provide rapidly and transparently.

More in-depth analyses

A more in-depth risk and opportunity analysis is likely to be required in order to sanction major investments.

Earlier David Wood OGJ publications and executive reports have explored the many-faceted nature of exploration and production asset and portfolio risk analysis and suggested ways in which this might be effectively conducted. It is not suggested that such a detailed analysis be replaced by the approach outlined here, rather recommended that the two approaches complement each other, with the quick-look approach useful in the context of seeking out opportunities.

It is perhaps also important to recognize that the global framework used to ground the risk-opportunity analyses can in some cases itself hide or obscure some opportunity. Again the reserves framework clearly illustrates this point. It is appropriate to use proved reserves statistics above as they are the volumes in which the industry by definition believes with the highest levels of confidence.

However, from an exploration and future development context, it is often the lower-confidence categories of reserves and yet-to-find resources in a region that may be more relevant to identifying future opportunities. Hence it may make more sense for certain analysis to be grounded in the less accurate potential resource framework rather than proved reserves framework.

Figs. 4 and 5 further illustrate this point, forecasting remaining fossil fuel resources from two perspectives or snapshots in time.

Fig. 4 is a forecast based on that made by Edwards in the mid-1990s when crude oil prices were less than $20/bbl and North American natural gas prices were less than $2/bbl.

It forecasts a situation in which exhaustion of the finite global fossil fuels is well advanced towards the end of the 21st Century, with production peaking well within the first quarter of this century. It further suggests

limited potential for nonconventional hydrocarbons— including coalbed methane, shale gas, deep tight gas, methane hydrates, tar sands, bitumen, and oil shales—and for new enhanced oil recovery technologies that might recover substantial residual resources from conventionally depleted giant reservoirs in which large volumes of petroleum remain in situ.

This illustrates a limited vision that peak oil advocates continue to promote as implying that the oil and gas industry is already in irreversible decline.

The world envisioned in Fig. 4 is one in which some 50% of the world's energy must come from renewables and nuclear by 2100 because fossil fuel resources would be in an advanced state of depletion.

In contrast, Fig. 5 is a forecast based on a high-priced petroleum environment with a vision of many opportunities for unconventional petroleum resources. Indeed the resource base, high prices, and the political will to back the development of innovative, but high-cost, technologies to exploit the unconventional petroleum resources suggests that fossil fuels may be supplying similar absolute volumes in 2100 as they were in 2000.

Opportunities remain

Clearly petroleum resources are not in unlimited supply, and nuclear, renewables, and new sustainable energies yet to be developed ultimately will be required.

The Fig. 5 vision, however, suggests that much opportunity remains within the petroleum industry for those willing to accept associated risks such as periods of lower prices or emissions penalties-carbon capture costs rendering costly exploitation projects subcommercial.

Lessons from the past 50 years suggest that prices are not likely to remain high indefinitely, and resource distributions are not likely to follow Gaussian distributions (i.e., bell-shaped curves) to their extremes.

The unconventional oil and gas industries will probably have to weather low price challenges and expensive technology development periods. However, the industry has a record of technical innovation second to none, and it is reasonable to expect at least some technical solutions that will commercially unlock many of the vast unconventional resources currently just out of reach.

Further opportunities within the petroleum industry materialize when that is coupled with the political realization within the Organization for Economic Cooperation and Development that an undesirable future is one in which Russia and the extreme wings of the Organization of Petroleum Exporting Countries and the emerging Gas Exporting Countries Forum—dominated by Russia—hold major industrial powers for ransom and repeatedly force them into deep recession.

For integrated risk and opportunity analysis in the petroleum industry to be most valuable in seeking out opportunities, that analysis needs to be grounded in a global vision and framework that provides space for opportunities to exist.

Opportunities will remain obscured or buried deep below the risks, no matter how detailed and quantitative the analysis, if risk analysis is considered in isolation or risk and opportunity analysis are within a constrained framework.

Companies that seek and can find the opportunities in the fat-tail of remaining global petroleum resources in regions with broadly manageable risks seem more likely to prosper within the industry.

On the other hand, those companies that focus their resources in applying flawed enterprise risk management systems on a limited range of risks seem destined to miss opportunities and probably will be caught by unexpected extreme risks.

ERM systems that exclude operational risks and other important but hard-to-quantify risks from their routine financial exposure evaluations and fail to focus on potential operational opportunities tend to be constrained to mitigating certain risks that they systematically underestimate. This is because they look myopically at the part of the uncertainty spectrum they unrealistically believe can be measured and predicted with precision. Such approaches, although mathematically elegant, frequently do not ground their high-level analyses in an appropriate global framework.

Excel workbook available

An Excel workbook providing the analytical framework (five attribute risk and opportunity methodology), with graphical displays similar to those included in Figs. 1-3 of this article, is available from OGJ (see box above).

The workbook includes tables listing summary risk and opportunity indices

For interested analysts

An expanded and more detailed accompanying report and operational workbook on E&P Risk Management by David Wood is available for purchase through the OGJ Online Research Center.

The 17,500-word report focuses on risks and opportunities surrounding international fiscal designs and issues of fiscal instability.

It includes 19 figures and is accompanied by Excel workbooks (in Excel 2003 and Excel 2007 formats) that enable quick-look and high-level risk and opportunity analyses applying the methodology proposed in the article, for a country or region.

For additional information, contact: www.ogjresearch.com

Topic: Research Reports

Report Title: Fiscal design strategies and fiscal instability impact oil & gas risk and opportunity analysis and international oil company decision-making

E-mail: orcinfo@pennwell.com

Tel: (918) 831-9488

and the individual attribute scores for:

- The 58 countries holding the most proved oil reserves.
- The 58 countries holding the most proved natural gas reserves.
- The 58 countries holding the most proved oil plus gas boe reserves.

All are ranked in descending order.

The individual attribute scores represent the author's perception at a snapshot in time in mid-2008. These can be overwritten with readers' preferred assessments, making the tool easy to tailor for use by many analysts.

In addition, an executive report compiling several articles on risked portfolio analysis in the upstream oil and gas industry and detailed risk analysis methodologies are also available from OGJ. ✦

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The author

David Wood (dw@dwasolutions.com) is an international energy consultant conducting project evaluation, research, and training, based in Lincoln, UK, and operating worldwide. He specializes in the integration of technical, economic, risk, and strategic information to aid portfolio evaluation and management decisions. He holds a PhD from Imperial College.

Salazar launches MMS ethics reform program

Nick Snow
Washington Editor

US Interior Secretary Ken Salazar launched an ethics reform program Jan. 29 to examine conduct of a group of US Minerals Management Service employees, look at restructuring the agency's oil and gas royalty program, and review DOI's ethics regulations and policies.

"Our agenda for reform will reach every part of this department. But it will also send a loud and clear signal to the special interests outside of this department who have become accustomed to the 'anything goes' attitude in Washington over the last 8 years," Salazar told MMS employees in Lakewood, Colo.

"The 'anything goes' will end. And this department, and the Minerals Management Service, will lead the way in ending it," he declared. Salazar said he announced the program to MMS Denver-area employees "because the ethical lapses in this office, and the individuals who engaged in blatant and criminal conflicts of interest and self-dealing, set one of the worst examples of corruption and abuse in government."

He said the effort will be led by Tom Strickland, his chief of staff, who was US Attorney for Colorado when Salazar was the state's attorney general.

Salazar ordered a re-examination of potential criminal conduct by persons named in DOI Inspector General Earl E. Devaney's three reports. The documents described misconduct ranging from blatant conflicts of interest to drug abuse and sexual activity by employees of MMS's royalty management program. They also charged that supervisors disregarded other employees' attempts to bring the violations to the appropriate authorities' attention.

"Our agenda for reform will reach every part of this department. But it will also send a loud and clear signal to the special interests," US Interior Secretary Ken Salazar told Minerals Management Service employees in Lakewood, Colo., as he launched a department-wide ethics reform program on Jan. 29. Photo by Tami Heilemann for DOI-NBC.

'Appropriate sanction'

"I have asked the [US] Department of Justice and, if appropriate, the Colorado US Attorney's office to review whether the criminal determinations made earlier were correct. Given the seriousness of the findings of the [Office of Inspector General], I want to make sure that those who blatantly flaunted the law receive the appropriate sanction," the secretary said.

He also ordered Strickland to review personnel actions taken against individuals who were involved to determine whether sanctions were appropriate or if additional action is needed. Strickland also will lead reviews of reports by Devaney, the US Government Accountability Office, and a joint commission led by former US Sens. Robert Kerrey (D-Neb.) and Jake Garn (R-Utah) to determine if their recommendations are being implemented.

"We want to ensure that the actions taken to date are comprehensive. If they are not, we will take additional steps," Salazar said.

He also ordered publication of a new code of conduct for MMS employees. "This was designed specifically to address some of the problems identified by the inspector general. To the extent there was any confusion about applicable government ethics standards or guidance, the code of conduct clari-

fies the ethics standards to which all employees are bound. There will be no exceptions," he said.

In a separate letter to MMS employees, Acting Director Walter D. Cruickshank asked them to keep ethics at the forefront of everything they do as they work in a conscientious and professional manner. He encouraged them to report it if they see anything wrong, and to contact the DOI agency's ethics office if they have any questions.

Gifts are prohibited

The code specifically states that MMS employees are prohibited from soliciting or accepting gifts or other items of monetary value from any prohibited source or that are given because of the employee's official position.

"A prohibited source includes any person or entity that is seeking official action by MMS, does business or seeks to do business with MMS, conducts activities regulated by MMS, has interests that may be substantially affected by the performance or nonperformance of the employee, or is an organization the majority of whose members" fit these descriptions, it says.

The prohibition applies to any gift, regardless of its value or nature, the code emphasizes. It includes gratuities, favors, discounts, entertainment, hospitality, loan, forbearance or any other item having monetary value. It also includes services as well as gifts of training, transportation, local travel, lodging and meals, "whether provided in-kind, by purchase of a ticket, payment in advance, or reimbursement after expenses have been incurred." Receipt of a gift is not made acceptable by comparable reciprocation such as that which might occur at a social event, the code says.

"In addition, even if a regulatory exclusion or exception may apply, it is never inappropriate and frequently prudent for an employee to decline a gift offered by a prohibited source or because of his official position," it adds.

The code also states that MMS employees will act impartially and not give preferential treatment to any private organization or individual. "If an employee's actions become the subject of scrutiny, they will be viewed after-the-fact with the benefit of hindsight. Therefore, an employee should consider how others might view their actions. Employees must always strive to maintain transparency of operations," it says.

It says that MMS employees also will not use federal property for unauthorized purposes. "Limited personal use of certain office equipment is authorized as long as it occurs on nonduty time, does not interfere with official business, is not a commercial gain activity or otherwise prohibited (e.g., gambling or the viewing of sexually explicit material), is of negligible expense, and is in compliance with applicable policy," it says.

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Arctic offshore gets busier

Equipment for responding to arctic maritime accidents could prove inadequate as polar sea ice declines, energy demand grows, and vessel traffic increases, according to a report released Jan. 29 by the National Oceanic and Atmospheric Administration and the University of New Hampshire.

The Coastal Response Research Center (CRRC), a UNH and NOAA partnership on the university's Durham, NH, campus, produced the report after a panel from arctic nation governments, industries, and indigenous communities assessed potential threats from maritime accidents in the Arctic.

"The reduction of polar sea ice and the increasing worldwide demand for energy will likely result in a dramatic increase in the number of vessels that travel arctic waters. As vessel traffic increases, disaster scenarios are going to become more of a reality," said Nancy E. Kinner, UNH codirector of the CRRC and a professor of civil and environmental engineering.

Recommendations included studying the behavior of oil in cold water and improving technologies for spill response in arctic conditions. They were based on the panel's examination of five potential arctic emergency response scenarios. Two of these directly involved oil: an explosion on a fixed drilling rig north of Alaska, and a large spill resulting from a collision between a tanker and fishing vessel.

Coldwater environments

Since 2005, CRRC "has been investing in research on spill-response techniques and know-how in coldwater environments," the report noted. It said the center is a collaborating partner with the Joint Industry Project (JIP) on Oil in Ice coordinated by SINTEF, a leading Scandinavian research organization based in Trondheim, Norway.

"The JIP is validating chemical and physical behavior of oils and response techniques (mechanical, in situ burning, and dispersant use) and developing best practices for spill contingency plans for a variety of sea ice conditions. CRRC's contribution to the project examines the potential for exposure to biological resources associated with first-year sea ice," the report said. Its other recommendations were to strengthen multinational plans and agreements for all types of responses, improve logistical support capabilities for disaster response entities, update arctic weather data and navigational charts, and designate potential ports where damaged vessels could be taken.

Sea ice declines

Sea ice coverage in the Arctic reached record lows during the summers of 2006 and 2007, and recent modeling by the US National Snow and Ice Data Center suggests that the Arctic will be consistently ice-free during the summer as soon as 2030, the report said.

"The decline of arctic sea ice has resulted in increased activities such as oil and gas exploration, mineral speculation and exploration, northern moving fisheries, and tourism in subarctic and arctic waters. Some of these previously unnavigable waters are becoming more available to vessel traffic," it noted. ✦

Outside employment

Employees also are barred from holding or seeking outside jobs which conflict with their official duties and responsibilities. They must obtain prior written approval to engage in activities, whether for compensation or not, that is related to their official duties with MMS, or is related to DOI's mission, or is performed for a prohibited source.

"An MMS employee seeking outside employment is responsible for ensuring that no real or apparent conflict of interest exists and that a reasonable person with knowledge of the relevant facts would have no cause to question the integrity of the bureau's programs," the code of conduct says.

MMS employees also are expected to disclose waste, fraud, abuse, and corruption to appropriate employees, it continues. Notifications may be anonymous but should contain as much specific information as possible to allow the matter to be adequately investigated. MMS is committed to complying with the Whistleblower Protection Act, which safeguards the rights of anyone coming forward in this manner, it says.

Employees also will avoid creating the appearance that they are violating the law or ethical standards, the code indicates. "Often, even the appearance of impropriety is as significant and damaging to the reputation of the employee and to the MMS as an actual infraction. Employees must be mindful of their responsibility to ensure that their high level of ethical standards is clearly evident to the American people," it says.

Salazar told the MMS employees in Colorado that in a memorandum to all DOI personnel, the department would thoroughly review its own ethics policies and guidelines. He said that this review would build on US President Barack H. Obama's order to the Office of Government Ethics to develop rules and regulations consistent with the ethics pledge for all Executive Branch employees.

"I have met with and direct the designated agency ethics official to review

our departmental specific regulations and recommend areas where we can improve on our own ethical policies and guidance," the secretary said.

"Finally, the problems that occurred here in Lakewood were the product of a few individuals and a set of special interests who capitalized on an outdated and flawed royalty collection system. So in addition to reviewing the cases of these individuals, we will examine a fundamental restructuring of MMS's royalty program so that taxpayers can get their fair share from the development of natural resources, like oil and natural gas, on our public lands. Last year, this office alone collected $23 billion on behalf of the American taxpayer. All ideas for reform will be on the table," he said. ✦

Murkowski: Interim Point Thomson ruling good for Alaska gas line

Nick Snow
Washington Editor

Alaska Natural Resources Commissioner Thomas E. Irwin's interim conditional decision to let leaseholders drill on two expired tracts this winter is good news for the Alaska natural gas pipeline project, US Sen. Lisa Murkowski (R-Alas.) said on Jan. 28.

Point Thomson field holds about 25% of the Alaskan North Slope's 35 tcf of proved gas reserves and is significant to plans for a large-diameter pipeline to the Lower 48 states, Murkowski said. Disagreements between lessees and the state on how best to produce the estimated 9 tcf of gas there have complicated negotiations to build the pipeline, Murkowski explained.

"Now that we are seeing positive steps toward resolving these issues, it is my hope that we can quickly see progress on beginning actual construction of the gas line. ExxonMobil [Corp.] and its partners have held the rights to Point Thomson for decades. I hope their renewed commitment to those leases results in speedy development of the state's resources," she said.

The field covers 106,201 coastal acres west of the Arctic National Wildlife Refuge, according to Murkowski. ExxonMobil is operator and holds 53%, with BP PLC holding 30%, Chevron Corp. 14%, ConocoPhillips Co. 3%, and other partners 1%, she said. A state-commissioned study last year found that in addition to the gas, the field holds 490-600 million bbl of natural gas liquids and 580-950 million bbl of oil, she said.

"Alaska natural gas is key to meeting our national energy needs and reducing carbon emissions, but we cannot afford further delay. We need to get our gas to markets in the Lower 48 before the country becomes dependent on foreign gas, just as we are dependent on oil from overseas," said Murkowski, who is the Senate Energy and Natural Resources Committee's ranking minority member.

Basis of decision

In his Jan. 27 interim conditional decision, Irwin said the lessees testified earlier in the month—in an appeal of his Aug. 4, 2008, decision that 31 leases in the field had expired—that their plans to drill two of the leases could go forward if the Alaska Department of Natural Resources gave them an ice road permit before the end of January and authorized drilling activities on two of the leases.

"Appellants have testified that this project provided for the drilling and producing from wells by 2014. Appellants have specifically testified that they are unconditionally committed to the initiation and continuation of drilling during this 2008 and 2009 winter season," Irwin said. This includes "drilling a well out of the conductors with a rig capable of drilling through the Thomson Sands on that lease, and completing the drilling of two wells, both penetrating the Thomson Sands reservoir, by 2010," he said.

The lessees also testified that they have mobilized equipment and materials to the ANS and hired subcontractors to support the operation, modified a drilling rig to make it suitable for the high-pressure Thomson Sands reservoir, and applied for and pursued all necessary permits, Irwin said.

He said he would reinstate Leases ADL 47559 and ADL 47471 if the appellants abide by the unconditional commitments they made for the record, obtain Alaska Oil & Gas Conservation Commission and DNR approval for the precise location and bottom hole of each well and DNR approval of the wells' operating plans, and diligently pursue all necessary permits. The appellants also will need to supply him with drilling plans for the wells, including rig contracts, and other relevant documents within 2 weeks, he said.

"This conditional interim decision is intended to effect more expeditious production of state oil and gas resources. However, I would remind [the] appellants that, under the terms of these two leases, the failure to diligently pursue drilling operations for the purpose of production will result in the automatic termination of these leases," Irwin indicated. The ruling does not apply to the other 29 leases, he said. ✦

API: Windfall profits tax could harm US economic growth

Nick Snow
Washington Editor

New taxes on the oil and gas industry could cost hundreds of thousands of jobs, slow down economic growth, and make the US more dependent on foreign energy sources, according to a new study released on Feb. 3.

The study, which was conducted by CRA International as commissioned by the American Petroleum Institute, said S. 2971, as it was proposed during the 110th Congress, would have imposed a windfall profits tax that likely would have shifted investment from exploration and production and from refining.

"It's ironic that this is promoted as a tax on oil companies. Our study shows that consumers would carry a large proportion of the cost," CRA Vice-Pres. W. David Montgomery told reporters during a teleconference.

In a separate announcement, API said there currently is no proposal for an oil and gas windfall profits tax before Congress, but added that a similar levy or combination of taxes would harm the general US economy in similar ways.

"I can't speculate on what Capitol Hill is going to do. We would hope it doesn't pass new oil and gas taxes. We continue to see posts and calls for taxes on the industry, however, and this study was designed to show what the negative implications would be," API Chief Economist John C. Felmy said during the teleconference.

Montgomery said taxes on any kind of production generally discourage investments. "Anticipation that losses taken when prices are low can be made up when prices are high affects spending decisions. If you can't win when the market is better, the incentive to invest is substantially reduced," he said.

Oil, gas impacts

Specifically, the study said a windfall profits tax on the oil and gas industry could reduce US oil production by 1.5-1.9 million b/d, or 21-26%, during 2010-30. Crude imports would climb by 1.2-1.5 million b/d, or 13-18%, as a result, it indicated.

US gas production potentially would be reduced by 1.6-2.4 tcf/year, or 9-13%, and imports would increase by 500 bcf/year to 1.2 tcf/year, or 14-55%, during the 20-year period, the study continued.

It said an oil and gas windfall levy possibly could cut refining investments to a point that domestic oil product production might drop by 416,000-600,000 b/d, or 2-4%, and oil product imports could grow by 230,000-430,000 b/d, or 15-21%, from 2010 to 2030.

The general US economy would feel negative impacts in several ways, the study concluded. It projected that the legislation as it was proposed would cost 370,000-490,000 jobs nationwide by 2030, with disproportionate impacts in certain US regions.

Greater direct consumer outlays for energy would be magnified by higher transportation and production costs for nonenergy goods, the study noted. It projected that by 2020, US households' total consumption of goods and services could be reduced by roughly $11-26 billion with enactment of an oil and gas windfall profits tax. The reduction potentially would be $20-42 billion by 2030, it added.

The US gross domestic product would be reduced by $140-240 billion, or 0.5-0.9%, by 2030 as a result, the study said. "If you're going to impose taxes on supplies, it's going to reduce demand. There's no 'could' on that. I'm as confident about that as I am about the sun rising tomorrow morning," Montgomery said. ✦

NAPE: Geoscience gains hiking oil, gas recovery

Stiff gas-on-gas competition and a shakeout are approaching in the North American unconventional gas business, attendees were told Feb. 4 at an introductory session to the North American Prospect Expo in Houston.

The American Association of Petroleum Landmen, chief NAPE sponsor, was expecting a record number of attendees and exhibitors at the exploration and production event in spite of what one speaker described as the world's worst postwar financial climate.

The industry can drill only 1-2%/year of the 31 million acres leased for shales in North America the last few years, said Mike Bahorich, executive vice-president of exploration and production, Apache Corp.

"We're getting ready for a real slugfest," said Bahorich, who predicted that the winning combination will be the best execution on the best acreage.

The advent of high-volume shale gas wells in 2007 reversed a 10-year decline in the average peak production rate and average estimated ultimate recovery for US gas wells, said Pete Stark, vice-president, industry relations, of IHS Corp.

IHS is getting only the first rays of clarity in a worldwide inventory of shale source rocks, Stark said.

Carlos Macellari, Repsol Exploration worldwide director of geology, said companies will meet the challenge of finding new reserves as they have before, mainly by exploring where reserves already exist, as long as govern-

ments allow them access.

Linda Kinney, vice-president, business development, for IHS Herold, said upstream mergers and acquisitions fell dramatically as oil and gas prices plummeted in the second half of 2008, and companies are "reluctant to act until there's more clarity about the bottom of the cycle."

