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

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

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- Refining
- Pipeline
- Gas Processing
- LNG
- Sulfur

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Updates in April and November.

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Semi-Submersibles Under Construction 2007-2011

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- Design
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Fields on Iraq's borders require joint operations
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OIL&GAS JOURNAL®

Apr. 28, 2008
Volume 106.16

CAPITAL SPENDING OUTLOOK

REGULAR FEATURES

COVER

The primary processing unit, including the atmospheric vacuum unit and the residue hydroconversion unit, at the Scotford Upgrader is part of Shell's Athabasca Oil Sands Project. The upgrader, located next to Shell Canada's Scotford refinery near Fort Saskatchewan, Alta., uses hydrogen-addition technology to upgrade the bitumen from the Muskeg River Mine into synthetic crude oils. Above, large trucks carry raw ore to an extraction plant. Photos courtesy of Shell Canada Ltd.

MORE BYTES & MORE BARRELS

2008 Digital Energy Conference & Exhibition

May 20-21, 2008 | Marriott Westchase | Houston, Texas

The **Digital Energy Conference & Exhibition** is the **convergence of Digital, Production and Geophysical** communities to broaden and leverage the ever-growing computing power available to the oil and gas industry. Join us and map out how you can **convert this power into profits.**

Program-at-a-Glance

Tuesday May 20th				
7:00 - 8:30 AM	Registration in Hotel Lobby Area / Continental Breakfast in Exhibit Area			
8:30 - 9:30 AM	Introductions: Mehrzad Mahdavi		Welcome: Allen Shook, SPE-GCS Chairman **Introductory Keynote: Don Paul, VP, Chevron**	
9:30 - 10:00 AM	Networking in Exhibit Area			
10:00 - 11:30 AM	*Unlocking the Value of Data	*Integrated Operations and Remote Operations Centers	*Work Processes / Workflows in Digital Oilfields	*Remote Computing / Visualization
11:30 AM - 12:30 PM	Lunch Introductions : Don Moore Announcement: RPSEA IT Technical Advisory Committee: Michael Ming Prize Drawing by Aspentech **Luncheon Keynote: Arjun N. Murti, Managing Director and Partner, Goldman Sachs**			
12:30 - 1:00 PM	Networking in Exhibit Area			
1:00 - 2:30 PM	*Data and Integration Architectures	*Integrated Operations and Remote Operations Centers	*Work Processes / Workflows in Digital Oilfields	*Intergration and Collaboration
2:30 - 3:00 PM	Networking in Exhibit Area			
3:00 - 4:15 PM	Concluding Keynotes Moderator: Don Paul **Concluding Keynotes: Dona Crawford, Associate Director for Computation, LLNL and John Gibson, President and CEO, Paradigm** IT Innovation Award			
4:15 - 6:00 PM	Networking Reception in Exhibit Area			
Wednesday May 21st				
7:00 - 8:30 AM	Registration in Hotel Lobby Area / Continental Breakfast in Exhibit Area			
8:30 - 9:30 AM	Introductions: Roger Hite		**Morning Keynotes: Ashok Belani, CTO, Schlumberger Brian Russell, Co-founder Hampson-Russell Software Services Ltd and Past President SEG**	
9:30 - 10:00 AM	Networking in Exhibit Area			
10:00 - 11:30 AM	*Reliability and Maintenance of Systems	*RTO for Mature Fields	*The Renaissance Man: Bridging the Silos of E & P	*Benefits and Issues for Seafloor Seismic Monitoring
11:30 - 12:00 PM	Networking in Exhibit Area			
12:00 - 1:30 PM	*Lunch & Learn - **Riding the IT Curve:** Advances in Software *Host: Murthy Divakaruni, Larson & Toubro & Scott Meyers, Shell*	*Lunch & Learn - **Riding the IT Curve:** Interface Technologies *Host: Art Schroeder, Ultra-deepwater Technology Manager, RPSEA*	*Lunch & Learn - **Riding the IT Curve:** High Performance Computing *Host: Herb Yuan, Shell Co-Host: Philippe Flichy, Merrick Systems*	
1:30 - 2:00 PM	Networking in Exhibit Area			
2:00 - 3:30 PM	*Information Integrity and Reliability	*RTO for Mature Fields	*Safe Operations in Digital Oilfields	*Shared Earth Modeling
3:30 - 4:45 PM	**CIO / CTO Roundtable - Now What?** Moderators: Don Paul, VP, Chevron Participants: **Don Moore, CIO, Occidental, Zhanna Golodryga, CIO, BHP Billiton, Washington Salles, IT Executive Manager, Petrobras and David Latin, Upstream CIO, BP**			
4:45 - 5:00 PM	Closing Remarks and Prize Drawing Moderator: Herb Yuan, Shell			

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Vice President
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General Interest — Quick Takes

Alaska rejects ExxonMobil's Point Thomson plan

Alaska state officials have rejected ExxonMobil Corp.'s latest plan to develop Point Thomson Unit (PTU) on Alaska's North Slope. The gas-condensate area has no production.

Alaska Natural Resources Commissioner Tom Irwin said the proposed plan was not in the state's best interest because it would have involved development on the 106,200-acre PTU, east of Prudhoe Bay, without any commitment to produce gas.

"In light of the history of this unit, I did not trust the appellant's commitment to follow through with their 23rd plan of development," Irwin said Apr. 22.

No immediate comment was available from ExxonMobil, PTU operator. It estimates the high-pressure reservoir has reserves of more than 8 tcf of gas and 200 million bbl of condensate (OGJ, Mar. 10, 2008, p. 36.)

ExxonMobil along with BP Exploration (Alaska) Inc., Chevron USA Inc., and ConocoPhillips Alaska Inc. hold working interests in PTU, covering 45 state oil and gas leases. The oil companies have said production hinges upon construction of an Alaska gas pipeline to the Lower 48.

MMS moving forward on alternative energy

The US Department of the Interior's Minerals Management Service designated five areas on the Outer Continental Shelf as priority areas for research on alternative energy in federal waters.

The agency issued an Apr. 18 published notice that outlines details about the areas along with instructions for a 30-day public comment period.

The five areas are off New Jersey, Delaware, Georgia, Florida, and California. The agency proposes limited, temporary leases in these areas for data collection and technology testing related to wind, wave, and ocean current energy development.

There will be no commercial energy production activity associated with the proposed leases. Randall Luthi, MMS director, said the research is intended to increase understanding of potential offshore renewable energy sources.

Before issuing leases or selecting specific project proposals, MMS is evaluating the five areas as they relate to environmental factors and commercial activities such as fishing and shipping.

Colorado lawmakers introduce Roan leasing bill

US Sen. Ken Salazar and Reps. John T. Salazar and Mark Udall introduced legislation Apr. 17 that the three Colorado Democrats said would protect the Roan Plateau while assuring that Coloradoans would receive a fair share of revenues from oil and gas development there.

S. 2879 would require the US Bureau of Land Management to issue leases on the plateau in phases, initially outside of cutthroat trout watersheds, and consider factors designed to maximize revenues to the federal treasury and to the state while minimizing environmental impacts, according to the federal lawmakers.

Before each new leasing round, BLM would have to confirm that wells necessary to recover 90% of the recoverable natural gas beneath the previously leased development area were completed and that stringent environmental standards were met, they said.

The bill also would expand BLM's Areas of Critical Environmental Concern to include the headwaters of two creeks, which the lawmakers said are critical native cutthroat trout watersheds. It also would limit development outside the ACECs and within development corridors along existing ridge-top roads to 20% of these areas.

A spokesman for the Independent Petroleum Association of Mountain States in Denver said on Apr. 22 that the organization was pleased that the three lawmakers apparently have dropped their opposition to any further Roan Plateau federal leasing.

But IPAMS Communications Director Jon Bargas also told OGJ that Congress transferred Naval Oil Shale Reserves 1 and 3 from the US Department of Energy to BLM in 1997 with the express purpose of leasing the 73,620 acres. "Since then, BLM has developed one of the most stringent leasing plans we've ever seen. Leasing of the Roan Plateau has been delayed long enough," he said.

Venezuela hits exported oil with new tax

Venezuela has increased taxes on crude oil and oil products moving out of the country.

On their exported oil volumes net of imports, companies must pay a per-barrel tax of 50% of the amount by which the monthly average price of Brent crude exceeds $70/bbl. The tax rate increases to 60% when the Brent price exceeds $100/bbl.

Payments of the new tax are deductible in calculations of income tax. Companies may deduct contributions to Venezuela's National Development Fund from their new-tax liabilities.

The move is the latest in a series of blows to producers in Venezuela and comes as the government moves to nationalize key industries, including cement and steel.

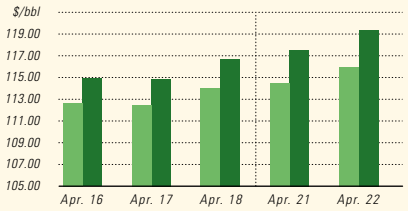
After welcoming international operators to Venezuelan exploration and production opportunities in the 1990s, the government reversed course after the election of President Hugo Chavez in 1998.

A hydrocarbons law enacted in 2001 raised royalties on production by private companies to 20-30% from 1-17%, guaranteed state-owned Petroleos de Venezuela SA majority interests in new projects, and required that foreign participation in oil and gas projects take the form of joint ventures with PDVSA.

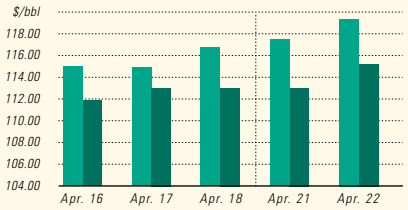
Since then the government has renegotiated agreements in effect when the 2001 hydrocarbons law took effect into joint ven-

Industry Scoreboard

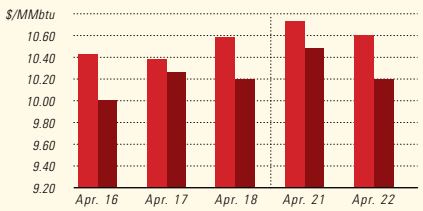
IPE BRENT / NYMEX LIGHT SWEET CRUDE



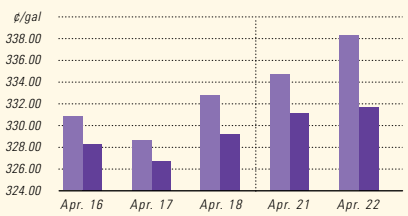
WTI CUSHING / BRENT SPOT



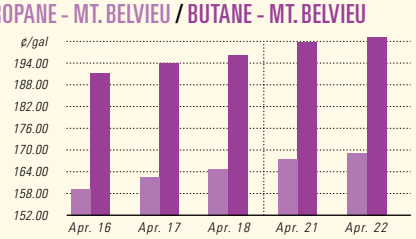
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



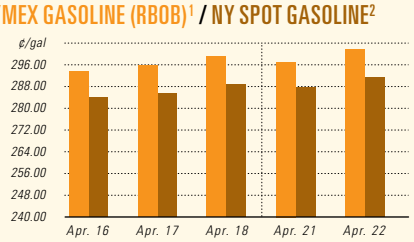
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Non-oxygenated regular unleaded.