Technology gains

With low commodity prices, the industry will rely more on technology refinements and incremental improvements than new inventions, Bahorich predicted.

Technological advances in engineering, petrophysics, and geophysical imaging are vastly improving recovery efficiency, he noted.

Vertical shale wells with a single frac might have recovered 500 MMcf of gas in 2000, whereas horizontal wells with six fracs per well led to much higher initial production rates in 2007. Some wells get 15 frac stages, and 20 stages are probable in the next few years, Bahorich said.

It used to be that a horizontal well would recover three times the gas at twice the cost of a vertical well, but now the recovery can be as much as 10 times greater depending on the number of frac stages, Bahorich said. To avoid overoptimism, initial production should be normalized to the number of frac stages, he advised.

Typical now are 6-7 frac stages in the East Texas Bossier tight sand play, 5 stages in western Oklahoma's Cleveland sands, and as many as 15 stages in northeast British Columbia's emerging Muskwa shale gas play, for example.

Apache sees several overseas areas in which its acreage probably has huge amounts of gas in place, but the domestic gas prices governments mandate in those areas would not support economic development, Bahorich said.

Gas recovery factors in shales are under debate. Early estimates were 8-16%, but microseismic monitoring of frac stimulations indicate that recovery may be as much as 50% or higher from the stimulated rock volume itself.

On the oil side, Bahorich said, Apache realized a 25% increase in initial rate to 400 b/d at Cretaceous Bahariya oil wells in Egypt's western desert from a simple oil frac redesign that calls for larger proppant at higher concentration.

Apache used to complete the full Bahariya interval in every well because it couldn't distinguish pay from nonpay on logs. A petrophysical advance that involved analyzing core, logs, and production led to a model for reasonably predicting permeability from an integrated log suite and from that predicting permeability thickness, an excellent indicator of pay.

Apache got cheap, high-quality seismic data in the western desert in a high-density test with 10 independent Vibroseis trucks that made a world record 6,500 shots/8 hr.

Among numerous geophysical firsts at Apache the past 2 years, with the falling cost of computer disk storage capacity the company has built up a 500 terabyte data base of gathers, formerly discarded as too costly to keep. The company can restack the data internally in a few days to a day.

Discoveries, acquisitions

The relationships between operating companies, service companies, and governments can create great inefficiency in periods of severe oil and gas price gyration, Repsol's Macellari noted.

Governments want greater stakes whether prices rise or fall, and when they fall fast, service company agreements can trap operators into sustaining exploration after it becomes uneconomic to do so, he said. He called for greater cooperation and renegotiation.

Macellari noted that the outlook for adding new reserves looked flat in 1989 for the foreseeable future, but by 2005 the industry had added twice the volume of reserves from the 1989 existing fields as it had from exploration in 1989-2005.

In determining where to explore, organizations should examine each basin for inconsistencies in recovery. For instance, a geographic area of lower-than-average recovery in Argentina's Neuquen basin was found to be overlain by volcanics that blur seismic imaging, implying untapped potential if good data could be obtained.

Kinney said world upstream merger and acquisition activity accelerated dramatically in 2005 as commodity prices rose, and values stayed high for 3 years.

In 2006 the majority of asset transactions involved mostly gas for the first time in 5 years. Oil-weighted deals dominated in 2007, and in 2008 unconventional gas was the driver led by North American shale plays and Australian coal seam methane.

No US corporate transactions took place in the fourth quarter of 2008, she said. ✦

Brazilian president endorses Petrobras's investment

Eric Watkins
Oil Diplomacy Editor

Brazilian President Luiz Inacio Lula da Silva, endorsing statements by officials of state-run Petroleo Brasileiro SA (Petrobras), said his country will fully implement projects laid out in the firm's 2009-13 business plan.

Lula's remarks, coming amid journalists' questions over changes in Brazil's oil and gas law, reiterated earlier comments by Petrobras Pres. Jose Sergio Gabrielli de Azevedo.

"We will implement upwards of 500 projects, ensuring investments and generating jobs at the lowest possible cost," Gabrielli said, referring to the company's 2009-13 business plan announced last month (OGJ, Jan. 26, 2009, p. 27).

"The preparation of the plan took the prices that were in effect in the last quarter of 2008 into account, in a scenario that was quite different from

the one we currently have," Gabrielli said. "It is not feasible for any company to keep prices at the same levels as in 2008. The economy has changed."

He also said Petrobras would initiate oil production in May from giant Tupi field in the offshore Santos basin.

Lula's statement coincided with a Petrobras announcement that it would start long-term tests at Tupi field in April, a delay of a month in the tests, which originally were scheduled to begin as early as March.

The delay was created by Brazil's environmental institute Ibama which recently cleared Petrobras to proceed with the long-term Tupi field tests, which are to be conducted by the Cidade de Sao Vicente platform.

Despite the delay at Tupi, Petrobras said it expects to begin production of crude oil at Jabuti field in the offshore Campos basin by the end of the month or the beginning of March when it deploys the 100,000-b/d floating production, storage, and offloading vessel, Cidade de Niteroi, to the field.

Meanwhile, a government panel studying possible changes to Brazil's oil laws was scheduled to present its proposals to Lula on Feb. 4, according to the country's mines and energy minister.

Minister Edison Lobao recently told the Noticias Financieras newspaper that the Brazilian government has to decide among five different regulatory models for the exploration of oil and gas in the subsalt areas.

According to Lobao, the definitive model will be announced in March, about a month after the conclusion of the interministerial studies and proposal approval by the Brazilian president. ✦

Algeria eyes Peruvian natural gas development

Eric Watkins
Oil Diplomacy Editor

Algeria's state-owned Sonatrach, eyeing the pending development of Peru's natural gas reserves and transport system, said it will join state-owned oil company Petroperu in hydrocarbon exploration and production activities.

Algerian Energy Minister Chakib Khelil, on a state visit to the South American nation, said his country will discuss the type of alliance that can be formed with Petroperu, pending resolution of several issues, which he did not specify.

For its part, the Algerian government said: "An Algerian-Peruvian work team operating in the hydrocarbon field has been installed during the visit of Energy and Mining Minister Chakib Khelil to Peru, from Feb. 1-4."

It said the team will implement the minutes signed during the visit that call for the "strengthening of cooperation between the two countries in hydrocarbon exports and production, marketing, transport of gas, refining, petrochemicals, and the training of Peruvian executives in Algeria."

Peru asked for help

The Algerian government statement, along with Khelil's remarks, followed an earlier request by Peruvian Energy and Mines Minister Pedrao Sanchez for more assistance from the North African country, especially in the transport of offshore hydrocarbons.

Sanchez said Peru, through technology transfer, also wants to benefit from Sonatrach's experience in the development and operation of petrochemical and natural gas liquids plants.

Sonatrach already is a 21% shareholder of the Peruvian firm Transportadora de Gas del Peru (TGP), which transports gas and liquids from Camisea gas fields to Peru's Pacific coast, as well as a 10% share in the Consorcio Camisea which operates Camisea fields.

The announcement of cooperation with Algeria follows reports in December that TGP, which operates twin gas pipelines from Camisea fields, was in talks with the government to more than double the existing pipeline capacity in wake of burgeoning demand.

Loans agreed and sought

Two major upgrades—both due for completion in second-half 2009—are already under way: a $130 million increase of capacity at a compressor station in the Ayacucho region and the $150 million construction of a loop along Peru's coast.

The Andean Development Corp., Peru's Banco de Credito, and French bank Natixis in December granted TGP a $150 million loan for the expansion project, which will increase capacity to 450 MMcfd from 314 MMcfd.

But the additional capacity, originally forecast to be reached by 2015, is already considered insufficient, given demand growth. Consequently, the government and TGP are considering plans to increase capacity to 1 bcfd with a new pipeline.

While such a pipeline expansion would help in meeting demand growth, the project still must be studied and financed before it can proceed. TGP Gen. Mgr. Ricardo Ferreiro last month said financing for the project would be sought this year.

Meanwhile, Sonatrach has expressed further interest in Peru's gas industry.

In November, Sonatrach Pres. Mohamed Meziane told Peru's El Comercio newspaper that his firm was seeking out Peruvian projects in which it could serve as operator.

In particular, Sonatrach wants to explore for gas and to build local gas pipelines, according to Meziane, who also expressed hope that exploration of areas near Camisea would prove fruitful and permit gas exports, especially to Mexico and the US. ✦

Pirates seize another tanker off Yemen

Eric Watkins
Oil Diplomacy Editor

Pirates operating in the Gulf of Aden, shrugging off recent military and political developments aimed at curbing their activities, hijacked the MV Longchamp, a German tanker bound from Europe to the Far East with a cargo of LPG. The tanker was seized before dawn on Jan. 29 by seven pirates in a corridor patrolled by EU naval forces off southern Yemen, about 95 km from the port of al-Mukalla.

German firm Bernhard Schulte Shipmanagement, which manages the Bahamas-flagged vessel, reported that crew members—12 Filipinos and an Indonesian—were safe and that no ransom demands have yet been made.

This month there have been 15 attacks on vessels and three ships seized, said Noel Choong, who heads the International Maritime Bureau's piracy reporting center. More than a dozen warships from the US, UK, France, Germany, and Iran now patrol Somali waters, and China and South Korea have ordered warships to the region to protect their vessels and crews.

In addition, Japanese Defense Minister Yasukazu Hamada on Jan. 28 ordered the Japanese navy to prepare ships to join the international fight, as the island nation depends on shipping for oil and other imports. Hamada said his dispatch order was an interim measure until Parliament passes a formal law outlining the ships' activities in their mission.

The decline in successful attacks since foreign navies rushed to the busy sea lane had raised optimism that piracy was being curbed, but the outlaws are finding ways to evade the warships. They pay "partners" in other countries for inside information on ships' routes, timetables, guards, and other information, and thus know which vessels are unguarded and when and where to strike them. Success has made them bolder. ✦

A job for Global Hawk

The oil and gas industry is concerned about maritime affairs, especially piracy in the Gulf of Aden. Besides disrupting the supply chain, piracy sends insurance costs soaring.

So far, the pirates have been getting the better of warships sent by 23 countries, including the US, the UK, France, Russia, China, Japan, Malaysia, and Sweden, to patrol the region.

The explanation for the pirates' success is simple: The area they work in is far too large for the number of available warships. Even naval commanders tasked with the job of deterring the pirates say that.

"It's not an easy challenge, thousands of square miles of sea with the air-space above. We could have a force of hundreds and hundreds of ships and still have gaps in our patrol area," said the UK's Rear Adm. Phillip Jones.

A question of size

"Geography is not on our side," Jones said, a day after the European Union launched its own antipiracy naval force called the Eunavfor Atalanta mission. Still, Jones drew attention to one possible bit of technology that could turn the tide.

"The more contributing capabilities to that surveillance mission the better," he said. "I'm constantly looking to source other elements of surveillance for which UAVs [unmanned aerial vehicles] would be very welcome."

Welcome is the right word, and the international mission aimed at ending piracy in the region is in very sore need of UAVs. So far, according to reports, there are only a handful of surveillance aircraft and no UAVs at all.

This sounds like the right time and place for the entrance of Global Hawk, the UAV of all UAVs. In case you have not heard of it, Global Hawk is produced by the Los Angeles-based Northrop Grumman Corp. and, in effect, is an unmanned U-2 surveillance aircraft.

Enter Global Hawk

To cut to the chase, the high-flying Global Hawk is a drone capable of collecting intelligence from above 60,000 ft altitude for a day or more at a time. Thus far, it has turned in nothing but stellar performances, largely for the US Air Force.

But the US Navy, as well as other naval forces around the world, is highly interested in the maritime capabilities of the Global Hawk, and plans have been in place to deploy the aircraft over trade lanes and other sensitive maritime locations.

In fact, last fall the Navy was said to be considering deploying its first Global Hawk to an air base near Iraq to experiment with its ability to conduct maritime surveillance.

According to industry analysts, those UAVs will give the Navy a tool to use for monitoring shipping activity in the Persian Gulf, where several scrapes with Iranian ships have occurred in recent months.

But if the Navy's Global Hawks can look at the Persian Gulf, they also can—and should—make a regular sweep of the pirate-infested Gulf of Aden. ✦

Equation aids early estimation of gas field production potential

Rafael Sandrea
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Natural gas is the world's fastest growing fossil energy source, contributing 287 bcfd or roughly 50 million b/d of oil equivalent oil. Natural gas liquids and condensate contribute another 10.5 million b/d of liquids to the oil supply stream.

Global supply-demand of natural gas has grown a sizzling 30% in the last 10 years, and according to the latest IEA outlook is expected to further increase 50% to 425 bcfd by 2030. Over the last decade, new discoveries of natural gas have averaged 103 tcf/year; in contrast, production-depletion of existing reserves averaged 79 tcf/year.

Since 2000, 521 gas and gas-condensate fields have been discovered worldwide with reserves totaling 897 tcf.

The top 29 "fields," with reserves varying from 265 tcf—supergiant Osman-South Yolotan (Iolotan) field in southern Turkmenistan—to 3.5 tcf, account for three-quarters of the total discoveries. Thirteen of these giant fields are offshore (Table 1).

This select list also includes five US unconventional shale gas plays—Haynesville, Marcellus, Fayetteville, Woodford, and Deep Bossier--with combined reserves of 185 tcf. Although they were not technically discovered during the 2000s, field-scale development did begin during this period.

Globally, there is a vast potential of unconventionals–tight sands gas, coalbed methane, and shale gas–waiting to be tapped. Together these represent an estimated in-place volume of nearly 12 qcf (quadrillion cu ft) worldwide versus 18.4 qcf of conventional resources discovered so far.[1]

Unconventionals have always been considered second-rate targets because current production technologies permit only modest recoveries on the order of 1-10%. Conventionals on the other hand have recoveries of 75% and higher.

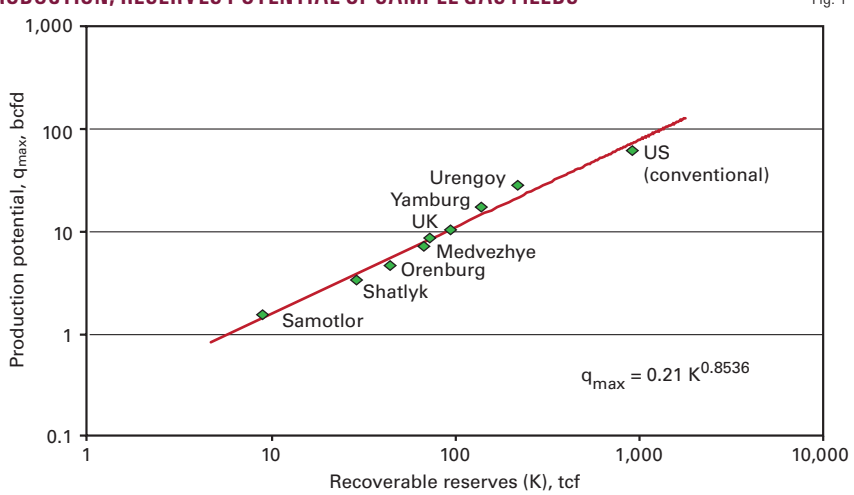
The US is the only country that has implemented large-scale production of unconventionals. These plays provided 24 bcfd or 47% of total US gas supply and 43% of ultimate recovery as of 2006.

Production of unconventionals in the US has grown 71% in the last decade. Worldwide, unconventionals presently account for barely 9% of the total natural gas output, but their contribution is expected to grow sharply in the future.

New discoveries always require a comprehensive production evaluation before a development plan for the field can be made. The evaluation period can

PRODUCTION, RESERVES POTENTIAL OF SAMPLE GAS FIELDS

Fig. 1



take 2 to 5 years or more from the time of discovery. Just 20% of the 521 new fields discovered during the 2000s are now on production.

Consequently, it is of paramount interest to have available an early estimate of the production capacity a new field discovery can put forward. This threshold is vital to supply analysts and for the design of production facilities.

The objective of this article is to develop an algorithm that would provide an early estimate of the production potential of new undeveloped gas fields. Due to the growing importance of unconventionals, the analysis looks into the feasibility of application of the algorithm-model to estimate their production capacity, also.

LARGEST GAS DISCOVERIES, 2000-08

Table 1

Field	Country	Discovery year	Reserves, tcf	Production potential, bcfd[2]
Osman-South Yolotan	Turkmenistan	2006	265	25
Haynesville shale	US	[1]2005	70	7.9
Marcellus shale	US	[1]2007	55	6.4
Fayetteville shale	US	[1]2004	35	4.4
•Kish	Iran	2006	30	3.8
Levoberezhnoye	Russia	2004	26	3.4
•Jansz	Australia	2000	20	2.7
Sulige	China	[1]2000	19	2.6
Longgang	China	2006	17.5	2.4
Woodford shale	US	[1]2004	15	2.1
•Abadi	Indonesia	2000	14	2.0
Puguang	China	2005	12	1.8
•Jupiter	Brazil	2008	11	1.6
•Kamennomyskoye	Russia	2000	10	1.5
Deep Bossier shale	US	[1]2003	10	1.5
Lavan	Iran	2003	8	1.2
•Clio	Australia	2006	6.5	1.0
•N. Alexandria	Egypt	2000	5.9	0.96
Incahuasi	Bolivia	2004	5	0.83
Chuandongbei	China	2004	5	0.83
•Pluto-Xena	Australia	2005	5	0.83
•Liwan	China	2006	5	0.83
•Shwe	Myanmar	2004	4.8	0.80
Homa	Iran	[1]2000	4.7	0.79
Dina-2	China	2001	4	0.69
•Wheatstone	Australia	2004	4	0.69
•Chandon	Australia	2006	4	0.69
•Calliance	Australia	2000	3.9	0.67
Dey	Iran	2000	3.5	0.6
Total			**679**	**81**

[1]Field on stream. [2]Estimated using Equation 2.
•Offshore field.

The model

Reserves are the foundation for determining the production capacity of any oil or gas field.

In a previous article,[2] it was established for oil fields that the correlation between production potential and ultimate recoverable reserves is one of a power relationship

$$q_{max} = a.K^b \quad (1)$$

where q_{max} is the production capacity, K the estimated ultimate recoverable reserves (EUR), a and b are constants. This basic model was applied to a suite of seven mature giant gas fields and two countries, the US and UK, for which we have reliable data on their field peak production and ultimate reserves (Table 2). Specifically, their ultimate reserves were determined by decline analysis of their historic production data.[1]

The fields were chosen to cover a wide spectrum of K-values ranging from 9 to 920 tcf. The resulting algorithm for gas fields is

$$q_{max} = 0.21\ K^{0.8536} \quad (2)$$

This has a correlation coefficient (r^2) of 0.980. The units for q and K are bcfd and tcf, respectively. The correlation is shown in Fig. 1. The K-value used to determine the production capacity of a new field would normally be a volumetric estimate of its reserves.

Additionally, we analyzed the validity of the algorithm for unconventionals, which are a special case. As a new unconventional field is being developed, determination of its in-place volumes and reserves is complex because classical volumetric formulas are not applicable.

For example, current estimates[3] of eventual recovery from the Barnett shale—the first of six major shale gas plays in the US to go on large-scale development—range from 35 to 50 tcf. Based on these estimates, Equation 2 establishes that the Barnett's production potential would be between 4.4 and 5.9 bcfd. Recent published production forecasts for the Barnett assume peak values of 4.5 or 6.5 bcfd. Recent actual Barnett production is 3.8 bcfd.

The production potential model was applied to the 29 giant gas fields discovered during the 2000s. Almost all of these fields are in the development planning stage. The exceptions are Sulige, Homa, and the five US shale gas plays under development. Table 1 summarizes the published estimates of reserves for the 29 giants and their corresponding production capacities as determined by the model. Overall, the combined production potential of the 29 fields is 81 bcfd.

SELECTED MATURE GAS FIELDS

Table 2

Field	Country	Field peak production (q_{max}), bcfd	Ultimate reserves (K), tcf
Urengoy	Russia	28	222
Yamburg	Russia	17	138
Groningen	Netherlands	8.6	73
Medvezhye	Russia	7.1	68
Orenburg	Russia	4.6	45
Shatlyk	Turkmenistan	3.3	29
Samotlor	Russia	1.5	9
All fields (conventional)	US	60	920
All fields	UK	10.4	95

Source: Sandrea, R., "Future Global Oil & Gas Supply—A Quantitative Analysis," Oil & Gas Journal Online Research Center, May 2008

Final comments

A production potential model was developed to pro-

vide an early estimate of the production capacity of newly discovered gas fields.

The model is intended to be applied as soon as a wildcat is confirmed to be a gas discovery. Establishing the real potential of a gas field may take several years after discovery, following a costly appraisal drilling program.

The predictive algorithm, Equation 2, is simple and only requires a geologic approximation of the recoverable reserves of the target field at the time of discovery. It covers a wide range of field sizes and is applicable to conventional and unconventional gas fields. ✦

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3. "Study analyzes nine US, Canada gas plays," OGJ, Nov. 10, 2008, p. 45.

The author

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Tanzania

Maurel & Prom, Paris, and Dominion Petroleum Ltd. spudded Mihambia-1, first commitment well on the onshore Mandawa PSA in Tanzania.

The vertical well is projected to 2,300-2,800 m or Middle to Lower Jurassic.

Vietnam

Exploratory drilling has demonstrated the existence of several hundred million barrels of oil in the Gulf of Tonkin off northernmost Vietnam, said ATI Petroleum, Oak Ridge, Tenn.

A group led by operator Petronas Carigali of Malaysia is reentering to flow test the Yen Tu-1X well, a 2004 discovery that found hydrocarbon bearing zones in two Miocene formations and the carbonate basement. It was the first oil discovery off northern Vietnam, the company said.

The group holds blocks 102 and 106 totaling 3.5 million acres off Hai Phong and has drilled the Yen Tu, Ha Long, Thai Binh, and Ham Rong wells since 2000, three of which are oil and gas field discoveries in the Song Hong basin.

The Ham Rong discovery is in 25-30 m of water on Block 106 about 75 km south of Hai Phong. Drilled to 3,700 m, it found oil in karstified carbonate basement and flowed at commercial but unspecified rates. TD is 3,700 m.

Thai Binh is a 2006 Miocene gas-condensate discovery on nearshore Block 102. It drillstem tested at 23 MMcfd in Middle Miocene at 1,200 m and 24 MMcfd in Lower Miocene at 1,600 m. TD is 2,900 m.