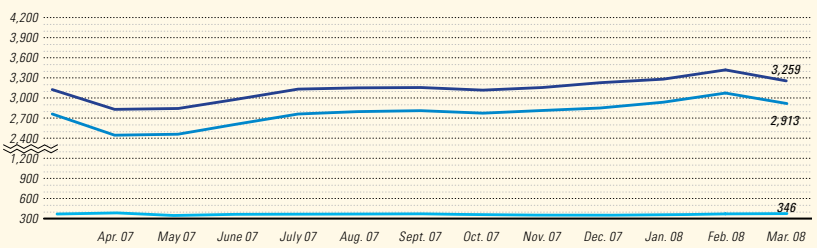
US INDUSTRY SCOREBOARD — 4/28

Latest week 4/11	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,268	9,192	0.8	9,049	9,049	—
Distillate	4,248	4,287	–0.9	4,268	4,374	–2.4
Jet fuel	1,540	1,588	–3.0	1,565	1,606	–2.6
Residual	689	746	–7.6	652	806	–19.1
Other products	4,817	4,734	1.8	4,922	4,896	0.5
TOTAL DEMAND	20,562	20,547	0.1	20,361	20,751	–1.9
Supply, 1,000 b/d						
Crude production	5,096	5,192	–1.8	5,081	5,179	1.9
NGL production[2]	2,447	2,419	1.2	2,409	2,312	4.2
Crude imports	9,243	10,278	–10.1	9,738	9,914	–1.8
Product imports	3,203	3,606	–11.2	3,349	3,408	–1.7
Other supply[3]	1,170	669	74.9	1,147	86.7	32.3
TOTAL SUPPLY	21,159	22,164	–4.5	21,724	21,680	0.2
Refining, 1,000 b/d						
Crude runs to stills	14,620	14,921	–2.0	14,620	14,828	–1.4
Input to crude stills	14,793	15,268	–3.1	14,793	15,188	–2.6
% utilization	84.7	87.5	—	84.7	87.0	—

Latest week 4/11	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	313,660	316,016	–2,356	332,405	–18,745	–5.6
Motor gasoline	215,751	221,268	–5,517	197,007	18,744	9.5
Distillate	106,079	106,027	52	117,327	–11,248	–9.6
Jet fuel-kerosine	39,709	38,510	1,199	40,686	–977	–2.4
Residual	38,339	39,258	–919	40,803	–2,464	–6.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	22.0	22.1	–0.5	22.0	—	
Motor gasoline	23.3	24.0	–2.9	21.0	11.0	
Distillate	25.0	24.6	1.6	27.0	–7.4	
Propane	20.6	19.5	5.6	22.8	–9.6	
Futures prices[5] **4/18**			**Change**		**Change**	**%**
Light sweet crude, $/bbl	114.41	109.41	4.67	62.85	51.56	82.0
Natural gas, $/MMbtu	10.33	9.91	0.42	7.80	2.53	32.5

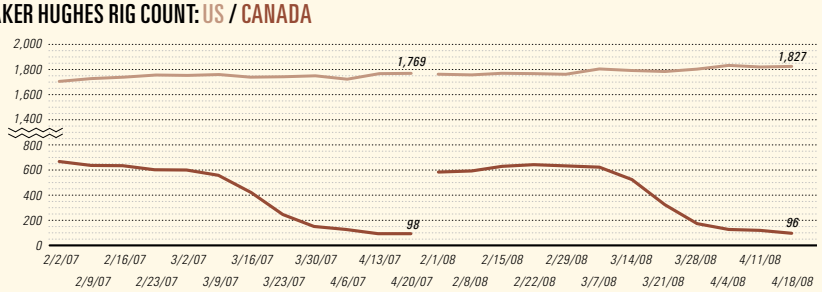
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

tures with PDVSA as controlling partner.

It also has restructured the four "strategic associations" producing extra-heavy crude from the Orinoco belt and raised their royalties and income-tax rates. In response, ConocoPhillips and ExxonMobil Corp. quit their Venezuelan heavy-oil projects.

Iraq expects new energy law, closer EU ties soon

Iraqi Prime Minister Nuri al-Maliki told European parliamentarians that his country's Oil and Gas Draft Law will be passed soon to attract international energy investment.

Al-Maliki told the European parliament's foreign affairs committee that his government is nearing a final agreement on the law, which will pave the way for signing strategic partnership agreements and developing investments.

Europe argues that the law's ratification is essential for development of international investment in Iraq's energy industry.

Meanwhile, the European Commission said Iraq has offered to increase its supply of natural gas to the European market over the next 3 years. The offer was made during talks between Iraqi Oil Minister Hussein al-Shahristani and EU Energy Commissioner Andris Piebalgs.

The EC said Iraqi officials are ready to sign a draft energy memorandum of understanding, which would open the way to closer EU-Iraqi energy ties.

The EC said Iraq made "a political gesture of goodwill" by promising to export at least 5 billion cu m of gas to the European market by 2011.

It said Iraq also was committed to increasing its oil production to 3 million b/d by yearend and that it aimed for 4.5 million b/d by 2012.

"This should be a favorable contribution toward decreasing oil prices," the commission reported in a statement. "Iraq confirms it is exploring new areas for production."

EC Pres. Jose Manuel Barroso said negotiations on a complete energy pact with Iraq "are going on very well" and suggested that a final agreement could be reached by May. ✦

Exploration & Development — *Quick Takes*

Dana makes oil find on West Rinnes structure

Dana Petroleum PLC will sidetrack well 210/24a-11 into the neighboring East Rinnes structure on Block 210/24a in the northern UK North Sea after discovering oil on the West Rinnes structure, also on Block 210/24a.

The well produced up to 7,800 b/d of 32° oil during a drill stem test from the Brent reservoir on the West Rinnes structure. Dana said it is confident the size of the East Rinnes structure is similar.

The well reached a total measured depth of 6,470 ft, and the flow rate was limited by test equipment on the drilling rig, the company said. Dana is encouraged by initial tests that the well's oil quality is similar to that being produced at Hudson oil field 5 km away. The well found excellent quality sands throughout the Brent sequence, Dana reported.

"A comprehensive set of wireline log data has been acquired, including pressure data and oil samples," Dana said.

Dana said the results "exceeded our predrill expectations" and that the discovery at West Rinnes gives "strong encouragement" for other prospects in the area.

Australia extends continental shelf acreage

The United Nations has allowed Australia to greatly extend its continental shelf after 15 years of lobbying.

The UN found that Australia's territory should be extended by 2.5 million sq km—an area about five times the size of France. The new area takes in extensions of the Exmouth Plateau and Wallaby Plateau in the west, the Great Australian Bight in the south, and the Lord Howe Rise in the east.

All are areas the government scientific body Geoscience Australia thinks could hold petroleum reserves and are future potential exploration areas.

No one will put a figure on likely petroleum resources in this new offshore territory, but all agree it is virtually unexplored.

The announcement leaves a lot of unexplored territory that may produce Australia's next oil and gas province, according to Belinda Robinson, Australian Petroleum Production and Exploration Association chief executive.

"We know very little about [the new areas] but a number of them are adjacent to existing producing areas, including the Browse and Carnarvon basins off Western Australia, so we'd be hopeful they may be prospective," Robinson said.

However, she added that having jurisdiction over the acreage is not enough. The challenge for Australia is to persuade potential investors to risk money here rather than elsewhere.

"This requires a two-pronged approach: first to ensure the availability of baseline geological information and second to ensure that the fiscal framework takes account of the high costs and high risks involved in exploring these areas," she said.

Husky, CNOOC to develop Madura BD field

Husky Energy Inc., Calgary, has reached an agreement with China's CNOOC Ltd. to jointly develop Madura BD gas and natural gas liquids field off East Java, Indonesia (OGJ, Jan. 22, 2007, p. 37). The agreement covers the development and further exploration of the Madura Straits production-sharing contract.

Deal specifics include payment of $125 million to Husky by CNOOC to acquire a 50% equity interest in Husky Oil (Madura) Ltd., which holds a 100% interest in the Madura Straits PSC.

Madura Straits PSC covers 2,794 sq km of exploration acreage about 40 km north of East Java. Since 1984, 10 wells have been drilled on this block, resulting in two discoveries: Madura BD and MDA fields. In 2007, Husky signed three gas sale and purchase agreements for the sale of 100 MMcfd of gas from Madura BD field to East Java buyers.

CNOOC subsidiary CNOOC Southeast Asia Ltd. currently operates two blocks in Indonesia and holds interests in numerous other blocks.

Husky holds a 100% interest in the East Bawean II PSC, off In-

donesia, and will continue to focus on exploration and drilling activities in Indonesia. Husky recently completed a 1,410 sq km, 3D seismic program over this block in preparation for a two-well exploration program in 2009. ✦

Drilling & Production — *Quick Takes*

IOR-EOR offers lowest-cost reserves additions

Unlike in past years, improved or enhanced oil recovery is now the least costly method for adding reserves, according to a presentation at the 16th SPE/DOE Improved Oil Recovery Symposium, Apr. 21 in Tulsa.

In his presentation, Rafael Sandrea, president of IPC Petroleum Consultants Inc., Tulsa, estimated that IOR-EOR could add reserves for a capital expenditure of $2-4/bbl. He said this is less than the needed $4.30-6.25/bbl capex for heavy oil production, $4-6/bbl spending for deepwater, $12.86/bbl for acquisitions, and $14.42/bbl for global finding and development costs.

Sandrea also said the target for IOR-EOR remains huge. His estimate of discovered conventional oil in-place to date is 10.9 trillion bbl. In this estimate, he does not include the 3 trillion bbl of heavy oil and bitumen found in Alberta and the Orinoco region of Venezuela.

The world has produced only 1.028 trillion bbl of conventional oil, and Sandrea said that without expanding the use of IOR-EOR methods, the ultimate worldwide recovery factor would be only 22%.

He also cautioned that without extensive increases in recovery factors, world oil demand would face the following supply shortfalls: 2010, 2.7 million b/d; 2015, 5.4 million b/d; 2020, 12.1 million b/d; and 2030, 30.6 million b/d.

Sandrea said the $200-400 billion capital spending needed for adding 100 billion bbl of IOR-EOR reserves is in the same range as the industry's current global spending of $260 billion/year.

BP begins oil production from Gunashli field

BP PLC has started oil production from the third phase of Azeri-Chirag-Gunashli (ACG) field in the Azerbaijan area of the Caspian Sea.

The field will produce plateau oil levels of 320,000 b/d via the deepwater Gunashli (DWG) platform complex in 175 m of water. The DWG facility has 48 drilling slots and a drilling and production platform bridge linked to a water injection and gas compression platform.

Oil will be delivered through the Baku-Ceyhan pipeline from the Caspian Sea to Turkey's Mediterranean coast.

BP said: "Production export off the complex is via two 30-in. oil pipeline tie-ins and a single 28-in. gas pipeline tie-in into pre-installed pipeline junctions located on the Azeri field subsea export pipelines to the onshore Sangachal terminal. In addition, uniquely for the ACG project, two subsea water injection manifolds, four water injection supply flowlines, and associated control umbilicals have been installed in the DWG development."

Oil production is expected to increase as more predrilled wells come on stream during the year. Overall, ACG's total production will hit more than 1 million b/d, including Chirag, East Azeri, West Azeri, and Central Azeri.

Shell considers carbon capture for Browse

Shell Australia is thinking of introducing a carbon dioxide capture and geosequestration (CCG) side to the proposed floating LNG (FLNG) development at its wholly owned Prelude gas find in the Browse basin off Western Australia.

According to documents lodged with environmental regulators in Australia, the company is planning to build a 3.5 million tonne/year FLNG for the field which lies 450 km northeast of Broome.

Shell says in the application document that the project has potential for CO_2 sequestration, thereby reducing its carbon footprint.

The CCG move comes in the wake of Prime Minister Kevin Rudd's federal government plans to introduce a carbon trading scheme by 2010 as part of its goal to limit greenhouse gas emissions.

If successful, the FLNG proposal at Prelude could be a catalyst for development of other 'stranded' gas in Australia and elsewhere. The Prelude plant proposal is for a vessel 480 m long and 70-80 m wide and designed to survive a once-in-10,000 years cyclone. It would be built outside Australia and towed directly to the field location, where it would then be anchored to the seabed.

Preliminary estimates indicate that Prelude field has a reserve of 2-3 tcf of gas. Shell has indicated an ambitious on-stream date of 2012 and expects the plant to run for 25 years.