Other group members are PetroVietnam and Singapore Petroleum Co.

British Columbia

Imperial Oil Ltd., Calgary, began drilling the first of four planned exploration wells in the Horn River basin of northeast British Columbia in the quarter ended Dec. 31, 2008.

Imperial and ExxonMobil Canada each have 50% interest in the gas prospect. The companies hold 152,000 net acres in the area, including 16,000 acres acquired in the quarter.

Alaska

Bald Eagle Energy Inc., The Woodlands, Tex., completed the acquisition of six oil and gas leases on the Alaska North Slope.

The leases, totaling 18,418 acres with 100% working interest and 78.33% net revenue interest, expire Jan. 31, 2012. The seller was not disclosed.

The leases are east of the Arctic Fortitude Unit and south of the Prudhoe Bay Unit.

Kansas

Team Resources Inc., Los Angeles, purchased majority ownership in 300 miles of interstate natural gas pipelines in four counties in Kansas and Oklahoma. Seller was not disclosed.

The main line runs from Ponca City, Okla., to El Dorado, Kan. Team Resources, which has a field office in Yates Center, Kan., and plans to develop gas production in the area, will manage day-to-day operation of the system.

Pennsylvania

Chief Oil & Gas LLC, private Dallas operator, expects to drill 40-45 wells and keep four to five rigs busy this year in multiple Pennsylvania counties in the Devonian Marcellus shale gas play.

The company has leased more than 500,000 acres for natural gas drilling in the Marcellus, which it noted is present from New York's southern tier through much of Pennsylvania, Ohio's eastern half, and through Maryland and West Virginia. In Pennsylvania, the formation extends from the Appalachian plateau into the western Valley and Ridge Province, the company noted.

West Virginia

GeoMet Inc., Houston, set a $24 million budget for 2009, down from an estimated $57 million in 2008.

Outlays include $10.1 million for Pond Creek field in West Virginia and Virginia, $7.7 million for Gurnee field in the Cahaba basin and the Garden City Chattanooga shale prospect in Alabama, and $4.8 million to the Peace River area in British Columbia.

The company expects daily net sales to grow 10-12% in 2009 from an estimated 20.4 MMcfd in 2008.

Kosmos, Tullow drill deepwater Cretaceous sands off Ghana

Nina M. Rach
Drilling Editor

Smaller independent oil companies are successfully drilling deep prospects off western Ghana, finding light sweet crude and natural gas in Cretaceous sandstones that may extend from Benin westward to Sierra Leone.

Dallas-based independent Kosmos Energy LLC discovered two deepwater fields off Ghana. In 2007, it used the Bedford Dolphin, a fifth-generation drillship to drill the Mahogany-1 discovery well at Jubilee field. In early 2008, Kosmos drilled the Odum-1 discovery well 13-km away on a separate structure. Six wells have intersected oil-bearing sands (Table 1).

Jubilee field

Jubilee field straddles two offshore license blocks (Fig. 1):

- West Cape Three Points Block covers 1,761 sq km (435,200 acres) in water depths ranging 50-1,800 m. It is operated by Kosmos Energy (30.875%), with working interest partners Anadarko WTCP Co. (30.875%); Tullow Ghana Ltd., an affiliate of Tullow Oil PLC (22.896%); E.O. Group (3.5%); and Sabre Oil and Gas Ltd. (1.854%). Ghana National Petroleum Corp. (GNPC) has a 10% carried interest. The block carries a 7-year exploration agreement.
- Deepwater Tano Block covers 1,106 sq km in water 200-2,060 m deep. It is operated by Tullow (49.95%), with working interest partners Kosmos Energy (18%); Anadarko (18%), and Sabre Oil and Gas (4.05%). GNPC has a 10% carried interest.

Tullow is Jubilee field operator.

Rigs

The first three wells at Jubilee field and the Odum-1 discovery well were drilled with the Songa Saturn drillship in 2007-08.

So far, the partners have leased four deepwater drilling units to drill off Ghana: Blackford Dolphin, Eirik Raude, Atwood Hunter, and Aban Abraham. Anadarko said the semisubmersible Blackford Dolphin arrived in Ghana during the second week of October 2008. It drilled the Hyedua-2 appraisal well and was moving to drill a Mahogany development well.

The Eirik Raude semisubmersible arrived in Ghana in fourth-quarter 2008 and drilled the Mahogany-3 well on West Cape Three Points Block. It will drill the Tweneboa-1 exploration well

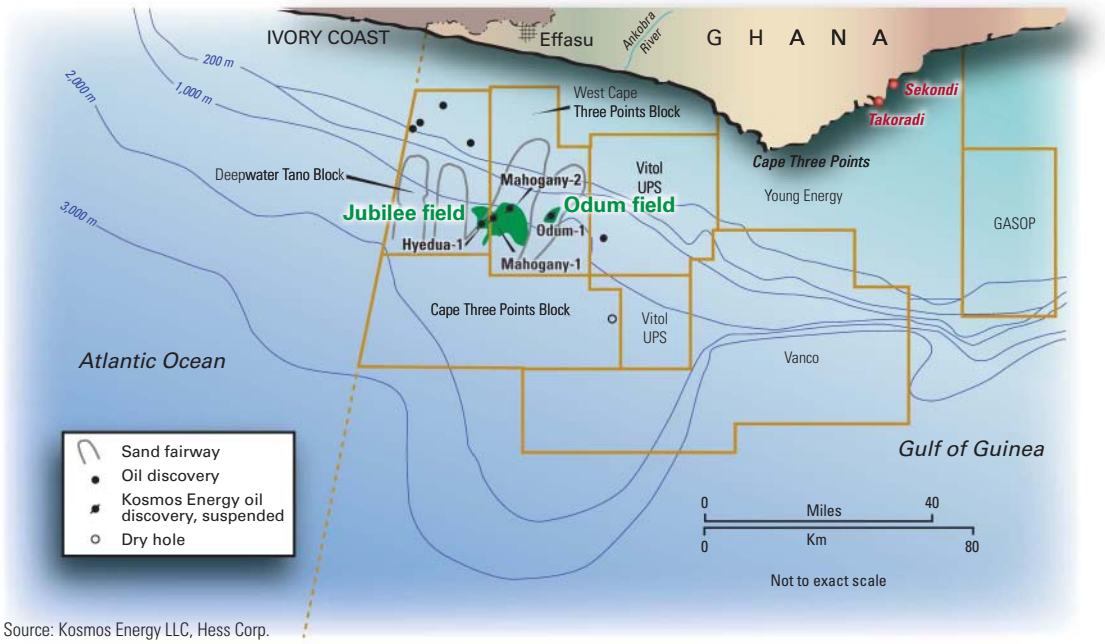
JUBILEE FIELD, GHANA

Table 1

Well	Block	Water depth, m	Spud date	TD, m	Gross (net) reservoir, m	Production tests
Mahogany-1	West Cape Three Points	4,330	2007	3,826	270 (95)	
Hyedua-1	Deepwater Tano	1,530	2007	4,002	202 (41)	
Mahogany-2	West Cape Three Points	1,080	2008	3,443	193 (50)	5,200 bo/d, 5.5 MMcfd
Hyedua-2	Deepwater Tano	1,246	2008	3,663	(55)	16,750 bo/d, 21 MMcfd
Mahogany-3	West Cape Three Points	1,236	2008	4,028, deepened to 4,345	(33)	
Development well	West Cape Three Points		Q1 2009	TBD		
Adjacent to Jubilee:						
Odum-1	West Cape Three Points	955	Feb. 2008	3,386	60 (22)	
Ankobra-1	Cape Three Points	1,732	Sept. 2008	3,963		
Tweneboa-1	Deepwater Tano		Q1 2009	TBD		
Teak-1			2009	TBD		

Based on operator reports.

Western Ghana deep water



Source: Kosmos Energy LLC, Hess Corp.

on Tano Deep Block during first-quarter 2009.

Anadarko said these two rigs will continue the exploration, appraisal, and development well drilling program in the two adjacent license blocks.[1]

On June 24, 2008, Kosmos contracted with Atwood Oceanics Pacific Ltd., a wholly owned subsidiary of Atwood Oceanics Inc., to use the Atwood Hunter moored semisub for 27 months beginning April 2009. Kosmos said its share of the drilling contract commitment is more than $400 million and that Kosmos and Noble Energy have an option to extend the drilling contract for 1 year.

The Aban Abraham and Atwood Hunter are expected in Ghana soon and will focus on exploratory and appraisal work. In January, Atwood Oceanics' Atwood Hunter, a third-generation semisub rated to drill to 28,000 ft, was drilling in 5,500-ft water off Israel for Noble Energy. Aban Offshore's Aban Abraham drillship, now rated to drill in water to 6,900 ft to a depth of 19,350 ft, left the Sembawang shipyard in Singapore on Dec. 17 after extensive modifications to extend its drilling depth capacity and was upgraded to fourth-generation capability from second generation.[2]

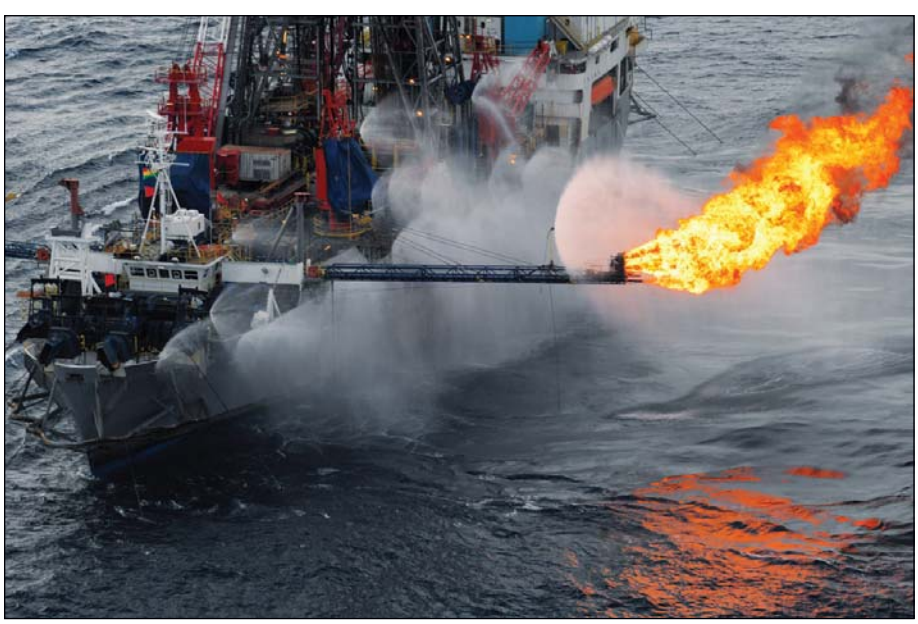
2007 wells

Kosmos drilled the Mahogany-1 well in 1,320 m (4,330 ft) of water, 63 km (39 miles) from the Ghanaian coastline and 132 km southwest of the port city of Takoradi.

The well reached 3,826 m TD and on June 18, 2007, the company announced, discovering a 270 m gross hydrocarbon column with 95 m of net stacked pay in a Cretaceous sandstone reservoir.

Kosmos and partners drilled the first appraisal well, Hyedua-1, on the adjacent deepwater Tano Block, about 5.3 km southwest of the Mahogany-1 discovery well.

Hyedua-1 was drilled in water 1,530-m deep and reached a TD of 4,002 m. It encountered a gross reservoir interval of 202 m, including 108 m of stacked reservoir sandstones and 41-m of net hydrocarbon-bearing pay.



Kosmos Energy used the Songa Saturn drillship to drill the Mahogany-2 delineation well, shown here during a drillstem test in 2008 (Fig. 2; photo by Anna Clopet, provided by Kosmos Energy LLC).

The discovery was announced August 2007.

2008 wells

Kosmos drilled the Odum-1 exploration well 13 km east of Mahogany-1 well and Jubilee field, West Cape Three Points Block. Kosmos and partners used the Songa Saturn drillship to drill in 955 m water to a TD of 3,386 m.

The Odum-1 intersected 60-m gross (22-m net) of 29° gravity oil pay.

The second appraisal well, Mahogany-2, was drilled on the West Cape Three Points license, in 1,080 m water with the Songa Saturn drillship. It is 6.1 km northeast of the Mahogany-1 well and 11.3 km northeast of the Hydeua-1 well.

The Mahogany-2 well encountered a 193-m-thick gross hydrocarbon-bearing interval with 50-m net hydrocarbon-bearing pay of high-quality, stacked reservoir sandstones. It reached 3,443 m TD and will be used as a potential development well (OGJ, May 26, 2008, p. 22).

Kosmos announced in June that the well flowed 5,200 bo/d of 36° gravity crude and 5.5 MMcfd of natural gas on a 40/64-in. choke with a flowing tubing pressure of 1,543 psi (Fig. 2). The test was from a single 17-m zone representing less than one-third of the oil-bearing pay intersected by the well. At that time, Kosmos estimated that a Jubilee production well should be capable of flowing more than 20,000 bo/d when completed with 5.5-in. tubing.

Following the first three wells, Tullow estimated Jubilee's ultimate upside potential at 1.8 billion bbl.

In late 2008, partner Anadarko estimated the recoverable resources at 500 million to 1.8 billion boe.[1]

2009 announcements

Recent discoveries suggest that the Tano basin may hold more oil than expected.

Kosmos announced results Jan. 8 from the Mahogany-3 well, drilled by the Eirik Raude semisub more than 5 km southeast of Mahogany-1 and 5 km south of Mahogany-2, in water 1,236 m deep (Fig. 3).

The Mahogany-3 well penetrated 33 m (net) oil-bearing sands and reached TD of 4,028 m. Part of the net oil pay (16 m) were reservoir sands equivalent to those in other wells.

Mahogany-3 well discovered the Mahogany Deep reservoir, with 17 m of oil pay. This interval is stratigraphically deeper and separately trapped, according to Kosmos. Reservoir fluid samples indicated 35° gravity oil.

On Jan. 12, 2009, Tullow and partners announced results from the Hyedua-2 appraisal well in the deepwater Tano license. The Bedford Dolphin spud the well in late 2008 in water 1,246-m deep to a TD of 3,663 m. The well encountered 55-m of oil-bearing pay.

Production tests were run on a 41-m zone within the pay interval. Kosmos said the Hyedua-2 well produced 16,750 b/d of 37° gravity oil and 21 MMcfd during a drillstem test conducted on an 88/64-in. choke with a flowing tubing pressure of 1,387 psi.

Goodbody analyst Gerry Hennigan said Tullow and partners should be able to extract "more than the 300-350 mbo originally proposed" during Phase 1 of Jubilee, which is to be developed with 17 wells.[3]

The Bedford Dolphin moved off site in January to drill a Mahogany development well, after which it will drillstem test Mahogany-1, according to Kosmos.

The partners will also spud a well on the Tweneboa prospect this quarter, in Deep Tano Block, with the Eirik Raude semisubmersible, and an exploration well on Teak prospect later in the year.

Oil production

Tullow said on Jan. 8 that it's targeting about 4 billion bbl of oil and gas resources in the Gulf of Guinea off Ghana and Ivory Coast. It plans to invest €2.3 billion to develop the Jubilee field and has other interests in shallow water.

Kosmos is targeting first production from Jubilee in 2010 using an FPSO with a processing capacity of 60,000 b/d of oil and 80 MMscfd of gas (OGJ, May 26, 2008, p. 22).

Anadarko planned to sanction the Jubilee field and said in late 2008 that,

The Eirik Raude semisubmersible was drilling the Mahogany-3 well last month in West Cape Three Points Block off Ghana (Fig. 3; photo by Marc L. Bik).

"a suitable FPSO has been selected and a letter of intent has been signed on the vessel."

Adjacent drilling

Hess recently finished drilling the Ankobra-1 well in 1,732 m water to 3,963 m TD. It did not encounter commercially significant hydrocarbons. Hess is currently acquiring 1,619 sq km of new 3D seismic data and will drill a well in the unexplored western half of the license area (OGJ Online, Dec. 17, 2008).

Gas market

At the time of the Jubilee discovery in 2007, Ghana was working out technical and economic details related to new Nigerian natural gas expected to reach Tema and Takoradi, Ghana's two international seaports via the West Africa Gas Pipeline (OGJ, Aug. 27, 2007, p. 68). Ghana was to take 75% of the line's 134 MMcfd start-up volume, expected to begin at the end of 2007.

West African Gas Pipeline Co. completed construction of the 1,033 km-WAGP pipeline in April 2008, but water content of the gas remained above specifications. In December 2008, the pipeline was repressured and start-up appeared imminent, with initial capacity of 200 MMcfd and capability to expand to 600 MMcfd. ✦

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OIL SHALE—Conclusion

Technology may control adverse environmental effects

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Technology may help control the potential adverse environmental effects of oil shale development in accordance with current and future US environmental policy.

It is critical that oil shale production not devastate the ecology of the region, atmosphere, or surrounding groundwater. This, however, may come at a high dollar value.

The environment and climate change have become topics on the global stage. Amid this movement, future demand for liquid fuels may out strip conventional world oil supply. Recent tight world oil supplies and record high prices have led industry and the federal government to look to US unconventional resources including oil shale as a means to augment domestic oil supply.

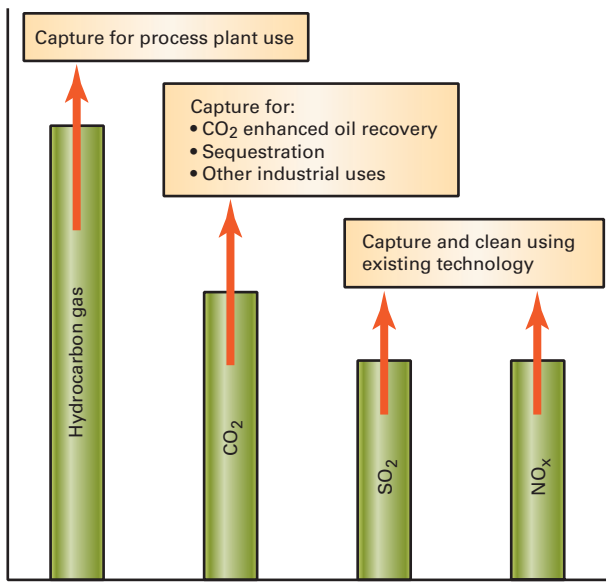
While there are many benefits associated with an increase in domestic production of oil, it is important to consider the potential adverse impacts that shale oil production activities may have on the environment including air quality, water use and quality, land disturbance, and wildlife.

Although the US has had no commercial development to date, analyses on technologies provide an approximation of the scale and scope of potential future development and associated impacts.

This concluding article of four, discusses environmental effects of shale oil development. Parts 1-3 covered the resource base (OGJ, Jan. 19, 2009, p. 56), production technologies (OGJ, Jan. 26, 2009, p. 44), and economics (OGJ, Feb. 2, 2009, p. 48).

OIL SHALE GASES POTENTIAL USE

Fig. 1



Air quality

The extraction of oil from shale requires heat. When the carbonate rock reaches temperatures necessary to pyrolize the kerogen, it will release the shale oil and a slate of gases. The associated effects on air quality depend on the process temperatures and control technologies employed.

Depending on the process used, the released gases from retorting oil shale include oxides of sulfur and nitrogen, particulate matter, water vapor, carbon dioxide, and hydrocarbons. The potential also exists for the release of other hazardous trace materials into the atmosphere.

Fig. 1 displays the gases along with potential uses for captured gases.

Air pollutants

Federal regulations cover many emitted gases under the Clean Air Act of 1963 (which was amended, most substantially in 1990). As currently written, the act sets limits for emissions on particulate matter, ground-level ozone, carbon monoxide, sulfur oxides, nitrogen oxides, and lead.[1]

The oil shale industry will have access to commercial stack-gas cleanup technologies for controlling emissions to within permitted quantities. Some beneficial uses for these captured hydrocarbon gases with these technologies include use in plant operations or sales for conventional energy use.

The industry can control nitrous oxides and sulfur oxides with commercially proven technologies developed for petroleum refining and coal-fired power generation.

CO_2 emissions

According to the Department of Interior Bureau of Land Management (BLM) Programmatic Environmental Impact Statement (PEIS) of December 2007, an oil shale project that processes 1.5 million tons/year of oil shale with a surface retorting plant would emit 802,061 tons of carbon dioxide.[2]

The retorting process produces the majority of these emissions. Other processes emitting carbon are the start-up

burner, electrical sources, hydrogen plant reformer, flue gas flaring, diesel combustion, and mine opening methane.

Much pressure is on the US Congress to enact legislation for limiting CO_2 emissions. In light of the long lead times on oil shale development, producers likely will have to contend with CO_2 regulations and possibly other greenhouse gases.

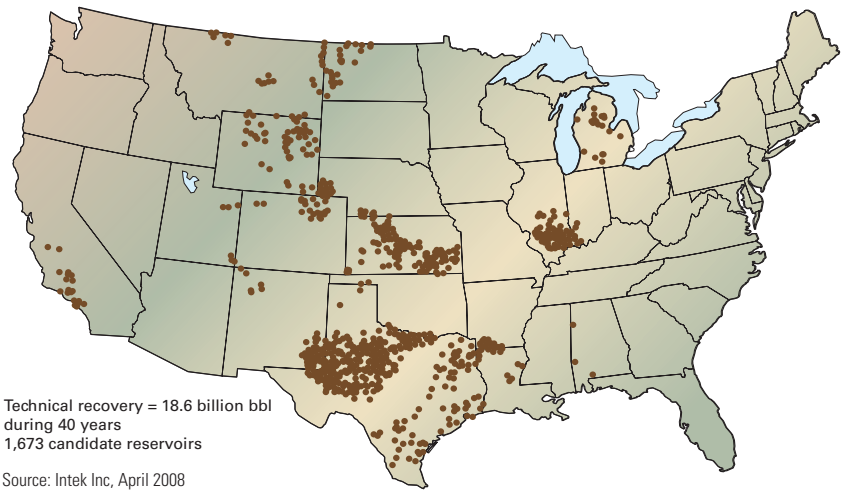
Several promising technologies, such as amine absorbers, may be able to capture a large portion of CO_2 from the gas stream. If producers can capture CO_2 successfully, they have several options for sequestering the CO_2.

With much conventional oil production in close proximity to the oil shale regions of Utah, Colorado, and Wyoming, one potential beneficial use for the CO_2 is improved oil recovery. Fig. 2 shows the location of reservoirs that are candidates for CO_2 miscible flooding in the US.[3]

Opportunities also may exist to sequester CO_2 from oil shale operations in depleted oil and gas reservoirs, and in the coal deposits in the region. Sequestering in coal beds could enhance coalbed methane production.