Eni starts gas production from Badhra field

A joint venture led by Eni SPA has begun gas production from Badhra field, southeast of Bhit gas field in Pakistan, and has commissioned the third train at Bhit gas treatment plant, which will process gas from nearby Badhra field, following the Badhra development and Bhit acceleration projects.

The $50 million Badhra development and Bhit acceleration project has boosted the existing capacity of the Bhit plant capacity by 17% to 315 MMscfd from 270 MMscfd. Badhra field is 250 km northeast of Karachi in Pakistan's Sindh province. ✦

Processing — *Quick Takes*

ConocoPhillips settles refinery pollution charges

ConocoPhillips agreed Apr. 8 to pay $1.2 million to settle federal water pollution charges involving a 146,000 b/cd refinery in Borger, Tex., that it operates, the US Department of Justice and Environmental Protection Agency said.

The company allegedly violated the US Clean Water Act (CWA) more than 2,000 times from 1999 through 2006, the agencies said. In a complaint filed with a consent decree in US District Court for the Northern District of Texas, authorities said the case

involved two types of pollutants, selenium and whole effluent toxicity.

ConocoPhillips brought the refinery into compliance with its CWA permit limits for both pollutants after federal enforcement actions began, according to DOJ and EPA. They said WRB Refining LLC, the refinery's current owner, also signed the agreement.

The proposed settlement, still subject to final judicial approval, requires ConocoPhillips to monitor surrounding waters, including Dixon Creek and the Canadian River, for selenium levels as well as for the accumulation of selenium in fish tissue.

The company also will maintain controls it put into place to minimize its selenium discharges and to correct whole effluent toxicity violations, DOJ and EPA said. It also agreed to perform a supplementary environmental project, which will cost an estimated $600,000, to reduce the amount of solids discharged into local waterways during storms, they indicated.

Shell FCC process raises diesel, propylene yields

Shell Global Solutions International BV announced the development of a new process to increase production of diesel and propylene from FCC units.

The middle distillates and lower olefins selective process (MILOS) uses an additional riser in the FCC, either in a revamp or grassroots unit, which gives the refiner options to simultaneously maximize production of diesel and propylene.

"Changing market demands for less gasoline and more diesel and propylene has proved difficult to achieve with the traditional and inflexible layout of the standard FCC. MILOS addresses this by providing the refiner an operational choice," said Mart Nieskens, global manager, catalytic cracking at Shell Global Solutions (US) Inc. (SGS). "The process is designed to be simple and easy to change between modes to help provide greater flexibility."

According to Shell, refiners can run an FCC in different modes with the new process. In the propylene mode, propylene production can double compared with a base-case FCC unit while maintaining traditional diesel yields and quality.

In diesel mode, diesel production can increase up to 20% with a seven point rise in cetane number and increased propylene production. The FCC unit can run anywhere between these modes or revert to normal FCC operation by changing operating parameters.

"The MILOS process should be particularly attractive to refineries linked to petrochemical complexes," said Pankaj Desai, SGS licensing sales manager. "Moreover, because it's designed to provide increased flexibility, the MILOS process can help refiners to take advantage of the seasonal demand patterns."

Feed to the additional riser can be different feedstocks, such as FCC naphtha, coker naphtha, visbreaker naphtha, vegetable oil, and GTL process products, or even paraffinic vacuum gas oil, according to Shell. ✦

Transportation — *Quick Takes*

BLM begins hearings on Ruby gas pipeline

The US Bureau of Land Management has begun a series of public hearings on a proposed $2 billion natural gas pipeline that would run 680 miles between southwestern Wyoming and southern Oregon near the California state line.

The Ruby Pipeline system, which would be built by subsidiaries of El Paso Corp., PG&E Corp., and Bear Stearns Cos., initially would transport 1.2 bcf/day of gas from the Opal Hub across northern Utah and Nevada to an interconnection near Malin, Ore. (OGJ, Dec. 24, 2007, Newsletter).

Two compressor stations, one near the 42-in. pipeline's origin and a second midway along its route, also would be built initially. Additional compression could increase capacity to 2 bcf/day.

BLM is holding the meetings as a participating agency in the Federal Energy Regulatory Commission's preparation of an environmental impact statement on the project. The US Forest Service also is participating because the system would cross the Wasatch-Cache National Forest in Utah and the Fremont-Winema National Forest in Oregon.

Iraq's NOC lets contract for Kirkuk-Banias repair

Iraq's state-owned North Oil Co. has signed a preliminary agreement with Russia's Stroytransgaz for the repair of the Iraqi section of the 880-km Kirkuk-Banias oil pipeline. In 2007, Stroytransgaz received a contract to bring the Syrian section of the line back into working condition.

The Kirkuk-Banias pipeline had a carrying capacity of 300,000 b/d before the US-led invasion of Iraq in 2003, but its original capacity when built in the 1950s was 1.4 million b/d.

The pipeline was closed for much of the 1970s and 1980s. In the 1990s, it was reopened so Iraq could bypass the United Nations oil embargo. At the time, reports put Iraq's exports through the line at about 150,000-200,000 b/d.

BG, Singapore sign LNG supply deal

BG Group PLC and Singapore's Energy Market Authority (EMA) have signed a memorandum of agreement for BG to provide as much as 3 million tonnes/year of LNG for up to 20 years, starting in 2012.

The deal underpins Singapore's desire to enhance its energy security and marks the first time it will become an LNG importer. It also has expressed a desire to create an LNG trade hub with spot cargoes.

BG Group, sourcing LNG from its global portfolio, will supply the LNG to the import terminal on Singapore's Jurong Island that also is scheduled for completion in 2012. PowerGas Ltd., a wholly owned subsidiary of Singapore Power Ltd., was contracted to build, own, and operate the terminal.

The plant's capacity can be expanded to 6 million tonnes/year and ultimately to 10 million tonnes/year by the mid-2020s.

Both parties declined to reveal the value of the agreement, saying only that the deal had been concluded at "competitive rates." ✦

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.

2008

APRIL

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, e-mail: c.pallen@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/mepipes8/mepipes8register.html. 12-14.

GPA Houston Midstream Conference, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 13-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

The CIS Oil and Gas Summit, Paris, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: l.hannant@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/summit8/summit8register.html. 28-30.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs, Va., (713) 651-1639, (713)

Calendar

951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website:

www.ite-exhibitions.com/og. 24-26.

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

PIRA's Globalization of Gas Study Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 25.

PIRA Understanding Natural Gas Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 26-27.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

International Offshore & Polar Engineering Conference, Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Annual Rocky Mountain Natural Gas Strategy Conference & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

IADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

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The rising diesel price

Laura Bell
Statistics Editor

As crude oil prices continue hitting record levels, prices for US on-highway diesel fuel hit an all-time high as well. For the week of Apr. 21, the national average for on-highway diesel fuel reached $4.143/gal, according to the US Energy Information Administration's weekly survey.

This latest price was an increase of 8.4¢/gal from the previous week's record-breaking average of $4.059/gal and up an astounding $1.292/gal from the level of a year ago. Diesel prices rose on the West Coast by 7.9¢/gal to $4.25/gal, while in California alone they soared to $4.317/gal. The New England area had the largest gain: 10.7¢/gal to $4.346/gal. The lowest prices were in the Gulf Coast region at $4.077/gal for the weekly survey. The Rocky Mountain region saw the smallest increase in price, 7.2¢/gal, to $4.111/gal.

Though most of today's media coverage focuses on regular unleaded gasoline prices for US automobiles, the diesel market recently has seen unprecedented prices. Before Hurricane Katrina battered the Gulf Coast refining industry in August 2005, diesel fuel prices were running around $2.50/gal. The week after Katrina, diesel prices jumped 12%. Currently, diesel fuel is 45% above year-ago averages. Regular unleaded gasoline is up 22%.

Low stocks

Contributing to currently high diesel fuel prices are low distillate inventories. Distillate stocks, which include both diesel fuel and heating oil, ran low throughout the heating oil season that just ended.

Winter was cold on the East Coast, where most heating oil is consumed. EIA reported that for the week ending Apr. 11 distillate stocks were 106,079,000 bbl, compared with 117,327,000 bbl a year ago—a 10.6% drop.

While US refiners this winter focused on increasing motor gasoline production in response to high prices, distillate production suffered. Currently, distillate output is 4.5% below last year's rate of 4.217 million b/d. In addition, the refinery utilization rate for the week ending Apr. 11 was one of the lowest that EIA has recorded at 81.4%. The week after Hurricane Rita, refinery utilization slumped to 69.8%. The low point before that was in 1992 at 79%.

Refinery utilization recently has been hit by a series of unscheduled outages (see Market Journal, p. 72).

Tight supplies of distillate and diesel are being felt elsewhere in the world. As demand for heating oil remained strong through winter in the US, Europe and emerging economies felt the pain, too. With heating season over, an easing of diesel prices can be expected.

Cost of diesel

EIA estimates that about 60% of the price of a gallon of diesel is related to the price of crude oil, compared with 72% for gasoline.

Tight refining capacity, international demand, imbalances related to upsets such as refinery outages and pipeline disruptions, and seasonal forces influence demand for diesel, as they do gasoline demand.

Refining costs represent around 21% of the retail price of diesel vs. 8% for motor gasoline. Taxes and the costs of distribution and marketing account for 19% of the diesel price and 20% of the gasoline price, according to EIA.

EIA notes that the US diesel price has exceeded the gasoline price generally year-round since September 2004. Before that, diesel usually sold at a discount to gasoline except when heating oil values rose.

EIA attributes the new pattern to strong worldwide demand for diesel and other distillate fuel oils, especially in China, Europe, and the US.

Also, all but the smallest US refiners have had to supply ultralow-sulfur diesel for highway use since 2006. The requirement has increased diesel production and distribution costs.

EIA also notes that the federal excise tax, at 24.4¢/gal, is 6¢/gal higher than that of gasoline. ✦

STEPPING UP

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The second Oil Sands and Heavy Oil Technologies Conference & Exhibition is scheduled for July 15 – 17, 2008, at the Calgary TELUS Convention Centre in Alberta, Canada. Once again this conference will highlight new technology in the growing oil sands and heavy oil industry.

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Editorial

The new imperative

Energy policy for many years has been impossible to discuss outside an environmental context. Within limits, the linkage makes sense. Energy production, transport, and use have environmental consequences that must be acknowledged and controlled. Distortion arises, however, when policy-making consistently favors environmentalism over energy supply and affordability. Long-standing distortion of this type now draws a new imperative into the energy-environmental policy nexus: food.

Alarm is spreading fast over a rapid increase in food prices. World Bank Pres. Robert B. Zoellick recently said food prices have doubled during the past 3 years in a crisis that threatens to push 100 million residents of poor countries deeper into poverty. The United Nations World Food Program (WFP) says its studies confirm the estimate.

"There is the new face of hunger—the millions of people who were not in the urgent hunger category 6 months ago but now are," WFP Executive Director Josette Sheeran said in London last week. The WFP, calling high food prices the biggest challenge of its 45-year history, wants new support from governments distracted by threats of recession.

Energy and food

Energy intersects the food-price crisis in several places, of course. Record prices of oil, gas, and other energy forms lift agricultural and transport costs. Prices of all commodities have been levitated by an influx of investment money seeking shelter from the dollar's weakness and the risks of other assets. And population growth provides a structural reason for consumption of food, like that of energy, to increase.

Then, of course, there are biofuels.

Promoters of fuel ethanol from grain and of diesel esters from oil seeds and other agricultural products insist that energy costs explain most of the food-price jump. Land-use changes show those claims to be self-serving nonsense. Farmers naturally dedicate acreage to crops that markets value most. In the US, that means corn, demand and prices for which are soaring because of mandates for heavily subsidized fuel ethanol. Farmers consequently are growing less wheat, soybeans, and other food crops, so those prices are soaring, too. Analogous patterns are evident elsewhere as governments push biofuels—supposedly to fight pollution, lower emissions of greenhouse gases, and extend oil supply but mostly to enrich farmers.

A World Bank study published this month refutes the energy-cost excuse for rising food prices as well as explanations based on crop failures. Only about 15% of the increase in food product prices is attributable directly to elevated energy and fertilizer costs, the study said. And supply slumps from poor crops in some areas have been offset by good crops and increased exports elsewhere.

Although the World Bank and UN continue to tip-toe around the obvious, the verdict is clear: The biofuels craze, while raising costs for everyone, is devastating the chronically hungry. And it will continue to do so until crop markets adjust. According to the World Bank study, the adjustment won't play out before 2015.

On the role of biofuels in the food crisis, World Bank and UN officials tread carefully. Both organizations advocate aggressive responses to global warming, inevitably including governmental support for biofuels. Neither organization has time for doubts about the extent to which humanity actually affects Earth's heat balance or for questions about biofuels' environmental performance. Neither organization pays much attention to assertions that a build-up of carbon dioxide in the atmosphere has a benefit much more definite than the heating for which it may well be receiving disproportionate blame: It promotes plant growth and thus can help fight hunger.

Right to food

Within the UN works a group called Special Rapporteur on the Right to Food, which asserts, "The right to food means that governments must not take actions that result in increasing levels of hunger, food insecurity, and malnutrition." In service to environmental alarmism and agricultural politics, governments are doing precisely that at the further expense of affordable energy supply.

Last year the group called for a 5-year moratorium on biofuels. It would be a reasonable and moral first step toward correction of worldwide policy errors fast proving to contradict basic human needs. ✦

Capital budgets grow in US, drop in Canada

Marilyn Radler
Senior Editor-Economics

Capital spending for oil and gas projects in the US will increase this year, buoyed by growth in upstream, midstream, and downstream developments and maintenance. The growth rates of US upstream and downstream spending will exceed those of last year.

In Canada, total project spending will decline but by a smaller margin than it did a year ago. While oil sands expenditures will increase, outlays for most other types of projects will shrink.

Capital budgets will be pulled by higher costs for materials, equipment, and labor, all of which are in high demand. Labor cost pressures are especially strong in Alberta.

Total budgets for capital spending in the US this year are estimated at $197 billion, up from $175 billion last year. Two years ago total spending was almost $169 billion.

Total spending in Canada will be $49 billion (Can.) this year, down from $51 billion last year and nearly $59 billion 2 years ago.

Spending outside the US and Canada will remain strong with upstream and downstream projects progressing.

OGJ's upstream capital spending forecast is based on estimates of drilling activity and costs, past expenditures, and companies' 2008 budgets. Downstream spending is estimated from the capital budgets of refiners, petrochemical manufacturers, pipeline companies, and others, in addition to individual project announcements.

US upstream spending

Oil and gas exploration, drilling, and production spending in the US this year will increase nearly 6% to $160.2 billion (Table 1).

This forecast is based on OGJ's annual drilling forecast, which projected that the total number of well completions in the US this year will be 49,012 (OGJ, Jan. 21, 2008, p. 35).

Drilling and exploration expenditures will total $130.2 billion, including $17 billion for geological and geophysical costs. Outlays for production will total $24.75 billion, up 4% from a year ago.

Upstream activity in the deep water of the Gulf of Mexico is reflected by the amount of bonus payments the Minerals Management Service (MMS) collects from lease sales related to the Outer Continental Shelf. OCS bonus payments in 2008 will jump 88%.

In 2006, OCS lease bonus payments totaled $914 million following two sales: one in the Central Gulf of Mexico and one in the Western Gulf of Mexico.

Last year, the MMS held another two sales offering tracts in these areas. These sales resulted in OCS payments of $2.8 billion.

The MMS has scheduled three lease sales for this year, from which OGJ forecasts that bonus payments will total $5.25 billion.

The next proposed lease sale, scheduled for Aug. 20, will include about 3,400 blocks covering 18 million acres in the Western Gulf of Mexico area off Texas. MMS estimates this lease sale could result in the production of 242-423

Construction advances at the Canaport LNG receiving and regasification terminal in Saint John, NB. Photo, taken in March, courtesy of Canaport LNG.

million bbl of oil and 1.64-2.64 tcf of natural gas.

Offshore E&P activity continues to move into deeper waters. In a February 2008 report on deepwater activity, WoodMackenzie said: "The lower level of exploration activity during 2007 is in part due to higher levels of appraisal and development drilling activity coupled with the tight rig market. We expect exploration drilling to pick up in 2008, driven by a combination of factors. Increased rig availability, further prospect identification from ongoing seismic analysis, and the acquisition of large amounts of acreage in 2007 will all encourage exploration."

US refining

Capital expenditures for transportation, downstream projects, and corporate spending in the US this year will total $36.7 billion, according to OGJ's forecast. This is up from $23.9 billion last year and $20.2 billion in 2006. Leading the spending growth are pipeline, refining, and LNG projects.

A few large expansion projects will boost spending to $13 billion at refineries this year. In 2007, refining capital outlays declined 8% to $8.3 billion.

Among current projects is Motiva's Port Arthur refinery expansion, which will bring total crude distillation capacity to 600,000 b/d. The additional 325,000 b/d of capacity will be online in 2010.

Encana and ConocoPhillips are expanding the heavy-oil processing capacity of the 306,000-b/d Wood River refinery in Illinois, which they operate via their WRB Refining LLC partnership. ConocoPhillips has allocated about $1.6 billion for capital spending at its US refineries this year, focusing on reliability, energy efficiency, capital maintenance, and regulatory compliance. The company also said work continues at a number of its refineries to increase crude capacity, expand conversion capability, and increase clean product yield.

In February, Total announced a project to build a 50,000 b/d coker, a desulfurization unit, a vacuum distillation unit, and related units at its Port Arthur, Tex., refinery. The project, scheduled for commissioning in 2011, will cost $2.2 billion.

The new units at Port Arthur will increase the refinery's deep-conversion capacity and expand its ability to process heavy and sour crude, and the project will add 3 million tonnes/year of ultralow-sulfur diesel to the refinery's current output.

Petrochemicals, pipelines

OGJ forecasts that 2008 US petrochemical spending will total $1 billion. This is up from last year. The majority of petrochemical investment, however, has shifted toward growth opportuni-

WHERE FUNDS WILL GO FOR US PROJECTS

Table 1

	2008, million $	Change 2008-2007, %	2007, million $	Change 2007-2006, %	2006, million $
Exploration-production					
Drilling-exploration	130,200	4.2	125,010	0.8	124,000
Production	24,750	4.2	23,760	0.8	23,560
OCS lease bonus	5,250	87.8	2,795	205.8	914
Subtotal	**160,200**	**5.7**	**151,565**	**2.1**	**148,474**
Other					
Refining	13,000	57.0	8,280	–8.0	9,000
Petrochemicals	1,000	19.0	840	7.7	780
Marketing	3,000	20.0	2,500	0.0	2,500
Crude and products pipelines	6,629	269.1	1,796	1,173.8	141
Natural gas pipelines	5,710	30.8	4,367	94.5	2,245
Other transportation	1,200	23.7	970	14.1	850
Mining, other energy	1,200	20.0	1,000	0.0	1,000
Miscellaneous	5,000	22.0	4,100	10.8	3,700
Subtotal	**36,739**	**54.0**	**23,853**	**18.0**	**20,216**
Total	**196,939**	**12.3**	**175,418**	**4.0**	**168,690**

CANADIAN SPENDING PLANS

Table 2

	2008, million $ (Can.)	Change 2008-2007, %	2007, million $ (Can.)	Change 2007-2006, %	2006, million $ (Can.)
Exploration-production					
Drilling-exploration	17,085	–15.0	20,100	–28.0	27,926
Production	6,515	–15.0	7,665	–28.0	10,648
Subtotal	**23,600**	**–15.0**	**27,765**	**–28.0**	**38,574**
Oil sands*	21,000	16.7	18,000	25.5	14,337
Other					
Refining	2,000	–42.3	3,465	–1.0	3,500
Petrochemicals	200	–39.9	333	11.0	300
Marketing	550	–18.8	677	–3.3	700
Crude and products pipelines	336	300.0	84	–84.6	546
Natural gas pipelines	470	—	0	–100.0	17
Other transportation	300	4.5	287	4.4	275
Miscellaneous	650	2.2	636	7.8	590
Subtotal	**4,506**	**–17.8**	**5,482**	**–7.5**	**5,928**
Total	**49,106**	**–4.2**	**51,247**	**–12.9**	**58,839**

*In situ, mining, and upgrading.

ties in the Middle East and Asia. Spending at petrochemical plants in the US this year will be directed toward maintenance as well as health, safety, and environmental improvements.

US pipeline spending will surge this year to $12 billion, up from $6 billion last year and $2 billion a year earlier.

Expenditures for crude and products pipelines will be $6.6 billion, as plans call for construction of almost 2,900 miles this year (OGJ, Feb. 18, 2008, p. 46).

Projects getting under way this year include the US portion of the Keystone pipeline to transport crude to the US Midwest from Canada. This project's total cost is estimated at $5.2 billion.

This year's natural gas pipeline projects will cost $5.7 billion, with nearly all the lines larger than 22 in. in diameter. Last year's US gas pipeline spending was $4.4 billion, double such 2006 expenditures.

OGJ also forecasts capital spending increases of about 20% for other transportation projects, marketing, mining, and other energy outlays.

All remaining US capital expenditures will total $5 billion this year. Half of this is allocated to new LNG receiving terminals and expansions at existing terminals. Other expenditures in this category include spending for natural gas liquids plants and corporate costs.

Spending in Canada

The expected 4% decline in Canadian expenditures this year will come mainly in conventional oil and gas categories.

Putting a damper on conventional oil and gas investment is Alberta's new royalty structure. The royalty increase, which begins next year, is widely expected to discourage drilling, especially for natural gas. Earlier this month, the government announced that it will ease the terms for production from deep oil and gas wells, citing unintended consequences (OGJ, Apr. 21, 2008, Newsletter).

OGJ's forecast estimated the number of 2008 well completions in Canada at 15,713, down from 18,535 last year. In 2006, there were 25,811 well completions in Canada, according to the Canadian Association of Petroleum Producers.

This year's conventional E&P spending in Canada will total $23.6 billion (Can.), down 15%. This follows a 28% decline last year.

Oil sands spending for in situ, mining, and upgrading activity will climb almost 17% to $21 billion. A year ago such spending surged more than 25%.

Strongly affecting all oil and gas development in Canada is the growing need for workers. A construction labor shortage will last through 2009, according to a November 2007 report from the Construction Owners Association of Alberta.

Suncor Energy Inc. announced a $7.5 billion (Can.) capital spending plan for this year. About 80% of the total capital budget will target growth, primarily oil sands projects. The budget also includes about $275 million to increase natural gas production, and the remainder is planned for sustaining existing operations company-wide.

All other spending in Canada this year will decline 18% from last year. Spending reductions for refining, petrochemicals, and marketing will overcome increases in pipeline, other transportation, and miscellaneous capital expenditures.

Refining outlays will post the largest percentage decline: 42%. Most of the refining projects in Canada this year

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will be new and expanded heavy oil upgraders, and this spending is included in the oil sands figures in Table 2.

Among the few current conventional oil refinery projects are Petro-Canada's Edmonton refinery conversion, to be completed this year, and a new coker at its Montreal refinery, to be completed in 2010.

Petrochemicals spending will decline 40% this year in Canada. Last year such expenditures grew 11%.

Nova Chemicals is making operational improvements to increase capacity at its polyethylene plant in Joffre. The expansion, to be completed next year, will increase capacity about 100 million lb/year to 1 billion lb/year.