US CANDIDATE RESERVOIRS FOR CO_2 SEQUESTRATION

Fig. 2



WATER CONSUMPTION REQUIREMENTS

Table 1

Oil shale production, 1,000 b/d	500	1,000	2,500
Oil shale industry water demand, million gpd	21-63	42-126	105-315
Projected population growth, No. of people	96,000	177,000	433,000
Additional water to support population, million gpd	13	24	58
Total new water demand, million gpd	34-74	86-150	163-373
Total new water demand, million acre-ft/year	0.04-0.09	0.10-0.17	0.18-0.42

Source: Reference 5

Water use, quality

The oil shale industry requires large amounts of water and the processing of the shale may greatly affect the quality of surface and groundwater. Water use in the Colorado, Utah, and Wyoming area will affect not only this three-state region, but also states that are downstream as well.

Development of oil shale resources will require large quantities of water for mine and plant operations, reclamation, supporting infrastructure, and associated economic growth. Current estimates based on oil shale industry water budgets suggest that water requirements for new retorting methods will be 1-3 bbl of water/bbl of oil.[4] Some processes may eventually be net water producers.

An oil shale industry producing 2.5 million b/d will have a cumulative demand on water of between 105 and 315 million gpd. Municipal and other water requirements related to population growth associated with industry development will require an additional 58 million gpd. This amounts to 0.18 million to 0.42 million acre-ft/year of water (Table 1).[5]

In the West, water will be drawn from local and regional sources with the majority likely coming from the Colorado River basin, including the Colorado, Green, and White Rivers[5] that have an annual flow of 12 million acre-ft/year.[1]

Western oil shale has high water content; some oil shale contains 30-40 gal/ton of shale. More typically, it holds 2-5 gal/ton of water. Much of this water can be recovered during processing and used to support operations.

Produced water will contain organic and inorganic substances that conventional filtering technologies can remove. Recycling and re-use of process water will help to reduce water requirements.

The operations will require protection of surface and groundwater contamination from mining and retorting operation runoff, treatment facility products, other wastewaters, and particularly the retorted shale waste piles that contain heavy metals in the leachate.

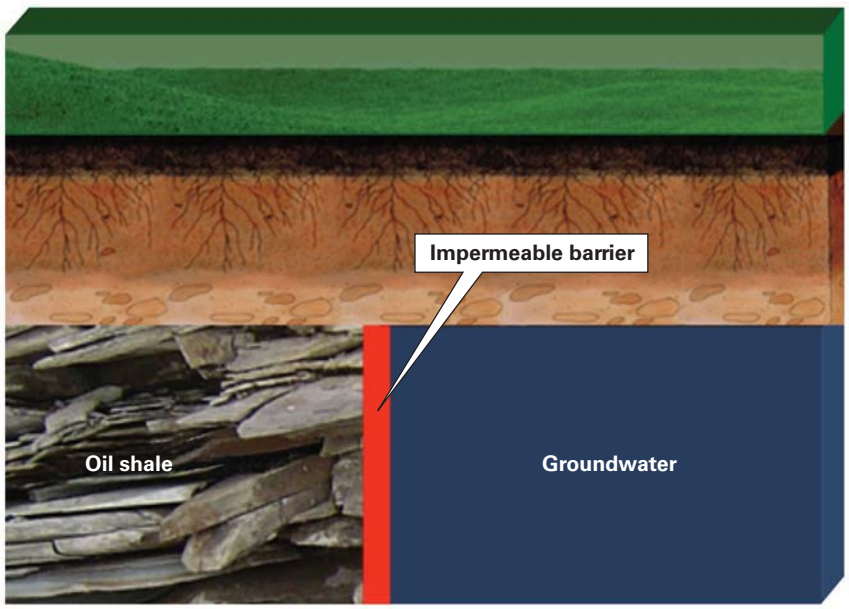
In addition, in situ heating and combustion of oil shale will require controls to prevent contamination. The varying processes for developing oil shale likely will lead to technology specific methods for ground and surface-water quality protection.

Groundwater protection is of critical importance and is of greater consideration for in situ processes. Currently emerging technologies create a barrier between the heated oil shale zone and any potential sources of groundwater (Fig. 3).

In conjunction with its in situ conversion process (ICP) currently being tested in Colorado, Shell Oil Co. has under test an environmental barrier system called a freeze wall. It creates the freeze wall by freezing groundwater occurring in natural fractures in the rock into a ring wall surrounding the area to be pyrolized.

PROTECTING GROUNDWATER FROM IN SITU PROCESSES

Fig. 3



Source: Intek Inc, September 2008

The barrier protects groundwater from contamination with products liberated from the kerogen while at the same time keeping water out of the heated area. Once pyrolysis is completed, the area is sufficiently cleaned and the freeze wall is melted to allow groundwater to flow through this area once more.

Land disturbance

The estimated maximum cumulative land needed for a 1 million b/d oil shale industry is 80,000 acres during 40 years.[6] Of this total, the industry needs about 50,000 acres for mine development, storage of overburden, storage of raw and processed shale, surface facilities, off-site land for access roads, power and transmission facilities, water lines, and natural gas and oil pipelines.

It will require up to 20,000 acres for urban development, and need the remaining 10,000 acres for utility rights-of-way.

The entire Green River formation covers about 11 million acres, so that the surface area impacted by development is about 1% of the total land area of the oil shale region (Fig. 4).

Spent shale disposal

Surface retorting operations produce leftover spent shale, composed of carbonate materials and other minerals, after extracting the shale oil. Depending on the location, ore characteristics, and the process, some spent shale can be contaminated with heavy metals or toxic organic compounds that may require special handling, treatments, or disposal methods.

In addition, the spent shale will have a 13-16% greater volume than its in-place volume.[6] Void spaces in the spent shale that are not present in the compacted shale before it is mined cause this volume increase.

Because of the increased volume, operators cannot return all spent shale to the oil shale mine, but will need surface disposal or alternative uses.

Some beneficial uses of spent shale can include roadbed material, and aggregate for concrete production and building materials.

In situ recovery residuals

True in situ processes do not have the problem of spent shale disposal; however, other subsurface effects, including potential groundwater contamination, are possible and must be controlled.

While the surface requirements are relatively small, oil shale processing will affect the local and regional environment. The actual affect on the land will vary from process to process.

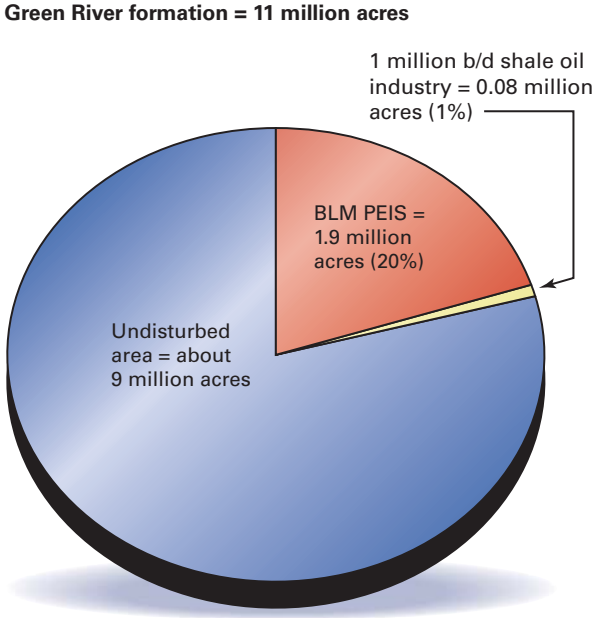
Mining and surface retorting processes create more land disturbance, but existing reclamation regulations require oil shale developers to restore the land once they have finished developing.

Wildlife

Oil shale development also affects wildlife. Before commercial oil shale development, site evaluations for individual projects will have to include

LAND DISTURBANCE MAGNITUDE

Fig. 4



project-specific environmental impact studies. Evaluating the specific flora and fauna for each project will help determine appropriate action needed for mitigating the effects on plants and animals.

Development will require wildlife management plans with federal and state wildlife authorities for monitoring and tracking wildlife dislocation and maintaining habitat quality.

Of utmost importance in developing oil shale is considering the endangered species in the region and in habitats in close proximity to oil shale production sites. Fig. 5 shows some species listed as endangered and therefore protected by the Endangered Species Act.

In addition, several species are threatened that may potentially be upgraded to an endangered status (Table 2).

The Endangered Species Act protects several species that live in areas with oil shale development potential (Fig. 5).

SUMMARY OF ENDANGERED AND THREATENED SPECIES IN THE OIL SHALE REGION

Table 2

Type	Protected Species	Concerns
Aquatic	4—Endangered	Surface water quality
Terrestrial	1—Endangered	Water supply
	2—Threatened	Land disturbance/fragmentation
Avian	2—Endangered	Land disturbance Protection of critical habitat
Plant	6—Endangered	Land disturbance
	10—Threatened	Some are unique to region
	41—Sensitive	

Four of 12 native fish species are listed and protected under the Endangered Species Act. Designated critical habitat for these species is within the Upper Colorado River basin. An additional 25 nonnative fish species also are in the basin.[1] Oil shale activities could contaminate the water system and use water needed by these fish.

Both large and small mammals range across the oil shale region. Large game includes elk, mule deer, pronghorn, bighorn sheep, moose, American black bear, and mountain lion. Smaller mammals such as jackrabbit, American badger, bobcat, coyote, red fox, bats, and rodents also live in the region.

The PEIS cited water supply as a major restrictive factor for large game. The oil shale industry's consumption of water in the region may affect greatly these species.[1]

Fragmentation of habitat is another important consideration. Fragmented habitats from oil shale projects may limit the species' ability to maintain a minimum viable population.

Various strategies exist for minimizing the effect of development on wildlife including wildlife corridors.

The region contains one endangered mammal and two that are threatened. The industry will have to give special consideration to these species in the wildlife management plans.

Many migratory and permanent birds reside in the region. The habitat, water supply, and overall ecosystem are important for supporting the avian populations.

The California condor and the Mexican spotted owl are both listed as endangered species and protected by federal law.[1]

The oil shale region has 6 endangered and 10 threatened plant species. The BLM further classifies 41 species of plants as sensitive.[1]

Mining and other land disturbing activities could decimate many of these plants. Some are unique to the region; for example, the Barneby Ridge-Cress is thought to be found solely on the Uintah and Ouray reservations of the Ute Indians.[1] The Endangered Species Act protects the range of these listed species. ✦

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The authors

James Killen's biography and photo appeared in Part 1 of this series (OGJ, Jan. 19, 2009, p. 56), and Emily Knaus's biography and photo appeared in Part 2 of this series (OGJ, Jan. 26, 2009, p. 44).

Gasoline-distillate price gap calls for refining investments

Robust worldwide demand growth for middle distillates has resulted in a disproportionate price increase compared to gasoline. The current global refining configuration is misaligned with these recent trends in product demand, a situation that calls for significant investment.

These are the conclusions of a December 2008 report from Energy Policy Research Foundation Inc. (EPRINC) entitled "The US Refining Industry: Background and Perspective for Policy Makers."

Diesel fuel, which historically sells at a discount to gasoline, now sells at a premium, the report reminds us. And because gasoline margins are now resulting in negative crack spreads, middle distillates are the only significant source of positive margins.

The recent increases in middle distillate prices are largely due to short-run constraints in the global refining industry to adjust its product output to meet adequately rising demand.

Existing US refineries are, "for the most part, technically constrained to relatively small yield shifts, although at some facilities the shift to higher distillate yields has been impressive," the report said. "New investment in basic capacity expansion might help rebalance the slate of products produced, but most investment has gone to capital equipment for making the existing product slate cleaner and for using lower-quality crudes. As investment takes place in new refineries and/or configuration adjustments are made at existing refineries, we would expect the large price differential between gasoline and distillate to narrow."

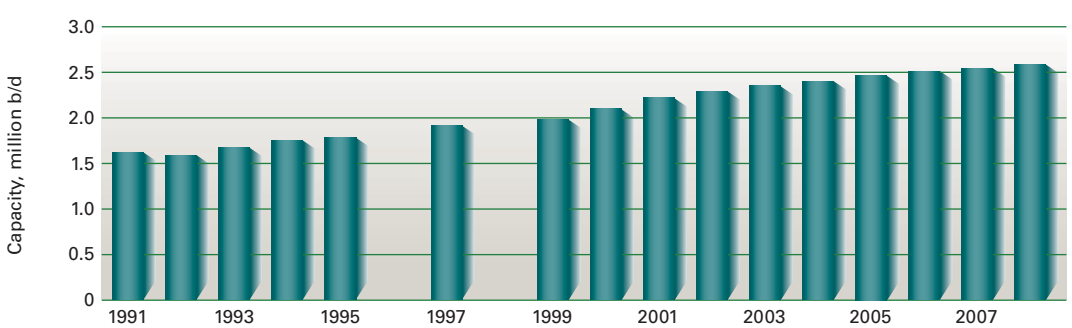
US refining returns on investment are highly volatile but have historically lagged all US manufacturing, the report said. EPRINC examined a sample of refiner stock prices and preliminary data of recent refinery margins and concluded that higher margins and ROIs prevalent for some refiners during 2005-07 are likely over.

Historically, US refinery capacity has increased despite a decline in the number of refineries since petroleum price controls were removed in the late 1970s. Investments have resulted in more robust and efficient operations in fewer but larger plants; refinery complexity has increased substantially.

"As US refining became more complex and capacity more streamlined, the global oil market changed as well," the report said. "Consumers' demand for fuels began to outstrip both the supply of produced crude and global refining capacity, creating a tight supply-demand balance where supply was unable to respond to increased demand or accommodate a supply outage without a price spike."

US COKING

Fig. 1



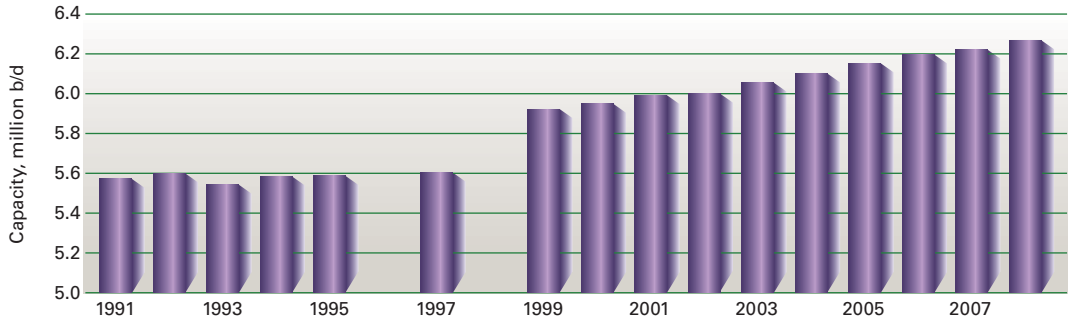
Source: EIA data

Ending a period of price stability, crude and product prices—especially diesel and heating fuels—saw prices rise sharply during 2005 to early 2008. A crude and product price reversal of "epic" proportions is currently under way and will likely lead to low rates of return in US refining in 2009, the report said.

The US refining industry is heavily exposed to foreign competition. The most important factor for policy makers, therefore, is to recognize that the industry is well integrated into the world product market and its competitive position is directly tied to its ability to raise capital and operate on as level a playing field as possible, EPRINC said. The alternative is growing reliance on foreign sources for petroleum products.

US FCC

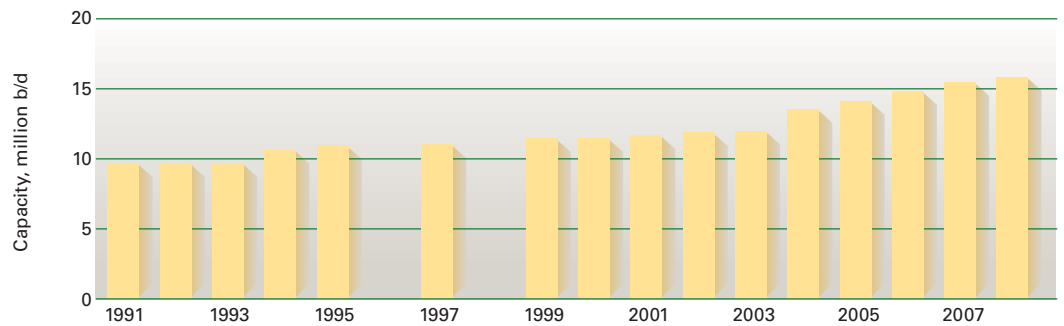
Fig. 2



Source: EIA data

US HYDROTREATING

Fig. 3



Source: EIA data

Refining realignment

The report summarized historical trends in the US refining industry, including the trend towards larger refineries, consolidations, and a shift in the refinery geographies.

The trend toward larger plants began during World War II due to economies of scale. In 1960, the average refinery was about 32,000 b/d; by 1981, that figure nearly doubled to 57,000 b/d; and doubled again by 2007, when the average plant was about 117,000 b/d, the report said.

In the 1970s, US refiners began increasing refinery complexity and consolidating refinery sites in order to control air emissions, produce 100% unleaded gasoline, handle more foreign crude due to reduced domestic output, receive more waterborne crude, and use more natural gas as a refinery input.

According to the report, refining capacity growth in the US has gravitated toward such coastal locations as the Texas-Louisiana coast, West Coast, and the Mid-Atlantic. Waterborne imports now fulfill most US petroleum needs. Refinery expansions have therefore centered on existing units with waterborne transport accessibility and good crude and product pipeline connections.

Exceptions to this general rule, the report said, are landlocked midwestern refineries that receive Canadian crude via pipeline and from Gulf Coast supply points. Some refineries in the Midwest have been consistently upgraded, therefore, and are now receiving feed from Alberta oil sands.

US refinery upgrades

According to the report, investments in US refineries have not led to a barrel-for-barrel increase in refinery throughput. It, however, allows refiners to make products to greater specifications and make them from crudes of decreasing quality.

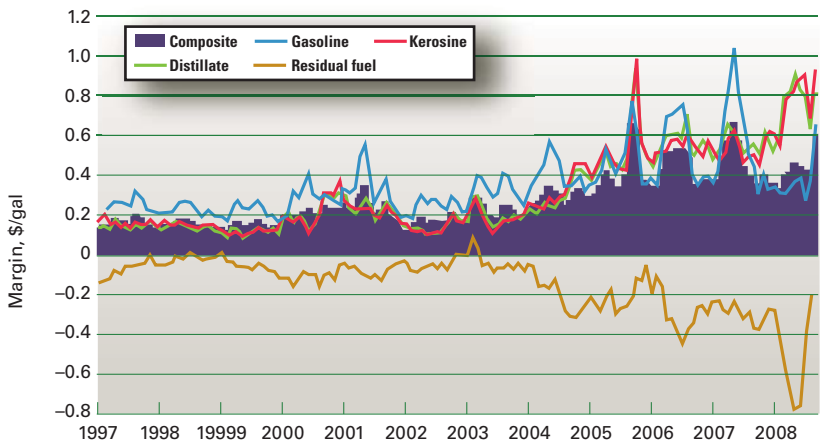
Some of the added capacity—notably hydrotreating for sulfur reduction—represents "staying in business" investment, replacing "old" products with low or ultralow-sulfur versions, the report said. These investments include coking, FCC, and hydrotreating capacity.

Fig. 1 shows that US refiners have increased coking capacity 1 million b/d since 1991, a 63% increase.

"To some extent, more coking capability has increased product output; more importantly, it has helped maximize the yield of gasoline and distillates from heavier crudes," the report said.

US REFINER MARGINS

Fig. 4



Source: EIA data, EPRINC calculations

"Additionally, greater coking capability has provided a path toward decreasing output of low-demand heavy fuel."

Fig. 2 shows that FCC capacity increased 13% since 1991; to 6.3 million b/d from 5.6 million b/d, "reflecting the continued trend toward more intensive processing to increase light product yields from heavier feedstock."

Fig. 3 shows that hydrotreating capacity has risen to 15.8 million b/d from 9.7 million b/d since 1991.

"Not only does this constitute a 63% increase in capability," but refiners' investments ensure that 9 bbl out of 10 "run in US refineries can be hydrotreated," the report said. "Intensive investment here helps to explain how the transition to low and ultra-low sulfur fuels was accomplished with such success."

Product margins

US gasoline margins improved steadily during 2004-07 but are currently falling, according to the report. In September 2008, refined product prices remained high due to Hurricanes Ike and Gustav, which caused the closure of more than 21% of US refining capacity. By late October, retail gasoline prices dropped more than 30% from their September peaks and have subsequently fallen dramatically.

Distillate margins were higher in 2008, reflecting worldwide growth, the report said. Currently, distillate—which has had the strongest market—is under price pressure and margins could fall.

Kerosine had stable prices until 2004, when prices and margins rose quickly. World economic growth since 2004 contributed to higher demand, and refiners have struggled to keep pace, the report said. The result is high prices and margins, at least until 2008, when economic conditions began to weaken margins.

Residual fuel (resid) margins have historically been negative and refiners have sold it at a loss simply to increase their cash flow. More advanced processing at high-conversion refineries minimizes resid production; all refineries do not have this amount of conversion, according to the report.

Fig. 4 shows margins for all four products individually, and a composite weighted average margin, calculated by EPRINC. It shows level positive margins in a narrow range for the three main products until 2004. Resid has the same general pattern, except in a slightly negative range, because it sells for less than crude cost.

After 2004, margins for the three products increased. Fig. 4 shows a sharp downturn in resid prices when they failed to keep pace with soaring crude prices.

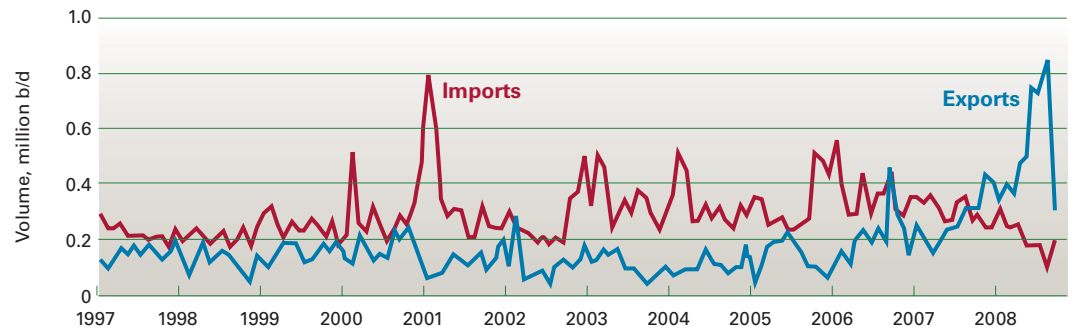
According to the report, composite margins would have fallen if the three product prices had not risen to offset losses from resid. This shows how important are resid and other bottom-of-the barrel products to healthy refiner margins. Recently, plunging resid margins and lower gasoline margins offset high jet fuel and distillate margins.