Nova also will continue a series of polyethylene plant modernization and expansion projects in Ontario. The projects will add a total of up to 250 million lb/yr of polyethylene capacity in stages over the next 2 years.

Crude and products pipeline spending will increase 300% this year, with plans for 416 miles of construction planned in Canada. Plans also call for the construction of 241 miles of gas lines, compared to none last year.

Miscellaneous spending in Canada, including corporate costs and LNG, will be $650 million, up slightly from last year.

Current LNG projects in Canada include the Canaport LNG receiving and regasification terminal in Saint John, NB, scheduled to begin operations late this year. Initial send-out capacity will be 1 bcfd.

There have been plans for other LNG terminals in Canada, including the Kitimat LNG terminal in Beese Creek, BC, and a Petro-Canada terminal in Quebec.

Construction of Petro-Canada's planned terminal in Gros Cacouna, Que., is uncertain. On Feb. 7, Gazprom decided not to pursue its proposed Baltic LNG project, the potential anchor supply for the Cacouna terminal.

Petro-Canada said supply shortages, capital cost pressures, excess North American regasification capacity, and worldwide natural gas economics have put a strain on the development of LNG import projects in North America.

Spending elsewhere

Outside the US and Canada, capital spending will remain strong.

In its most recent spending outlook, Lehman Bros. reported that such E&P expenditures will rise 16% this year to $267 billion.

Pemex has announced spending plans for 2008 of $19.4 billion, with 83% dedicated to upstream operations, focusing on maintaining oil production.

During a Mar. 26 conference call on Mexico's reserves, Carlos Morales, head of E&P at Pemex, said that although the country's oil production during the first 2 months of this year averaged 2.9 million b/d, the company expects output for the year to average 3-3.1 million b/d.

On Mar. 30, Pemex released a report detailing 13 years of production expectations, with output declines from Cantarell field plus a declining reserves base in Mexico.

George Baker of Baker & Associates, Houston, commented on the report: "Pemex, in its diagnostic report, reveals determination to develop fields in deep water, fully realizing the value of experience in the selection and timing of technology. The document stops short, however, of advocating the long-awaited strategic alliances of [international oil companies]."

Total downstream spending outside North America includes large petrochemical projects in China, India, Qatar, Singapore, and Saudi Arabia, as detailed in OGJ's most recent worldwide construction update (OGJ, Apr. 7, 2008, p. 24).

LNG spending outside the US and Canada will mostly go toward liquefaction capacity in the Middle East, Africa, and Australia. ✦

SAFE: US economic survival tied to oil, gas production hikes

Nick Snow
Washington Editor

Record high crude prices, combined with the declining value of the US dollar and growing signs of a recession, make increased US oil and gas production necessary not only for the nation's energy security but also for its economic survival, a leading advocacy group told reporters Apr. 17.

"Energy security can't be subjugated to climate change. If we don't address both, we'll have neither," said Robbie Diamond, president and chief executive of Securing America's Future Energy (SAFE), as the organization released a new report, A Different Type of Price Spike.

"While we pursue the health of our planet, we need to protect the health of our economy," added David P. Steiner, chief executive of Waste Management Inc. and one of four members of SAFE's Energy Security Leadership Council who joined Diamond at the briefing. Adam M. Goldstein, president and chief executive of Royal Caribbean International; Eric S. Schwartz, a senior director at Goldman Sachs; and retired US Air Force Gen. Charles F. Wald also participated. The latest oil price escalation differs greatly from its predecessors, which could be traced to constrained supplies, Schwartz observed. "Starting a few years ago, we had a demand-side shock from emerging economics, and not just for oil. There also was a shift in financial markets as economically rational investors moved into commodities to diversify their portfolios and diversify their returns," he said.

Emphasizing that it was his personal opinion, Schwartz conceded that derivative markets can have a marginal

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WATCHING GOVERNMENT

Nick Snow, Washington Editor

New York nixes LNG plant plan

Three weeks after winning Federal Energy Regulatory Commission approval, a large floating liquefied natural gas terminal and regasification facility proposed for construction in Long Island Sound was rejected by New York's state government.

Sec. of State Lorraine A. Cortes-Vazquez said on Apr. 10 that the Broadwater LNG project, a joint venture of TransCanada Corp. and Shell US Gas & Power Co., is not consistent with six policies under New York's coastal zone management plan. The installation aims to deliver up to 1.25 bcfd of gas. FERC approved the project on Mar. 20.

Gov. David A. Paterson said that his concerns regarding the LNG project include its size, potential disruption of commercial and recreational fishing, and alleged failure to guarantee low-cost gas to Long Island consumers.

He reactivated the state's energy planning board after 5 years to prepare a comprehensive strategy that would examine renewable technologies but not rule out LNG or other traditional sources. Paterson, who chaired the state's renewable energy task force when he was lieutenant governor, said that Broadwater might not be needed.

'The best option'

In response, John Hritcko, Broadwater senior vice-president and the project's director, said, "We continue to believe that the Broadwater project, as proposed, is the best option for New York State to meet its growing demand for clean, affordable, reliable natural gas, and does so with no near-shore or onshore impacts."

Sponsors will review specific aspects of the state's decision before deciding on their next steps.

At first glance, this looks like an impasse. But the federal LNG project permitting process lets Broadwater's sponsors ask US Commerce Sec. Carlos Gutierrez if New York's action actually follows its coastal plan. The state also has proposed two alternative sites in the Atlantic Ocean on the other side of Long Island.

Bill Cooper, president of the Center for Liquefied Natural Gas in Washington, said that Paterson's idea of having an energy task force develop a comprehensive strategy for New York is hardly new. "People in the Northeast agree they need more natural gas. The question still is where to put the facilities," he told me.

'Certainly, there's demand'

Markets determine the need for projects, while the federal and state governments protect the environment and surrounding communities, he said. "Certainly, there's demand for the gas Broadwater would provide. You have only to look at the New York city-gate spot prices through each winter to see this."

FERC's Mar. 20 approval of the Broadwater project does not necessarily mean it will go ahead exactly as proposed, he added. The decision provided a working document with more than 80 conditions which developers will have to meet before the federal energy regulator issues a construction permit. "The important point is that the process apparently is moving forward. And yes, developers of other LNG projects are watching closely as it does," Cooper said. ✦

impact on prices but added that growing demand amid limited supplies is a much greater force. Government has a role in constraining participants who try to move prices, but placing the blame for higher prices entirely on speculators is a mistake, he continued.

Impact delayed

"It's pretty clear to American families that oil prices are going up and that it's regressive," said Goldstein. The impact was delayed because growing home equity served as a buffer against rising energy costs as long as real estate boomed, he explained. That changed when the subprime mortgage crisis undermined the market and slowing discretionary purchases began to accelerate economic uncertainty, he said.

Soaring crude oil prices pose serious implications for US military forces, according to Wald. "Even though instability and insurgencies pose threats, I believe limited resources, whether oil or water, are a greater problem," he said, adding that 85% of what a soldier, airman, or sailor carries into the field is either water or petroleum products.

He also said that US military services generally provide the only protection for global oil shipments, whether in the area of the Strait of Hormuz or off West Africa, where multinational oil companies are committing $100 billion to develop new fields. Diamond said that Congress took a good first step at reducing demand by including tougher automotive efficiency requirements in the 2007 Energy Independence and Security Act. Now it needs to take similarly decisive actions to increase domestic oil and gas production, he maintained.

Participants agreed that it would take time for additional US oil and gas production to have an impact, but they added that it would be worthwhile because it would keep in the US more of the money consumers spend on energy. "Think of the investment that could be made in future energy technologies' research and development with $357 billion if you don't send that money overseas," Steiner said. ✦

CSU researchers see more active hurricane season

Nick Snow
Washington Editor

The 2008 Atlantic Basin hurricane season could be as active as ever, with 15 named storms expected, two Colorado State University scientists predicted on Apr. 9. Eight of those storms could be hurricanes and four of the eight could be intense hurricanes, they said.

"Current conditions in the Atlantic Basin are quite favorable for an active hurricane season," said William Gray and Phil Klotzbach in their latest periodic analysis of trends contributing to storms in the tropical Atlantic Ocean, Gulf of Mexico, and Caribbean Sea. They added that they see a 69% chance of at least one major hurricane (Category 3 or stronger) making landfall on the US coastline.

Their forecast prompted US Sen. Mary L. Landrieu (D-La.) to reiterate her call for better hurricane impact preparedness. "We should bear in mind the lessons of 2005 and the catastrophic effects of Hurricanes Katrina and Rita. Preparedness is key in the face of a natural disaster, and 2½ years later we are still grappling with the consequences of ill-prepared agencies," she said.

Current Atlantic Ocean surface temperatures are following a pattern which is typical prior to very active hurricane seasons, the researchers said. "Waters off the coast of Iberia as well as the eastern Tropical Atlantic are very warm right now. The Azores High has also been quite weak during the month of March. Typically, a weakened Azores High leads to weaker trade winds that enhance warm [sea surface temperature] anomalies due to reduced levels of evaporation mixing and upwelling in the eastern tropical Atlantic," they observed.

Gray and Klotzbach's latest forecast is an increase from one they issued on Dec. 7, 2007, in which they predicted there would be 13 named storms, seven hurricanes, and three intense hurricanes. Atlantic Basin cyclone activity averaged 9.6 named storms, 5.9 hurricanes, and 2.3 intense hurricanes from 1950 to 2000, they said.

They also questioned the idea that global warming has increased storm activity in the region. They conceded that there were more hurricanes in the Atlantic Basin from 1995 through 2007 (an average of 3.8/year) than there were in the previous 25 years (1970-94 where there were an average 1.5/year). But they traced the increase to rising thermohaline circulation and growing salinity in the Atlantic over several decades, which they said is not directly related to rising global temperatures.

"There have been similar past periods (1940s and 1950s) when the Atlantic was just as active as in recent years. For instance, when we compare the Atlantic Basin hurricane numbers over the 15-year period from 1990-2004 with an earlier 15-year period (1950-64), we see no differences in hurricane frequency and intensity even though the global surface temperatures were cooler and there was a general global cooling during 1950-64 as compared with global warming during 1990-2004," Gray and Klotzbach said. ✦

CTL deemed 'credible' fuel option despite drawbacks

Doris Leblond
OGJ Correspondent

Coal-to-liquids appears to be one of the more credible alternatives to oil "for the long-term supply of transport fuels," said Institut Francais du Petrole Pres. Olivier Appert, in a keynote address concluding the World Coal-to-Liquids Conference in Paris Apr. 3-4.

IFP was a conference sponsor along with the World Energy Council, the World Coal Institute, and the World CTL Association.

Appert was careful to mention, however, that while coal reserves are huge compared to oil or natural gas, "it is clear that we need to consider seriously the different constraints [on] coal production: [the] environmental issue and technological and financial challenges."

The conference was convened to assess the possibilities of using liquefied coal as a complement to road transport fuels because oil prices are likely to remain high. Coal-rich countries China, the US, Australia, Indonesia, India, and Germany are studying or preparing CTL ventures, and South Africa and China are already engaged in industrial production.

CTL drawbacks

The conference brought out drawbacks to CTL development, the greatest being the need to combine it with capture and storage of carbon dioxide, which the process emits. Producing diesel fuel from coal generates 850 g/mile of CO_2 compared with 500 g/mile from oil and requires large quantities of water. Gasoline from coal also emits more greenhouse gases than gasoline from oil.

Cost is another drawback. Based on the experience of South Africa's Sasol, the cost of CTL was evaluated at $67-82/bbl, excluding the cost of CO_2 capture.

"It is cheaper than extraheavy oil production," said Alain Quignard, who

manages new projects and new motor fuel resources at IFP. He told OGJ: "From coal onwards, one finds the refining processes applied to heavy oil and deep conversion products."

Whether produced from direct liquefaction, with hydrogen added to the organic structure of coal, or from indirect liquefaction through breaking down the coal structure by gasification with steam, investment in a CTL plant costs as much as a large refinery but produces much less fuel volumes.