Other factors

According to the report, developments with little or no precedent have affected US and global fuel markets during the past decade, often catching refiners, policy makers, and consumers by surprise. These developments include more gasoline and distillate imports and increased demand for middle distillates.

US DISTILLATES

Fig. 5



Source: EIA data

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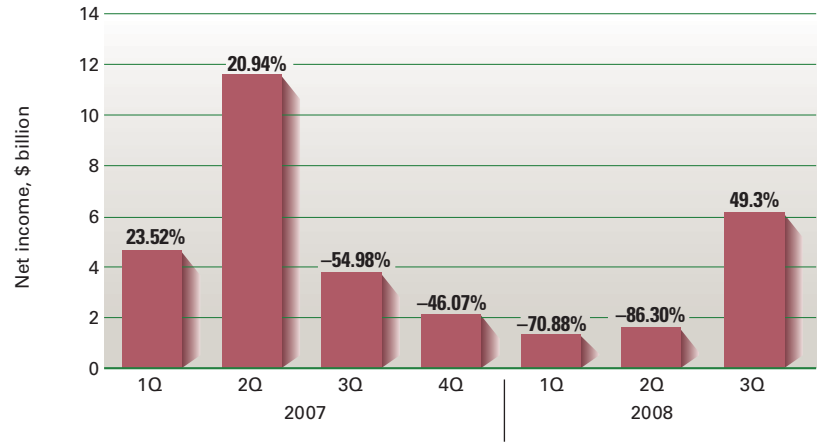
US REFINING, MARKETING

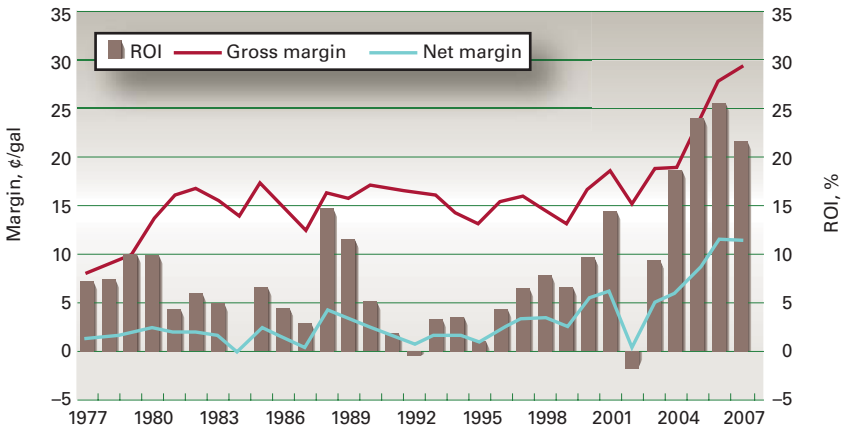
Fig. 6



Source: EIA data, EPRINC calculations

REFINER ROI, MARGINS

Fig. 7



Source: EIA data

Growth in gasoline imports to the US began in the late 1990s from about 500,000 b/d, reaching a peak of 1.6 million b/d during some high-demand periods in recent years. In September 2008, US gasoline imports averaged about 1.1 million b/d, which was more than 10% of consumption.

In the US gasoline market, competition from international refiners plays a key role in determining prices. Outside US refiners are so entrenched in the US gasoline market that they are regular competitors, adding often-overlooked competitive increment volumes of products, the report said.

Distillate imports are as important in the US as gasoline imports. But the distillate picture is much more complicated than gasoline because exports are also significant, the report said. In some months, net imports are as high as 600,000 b/d, typically peaking during the heating season.

Fig. 5 shows distillate imports and exports. Until recent months, when extremely strong global demand has taken supplies from the US market, the US imported about 7% of its distillate needs. But distillate exports grew during 2008, peaking at 849,000 b/d in August 2008, before declining to 313,000 b/d in September, according to the report. The US has been a net distillate exporter since late 2007.

According to US Energy Information Administration data, all distillate exports in 2008 had a sulfur content of 15 ppm or greater; no ultralow-sulfur diesel was exported. Furthermore, refiners managed to increase distillate production from the average barrel of crude. This continues a trend that started in 2002; its most recent effect was in 2008, when refiners increased distillate yields about 5% of the barrel, mostly reducing gasoline production, the report said.

Increased diesel demand for transportation of all types has caused the middle of the barrel to be the high-growth component of petroleum consumption, the report said. Global economic growth since 2004 resulted in a 3 million b/d increase in distillate consumption.

"Economic development in China, a continued trend toward diesel passenger cars in Europe, and trend growth in a strong US economy all contributed," the report said. "The growth increment here was the equivalent of two thirds of the increase in refining capacity globally."

Refiner profitability

EPRINC feels that the true measure of profitability is ROI, which is highly correlated with but differs from, refiner margins. EPRINC uses EIA data from "Performance Profiles of Major Energy Producers" to analyze the refining and marketing segment.

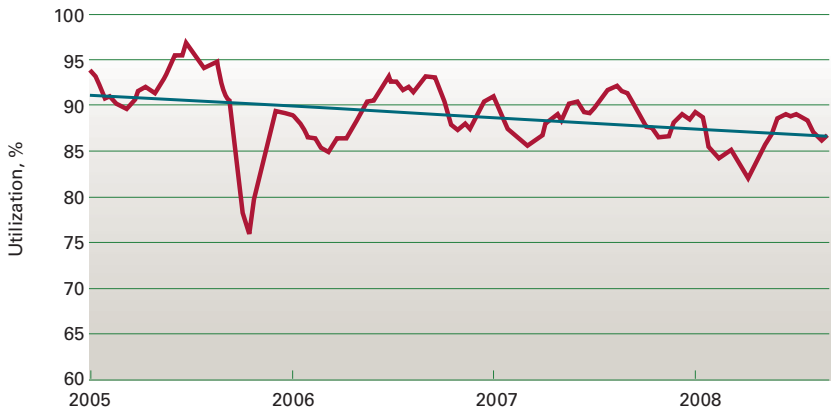
EPRINC calculated US refining ROI for 26 companies in EIA's Financial Reporting System (FRS) database during 1980-2006. The US refining industry has historically underperformed the entire US manufacturing sector.

During the 1980s and 1990s, refining and marketing ROI averaged 5.2%. For 12 of those years, ROI was less than 5%, according to the report. Returns underperformed the manufacturing sector until 2004, when for the first time in recent history, refining and marketing ROI exceeded 10%.

Because EIA's FRS data end in 2007, EPRINC extrapolated using quarterly

US REFINERY UTILIZATION

Fig. 8



Source: EIA data

data for the 11-firm FRS subset that reported US net income through second-quarter 2008 in EIA's publication, "Financial News for Major Energy Companies."

Fig. 6 shows a large drop in net income of the reporting companies starting with third-quarter 2007 and continuing through second-quarter 2008, when earnings were only 17% of year-earlier levels. Earnings increased in third-quarter 2008 but started eroding before the quarter ended. Fig. 6 shows the year-over-year change at the top of each bar.

EPRINC's analysis indicates that margin improvements in "recent years have dissipated, and profitability has reverted to historic levels, which are lower than US manufacturing. Recent volatility in oil markets makes generalization difficult, but it appears as if refining profitability—along with crude and product prices—collapsed in late 2008."

Refiner margins, ROI

Fig. 7 shows US refiners' actual margins and ROI from the recent EIA report, "Performance Profiles of Major Energy Producers 2007." These data are expressed in nominal dollars, based on data provided to EPRINC from the EIA (the actual report expresses these figures in 2007 constant dollars).

Margin data in Fig. 7 are net margins, meaning total production costs for the comprehensive refinery product slate were subtracted from revenues realized from the sale of all products. This gives an overview of industry profitability, while not detailing the role of products individually, according to the report.

In 2007, average margin on refined products was $4.78/bbl (11.3¢/gal), a decrease from $4.85 (11.5¢) in 2006. These are historically high margins and coincident with high ROIs, 21.6% and 25.6%, respectively.

Margins, however, are volatile. As recently as 2002, margins were $0.21/bbl (0.5¢/gal). That corresponded to an accounting ROI of –1.7%.

Lower utilization

Refinery utilization rates influence profitability that is unrelated to refined product prices, according to the report. Individual product margins are calculated without accounting for operating costs; that can give an oversimplified and misleading picture of higher profitability than quarterly or annual reports will show.

High utilization means fixed costs are spread among more barrels of products, lowering unit costs and contributing to better ROI.

Refinery operating rates have been declining since 2005, when ROI and refinery utilization both peaked (Fig. 8). During some periods in 2005, capacity utilization exceeded 96%, a very high rate. For 2005 as a whole, utilization averaged 90.5% despite outages from Hurricanes Rita and Katrina.

Fig. 8 also shows a downward trend in utilization—it has fallen to 88.8% in 2007, from 89.3% in 2006 and 90.5% in 2005. Utilization for the first 8 months of 2008 is only 86.4%.

The factors lowering utilization are falling petroleum product demand, greater use of ethanol, and more gasoline imports. The latter is due to a surplus in Europe, with significant amounts of discounted gasoline exported to the US, according to the report. ✦

Current pipeline expansion slows; future plans contract

Christopher E. Smith
Pipeline Editor

Planned pipeline construction to be completed in 2009 rose more slowly than in 2008, increasing by more than 13% from the previous year, driven by large natural gas transportation projects in both the US and Asia-Pacific but constrained by a drop in planned crude mileage.

Operators plan to complete installation of more than 15,000 miles in 2009 alone (Table 1), with natural gas construction making up 60.5% (more than 9,200 miles) of the plans, based on reports from the world's pipeline operating companies and data collected by Oil & Gas Journal.

For 2009 and beyond, less mileage is planned in all pipeline categories than had been the case the previous year, as a combination of the global economic crisis and lower commodity prices begin to affect infrastructure development plans..

Global demand for natural gas drove a number of the large pipeline projects set for completion in 2009. Long-term natural gas pipeline plans (2009 and beyond), however, seem to already reflect the slowing in demand forecast since, with fewer plans for pipelines from producing regions such as Canada and the Middle East leading the downward trend.

Fewer crude plans in both the Asia-Pacific and Africa keyed an 18% 2009 slide in miles expected to be completed in that sector from global totals the previous year.

Plans for construction of product pipelines in 2009 rose globally, driven by the continued construction of ethanol pipelines in Brazil and new clean products pipelines in Africa.

As 2008 began, operators had announced plans to build nearly 78,000 miles of crude oil, product, and natural gas pipelines beginning this year and extending into the next decade (Fig. 1), a 9% decrease from data reported last year (OGJ, Feb. 18, 2008, p. 47) in this report. The vast majority (nearly 75%) of these plans is for natural gas pipelines, an increase from the previous year.

Outlook

The downturn in worldwide pipeline construction trends reflects the current economic unrest but run counter to US Energy Information Administration's energy consumption forecasts, which show continued growth, even if more slowly than predictions from a year ago.

EIA forecast world marketed energy consumption to increase by 50% through 2030 (using a 2005 baseline), a period that encompasses the long-term pipeline construction projections stated here.

Energy demand growth will be strongest, according to mid-year 2008 analysis, among countries outside the Organization for Economic Cooperation and Development. This non-OECD growth will be led by China and India, whose combined energy use will more that double over the projection period to one-quarter of world energy consumption. US demand share will contract during the same period from 22% to 17%.

Fuelling this energy demand growth is projected gross domestic product

growth in non-OECD Asia of 5.8%/year through 2030—led by China at 6.4%/year, the highest projected growth rate in the world—compared with 4% worldwide. Each of these levels are flat or slightly lower than EIA projections from a year earlier, reflecting US-led economic uncertainty and ending recent expansion in the projected rate of GDP growth.

Structural issues that have implications for medium to long-term growth in China include the pace of reform affecting inefficient state-owned companies and a banking system carrying a large number of nonperforming loans, according to the EIA. Development of domestic capital markets to help macroeconomic stability and ensure China's large savings are used efficiently supports medium-term growth projections, according to the EIA.

EIA described the medium-term prospects for India's economy as positive, as it continues to privatize state enterprises and increasingly adopt free-market policies. EIA projects 5.8%/year demand growth in India 2005-30.

In December 2008, EIA reduced projected US energy consumption in 2030 to 113.35 quadrillion btu from 123.8 quadrillion btu, 10.45 quadrillion btu lower than the previous year's projection. This 8.4% drop in energy consumption, combined with projected increases in domestic supply, are projected to reduce net liquids imports by 2030 from the 54% projected in 2008 to 41% in the 2009 outlook.[2]

EIA projects domestic natural gas production in 2030 of 24.28 tcf/year, compared with the 19.9 tcf/year projected a year earlier. The increased production is more than enough to counter the increase in projected consumption also made by EIA. Pegged in 2008 at 23.4 tcf/year by 2030, this year's projections place 2030 consumption at 25.08 tcf/year, reducing net imports to just 3% vs. the 14% projected in 2008. Unconventional production will make up the bulk of the supply increase.

The 2009 outlook projects the US will be a net pipeline exporter by 2030. Net pipeline imports of natural gas from Canada and Mexico will fall from 2.94 tcf in 2006 to -0.16 tcf in 2030, according to the EIA, which last year pegged 2030 net pipeline imports at 0.5 tcf. EIA once again also sharply reduced the amount of LNG it expects the US to be importing annually in 2030, from 2.9 tcf in its 2008 annual outlook to 0.84 tcf in this year's publication.

Current pipeline construction plans reflect the landscape described by EIA, with the bulk of US work both this year and looking forward centered on moving new domestic production to market.

OGJ has for more than 50 years tracked applications for gas pipeline construction to what is now called the Federal Energy Regulatory Commission. Applications filed in the 12 months ending June 30, 2008 (the most recent 1-year period surveyed) reflect the expected slowdown in US interstate pipeline construction.

- Nearly 900 miles of pipeline were proposed for land construction and no miles for offshore work. For the earlier 12-month period ending June 30, 2007, 2,032 miles were proposed for land construction.
- FERC applications for new or additional horsepower at the end of June 2008 fell even more sharply, reaching more than 238,500 hp, all onshore, compared with 713,000 hp of new or additional compression applied for a year earlier and 583,000 hp the year before that.

Bases, costs

For 2009 only (Table 1), operators plan to build more than 15,250 miles of oil and gas pipelines worldwide at a cost of nearly $61.5 billion. For 2008 only, companies had planned nearly 13,500 miles at a cost of more than $37.6 billion.

For projects completed after 2009 (Table 2), companies plan to lay more than 62,500 miles of line and spend roughly $225.5 billion. When these companies looked beyond 2008 last year, they anticipated spending more than $201 billion to lay more than 72,000 miles of line.

- Projections for 2009 pipeline mileage reflect only projects likely to be completed by yearend 2009, including construction in progress at the start of the year or set to begin during it.
- Projections for mileage in 2009 and beyond include construction that might begin in 2009 and be completed in 2009 or later.

Also included are some long-term projects judged as probable, even if they will not break ground until after 2009.

US average cost-per-mile for onshore pipeline construction (Table 4, OGJ, Sept. 1, 2008, p. 58) on FERC applications submitted by June 30, 2008, was $3.38 million. There were no offshore applications submitted.

US average cost-per-mile for offshore construction (Table 7, OGJ, Sept. 1, 2008, p. 62) on projects completed in the 12 months ending June 30, 2008, was $15.17 million.

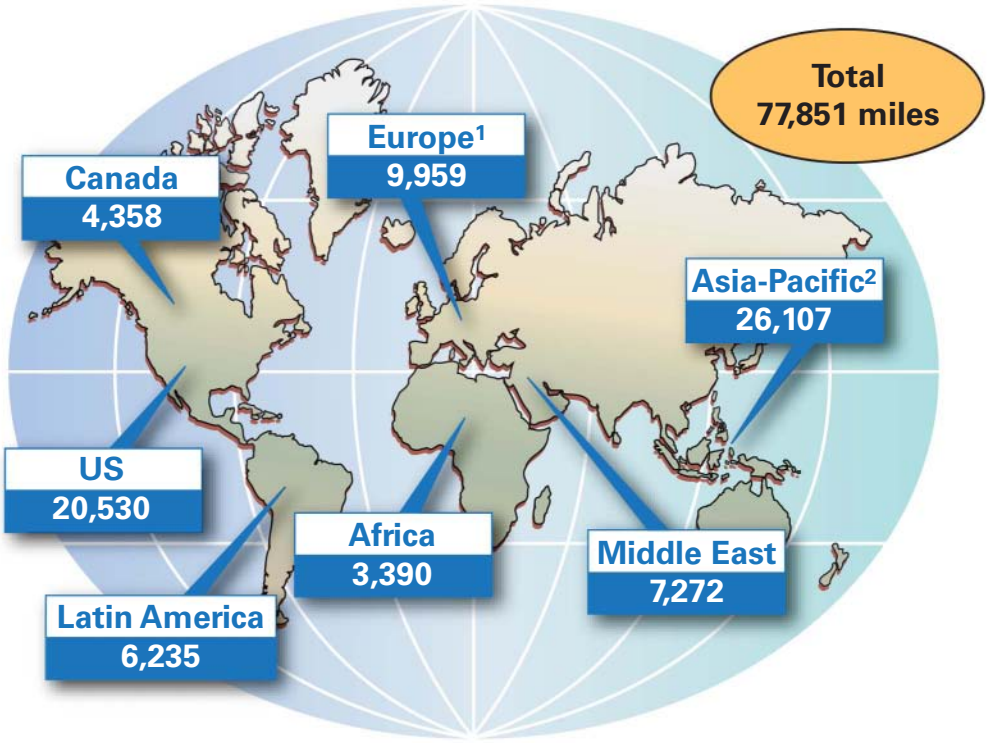
Based on historical analysis and a few exceptions and variations notwithstanding, these projections assume that 90% of all construction will be onshore and 10% offshore and that pipelines 32 in. OD or larger are onshore projects.

Following is a breakdown of projected costs, using these assumptions and OGJ pipeline-cost data:

- Total onshore construction (14,428 miles) for 2009 only will cost almost $48.8 billion:
  - —$3.4 billion for 4-10 in.
  - —$13 billion for 12-20 in.
  - —$9 billion for 22-30 in.
  - —$23.4 billion for 32 in. and larger.
- Total offshore construction (836 miles) for 2009 only will cost nearly $12.7 billion:
  - —$1.7 billion for 4-10 in.
  - —$6.5 billion for 12-20 in.
  - —$4.5 billion for 22-30 in.
- Total onshore construction (61,411 miles) for beyond 2009 will cost nearly $208 billion:
  - —$1.5 billion for 4-10 in.
  - —$14.6 billion for 12-20 in.
  - —$19.7 billion for 22-30 in.
  - —$172 billion for 32 in. and larger.

FORECAST PIPELINE CONSTRUCTION

Fig. 1



[1]Including Russia and former Soviet republics west of the Ural Mountains. [2]Including Russia and former Soviet republics east of the Ural Mountains.

• Total offshore construction (1,176 miles) for beyond 2009 will cost nearly $18 billion:
—$728 million for 4-10 in.
—$7.3 billion for 12-20 in.
—$9.8 billion for 22-30 in.

Action

What follows is a quick rundown of some of the major projects in each of the world's regions.

Pipeline construction projects mirror end users' energy demands, and much of that demand continues to center on natural gas, with the industry remaining focused on how to get that gas to market as quickly and efficiently as possible. The following sections look at both natural gas and liquids pipelines.

North American gas

BP PLC and ConocoPhillps have joined resources to build a 4-bcfd natural gas pipeline extending from Alaska's North Slope to market in Canada and the US at an estimated cost of $20 billion. The companies plan to spend $600 million preparing for an open season slated to begin before yearend 2010. After the open season, the companies will file for certification from the US FERC and Canada's National Energy Board for authorization to move forward with building the project.

The partners must also convince Alaskan authorities that their plan is the best one for developing the state's gas resources and that it conforms to the Alaskan Gasline Inducement Act (AGIA), under which TransCanada in January 2008 obtained rights to build a North Slope gas pipeline. AGIA requires TransCanada to meet certain requirements that will advance the project in exchange for a license providing up to $500 million in matching funds.

Alaska received five applications for gas pipeline proposals under AGIA from AEnergia LLC, the Alaska Gasline Port Authority, the Alaska Natural Gas Development Authority, Little Sustina Construction Co., and a joint application from TransCanada Alaska Co. LLC and Foothills Pipe Lines Ltd. The state said a proposal submitted by ConocoPhillips did not meet the AGIA's application criteria. BP and ExxonMobil did not submit applications.

TransCanada already has NEB authorization for its project.

In Canada, the proposed Mackenzie Valley pipeline would stretch more than 750 miles to transport Mackenzie River Delta gas to Alberta and beyond. Plans call for initial capacity of 1.2 bcfd, expandable to 1.9 bcfd. A combination of regulatory delays and mounting cost estimates has prevented tangible progress on this project. Canada's Joint Review Panel, examining the environmental and socio-economic impacts of the $16.2-billion (Can.) project, plans to release its report in December 2009.

In addition to the Aboriginal Pipeline Group, other pipeline partners are Imperial Oil Ltd. 34.4%, ConocoPhillips Canada 15.7%, Shell Canada, 11.4%, and ExxonMobil Canada 5.2%

Costs include $7.8 billion for the Mackenzie Valley mainline, $3.5 billion for the gas gathering system, and $4.9 billion for anchor-field development.

Large US natural gas pipeline projects designed to move Midcontinent supplies to market centers continued to progress, with new projects also proposed. The Rockies Express pipeline, running 1,323 miles of 42 in. pipe from Cheyenne, Wyo., and Colorado to Clarington, Ohio, is the largest new US pipeline project undertaken in 20 years. The 1.8 bcfd, $3 billion line has firm commitments in place for 900

MMcfd, including a binding 500 MMcfd by EnCana Corp. and a conditional 400 MMcfd from the Wyoming Natural Gas Pipeline Authority.

Kinder Morgan Energy Partners LP will operate the pipeline and owns two thirds of the project. Sempra Pipelines & Storage holds one third of it. In exchange for capacity commitments, some shippers may exercise options for equity in the project, which could give KMP a minimum of 50% and Sempra 25% after construction.

The pipeline, which KMP expects to be completed by autumn 2009, will be brought on line in three segments.

REX-Entrega, running from Greasewood, Kanda, and Wamsutter to the Cheyenne Hub in Colorado and REX-West, covering the next 710 miles from the Cheyenne Hub in Colorado to Audrain County, Mo., and interconnecting with five other interstate pipelines, are already in service.

The 639-mile REX-East segment from Missouri to Ohio received its draft environmental impact statement in November 2007. In addition to the 42-in pipeline, FERC's REX-East draft EIS covered the possible environmental impacts of 20 metering stations and 7 new compressor stations, including 2 to be built along REX-West in Wyoming and Nebraska.

FERC noted that the REX-East project would follow existing rights-of-way for more than 59% of its route and would be consistent with or conform to federal resource management plans.

REX-East construction began in summer 2008. Service to Lebanon, Ohio, is scheduled for spring 2009, with full service to Clarington targeted for autumn.

Alliance Pipeline Inc. and Questar Overthrust Pipeline Co. held an open season on their Rockies Alliance Pipeline project in June 2008. Initial support totaled 500,000 dekatherms/day (500 MMcfd) from both Rockies producers and Midwest markets. The pipeline will take delivery of natural gas from Opal, Meeker, and Wamsutter and terminate at Alliance Pipeline delivery points in the Chicago area.

The 875-mile, 42-in. OD pipeline will have capacity of 1.3 bcfd, expandable to 1.8 bcfd with extra compression. The Alliance system connects to the Guardian, Vector, Peoples, Nicor, ANR, NGPL, and Midwestern pipeline systems.

TransCanada proposed a competing Rockies-to-Midwest project, Pathfinder, consisting of 673 miles of 36-in. OD pipe running from Meeker, Colo., to an interconnection with the Northern Border Pipeline Co. system for delivery into the Ventura and Chicago area markets. The pipeline's initial capacity will be 1.2 bcfd, with an ultimate capacity of 1.6 bcfd.

Ventura is a major connection with Northern Natural Gas, the major pipeline into Minnesota. The Chicago market provides access to numerous pipelines serving Wisconsin, Illinois, Indiana, Michigan, and Ontario.

El Paso Corp. proposed the $3-billion Ruby Pipeline connecting Rockies reserves to western US markets. The pipeline includes 670 miles of 42-in. OD pipe beginning at the Opal hub in Wyoming and terminating at a Malin, Ore., interconnect near California's northern border. Ruby will have initial capacity between 1.3 and 1.5 bcfd, depending on final customer commitments.

Pipeline rights-of-way will cross four states: Wyoming, Utah, Nevada, and Oregon. El Paso has proposed four compressor stations: one near Opal hub in southwestern Wyoming; one south of Curlew junction, Utah; one at the project mid-point, north of Elko, Nev.; and one in northwestern Nevada.

Pending regulatory approvals, construction could begin in early 2010, with an estimated in-service data of March 2011.

Ruby was a competing proposal to Spectra Energy's 1-bcfd Bronco Pipeline, also designed to deliver Rockies gas to Malin. Spectra held an open season on the $3-billion project in January 2008, with plans to put the line in service during 2011, but has since cancelled the project. The company is still evaluating other opportunities to move Rockies gas west.

Williams Gas Pipeline Co. and TransCanada PipeLines USA Ltd.'s proposed Sunstone Pipeline project was a third contender through this corridor, but the companies are reevaluating the scope and timing of the project and have temporarily suspended field work, including survey activities.

PIPELINE CONSTRUCTION IN 2009[1]

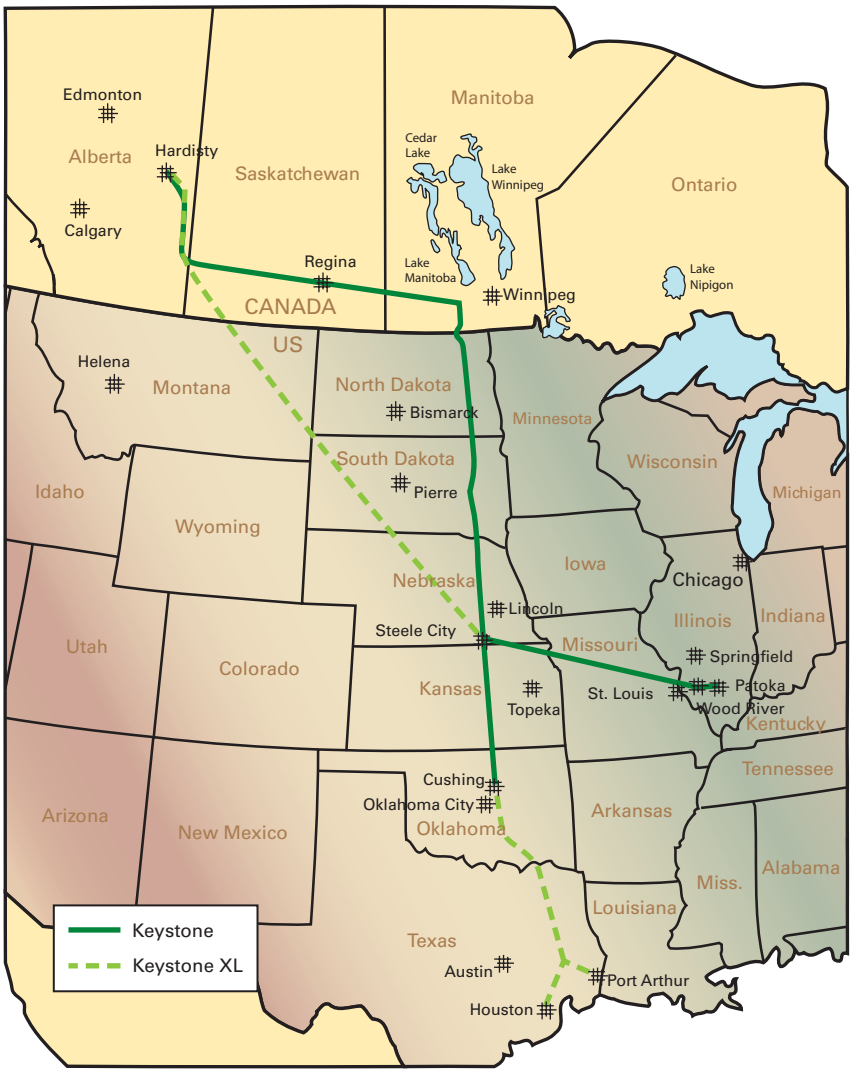
Table 1

	4-10 in.	12-20 in.	22-30 in.	32+ in.	Total
			Miles		
GAS PIPELINES					
US	0	313	324	3351	3988
Canada	34	0	0	0	34
Latin America	208	841	0	195	1244
Asia-Pacific[2]	311	366	0	1135	1812
Europe[3]	0	300	115	0	415
Middle East	0	0	56	1439	1495
Africa	50	72	130	0	252
Total gas	**603**	**1,892**	**625**	**6,120**	**9,240**
CRUDE PIPELINES					
US	0	0	1,054	507	1561
Canada	0	0	236	240	476
Latin America	0	0	146	0	146
Asia-Pacific[2]	0	72	888	0	960
Europe[3]	0	0	0	0	0
Middle East	0	152	0	40	192
Africa	0	0	0	0	0
Total crude	**0**	**224**	**2,324**	**787**	**3,335**
PRODUCT PIPELINES					
US	60	1,424	0	0	1,484
Canada	0	28	0	0	28
Latin America	0	715	0	0	715
Asia-Pacific[2]	112	0	0	0	112
Europe[3]	0	0	0	0	0
Middle East	0	0	0	0	0
Africa	350	0	0	0	350
Total product	**522**	**2,167**	**0**	**0**	**2,689**
WORLD TOTALS					
Gas	603	1892	625	6120	9240
Crude	0	224	2324	787	3335
Product	522	2167	0	0	2689
Total	**1,125**	**4,283**	**2,949**	**6,907**	**15,264**

[1]Projects planned to be completed in 2009. [2]Regions east of the Ural Mountains and south of the Caucasus Mountains, excluding the Middle East. [3]Regions west of the Ural Mountains and north of the Caucasus Mountains.

KEYSTONE PIPELINE PROJECT

Fig. 2



Source: TransCanada

North American crude

Canadian oil sands development has slowed as oil prices plunged and the economy spiraled. Even so, this supply's proximity to US demand has helped make export lines for Canadian crude a large portion of the work to be completed in the US for 2009.

TransCanada Corp. received permitting from the US Department of State in March 2008 to begin construction of border crossing facilities for its 2,148-mile Keystone oil pipeline project, which will transport oil from Canada to the US Midwest. ConocoPhillips is TransCanada's partner in the project.

In addition to 1,379 miles of newbuild US line, Keystone includes additions to existing Canadian pipelines and mainline flow reversals. It is expected to start up in late 2009 with the capacity to deliver 435,000 b/d of crude oil from Hardisty, Alta., to the US at Wood River and Patoka, Ill.

TransCanada plans to expand Keystone's capacity to 590,000 b/d and extend the line to Cushing, Okla., starting in 2010. The project has secured firm long-term contracts totaling 495,000 b/d for an average of 18 years.

TransCanada announced plans in July 2008 for the Keystone Gulf Coast Expansion Project (Keystone XL), providing additional capacity of 500,000 b/d from western Canada to the US Gulf Coast by 2012. The expansion would boost the system's total capacity to 1.1-million b/d at a total capital cost of about $12.2 billion. Keystone XL has secured additional firm, long-term contracts for 380,000 b/d for an average of 17 years from shippers.

Keystone XL includes 1,980 miles of 36-in. OD line starting in Hardisty, Alta., and extending to a delivery point near existing terminals in Port Arthur, Tex. (Fig. 2). Subject to shipper support, Keystone XL will include an additional 50-mile lateral to Houston. Additional pumping could boost the combined Keystone system's throughput to 1.5 million b/d. TransCanada anticipates beginning construction in 2010, pending regulatory approvals, and intends to start the line in 2012

Enbridge Energy Partners LP plans its own pipeline expansion to deliver 450,000 b/d of crude oil to the US. Following on the heels of the Southern Access/Southern Lights expansion, Enbridge intends to build the Alberta Clipper crude pipeline between Hardisty, Alta., and Superior, Wis. This 1,000-mile line is expected to be in service by mid-2010. Initial capacity can be expanded to as much as 800,000 b/d.

Enbridge Inc. and ExxonMobil Pipeline Co. have tabled their own proposed pipeline system to transport crude from Patoka to the Texas Gulf Coast for the time being. The Texas Access Pipeline would have transported crude oil sourced from the Canadian oil sands region in Alberta and the upper US Midwest to refiners in Nederland and Houston, Tex.

Altex Energy is pursuing a completely newbuild 36-in. pipeline running directly from northern Alberta to the US Gulf Coast. The line's initial capacity will be 425,000 b/d, but the company says expansion to 1 million b/d is possible as demand warrants (OGJ, Nov. 3, 2008, p. 60).

Enbridge has renewed plans to build the Northern Gateway Pipeline to transport 525,000 b/d of oil sands crude from near Edmonton, Alta. to a tanker

terminal in British Columbia for shipment to China, other parts of Asia, and California. Enbridge is likely to submit pipeline plans to the NEB in 2009.

Northern Gateway includes a 1,170-km, 36-in. OD pipeline to move oil to the west and a parallel 20-in. OD pipeline for shipping 193,000 b/d of condensate from the coast east to Alberta refineries. Enbridge put the project on hold in December 2006 to focus on completing its Southern Access/Southern Lights project. Each line's capacity is largely subscribed.

North American products

Colonial Pipeline Co. is proposing an additional pipeline from Jackson, La., to Austell, Ga., running alongside the two current main lines to the extent possible. The 460-mile Project ExCEL, prompted by announced Gulf Coast refinery expansions, represents a more than $2 billion investment.

Colonial is currently conducting permitting, with environmental analyses to follow once the route is finalized. The company hopes to begin construction in 2010, targeting a 2012 completion date.

Kinder Morgan Energy Partners LP is continuing to develop its $400 million expansion of the 550-mile CALNEV pipeline. This involves construction of a 16-in. pipeline from Colton, Calif., to Las Vegas, Nev., and will increase the system's capacity to 200,000 b/d, transporting products for the military at Nellis Air Force Base. A further capacity increase to more than 300,000 b/d is possible with the addition of pump stations.

The new pipeline will parallel existing utility corridors between Colton and Las Vegas. Following its completion, the existing 14-in. line will be transferred to commercial jet fuel service for McCarran International Airport and any future airports planned in Las Vegas, with the 8-in. pipeline that currently serves the airport purged and held for future service.

Start-up of the line is scheduled for late 2009 or early 2010.

Holly Corp. and Sinclair Transportation Co. plan to jointly build a products pipeline extending from Wood Cross, Utah, refineries to a terminal north of Las Vegas. The UNEV Pipeline project includes construction of associated terminal facilities in Cedar City, Utah, and northern Las Vegas.

The US Bureau of Land Management issued a draft environmental impact statement in December 2008.

The 400 mile, 12-in. line will cost about $300 million and have an initial capacity of 62,000 b/d, expandable to 120,000 b/d. It will serve refineries and shippers along its route and interconnect to the Pioneer Pipeline.

The system is slated for completion by the end of this year.

Latin America

Brazil's 862-mile Southeast-Northeast Interconnection Gas Pipeline

(GASENE) will connect the existing southeastern gas system to the northeastern gas system, creating a common gas market and allowing gas imports at Bahia. GASENE connects Cabiúnas terminal in Rio de Janeiro state to Catu, Bahia (Fig. 3). It will create a common gas market in Brazil and allow gas import from Bahia.

Construction on the final 605-mile stretch of the pipeline, between Cacimbas and Catu started in May 2008. The 28-in. OD pipe, using one compressor station, is scheduled to enter service in 2010. Sinopec is building the pipeline, financed by China Development Bank.

Petrobras signed an accord with the Goias state government to build the country's first new ethanol pipeline, a 12-in. OD, 975-km line to transport 12 million cu m/year. The pipeline will run from Goias to a refinery in Paulinia, near Sao Paulo. Japan's Mitsui and Brazil's Camargo Correa are also participating in the project, dubbed Projetos de Transporte de Alcool (PMCC). Petrobras plans to have the line in service by 2010.

Plans call for a future leg between Paulinia and Guararema, stretching from there to coastal terminals in Sao Sebastiao, Sao Paulo, and Ilha D'Agua, Rio de Janeiro.

Petrobras also said it would sign a cooperation agreement with two Brazilian states for a second 12-in. ethanol pipeline. Petrobras and the states of Mato Grosso do Sul and Parana plan to develop viability studies for the pipeline, which would cover 528 km, linking Campo Grande in western Brazil to the port of Paranagua in southern Brazil.

Peru's Ministry of Energy reports that work is progressing on Camisea II, a gas export project featuring a 253-mile, 34-in. natural gas pipeline connecting Camisea Block 56 to a liquefaction plant being built on the coast 106 miles south of Lima. Peru LNG (Hunt Oil Co., 50%; SK Energy Co. Ltd., 30%; Repsol YPF, 20%) expects the project to enter service in 2010.

GASENE PIPELINE Fig. 3

Source: Petrobras

Asia-Pacific

PetroChina has begun building its second West-East Pipeline (WEPP II) and expects to bring it into service during 2010. The pipeline is part of the larger Asian Gas Pipeline, running from Turkmenistan to eastern China. The Chinese section covers 3,400 miles, connecting Xinjiang province to Guangzhou and Shanghai. The development also calls for 1,240 miles of branch lines. WEPP II will carry 30 billion cu m/year from Central Asia to consuming centers in China.

The Chinese section of WEPP II will use 1.1 million tonnes of X80 42-in. OD welded pipe and 3.2 million tonnes of X80 18-in. OD spiral pipe.

Construction began on the Turkmen section in August 2007. About 117 miles will be laid in Turkmenistan, 329 miles through Uzbekistan and 803 miles through Kazakhstan. Service to the Chinese border is slated for 2012 (Fig. 4).

CNPC is also seeking 800,000 tonnes of steel for WEPP III, set to begin construction in 2010 or after completion of WEPP II. The pipeline will run 3,728 miles from Altai to Bohai Bay.

A planned 1,480 km pipeline running from western Kazakhstan to western China would carry 10 billion cu m/year once complete. The 1,040-mm OD pipeline, running from Beyneu to Chimkent (Fig. 4) has been in the works since 2005 and was originally proposed to carry as much as 40 billion cu m/year between Atyrau and Alashankou. Economic concerns and delays in developing Kazakhstan's reserves dictated the route and capacity changes (OGJ, Jan. 5, 2009, p.58).

The Caspian nations are not the only countries actively pursuing export projects to China, with much of the crude mileage planned in the Asia Pacific region for 2009 consisting of the Eastern Siberia-Pacific Ocean crude line running from Russia to Japan and China.

The first stage of the 4,700-km project includes construction of a 2,400-km oil pipeline from Taishet to Skovorodino near the Chinese border and of a rail oil terminal at Perevoznaya Bay at a combined cost of $7.9 billion. The second stage, depending on development of Eastern Siberian oil fields, involves construction of a pipeline link between Skovorodino and Perevoznaya on Russia's Pacific Coast.

China looks to import as much as 30 million tonnes/year of crude if a pipeline spur is built from Skovorodino to Daquing.

Russia and China suspended talks on construction of the proposed spur in November 2008, reversing a memorandum of understanding signed the previous month by Russian Prime Minister Vladimir Putin and his Chinese counterpart Premier Wen Jiabao.

Under terms of that MOU, China was to grant $15 billion in loans to Russia's OAO Rosneft and $10 billion to Transneft for construction of the pipeline spur and for the supply of 15 million tonnes/year of oil over 20 years.

The branch pipeline was planned to

extend some 70 km from Skovorodino in Siberia to the Chinese border and was to supply the oil hub of Daqing in northern China.

The long-awaited agreement about construction of the spur coincided with an announcement by Russian Deputy Prime Minister Igor Sechin that the Chinese government would provide Russian oil firms with "considerable" loans in return for increased oil supplies (OGJ Online, Oct. 29, 2008).

China subsequently made demands Russia found objectionable, in particular higher interest rates on the loans owing to a freeze in lending following the global financial crisis. Supplies along the Skovorodino-Perevoznaya route would total 50 million tonnes/year, the bulk of which would be exported to Japan, but hinge entirely on the combination of continued development of the other Siberian fields and Russia's continued desire to export to Japan.

Gas Authority of India (GAIL) plans to complete construction of a 48-in. OD, 3,500-km pipeline system connecting existing terminals to the 1,600-Mw Pragati Phase III powerplant in Bawana, near Delhi by January 2010. The system will include compressors installed at Vijaipur and Jhabua. GAIL has also been authorized to construct pipelines between Chainsa and Hissar, Kochi and Bangalore, and Dabhol and Bangalore.

Myanmar awarded China the right to manage planned pipelines that will transport crude oil and natural gas from the Bay of Bengal across Myanmar to Kunming in southwestern China.

China National Petroleum Corp. will acquire a 50.9% stake in the firm that will build and operate the pipelines, while Myanmar players, including state-run Myanmar Oil & Gas Enterprise, will hold 49.1%.

Under the agreement, Myanmar and China will jointly construct two pipelines, one to transport oil carried by tanker from the Middle East and the other to carry gas obtained from Myanmar's A-1 and A-3 blocks offshore.

A gas collection terminal and a port for oil tankers will be constructed on an island near Kyaukpyu on the Bay of Bengal in western Myanmar.

The pipelines will extend from Mandalay in central Myanmar; through Lashio in the Myanmar state of Shan and Muse, a town bordering the Chinese province of Yunnan. It will terminate in Kunming. In addition to Yunnan, analysts said, other areas will benefit from the pipelines: Chongqing municipality, Guangxi Zhuang autonomous region, Sichuan province, and Guizhou province in southwest China.

Total estimated project costs amount to $1.5 billion for the oil pipeline and $1.04 billion for the gas pipeline.

Yunnan will start construction in first-half 2009 as part of its plan to spend some $10.55 billion on energy projects next year, according to Mi Dongsheng, head of the province's Provincial Development and Reform Commission.

The new pipelines will give China better access to Myanmar's resources and will speed deliveries and improve China's energy security by bypassing the congested Malacca Strait, which currently ships most of China's imported crude oil.

Pipeline construction in 2009 and beyond[1]

Table 2

Area	4-10 in.	12-20 in.	22-30 in.	30+ in.	Total
			Miles		
GAS PIPELINES					
US	25	325	1,427	7,526	9,303
Canada	0	0	253	380	633
Latin America	400	212	1,989	1,177	3,778
Asia-Pacific[2]	0	573	0	19,283	19,856
Europe[3]	0	124	859	7,963	8,946
Middle East	0	0	43	3,855	3,898
Africa	0	0	0	2,354	2,354
Total gas	**425**	**1,234**	**4,571**	**42,538**	**48,768**
CRUDE PIPELINES					
US	57	157	0	2,394	2,608
Canada	0	0	866	1,934	2,800
Latin America	0	0	0	0	0
Asia-Pacific[2]	0	0	682	2,685	3,367
Europe[3]	0	83	0	515	598
Middle East	0	0	43	303	346
Africa	0	0	0	0	0
Total crude	**57**	**240**	**1,591**	**7,831**	**9,719**
PRODUCT PIPELINES					
US	0	812	314	460	1,586
Canada	0	387	0	0	387
Latin America	0	352	0	0	352
Asia-Pacific[2]	0	0	0	0	0
Europe[3]	0	0	0	0	0
Middle East	0	1,341	0	0	1,341
Africa	0	434	0	0	434
Total product	**0**	**3,326**	**314**	**460**	**4,100**
WORLD TOTALS					
Gas	425	1,234	4,571	42,538	48,768
Crude	57	240	1,591	7,831	9,719
Product	0	3,326	314	460	4,100
Total	**482**	**4,800**	**6,476**	**50,829**	**62,587**

[1]Projects under way at the start of or set to begin in 2009 and be completed in 2010 or later. Includes some probable major projects whose installation will begin in 2010 or later. [2]Regions east of the Ural Mountains and south of the Caucasus Mountains, excluding the Middle East. [3]Regions west of the Ural Mountains and north of the Caucasus Mountains.