China's Shenshua CTL plant, due on stream this year in Inner Mongolia, is a large complex having associated coal treatment and refining operations. It will produce only 20,000 b/d of CTL but will cost several billion dollars. Shenshua is using the direct liquefaction process, while Sasol chose the indirect process.

Brian Ricketts, an International Energy Agency coal analyst, said the liquid coal market would not exceed 15% of transport fuels before 2050. And if clean technologies are included, it would not be more than 10% by then. However, use of the direct or indirect technology would accelerate after 2020-30, he said.

Coal plentiful

At the conference Poland's former Prime Minister Jerzy Buzek, a member of the European Parliament and vice-president of the European Energy Forum, described his country as having the "largest coal reserves in Europe." He said Poland is engaged "in resolving a coal conversion dilemma: whether to use coal as power for electricity or only for liquid fuels."

William Anderson, assistant secretary of the US Air Force for installations, environment, and logistics, told the conference the USAF is committed to synfuels development to reduce dependence on foreign oil. Within the USAF's "energy initiatives," Anderson plans to test certification of synfuels on the air fleet by 2011 and use a synfuels blend by 2016 for half the fuels purchased.

Meanwhile, his department is developing "a major international initiative" through ongoing talks with the UK's Royal Air Force and France's Air Force about alternative aviation fuels, greenhouse gases, and aviation fuel demand reduction. It also is "reaching to Air Forces across the world; fuel needs to be international," he said.

Closing the conference, Appert gave his own cautious view, warning, "In an uncertain environment, the industry needs to understand the constraints of financing and engineering. But, as well, the finance and engineering worlds have to understand and manage the specificities of CTL.

"Given the size of CTL commercial plants, the needs for commodities will be huge." He urged the industry to continue "studying and improving CTL, [while] keeping our eyes open to other energy routes. By doing so, I am convinced that CTL will be part of the solution to the dramatic challenges of energy and environment the world is facing." ✦

Project would bring heavy oil to West Texas

Centurion Pipeline LP launched an open season to determine interest in a proposed reversal project that would deliver heavy Canadian crude from Cushing, Okla., to West Texas.

A possible buyer of heavy crude is Holly Corp. of Dallas, which plans to reconfigure its Artesia, NM, refinery to handle heavy crude. A Holly spokesman confirmed that the pipeline reversal, if implemented, would give Holly access to heavy crude.

Holly's 85,000-b/sd refinery is being expanded to 100,000 b/sd, with completion scheduled for first-quarter 2009. The reconfiguration to process heavy crude also is expected to be completed in 2009.

Centurion's 16-in., 375-mile pipeline runs to Slaughter, Tex., which is within 60 miles of the Artesia refinery, the Holly spokesman said.

The pipeline is known as the No. 1 Pipeline. Centurion's 30-day open season began Apr. 14.

Occidental Petroleum Corp., Centurion's parent company, said the No. 1 Pipeline is one of two 16-in. pipelines that Centurion currently operates from Slaughter to Cushing.

"Centurion recognizes that there are several ongoing projects that will bring heavy Canadian crude to more than one Cushing terminal," said Richard Kline, Occidental communications vice-president in Los Angeles. "Centurion is looking to be able to provide a new transportation capacity from Cushing for those projects and movements to markets in the Permian basin and surrounding area," he said.

The reversed pipeline could be in southwest-bound service as early as fourth-quarter 2009. Its projected capacity is 60,000 b/d.

"Oxy will continue to market Permian basin production so as to receive the maximum possible value," Kline said.

Holly's reconfiguration

Holly is making a series of investments in the Artesia refinery, which is also known as the Navajo Refining Co. LP refinery.

In 2006, Holly completed an ultra-low-sulfur diesel (ULSD) project and expanded the refinery to 83,000 b/sd from 75,000 b/sd. This included a refinery expansion and conversion of the

Float-off of Maari wellhead platform completed successfully

Earlier this month, Australian engineering and construction firm Clough completed float-off of the Maari wellhead platform in New Zealand for OMV New Zealand Ltd. on behalf of Maari joint venture partners. The 9,770-tonne platform, standing 140 m in height, arrived in New Zealand after sailing from Malaysia in a 22-day dry transport on the MV Blue Marlin semisubmersible heavy transport vessel, contracted from Dockwise Shipping BV, the Netherlands. The float-off was carried out in the topographically sheltered waters of the Marlborough Sounds region on the north coast of New Zealand's South Island. With the float-off completed, the project's focus turns to wet-towing the platform from its current location to the field and self-installing it into position in the Tasman Sea off the west coast of Taranaki. Photo from Clough.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Biofuels begin to feel the heat

The oil and gas industry is not alone in taking heat from environmentalists these days. Even biofuels—long thought to be the answer to hydrocarbons—have come in for criticism.

A recent United Nations report called biofuels a "crime against humanity" for diverting food crops toward fuel production as a global scarcity deepens and food prices rise.

The UN report said farmers worldwide must reduce dependency on fossil fuels and better protect the environment, as riots erupt over food shortages in the Caribbean and Africa and hunger approaches a crisis in parts of Asia.

It even recommended an international moratorium on incentives for producing and marketing biofuels.

Thilo Bode, the head of German consumer protection group Foodwatch, also lashed out against the "lethal" trade policies of industrialized countries. "We need a different energy policy," Bode said. "It is not right that we fill our tanks at the expense of those who are famished."

Food, not fuel

Senior executives from BP PLC on Apr. 17 affirmed that biofuels have a role in the energy mix, but they also agreed that such energy sources must not compete with food crops or be environmentally destructive.

"Biotechnology will play a pivotal role in improving environmental sustainability," BP Chairman Peter Sutherland said at the company's annual general meeting in London. "But it has to be conducted in a manner that does not disrupt food supply chains...and is not damaging the environmental sustainability of agricultural land."

Chief Executive Tony Hayward said BP will focus on "the next generation of biofuels, which will be based on more efficient molecules and will not be derived from food crops."

US Energy Sec. Samuel Bodman took a similar view, saying the nation should begin "moving away gradually" from ethanol made from food such as corn.

"As we pursue diversity in our overall energy mix, we must also pursue diversity in our biofuels," Bodman said at a conference in Alexandria, Va.

Lula backs biofuels

Perhaps the stoutest response came from Brazilian President Luiz Inacio Lula da Silva, who Apr. 16 made an impassioned defense of biofuels, denying that their production contributes to food scarcity or rising prices.

"Biofuels aren't the villain that threatens food security," he said at a Latin American meeting of the UN's Food and Agricultural Organization. "On the contrary...they can pull countries out of energy dependency without affecting foods."

He would say that, wouldn't he? After all, Brazil is the world's leading exporter of ethanol, and the world's No. 2 producer after the US.

There are, of course, those people who object even to biofuels developed from sugar cane. They say that more and more land that could be used for edible crops is being turned over to sugar cane. They may be right. But for most people right now, the Brazilian solution seems the sweetest choice in alternative fuels. ✦

distillate hydrotreater to gas oil service, conversion of the gas oil hydrotreater to ULSD service, expansion of the continuous catalytic reformer, expansion and conversion of the kerosene hydrotreater to naphtha service, installation of additional sulfur-recovery capacity, and installation of a 10 MMscfd hydrogen plant.

Crude capacity then was increased to 85,000 b/sd by relocating heat exchangers and replacing pumps in the crude unit.

In December 2006, Holly announced plans to install a 15,000 b/d hydrocracker and a 28 MMscf hydrogen plant at a cost of $125 million to increase liquid volume recovery, increase the refinery's capacity to process outside feedstocks, and increase high-value product yields, as well as meet new low-sulfur gasoline specifications (OGJ, June 4, 2007, Newsletter).

The hydrocracker and hydrogen plant projects will provide improved heavy crude oil processing flexibility.

In February 2007, Holly said it was revamping a crude unit to increase crude capacity at the refinery to 100,000 b/sd. Holly also plans to revamp a second crude unit and to install a solvent deasphalter unit.

It expects the expansion portion of the overall project consisting of the initial crude unit revamp, the new hydrocracker, and the new hydrogen plant to be completed and operational by the fourth quarter.

"The completion of the heavy crude oil processing portion of the overall project, including the second crude unit revamp and the installation of the new solvent deasphalter, will be targeted to coincide with the development of future pipeline access to the Navajo refinery for heavy Canadian crude oil and other foreign heavy crude oils transported" from Cushing, the Holly web site said.

A new sulfur recovery unit currently under way will permit the refinery to process 100% sour crude and is planned for start-up in the third quarter of 2008. ✦

DOE monitors CO_2 injection in Australian gas field

The US Department of Energy provided technology that helped Australia launch the Otway basin pilot project, which will inject carbon dioxide into a depleted gas field in southeastern Australia.

The project involves monitoring the CO_2 to demonstrate the feasibility of storing it in the Waarre formation.

The Otway basin pilot project is one of 19 sequestration projects endorsed by the Carbon Sequestration Leadership Forum (CSLF), an international climate change initiative that focuses on sequestration technology development.

The project is directed by Australia's Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) of Canberra. Project partners include DOE and various public and private organizations.

Up to 100,000 tonnes of CO_2 will be injected more than a mile beneath the earth's surface. A team of Australian, American, and other international researchers will monitor the storage reservoir.

CO2CRC is 100% owner of licenses PPL11 and PPL13, which cover Buttress CO_2 field and nearby depleted Naylor natural gas field.

The program will involve production of CO_2 from Buttress at a rate of 3 MMcfd, piping the gas 1.75 km to Naylor, and injecting it into the Cretaceous Waarre reservoir on the flank of the depleted field (OGJ, Mar. 10, 2006, Newsletter).

The injection process will span 1-2 years, while monitoring and modeling activities will last for several years beyond that.

Buttress reserves exceed 10 bcf, 90% of which is CO_2. Minor amounts of methane will be stripped out and used to power the compressors and other equipment. The Otway project is unusual in that researchers own the petroleum leases, the CO_2 source, and the depleted storage reservoir.

DOE provides expertise

In DOE-sponsored research, the Lawrence Berkeley National Laboratory (LBNL) developed instrumentation to track the CO_2 plume during and after the injection. Sophisticated seismic techniques will provide data about the location, migration, and permanent storage of the CO_2 plume.

Remote sensing is just one of several monitoring techniques LBNL research-

ers will deploy. Another technique is a unique formation well-sampling method that taps the reservoir and delivers fluid samples to the surface for determination of CO_2 content and other geochemical analyses.

Using geophysical, geochemical, and other reservoir data acquired during storage operations, the researchers also will be able to refine models to significantly increase the predictability of formations to permanently store CO_2. ✦

Turkmenistan seeks energy cooperation, offshore PSAs

Eric Watkins
Senior Correspondent

Turkmenistan will allow international oil companies to develop Caspian Sea offshore deposits under production-sharing agreements, said Tacberdi Tagyyew, deputy chairman of the Turkmen council of ministers.

Tagyyew told delegates at a conference on "Oil and Gas of Turkmenistan 2008" in London that some 32 licenses for oil and gas exploration in the Turkmen section of the Caspian Sea have already been issued, and international oil companies may participate in several projects.

However Turkmenistan will reserve the exclusive right of domestic companies to extract oil and gas from the country's onshore deposits, he added, although foreign partners may participate by providing services.

Tagyyew's remarks coincided with a call for a new atmosphere of cooperation on energy that appears to be emerging among the "energy triangle" countries that include Russia, the European Union (EU), and Central Asian states.

"Each member of this 'energy triangle' depends on the other two, and it requires a new atmosphere of cooperation," said Pierre Morel, the EU's special representative for Central Asia. Morel called on all sides to quit "politicizing" energy issues and seek a long-term energy strategy.