Europe

Work started in early December 2005 on the Russian onshore section of the Nord Stream pipeline in Babayevo. This 56-in. segment will stretch 917 km to the Baltic Sea coast near Vyborg, linking existing gas pipelines from Siberia to the NEGP project. Seven compressor stations will provide the necessary pressure. The pipeline will cross the Baltic, making landfall near Greifswald, Germany. This section will be 1,200 km long with a 48-in. OD.

The full system is scheduled to start operations in 2011 at a capacity of 27.5 billion cu m/year. The project includes building a second, parallel pipeline, doubling capacity to about 55 billion cu m/year. This second pipeline is planned to come on stream in 2012.

A joint venture of Gazprom (51%), Wintershall AG (20%), E.ON Ruhrgas AG (20%), and NV Nederlandse Gasunie (9%) is building the pipeline. For the two-leg option, the total cost for the offshore project will amount to more than €5 billion, with Gazprom investing an additional €1.3 billion in the onshore section. Russia began production at the 825.2 billion cu m Yuzhno Russkoye oil and gas condensate field in December 2007. Gas from this field will be shipped through Nord Stream once it is completed.

Gazprom and Eni SPA agreed in December 2007 to build the 560-mile South Stream gas pipeline under the Black Sea and through Bulgaria. Bulgaria and Russia reached agreement in January 2008. On completion, the $10-billion line could distribute gas to northern and southern Europe, with an estimated capacity of 30 billion cu m/year. Participants plan to deliver first gas through South Stream by 2013.

Gazprom Vice-President Alexander Medvedev said in December 2008 that work on both Nord Stream and South Stream would continue despite the financial and economic crises.

Plans to export Algerian gas via Italy also progressed. Galsi SPA and Snam Rete Gas SPA signed a memorandum of understanding in November 2007 to construct the Italian section of the planned 8 billion cu m/year Galsi natural gas pipeline, which will deliver Algerian gas to Italy via Sardinia.

Gasli shareholders are Sonatrach, Edison SPA, Enel SPA, Hera Trading, Regione Sardegna, and Wintershall AG.

The project envisions four pipeline segments: 640 km onshore between Hassi R'mel gas field in Algeria and El Kala on the Algerian coast; 310 km between El Kala and Cagliari on Sardinia in water as deep as 2,850 m; 300 km between Cagliari and Olbia on the northern Sardinian coast; and 220 km between Olbia and Pescaia, southeast of Florence, in water as deep as 900 m.

Sonatrach will deliver 3 billion cu m/year into the system, Enel, 2 billion cu m/year, and Hera Trading, 1 billion cu m/year.

Work on the line was under way in January 2009, with Snam Rete Gas CEO Carlo Malacarne having said in October 2008 the line would enter service in 2012-2013

Austria's OMV AG continues to advance the 56-in. Nabucco pipeline, which will bring some combination of Central Asian, Caspian, and Middle Eastern gas to the Baumgarten hub in Austria near the Slovakian border at a rate of 31 billion cu m/year, before moving it on to Western Europe. The $6.5-billion pipeline, spanning 3,300 km, is expected to be completed by 2013.

Feasibility studies have led to a two-stage construction plan. The first phase, starting next year calls for 2,000 km of pipe between Ankara, Turkey, and Baumgarten, allowing 8 billion cu m/year of gas from the existing Turkish pipeline network to be transported through the line by 2012. Second-stage construction would begin in 2012 and build eastward from Ankara to the Iranian and Georgian borders (Fig. 2).

The US supports construction of Nabucco, citing the need to move gas into Europe though economically viable and secure routes.

To deliver gas from Bovanenkovo field—projected production 115 billion cu m/year—Russia is building a multiline gas transmission system connecting

TRANS-ASIAN, KAZAKHSTAN-CHINA PIPELINES

Fig. 4

the Yamal Peninsula and central Russia. Construction calls for 1,420-mm OD pipes designed to work at higher pressures than existing Russian lines.

Total pipeline length will exceed 2,400 km, consisting of the Bovanenkovo-Ukhta pipeline (1,100 km, 140 billion cu m/year) and the Ukhta-Torzhok gas pipeline (1,300 km, 81.5 billion cu m/year).

Gazprom began building the 72 km subsea section of the Bovanenkovo-Uktha line, crossing Baidarate Bay, in August 2008. Construction of the main trunkline began in December 2008.

Middle East

Iran, Pakistan, and India continued discussions toward building the long-contemplated gas export line from Iran to India during 2008. The $7 billion project would transport as much as 2.2 bcfd of natural gas from the South Pars field in the Persian Gulf through 2,100 km of 56-in. OD line. (Iran, 1,100 km; Pakistan, 750 km; India, 250 km). Pakistan's share of gas from the pipeline would be 1.05 bcfd. If India does not participate, Pakistan would take the entire volume.

Natural gas pricing agreements were once reached between Iran and Pakistan, but India's status remains uncertain and as of December 2008 pricing disputes had reemerged between Iran and Pakistan. In addition to difficulties reaching economic terms, India is under US pressure to not participate in the project and has security concerns regarding having such a major energy artery running through Pakistan.

Pakistan says it will require $1 billion to build underground storage for gas to be imported from Iran and Turkmenistan, according to the country's petroleum ministry and the Asian Development Bank in a joint study with Sui Northern Gas Pipeline Ltd. (SNGPL) and Sui Southern Gas Co. Ltd. (SSGCL).

Four stages of the 56-in. OD Iranian Gas Trunkline (IGAT) system are still under development. IGAT VI will transfer gas produced by South Pars phases 6-10 from Asalouyeh across 492 km to Khuzestan province for consumption and injection. Construction is expected to be complete in 2009.

IGAT VII will move South Pars 9-10 gas from Asalouyeh 878 km to Hormozgan province and the Shar-Khoon refinery. Part of the gas will be shipped onward to Sistan and Baluchistan provinces, with some also potentially used for export. Completion is expected 2010-2011.

IGAT VIII, scheduled for completion in 2009, will transport South Pars gas across 1,050 km from Asalouyeh to the Parsian gas plant and Tehran.

IGAT IX, slated for 2011 completion and also termed the Europe Gas Export Line, will move South Pars 9-10 gas 1,863 km from Asalouyeh to the Turkish border. Construction on the stretch from Asalouyeh to Bidbolyand was completed as of June 2008.

Iran expressed interest later in 2008 in finding an international partner on a build-own-operate basis for the balance of IGAT IX, which could link with either the proposed Trans-Adriatic pipeline or the proposed Nabucco pipeline for exports further west.

Iran is also building a 2,163-km ethylene pipeline from Asalouyeh in southern Iran to the country's northwestern provinces. The pipeline will transport ethylene to meet the feed requirements of new petrochemical complexes in Gachsaran, Khoramabad, Kermanshah, Sanandaj, and Mahabad.

Construction of the pipeline began in 2003 and is targeted for completion in 2009-10. The West Ethylene Pipeline was initially to transport 1.5 million tonnes for 1,500 km to feed five planned petrochemical complexes. The

Iranian Parliament, however, instructed the Petroleum Ministry to build five more complexes in the cities of Andimeshk, Dehdasht, Hamedan, Kermanshah, and Miyandoab as a means to boost production in the less-developed parts of the country. The pipeline's length, therefore, was extended to 2,163 km and capacity increased to 2.8 million tonnes.

An eleventh plant was added to the plan in June 2008 with construction of the pipeline roughly 50% complete at that time, raising doubts that the balance will be completed on schedule.

Olefin plants in Asalouyeh and the Bandar Imam special economic petrochemical zone in Mahshahr City will supply the ethylene; one set for completion in 2010 and the other in 2013.

Bakhtar Petrochemical Co., which is constructing the pipeline, is a private joint stock holding company.

Africa

Nigeria, Algeria, and Niger hope to start gas exports via the proposed 18-25 billion cu m/year Trans-Sahara gas pipeline in 2015. Once built, the 4,300-km line would transport gas from the Niger Delta in southern Nigeria through Niger and into Algeria and Europe. Cost estimates for the project are $13 billion.

According to the feasibility report published by engineering company Penspen Consulting, TSGP would consist of a 48-56-in. pipeline from Nigeria to Algeria's Mediterranean coast at Beni Saf and subsea pipelines of 20-in. between Beni Saf and Spain.

Europe expects to import 500 billion cu m of gas in 2020. Europe's Energy Commissioner Andris Pielbags cautiously welcomes the pipeline, stressing the need for Europe to diversify gas suppliers and enhance security of supply. Pielbags, however, said it was important to determine the availability of proved gas reserves, the feasibility of the project, its economic viability, and geopolitical developments in the region.

Nigeria's export plans are ambitious, particularly as it is trying to boost the use of domestic gas for electric power generation, but the country has expressed its continued commitment to the project as recently as January 2009.

Nigeria and Russia have held talks regarding the latter's involvement in the project, which both countries appear to desire. India's GAIL has also voiced interest in participating in the project.

South Africa's New Multi-Products Pipeline (NMPP) project will move diesel, gasoline, and jet fuel from an import terminal in Durban roughly 525 km northwest to the inland Gauteng region. Transnet Ltd. received the final environmental impact report for NMPP in November 2008, with the report submitted at the same time to the Department of Environmental Affairs and Tourism for a decision.

NMPP will include as many as 10 pump stations, with 4 planned at start-up and others added as needed to meet demand. The 24-in. OD pipeline will supplement the existing 12-in. Durban-Johannesburg Pipeline (DJP), completed in 1965 and already operating at capacity.

Should final approval be granted early in 2009, Transnet plans commissioning for late 2010.

Algeria's Sonatrach plans to build a 585-km natural gas pipeline, GK3, from Hassi R'mel to an LNG terminal at Skikda. The 48-in. OD pipeline would run 275 km from Hassi R'mel to Chaiba and then 310 km from Chaiba to Skikda. Gas from the line would go into power generation and the planned Galsi pipeline in addition to being used for LNG at Skikda. Sonatrach intends to complete the pipeline in 2010.

Sonatrach also plans to complete the 532-km GR4 pipeline from Rhourde Nouss field near the Libyan border to Hassi R'mel in 2010. ✦

References

1. International Energy Outlook 2008, US Energy Information Administration, June 2008.

2. Annual Energy Outlook 2009 Early Release, US EIA, Dec. 17, 2008.

Equipment/Software/Literature

Wellhead outlet reengineered for high-heat wells

The reengineered wellhead outlet shown on the left promises to operate safely in higher temperatures typically generated by the majority of high pressure, high temperature wells.

The unit is used to connect downhole cable to the surface telemetry system. The downhole cable terminates in a pressure bulkhead and then connects to the surface cable. This ensures that if, for any reason, the downhole cable is flooded, the integrity of the wellhead is maintained. It is used in permanent completions where pressure and temperature must be continuously monitored.

Source: **AnTech Ltd.,** Unit 7, Newbery Centre, Airport Business Park, Exeter, England, UK EX5 2UL.

New, nonmetallic valve for highly corrosive processes

A nonmetallic valve designed for highly corrosive processes is on the market.

Constructed of nonmetallic, corrosion-resistant materials, the company says its valves will operate in highly caustic environments not suitable for metal and fiberglass. The all-polymer internal construction enables the valves to operate in harsh chemicals, suiting them for use with chlorine, ethylene dichloride, and hydrochloric acid.

Polymer valves operate in a similar fashion to their metal and fiberglass counterparts, the firm notes. Valves protect low-pressure atmospheric storage tanks from excessive pressure and-or vacuum and limit fugitive emissions by preventing constant tank breathing to atmosphere. The relief valve is available in vent to atmosphere or pipe-away configurations.

Source: **Groth Corp.,** 3160 W. Heartland Drive, Liberty, MO 64068.

Services/Suppliers

Aker Solutions,

Oslo, has appointed Gary Mandel executive vice-president of its process and construction business area. Mandel replaces Jarle Tautra, who moves to a similar position in Aker Solutions' energy development and services area. Previously, Mandel worked for Aker US Inc. and as CEO of Aker American Shipping. Prior to this, Mandel served as EVP for Aker Solutions' former oil, gas, process, and energy business area. Tautra has been part of Aker Solutions' executive management team since 2002 as EVP for the company's process and construction business. From 1997, he served as president of Aker Oil & Gas and as EVP of EPC Norway in Aker Maritime ASA. Prior to this, he held various positions in Norsk Hydro ASA. Nils Arne Hatleskog, previously head of energy development and services, has left the company.

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

Canadian Advanced ESP Inc.,

Edmonton has named Michael Kruk vice-president, sales, marketing, and service. His primary responsibilities will be leading and directing the domestic and international sales and service teams, as well as the marketing communications group. Kruk brings many years of extensive marketing and service experience in the ESP industry. Previously, he held a progression of management positions at A. Comeau & Associates, Reda Pump Co. Libya, and most recently Alkhorayef Commercial Co. in Kuwait. Kruk is an electronics engineering technology honors graduate of the Northern Alberta Institute of Technology.

Canadian Advanced ESP Inc. supplies all equipment and services associated with electrical submersible pump systems for artificial lift applications, horizontal pumping systems for a variety of surface high-pressure applications, and innovative variable frequency generator systems to the global oil and gas industry.

Duoline Technologies,

Odessa, Tex., has promoted Tim Stewart to FRP Supervisor. Initially hired as a material handler, Stewart then worked as an engineering technician. Prior to joining Duoline, he had more than 15 years in retail management and warehouse distribution. Stewart also attended Tarleton State University for 2 years and served 4 years in the US Army.

Stewart

Duoline is an industry leader in solving oil field corrosion problems with a unique insert liner process that secures a corrosion-resistant material such as glass-reinforced epoxy or PVC inside the steel pipe, thereby protecting steel tubulars by isolating corrosive oil field fluids and gases.

Imports of crude and products

	Districts 1–4 1-23 2009	Districts 1–4 1-16 2009	District 5 1-23 2009	District 5 1-16 2009	Total US 1-23 2009	Total US 1-16 2009	Total US *1-25 2008
	1,000 b/d						
Total motor gasoline	1,097	1,144	57	10	1,154	1,154	1,156
Mo. gas. blending comp.	790	948	53	10	843	958	673
Distillate	264	362	0	0	264	362	277
Residual	429	293	95	177	524	470	206
Jet fuel–kerosine	78	64	23	5	101	69	182
Propane–propylene	212	215	61	23	273	238	182
Other	401	491	26	(23)	427	468	657
Total products	**3,271**	**3,517**	**315**	**202**	**3,586**	**3,719**	**3,333**
Total crude	**8,861**	**8,555**	**847**	**1,311**	**9,708**	**9,866**	**10,056**
Total imports	**12,132**	**12,072**	**1,162**	**1,513**	**13,294**	**13,585**	**13,389**

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

Purvin & Gertz LNG netbacks—Jan. 30, 2009

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	11.42	9.06	10.64	8.96	9.96	10.56
Everett	5.07	3.27	4.76	3.38	3.72	5.31
Isle of Grain	6.94	5.01	6.37	4.92	5.49	6.39
Lake Charles	2.42	0.90	2.24	1.03	1.16	2.92
Sodegaura	5.73	9.09	6.00	8.83	6.81	5.21
Zeebrugge	9.24	6.25	8.02	6.16	6.75	8.10

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

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane-propylene
	1,000 bbl						
PADD 1	14,245	61,234	36,881	8,373	54,326	12,807	2,567
PADD 2	83,322	51,661	19,330	7,521	33,797	1,171	14,452
PADD 3	173,210	72,437	39,694	12,891	39,352	16,377	29,188
PADD 4	13,745	6,363	2,026	498	2,967	287	[1]1,430
PADD 5	54,359	28,164	23,445	9,118	13,510	5,403	—
Jan. 23, 2009	**338,881**	**219,859**	**121,376**	**38,401**	**143,952**	**36,045**	**47,637**
Jan. 16, 2009	**332,663**	**219,980**	**122,772**	**38,429**	**144,957**	**36,057**	**50,595**
Jan. 25, 2008[2]	**292,952**	**223,899**	**110,662**	**40,609**	**127,004**	**35,531**	**42,374**

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

Refinery report—Jan. 23, 2009

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,312	1,309	2,184	84	398	88	63
PADD 2	3,135	3,106	2,100	189	940	53	190
PADD 3	6,880	6,726	2,682	702	2,115	245	632
PADD 4	546	544	302	28	175	9	[1]218
PADD 5	2,658	2,451	1,392	382	542	134	—
Jan. 23, 2009	**14,531**	**14,136**	**8,660**	**1,385**	**4,170**	**529**	**1,103**
Jan. 16, 2009	**14,670**	**14,145**	**8,729**	**1,361**	**4,153**	**550**	**1,047**
Jan. 25, 2008[2]	**14,814**	**14,618**	**8,887**	**1,494**	**3,894**	**565**	**1,079**
	17,621 Operable capacity		**82.5% utilization rate**				

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

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

OIL&GAS JOURNAL online research center

OGJ crack spread

	*1–30–09	*2–1–08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	54.58	99.83	–45.26	–45.3
Brent crude	44.01	93.24	–49.23	–52.8
Crack spread	10.57	6.59	3.98	60.3
FUTURES MARKET PRICES				
One month				
Product value	53.84	100.71	–46.87	–46.5
Light sweet crude	42.52	91.13	–48.61	–53.3
Crack spread	11.32	9.58	1.74	18.2
Six month				
Product value	58.88	104.06	–45.17	–43.4
Light sweet crude	52.02	90.16	–38.14	–42.3
Crack spread	6.87	13.90	–7.03	–50.6

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

OGJ GASOLINE PRICES

	Price ex tax 1-28-09	Pump price* 1-28-09	Pump price 1-30-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	130.7	177.2	309.2
Baltimore	132.6	174.5	299.1
Boston	135.9	177.8	306.8
Buffalo	119.6	180.5	326.5
Miami	129.3	180.9	321.8
Newark	136.9	169.5	295.4
New York	126.9	187.8	306.5
Norfolk	131.1	169.5	295.8
Philadelphia	136.1	186.8	309.5
Pittsburgh	142.8	193.5	307.8
Wash., DC	158.4	196.8	307.1
PAD I avg	134.6	181.3	307.8
Chicago	145.0	209.4	340.4
Cleveland	149.9	196.3	299.2
Des Moines	146.1	186.5	296.8
Detroit	135.0	194.4	302.8
Indianapolis	134.0	193.4	301.2
Kansas City	144.5	180.5	288.5
Louisville	145.6	186.5	301.5
Memphis	139.6	179.4	291.8
Milwaukee	140.1	191.4	299.8
Minn.-St. Paul	140.5	184.5	296.1
Oklahoma City	131.5	166.9	281.9
Omaha	133.6	178.9	296.0
St. Louis	143.5	179.5	284.1
Tulsa	136.2	171.6	286.7
Wichita	134.1	177.5	283.5
PAD II avg	139.9	185.1	296.7
Albuquerque	140.1	176.5	292.8
Birmingham	135.2	174.5	294.5
Dallas-Fort Worth	134.1	172.5	287.5
Houston	128.7	167.1	290.5
Little Rock	138.2	178.4	289.0
New Orleans	136.1	174.5	294.8
San Antonio	134.1	172.5	287.8
PAD III avg	135.2	173.7	291.0
Cheyenne	118.1	150.5	278.8
Denver	126.8	167.2	290.5
Salt Lake City	122.5	165.4	296.0
PAD IV avg	122.5	161.1	288.5
Los Angeles	132.3	199.4	314.9
Phoenix	141.9	179.3	287.7
Portland	161.0	204.4	302.7
San Diego	143.3	210.4	321.3
San Francisco	147.9	215.0	343.7
Seattle	146.5	202.4	312.3
PAD V avg	145.5	201.8	313.8
Week's avg.	**137.3**	**182.9**	**300.5**
Jan. avg.	**131.5**	**177.1**	**304.5**
Dec. avg.	**125.5**	**171.1**	**300.6**
2009 to date	**131.5**	**177.1**	—
2008 to date	**262.1**	**305.7**	—

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

REFINED PRODUCT PRICES

	1-23-09 ¢/gal		1-23-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	116.85	New York Harbor	144.75
Gulf Coast	115.40	Gulf Coast	135.00
Los Angeles	143.00	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	105.38	ARA	139.77
Singapore	143.79	Singapore	132.14
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	112.60	New York Harbor	90.79
Gulf Coast	116.40	Gulf Coast	111.98
Los Angeles	149.00	Los Angeles	118.73
		ARA	84.18
		Singapore	96.48

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

BAKER HUGHES RIG COUNT

	1-30-09	2-1-08
Alabama	2	3
Alaska	10	9
Arkansas	50	42
California	25	34
Land	24	33
Offshore	1	1
Colorado	78	119
Florida	1	0
Illinois	0	0
Indiana	3	1
Kansas	16	13
Kentucky	11	8
Louisiana	170	142
N. Land	87	50
S. Inland waters	8	20
S. Land	22	25
Offshore	53	47
Maryland	0	1
Michigan	0	1
Mississippi	12	11
Montana	4	12
Nebraska	0	0
New Mexico	57	71
New York	1	5
North Dakota	68	50
Ohio	8	11
Oklahoma	144	193
Pennsylvania	23	20
South Dakota	0	1
Texas	662	859
Offshore	5	9
Inland waters	0	3
Dist. 1	8	21
Dist. 2	35	32
Dist. 3	53	68
Dist. 4	57	85
Dist. 5	139	183
Dist. 6	110	128
Dist. 7B	19	30
Dist. 7C	47	47
Dist. 8	80	124
Dist. 8A	22	19
Dist. 9	38	43
Dist. 10	49	67
Utah	23	39
West Virginia	27	31
Wyoming	61	74
Others—NV-6; TN-4; VA-4; WA-2	16	13
Total US	**1,472**	**1,763**
Total Canada	**432**	**593**
Grand total	**1,904**	**2,356**
US Oil rigs	309	324
US Gas rigs	1,150	1,432
Total US offshore	60	57
Total US cum. avg. YTD	**1,623**	**1,752**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	1-30-09 Percent footage*	Rig count	2-1-08 Percent footage*
0-2,500	67	—	70	7.1
2,501-5,000	67	50.7	105	48.5
5,001-7,500	195	23.5	222	25.2
7,501-10,000	329	3.3	431	3.0
10,001-12,500	292	2.7	435	4.3
12,501-15,000	290	0.3	302	0.3
15,001-17,500	145	—	93	—
17,501-20,000	63	—	72	—
20,001-over	43	—	31	—
Total	**1,491**	**6.7**	**1,761**	**8.2**
INLAND	18		36	
LAND	1,421		1,676	
OFFSHORE	52		49	

*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]1-30-09	[2]2-1-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	720	710
California	657	651
Colorado	62	65
Florida	7	6
Illinois	28	26
Kansas	104	109
Louisiana	1,175	1,262
Michigan	15	15
Mississippi	62	58
Montana	95	87
New Mexico	166	162
North Dakota	178	136
Oklahoma	175	171
Texas	1,328	1,324
Utah	53	54
Wyoming	152	148
All others	68	70
Total	**5,065**	**5,075**

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

US CRUDE PRICES

	1-30-09 $/bbl*
Alaska-North Slope 27°	49.32
South Louisiana Sweet	39.75
California-Kern River 13°	29.05
Lost Hills 30°	37.95
Wyoming Sweet	27.18
East Texas Sweet	37.75
West Texas Sour 34°	30.50
West Texas Intermediate	38.25
Oklahoma Sweet	38.25
Texas Upper Gulf Coast	32.25
Michigan Sour	31.25
Kansas Common	37.25
North Dakota Sweet	25.00

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

WORLD CRUDE PRICES

$/bbl[1]	1-23-09
United Kingdom-Brent 38°	44.01
Russia-Urals 32°	42.29
Saudi Light 34°	39.51
Dubai Fateh 32°	42.43
Algeria Saharan 44°	44.50
Nigeria-Bonny Light 37°	46.35
Indonesia-Minas 34°	44.89
Venezuela-Tia Juana Light 31°	38.56
Mexico-Isthmus 33°	38.45
OPEC basket	42.27
Total OPEC[2]	41.21
Total non-OPEC[2]	40.61
Total world[2]	40.95
US imports[3]	37.82

[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]

	1-23-09	1-16-09	1-23-08	Change, %
	bcf			
Producing region	808	856	745	8.5
Consuming region east	1,212	1,343	1,298	–6.6
Consuming region west	354	361	296	19.6
Total US	**2,374**	**2,560**	**2,339**	**1.5**
	Nov. 08	**Nov. 07**	**Change, %**	
Total US[2]	**3,346**	**3,442**	**–2.8**	

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

Statistics

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Nov. 2008	Oct. 2008	11 month average production 2008	11 month average production 2007	Change vs. previous year Volume	Change vs. previous year %	Nov. 2008	Oct. 2008	Cum. 2008
	Crude, 1,000 b/d						Gas, bcf		
Argentina	630	627	609	626	–17	–2.7	116.6	123.3	1,373.49
Bolivia	40	40	40	44	–3	–8.0	41.0	43.0	461.60
Brazil	1,807	1,832	1,809	1,742	67	3.8	35.0	39.0	406.00
Canada	2,691	2,599	2,581	2,632	–51	–1.9	447.6	461.4	5,103.56
Colombia	600	590	579	528	50	9.5	22.0	23.0	248.00
Ecuador	500	500	500	499	1	0.2	1.0	1.0	11.00
Mexico	2,711	2,757	2,806	3,094	–288	–9.3	217.2	222.7	2,304.24
Peru	109	103	79	75	4	4.9	10.6	11.0	107.70
Trinidad	115	115	113	121	–7	–6.0	113.0	117.0	1,264.72
United States	5,008	4,645	4,945	5,065	–120	–2.4	1,797.0	1,801.0	19,584.00
Venezuela[1]	2,350	2,350	2,357	2,395	–37	–1.6	72.0	75.0	816.00
Other Latin America	83	83	83	83	—	0.1	5.3	5.5	60.04
Western Hemisphere	**16,644**	**16,241**	**16,502**	**16,905**	**–402**	**–2.4**	**2,878.3**	**2,922.9**	**31,740.34**
Austria	18	18	17	17	—	–0.7	4.8	5.0	48.95
Denmark	292	264	287	312	–25	–8.1	28.2	22.5	299.53
France	18	19	20	19	0	1.4	2.8	1.6	29.84
Germany	58	59	60	68	–7	–11.0	46.0	47.4	499.08
Italy	91	109	101	108	–8	–7.1	23.0	26.0	276.00
Netherlands	29	28	34	40	–6	–15.4	300.0	250.0	2,680.00
Norway	2,276	2,241	2,170	2,275	–104	–4.6	332.0	310.0	3,149.75
Turkey	42	42	41	41	—	0.9	—	—	—
United Kingdom	1,412	1,398	1,409	1,521	–112	–7.4	225.9	217.2	2,358.83
Other Western Europe	3	3	4	4	–1	–14.2	1.7	1.5	17.73
Western Europe	**4,240**	**4,181**	**4,143**	**4,405**	**–263**	**–6.0**	**964.4**	**881.1**	**9,359.71**
Azerbaijan	750	750	900	825	75	9.0	31.0	31.0	353.00
Croatia	15	14	15	16	–1	–6.2	5.6	5.5	61.36
Hungary	14	14	15	16	–1	–8.9	7.8	8.2	82.23
Kazakhstan	1,450	1,400	1,388	1,082	306	28.3	100.0	100.0	918.00
Romania	90	90	93	98	–6	–5.6	18.0	19.0	196.00
Russia	9,760	9,830	9,755	9,884	–128	–1.3	1,900.0	1,850.0	20,750.00
Other FSU	400	450	405	462	–57	–12.4	550.0	500.0	5,190.00
Other Eastern Europe	46	46	48	48	—	–0.1	17.8	18.8	187.28
Eastern Europe and FSU	**12,526**	**12,594**	**12,618**	**12,430**	**187**	**1.5**	**2,630.2**	**2,532.5**	**27,737.87**
Algeria[1]	1,360	1,390	1,378	1,355	24	1.7	270.0	280.0	3,025.00
Angola[1]	1,888	1,860	1,900	1,688	212	12.5	5.0	5.0	54.10
Cameroon	80	81	84	85	—	–0.5	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	700	700	677	645	33	5.1	130.0	135.0	1,475.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.66
Gabon	240	240	235	230	5	2.0	0.3	0.3	3.36
Libya[1]	1,710	1,730	1,725	1,705	20	1.2	35.0	37.0	377.00
Nigeria[1]	1,900	1,940	1,947	2,166	–219	–10.1	78.0	82.0	875.00
Sudan	500	500	489	472	17	3.7	—	—	—
Tunisia	88	88	85	96	–11	–11.2	8.0	8.3	70.57
Other Africa	221	221	221	222	—	–0.2	8.7	9.1	97.80
Africa	**9,271**	**9,335**	**9,326**	**9,247**	**79**	**0.9**	**535.1**	**556.8**	**5,978.49**
Bahrain	170	170	170	172	–2	–1.4	33.0	35.0	300.26
Iran[1]	3,760	3,850	3,909	3,932	–23	–0.6	280.0	295.0	3,215.00
Iraq[1]	2,370	2,260	2,375	2,070	305	14.7	22.0	22.0	219.20
Kuwait[1,2]	2,585	2,640	2,610	2,435	175	7.2	42.0	45.0	459.00
Oman	710	720	719	711	8	1.2	58.0	60.0	642.00
Qatar[1]	820	850	853	799	54	6.7	180.0	185.0	1,990.00
Saudi Arabia[1,2]	8,765	9,260	9,127	8,594	533	6.2	200.0	215.0	2,370.00
Syria	390	390	387	390	–3	–0.7	17.0	18.0	193.00
United Arab Emirates[1]	2,300	2,540	2,598	2,531	67	2.7	120.0	130.0	1,435.00
Yemen	300	300	307	339	–32	–9.4	—	—	—
Other Middle East	—	—	—	—	—	28.2	10.0	10.6	118.17
Middle East	**22,170**	**22,980**	**23,055**	**21,972**	**1,082**	**4.9**	**962.0**	**1,015.6**	**10,941.63**
Australia	511	504	456	452	4	0.9	122.6	110.5	1,228.90
Brunei	160	165	160	179	–19	–10.6	33.0	34.1	370.65
China	3,870	3,861	3,811	3,751	61	1.6	241.3	221.1	2,593.90
India	681	700	676	688	–12	–1.7	85.5	89.2	941.67
Indonesia[1]	850	850	859	839	20	2.4	215.0	225.0	2,510.00
Japan	14	15	16	16	—	—	9.0	9.5	114.84
Malaysia	770	730	752	755	–4	–0.5	140.0	140.0	1,585.00
New Zealand	44	47	56	35	21	60.6	11.0	12.0	136.90
Pakistan	66	64	66	69	–2	–3.4	120.1	115.4	1,338.69
Papua New Guinea	40	40	41	47	–6	–12.5	0.9	1.0	10.50
Thailand	227	234	228	212	16	7.8	32.0	43.0	471.00
Vietnam	250	250	275	311	–35	–11.4	14.0	15.0	163.50
Other Asia–Pacific	35	35	39	34	5	15.1	94.5	97.5	1,071.56
Asia–Pacific	**7,517**	**7,494**	**7,436**	**7,387**	**49**	**0.7**	**1,118.8**	**1,113.4**	**12,537.12**
TOTAL WORLD	**72,368**	**72,825**	**73,080**	**72,347**	**733**	**1.0**	**9,088.8**	**9,022.3**	**98,295.15**
OPEC	31,158	32,020	32,137	30,508	1,630	5.3	1,520.0	1,597.0	17,356.30
North Sea	4,005	3,922	3,885	4,126	–241	–5.8	676.0	624.5	6,608.86

[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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Relief from tax law complexity would help US economy

The new Treasury secretary's tax embarrassment highlights a lever that he and Congress profitably might pull to repair a broken economy.

Alas, no one is talking about fixing a misshapen and abused tax code.

The $42,702 that Timothy Geithner paid in back income tax and fines didn't keep the former New York Federal Reserve Bank chief from becoming head of the Treasury Department.

Americans, after all, know how difficult it can be to comply with serpentine tax laws and raised scant fuss about Geithner. Most of them over a certain age have made honest tax mistakes, too, and amiably put Geithner's misstep in that benign category.

If someone with his financial acumen can get caught overlooking self-employment taxation for 4 years while employed by the International Monetary Fund, other taxpayers who've received dunning notices from the Internal Revenue Service needn't feel stupid.

On the other hand, many American taxpayers do routinely cheat, trusting statutory complexity to obscure their malfeasance and probably smirking over the Geithner affair.

Use by lawmakers for the political management of human behavior has made the tax code scandalously incomprehensible.

The legislative juggernaut marketed as a stimulus package is just the latest example.

Amid hundreds of billions of dollars' worth of claims against future prosperity now barreling toward an economy in crisis lurk countless tax favors for people who act in accordance with governmental wishes.

Producers, dispensers, and users of alternative and renewable forms of energy, for example, will benefit even more than they already do from these goodies.

Somehow, the subsidized use of noncompetitive energy is supposed to stimulate the economy. "Green jobs," and all that.

In fact, the strategy makes as much sense as further complicating a tax code too confusing even for someone qualified to be Treasury secretary.

A strong step toward economic restoration would be replacement of a corrupt tax system with something simpler and less politically vulnerable, such as a flat tax or consumption tax.

But Geithner will be loath to bestir the tax snake that bit him. And Congress won't surrender its insidious implement of manipulation without a fight.

(Online Jan. 30, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Crude prices may be bottoming

As February opened, crude prices appeared to be "in the early stages of a bottoming process" amid growing speculation that production cuts by the Organization of Petroleum Exporting Countries might finally be catching up to the demand destruction from the international financial crisis.

In New Orleans, analysts at Pritchard Capital Partners LLC said OPEC is "moving forward diligently" with reductions below its 24.8 million b/d target. The 11 participating OPEC members, aside from Iraq, are expected to produce 23.6 million b/d in the 4 weeks ending Feb. 14, down from 23.7 million b/d in the 4 weeks through Jan. 17.

Furthermore, flattening of the forward price curve as the 12-month strip contango narrowed to $11/bbl from $27/bbl was seen by Pritchard Capital Partners as "a clear signal that OPEC production cuts are having an impact on the crude oil market."

During the last week of January, the March contract for benchmark US light, sweet crudes fluctuated between $41.44-45.73/bbl before closing at $41.68/bbl Jan. 30 on the New York Mercantile Exchange. In the first trading session of 2009 on Jan. 2, the March contract closed at $50.21/bbl, while the then front-month February contract was at $46.34/bbl.

At EnVantage Inc., a Houston advisory and energy investment firm, analysts said, "It is highly probable that the March WTI contract will follow the same track as the February contact and go back into the $30/bbl range, but we continue to see WTI prices trading between $35/bbl as a bottom and $50/bbl as a ceiling."

North Sea Brent historically has traded at a 3-5% discount to US benchmark West Texas Intermediate. However, analysts in the Houston office of Raymond James & Associates Inc. reported, "Since the beginning of 2009, this trend has reversed, with Brent oil…trading 10% higher than WTI [on Jan. 30]. We believe this is largely driven by higher than average inventory levels in the US, including at Cushing, Okla., the hub from which WTI is sold. In addition, the current contango forward strip is exacerbating the situation with a contract for WTI delivery in August 2009 trading at $52.07/bbl…thereby encouraging storage. We do not expect this differential to narrow materially as long as US inventories remain high."

The two benchmark crudes were moving "in diverging trends," with the WTI contango widening and the Brent contango narrowing, said Olivier Jakob at Petromatrix, Zug, Switzerland. "But given that the widening of the WTI futures contango is immediately offset by a rise in [US Gulf market] physical cash differentials," he said, "…Brent [is] a better benchmark of the world crude oil supply and demand."

Natural gas outlook

Although Raymond James analysts refrained from trying to predict winter weather Feb. 2 on Groundhog Day, they said, "We do foresee 6 more months, not weeks, of deteriorating natural gas prices."

Pritchard Capital Partners said, "Natural gas prices have declined sharply to multi-year lows as demand destruction appears to be outpacing any slowdown in domestic supply growth." However, with the US land rig count down 28% over the last 5 months, they expect declining demand and reduced drilling activity to result in a supply-demand balance by mid-year.

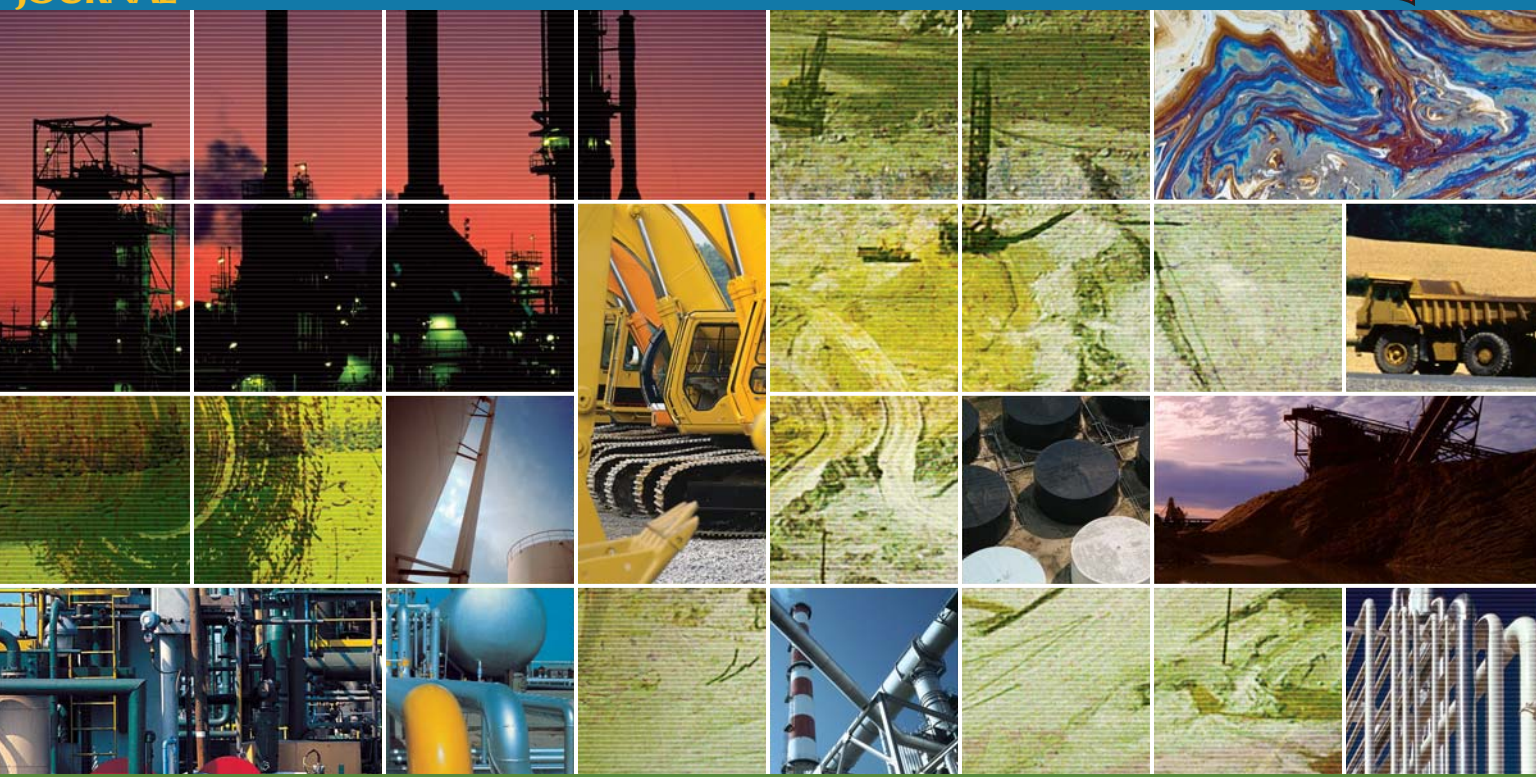
Raymond James analysts expect a 60% drop in the US rig count this year, compared with a 40% prediction just 2 months ago. The bigger reduction will include a 65% roll-back in the number of rigs drilling for gas and a 50% cut in the number drilling for oil.

However, they said US production likely will not fall "as fast or as far" as the rig count.

"Producers will stop drilling their least productive, least economic wells first," Raymond James analysts observed. "When we account for the highly productive shale wells and consider that horizontally drilled wells (the most productive) are being dropped from drilling programs at a much slower rate, we find that gas production will probably not fall as fast or as far as the rig count (in percentage terms)."

Meanwhile, they said, "We do not think a 60% decline in the rig count is priced into the stocks for North American gas-driven companies. Likewise, we still do not believe the magnitude of the gas markets supply and demand problem is priced into US natural gas prices. While we think a late 2009 gas price and stock price rally may still be in the cards, asset utilization rates and North American service company earnings should be down year over year in both 2009 and 2010."

(Online Feb. 2, 2009; author's e-mail: samf@ogjonline.com)



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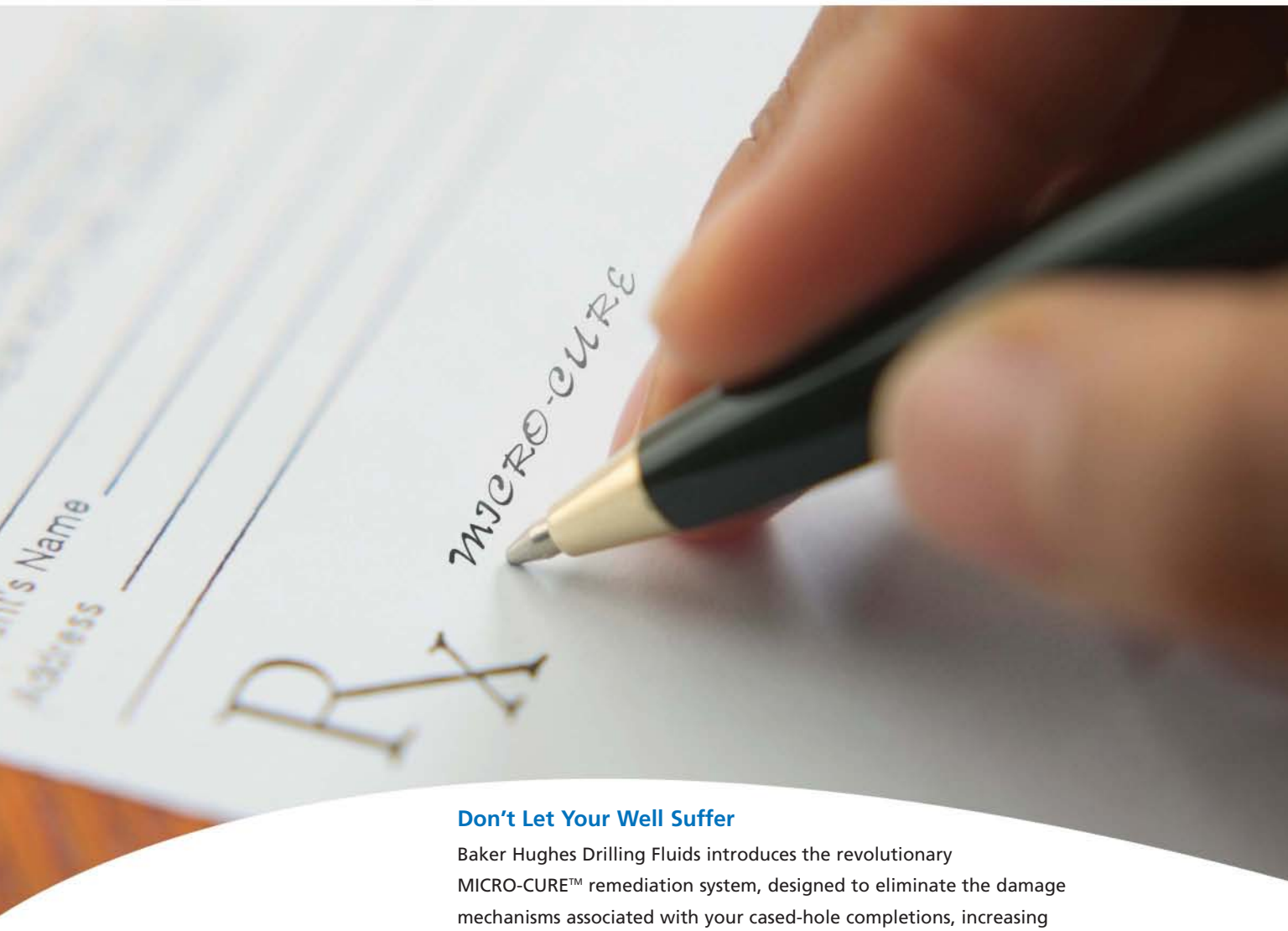

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