Gas export routes vary

In that vein, Turkmenistan is supporting a broad-based policy on natural gas exports, according to Tagyyew. He said Turkmenistan adheres to a "multiple-version" approach toward routes for exporting gas extracted in the country.

He said strategic relations, based on a 25-year trade agreement concluded in 2003, link Russia and Turkmenistan, which currently delivers 50 billion cu m/year of gas to Russia's OAO Gazprom. Soon, he said, deliveries will increase to 70-80 billion cu m.

Tagyyew also said a gas pipeline to China would go online in 2009, with some 30 billion cu m of gas transiting the line from eastern Turkmenistan to China via Uzbekistan and Kazakhstan.

Meanwhile, he said, Turkmenistan is considering other export possibilities, including a gas pipeline to Pakistan via Afghanistan and a gas pipeline to Europe via the so-called southern Caspian-Black Sea corridor or Nabucco gas pipeline. ✦

COMPANY NEWS

GEPetrol acquires Equatorial Guinea assets from Devon

Equatorial Guinea state oil concern GEPetrol reported acquiring assets in Equatorial Guinea from Devon Energy Corp. for $2.2 billion.

In other recent company news:

- XTO Energy Inc. agreed to acquire producing properties, pipeline, and leasehold acreage from Linn Energy LLC for $600 million.
- A trio of major oil companies agreed to sell their 200,000 b/d Rainbow oil pipeline in northern Alberta to a subsidiary of Plains All American Pipeline LP for $540 million (Can.).
- PetroFalcon Corp. plans to acquire Anadarko Venezuela Co. from Anadarko Petroleum Corp. for $200 million.
- Oil Search Ltd., Sydney, has sold a number of its Middle East and North African division assets to Kuwait Energy Co. for $200 million plus working capital to enable the company to focus its attention on the Papua New Guinea LNG joint venture operated by ExxonMobil Corp.
- British Gas owner Centrica is to expand its presence in Canada with the purchase of TransGlobe Energy Corp.'s Canadian assets for $56.7 million (Can.).
- Rowan Cos. Inc. reported it intends to "monetize," through an initial public offering or a private sale, its wholly owned manufacturing subsidiary LeTourneau Technologies Inc. (LTI).
- Parker Drilling Co. plans to sell its 50% interest in a Saudi Arabian joint venture, Al-Rushaid Parker Drilling Co. Ltd., to an affiliate of Al-Rushaid Investment Co., the Saudi firm owning the other 50% stake.
- Australian engineering firm WorleyParsons Ltd. plans to acquire Intec Engineering BV from Heerema Group for $108.5 million.
- Green Dragon Gas Ltd. has signed

a conditional agreement with Pacific Asia China Energy Inc. (PACE) through its wholly owned subsidiary Greka China Ltd. to acquire PACE for $35.18 million (Can.).

• Brazil's state-owned Petroleo Brasileiro SA (Petrobras) plans to resume negotiations with Valero Energy Corp. for the acquisition of the San Antonio-based company's 275,000 b/d Aruba refinery.

• Royal Dutch Shell PLC is to cut 180 jobs at its offices in Aberdeen because of rising oil recovery costs from its assets in the UK North Sea.

GEPetrol in Equatorial Guinea

GEPetrol has acquired a 23.75% participating interest in offshore Zafiro oil field on Block B, where proved reserves were estimated at 55 million bbl of oil at yearend 2007. Devon's share of production from Zafiro is 20,000 b/d.

The other assets are Devon's interests in undeveloped offshore Blocks C and P.

Devon is selling its interests in African acreage as it wants to concentrate on its North American operations instead.

The transaction took effect from Jan. 1 and is expected to close on or before May 30.

Devon estimates its aftertax proceeds will be $1.7 billion and said that this transaction represents the largest piece of its African divestiture program.

XTO acquires Marcellus shale

XTO's acquisition includes 152,000 net acres of Marcellus shale leasehold in western Pennsylvania and West Virginia. XTO estimates proved reserves to be 145 bcfd of gas equivalent from the shallow Mississippian and Devonian reservoirs.

The acquisition will add 25 MMcfd to XTO's production base. The pipeline and gathering facilities included in the transaction are valued at $50 million.

The acquisition is scheduled to close on or before July 1.

Plains buys Rainbow line

Imperial Oil Ltd., ExxonMobil Corp., and Royal Dutch Shell PLC each own a third of the pipeline that extends 781 km from Zama in northwest Alberta to Edmonton, connecting to the major oil artery between Canada and the US Midwest operated by Enbridge Inc. It's also linked to Kinder Morgan Canada's TransMountain line to the West Coast and refineries in the Edmonton region.

The deal is expected to close during the second quarter, subject to regulatory approval. Plains All American expects the acquisition to boost cash flow within 6 months of closing. The Houston oil transportation company also will buy 1.1 million bbl of oil line fill at a cost based on market prices at closing. That acquisition would be worth $120 million (Can.) at current prices.

PetroFalcon-Anadarko deal

PetroFalcon's agreement is subject to the approval of the

Venezuelan Ministry of Energy and Petroleum. PetroFalcon is a Canadian company operating in Venezuela.

Anadarko Venezuela indirectly owns 18% of Petroritupano SA, a joint venture of Petroleos de Venezuela SA and Brazil's Petroleo Brasileiro SA (Petrobras). Anadarko Venezuela's working interest production from Petroritupano is 7,440 boe/d before royalties. Petroritupano has exclusive rights to explore, develop, and produce oil and gas through 2025 from the Oritupano-Leona Block.

Juan Francisco Clerico, PetroFalcon's chairman and chief executive officer, said the acquisition will multiply the firm's daily oil production by almost eight times and more than double its proved and probable reserves.

Petroritupano's business plan calls for the drilling of 90 infill wells and 147 recompletions over the next 16 years.

Oil Search's divestiture

Oil Search's Egyptian assets include a 70% interest in Area A in the Eastern Desert next to the Gulf of Suez, a 49.5% interest in East Ras Qattara concession, and a 30% interest in Block 6 in Mesaha.

The Yemen assets sold include 35% of Block 15, 32.5% of Block 35, 42.33% of Block 49, 34% of Block 74, and 28.33% of Block 43 in the Hadraumat region of the country's southeast.

The transaction took place at the end of February, but completion is not expected until midyear because the deal is subject to government and joint venture partner approvals.

Peter Botten, Oil Search's managing director, said, while the company had successfully built a diversified portfolio in the Middle East and North Africa, a number of the licenses were not material in the context of Oil Search's growing gas portfolio.

Botten added that the sale of these assets would provide cash and reduce near-term capital requirements, freeing up funds to go towards Oil Search's share of the proposed Papua New Guinea LNG project, which aims to establish an LNG plant near Port Moresby based on gas reserves in the central highlands fields.

Oil Search has retained some interests in the Middle East and North Africa, namely Blocks 3 and 7 in Yemen, Area 18 off Libya, and the recently acquired Tajerouine and Le Kef permits in Tunisia plus the Bina Bawi concession in Kurdistan.

Centrica expands in Canada

Centrica's purchase, conducted through Centrica unit Direct Energy, gives the company access to reserves of at least 15 bcf of gas equivalent, the company said.

The assets are in Alberta, next to Direct Energy's current gas portfolio. In addition to a production base of 8.7 MMcfd of gas equivalent, of which 75% is gas, the acquisition also includes 50,000 acres of land with development potential, said Direct Energy parent Centrica. The deal is expected to close by the beginning of May and is not subject to shareholder approval. It will become effective from Jan. 1.

Direct Energy said that it is looking to make more deals, and TransGlobe will focus on its plays in Egypt and Yemen after reducing its debt.

Rowan monetizes LTI

Rowan's LTI division manufactures offshore rigs, mud pumps, and large mobile equipment used in the forestry, mining, and transportation businesses and has designed or constructed all of the Rowan-operated jack ups.

Rowan said it plans to use at least $400 million of the proceeds to repurchase shares.

"LTI's leading market positions in its operating segments have enabled it to generate significant returns for Rowan over time," said Daniel F. McNease, Rowan chairman and chief executive officer. "Given LTI's record performance in 2007 and strength heading into 2008, we believe that now is the appropriate time for Rowan to crystallize the value we have created in LTI for the benefit of our stockholders."

Parker divestiture

Al-Rushaid Investment's affiliate is Abdullah Rasheed Al-Rushaid Co. for Drilling Oil & Gas Ltd. (OGJ, Mar. 3, 2006, Newsletter). Subject to finalization of financing details and approval by the Saudi Arabian government, closing is expected on or before Apr. 14.

The divestiture will result in aggregate payments of $2 million to Parker. The Houston-based drilling contractor expects to report a $1.5 million net loss from the joint venture.

Parker Drilling Chairman and Chief Executive Officer Robert L. Parker Jr. said his company decided to sell its joint venture stake because it "was not the best organizational structure for applying our project management expertise and disciplined processes."

The company believes the North Africa and Middle East market hold long-term growth potential and plans to continue offering drilling services in this region, he said.

WorleyParsons to buy Intec

WorleyParsons' Intec acquisition will provide the firm with expertise on deepwater projects and also with experience in arctic developments, WorleyParsons said. Intec is based in Houston.

WorleyParsons Chief Executive Officer John Grill said the world's remaining oil reserves are being found in areas that are difficult for oil companies to reach. "The acquisition of Intec completes the missing link in our hydrocarbons business," he said.

The transaction will not affect projects under existing or pending contracts involving Intec, Heerema Group, and third parties, the companies said.

Green Dragon to buy PACE

PACE, listed in Vancouver, BC, has operations exclusively in China focused on coalbed methane through a production-sharing contract covering a 946-sq-km block in Guizhou province. The company also has a 50% interest in a joint venture drilling service company with exclusive rights to utilize Mitchell

Drilling's Dymaxion horizontal drilling technology in China for degassing coal mines and exploiting CBM.

Green Dragon said PACE's board unanimously approved the transaction. Pace's offices in Vancouver will be shut following completion of the deal and its Beijing offices will be consolidated with Greka China.

Randeep S. Grewal, Green Dragon's chairman and chief executive, said the buyout would boost the company's CBM acreage in China. It also would increase the company's PSC acreage to 7,566 sq km, making it the largest foreign CBM operator in China. Additionally, the PACE-Mitchell JV adds two Schramm rigs to the fleet of five ordered by Greka Technical Services, providing commonality within rigs while enhancing the capability to drill horizontal wells.

Petrobras still eyeing Aruba

Petrobras said a January fire at the refinery damaged the facility's vacuum distillation unit, which is being repaired.

Recently Petrobras has been expanding its refinery network either through expansion or acquisition. It recently bought a refinery in Okinawa, Japan, and is expanding its refinery in Pasadena, Tex.

In addition, it has bid on Exxon-Mobil Corp.'s Esso-brand network of retail outlets in Brazil, and plans to start negotiations to buy the Esso networks in Chile and Uruguay.

Shell's Aberdeen cuts

Shell union leaders have criticized Shell's move to cut the Aberdeen positions. The company hopes to avoid compulsory redundancies, saying it needs to cut the jobs by 2010 to maintain its long-term competitiveness. Its North Sea operational costs have leapt by as much as 60% over the last 3 years, it said.

The cuts will affect office-based posts. Shell employs more than 2,000 workers—including contractors—in Aberdeen. About 7% of the workforce will be affected.

The decision was taken after the company carried out a cost and efficiency study. Last June Shell dropped plans to build a £25 million headquarters in Aberdeen and has put up part of its operations in the UK North Sea for sale.

Shell's actions follow a similar move by BP PLC that will cut its onshore North Sea workforce by almost 20%—a loss of 350 jobs. Both companies have insisted that they remain dedicated to the area. ✦

Independents nurtured Bakken to economic producibility

Alan Petzet
Chief Editor-Exploration

Shale formations can contain vast stores of hydrocarbons, and it can take industry decades to develop them commercially.

The recent federal estimation of 4.3 billion bbl of undiscovered, technically recoverable oil in the Williston basin Bakken shale pretty much mirror's the beliefs of newly public Continental Resources Inc., Enid, Okla., the Bakken's largest oil producing company (see map, OGJ, Apr. 24, 2008, p. 37).

As the Fort Worth basin Barnett shale had a 20-year gestation period to commerciality with Mitchell Energy & Development Corp. in Texas, Continental's Chairman Harold G. Hamm can trace his company's foray into the Bakken since the 1980s.

Hamm's desire to balance his then-private company's gas dominance with oil discoveries, along with technology advances pioneered in Montana and Dakota fields, placed Continental in the thick of the Bakken evolution.

Bakken attempts

In the 1980s when Continental was rooted in Oklahoma and owned 65% gas assets and field gas prices were newly deregulated, Hamm looked to less-mature Rocky Mountain basins for the potential to make large oil discoveries.

He began working in Bowman County, ND, looking for structures in the Ordovician Red River sandstone formation. He made his first Rocky Mountain region discovery in Montana's Midfork field in 1989, and in 1995 Continental and Meridian Oil Inc. discovered the large Cedar Hills field in North Dakota.

One Continental geologist mapped the Middle Bakken in the Williston basin in Montana, and Hamm approached companies that had discovered Mustang field in Richland County proposing a pilot waterflood, but they were not interested.

The companies, Headington Oil Co. and Lyco Energy Corp. of Dallas, had completed vertical wells in the Bakken after failed attempts to complete for Red River oil, but the Bakken production wasn't commercial if a new well were drilled from surface, Hamm said.

Later Lyco aligned with Halliburton Energy Services and began drilling the Bakken horizontally on 320-acre units. Laterals were short and production rates weren't commercial at first. Eventually fracs were tried, but rates still weren't commercial.

Commercial step

Then Headington tried fracs in unlined holes and made 800-b/d Bakken wells.

Continental leased 125,000 acres in what became Montana's Elm Coulee field, largest to date in the Bakken play. Elm Coulee averages 50,000 b/d plus associated gas, and Continental is one of its largest producers with 7,200 b/d.

Elm Coulee is developed on 500 sq miles. Initial spacing was one horizontal well per 1,280-acre unit. Continental then drilled a second well per unit and is now drilling a third well per unit and looking at secondary and tertiary recovery potential.

Hamm took a geological team in 2003 and tasked it with finding the "next Elm Coulee" on the North Dakota side. After a review of cores, the team recommended leasing the crest of the 140-mile Nesson anticline.

Continental leased more than

MONTANA BAKKEN EVOLUTION

	Wells	Initial production, bo/d	Estimated ultimate recovery, 1,000 bbl	Comment
2000	1	100	200	—
2001	12	160	220	Without refrac
2002	15	200	260	—
2003	42	330	450	Success is achieved
2004	100	280	400+	Includes infill wells
2005	150	300	400+	—

Source: Continental Resources Inc.

300,000 acres in North Dakota and later entered a joint venture with ConocoPhillips Co., bringing in rigs as they were released at Cedar Hills. The companies are running 10 rigs now.

Of 66 rigs running in North Dakota, 56-58 are drilling toward the Bakken formation.

The USGS estimate of recoverable oil in the assessment unit that most closely covers Continental's North Dakota acreage agrees remarkably with Continental's expectations, Hamm noted.

Of 27 Bakken wells that Continental operated in 2007, the average estimated ultimate recovery is 335,000 bbl. Some won't make much oil, and others will make 500,000-700,000 bbl, Hamm said.

Learning curves

The Red River B formation was noncommercial when drilled vertically at Cedar Hills field (see map, OGJ, Jan. 15, 1996, p. 21).

Cedar Hills was the first US oil field developed from the start entirely with horizontal wells, Hamm recalled. Continental spaced several townships and drilled mostly 4,000-5,000-ft laterals NE-SW across each square mile, the longest reaching 5,600 ft.

Meridian and Apache Corp. won approvals to drill South Dakota's first horizontal wells, to Red River in the Buffalo field area in Harding County, in 1989 and 1994.

At the end of 1995, Continental purchased Koch Exploration Co.'s oil and gas properties in Harding County, SD, and Bowman County, ND. The South Dakota properties consisted of three air injection-in situ combustion units in vertically drilled Red River wells in the Buffalo fields.

Continental hiked production modestly by drilling laterals out of 23 of the vertical wells in 2005-06, and has continued to expand lateral drilling in the units.

Another horizontally drilled US formation, the Austin chalk in Texas, had an oil target 40-50 ft thick, but drilling in the Red River involved much higher precision, Hamm noted. There drillers were challenged to keep the sideways-pointing bit in the upper 3-4 ft of a zone that is only 7-10 ft thick.

The Montana Bakken Elm Coulee field, with horizontal drilling and 9,000 psi high pressure fracs and ceramic proppants, has become the 15th largest US onshore oil field.

"Generally, it takes many years and much capital to find out if these shales can be productive. Not all of them are and for the ones that are it can take many years to 'break the code' and find out how to drill, treat, and produce them," Hamm told the Oklahoma Legislature last month. "This is the case of nearly every resource play." ✦

H Oil Group applies for Block Ea in Sudan

Eric Watkins
Senior Correspondent

Sudan's National Petroleum Commission (NPC) has mapped out a new oil concession in the southern region of the country, calling it Block Ea, according to officials.

South Sudan's Industry and Mining Minister John Luk said the location of the new block followed an application by the privately owned H Oil Group, Limassol.

Luk did not reveal the total acreage of the block but said H Oil had asked for the entire area. Luk said the H Oil application would be considered by next month.

Meanwhile, Luk said, officials adjusted the coordinates to allow opportunities for other companies interested in applying to work on the block. He did not say which, if any, other companies had expressed interest in the block.

Ea Block adjoins Total SA's existing Blocks B and C as well as Block 5A, which is the site of Thar Jath oil field 900 km south of Khartoum in the Muglad basin.

Sudan signed an agreement in 2005 with White Nile Petroleum Operating Co. for development of Thar Jath and Mala fields on Block 5A. White Nile is comprised of operator Petronas 68.875%, Oil & Natural Gas Corp. 23.125%, and Sudapet 8%.

According to the US Energy Information Administration, first oil from Block 5A came online in June 2006 at an initial 38,000 b/d. As of March 2007, the field was still producing 38,000 b/d, while full capacity is estimated at 60,000 b/d. H Oil began negotiations with southern authorities for the area now called Block Ea before a 2005 peace agreement that ended more than 20 years of conflict between the Sudanese government and southern military forces.

In October 2005, as part of the peace agreement, Sudan established the NPC to bolster the development of the country's oil resources.

To accomplish its mission, NPC allocates new oil contracts, and ensures an equal sharing of oil revenues between the national government in Khartoum and the South Sudan government. ✦

Spraberry Trend resource estimate up sharply

Pioneer Natural Resources Co., Dallas, estimated that its properties in the Spraberry Trend in West Texas contain 1 billion boe of net resource potential in addition to the 481 million boe of proved reserves the company had booked at the end of 2007.

Pioneer, which plans to accelerate drilling in the giant field in 2009, estimated it has a drilling inventory of 19,000 locations. It is the field's largest driller and producer with 869,000 acres more than 75% held by production, 5,300 active wells, and 16 rigs running.

The 1 billion boe of further net

resource potential includes 200 million boe of resource potential, beyond the 248 million boe of proved undeveloped reserves already booked, related to Spraberry formation development on 40-acre spacing with deeper Wolfcamp drilling where applicable; 500 million boe related to 9,500 highgraded 20-acre infill locations; and 300 million boe related to waterflooding selected areas.

Production history suggests that 20-acre infill wells can be expected to recover 75-80% of the reserves being recovered by 40-acre wells, Pioneer said. The company drilled four successful 20-acre infill wells in the 2008 first quarter and plans 20-25 more this year.

Ten waterfloods have recovered 82 million bbl of oil, and their histories suggest that "secondary waterfloods" where appropriate can be expected to recover a further 50% of the reserves recovered under primary recovery, the company said.

Pioneer estimated that 40% of its Spraberry acreage has waterflood potential and plans to begin a large-scale waterflood program in 2009. It also sees substantial upside from completion technology advances and plans to frac five previously drilled horizontal wells with isolation packers.

Pioneer expects to add 250 million boe of proved reserves in the next 5 years and average 15% compounded annual production growth from the field through 2011. It foresees before-tax internal return rates for 40-acre and 20-acre wells of 50% and 40%, respectively, at $95/bbl.

The company information is derived from a comprehensive 2007 study by Pioneer's Permian Basin asset team that found the field to have contained more than 30 billion boe of original oil in place with estimated ultimate recovery of 3.5 billion boe (OGJ, Apr. 27, 2006, p. 30).

The study indicated that primary recovery is 12-13% on 40-acre spacing with the potential to increase 6 percentage points with 20-acre infill drilling and 9 percentage points more with waterflooding. ✦

Chesapeake sees large potential in US plays

A Jurassic Haynesville shale play in Louisiana, with only a few wells producing gas so far, could eventually be worth 7.5-20 tcf of recovery net to Chesapeake Energy Corp., the company said in late March.

The 20 tcf figure depends on the company's securing 500,000 net acres in the play, compared with the 200,000 acres it held in late March. Haynesville could have "a larger impact on the company than any other play in which it has participated to date," said the large Oklahoma City independent.

Chesapeake also has become involved in five unconventional oil projects, four of which were developed internally, in four states that range in size from 100,000 to 1 million acres and have a collective 1 billion bbl recovery potential net to the company. Two of the plays are producing, and the other three are to be drilled in the next 12 months.

The company also is pursuing the Colony and Mountain Front Granite Wash plays in the Anadarko basin in Oklahoma and Texas, each of which could mean 1 tcfe of net recovery. About 40% of the energy content of the Colony play is in oil and natural gas liquids.

Chesapeake expects to drill 250 more net horizontal wells on 60,000 acres in Oklahoma in the Colony play, now producing 40 MMcfd, and 400 more net horizontal wells on 75,000 acres in the three-discovery, 150-mile Mountain Front play in both states.

Chesapeake disclosed few details about the plays due to competitive considerations.

The company also said it is ready to accelerate drilling in the Appalachian basin, where it owns 1.1 million net acres in the Devonian Marcellus shale and 500,000 net acres in the Devonian Lower Huron shale, where the combined ultimate recovery could exceed 10 tcf net. It plans to drill 165 wells in the two formations this year and next. ✦

Newfoundland

NWest Energy Inc., St. John's, let a contract to Geophysical Service Inc., Calgary, to shoot industry's first 3D seismic survey off western Newfoundland in the 2008 third quarter.

NWest, which holds four licenses in the Gulf of St. Lawrence between Corner Brook and Port au Choix, did not identify the location of the 900 sq km survey precisely.

The survey targets several stacked targets of the 11 highgraded oil targets the company has identified on 2D seismic data and other geological data. Drilling is planned in 2009.

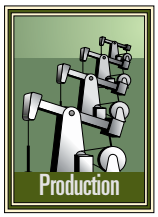
Arkansas

Bonanza Creek Energy Co., Bakersfield, identified more than $50 million in investment opportunities the next 3 to 4 years on properties in Union, Lafayette, and Columbia counties it has acquired from Macquarie Oil & Gas Holdings Inc. for an undisclosed sum.

The properties in the Cotton Valley Trend have 93 wells on 12,237 net acres producing 1,200 boed, 70% oil and NGL, from 9 million boe of proved plus 4 million boe of probable and possible reserves.

Development and exploration upside exists in the Cotton Valley, Travis Peak, Rodessa, James lime, and Lower Smackover formations.

Included in the acquisition is a 15 MMscfd plant with 225 miles of gathering lines that processes gas from the properties and other producers. Bonanza Creek opened an office in Houston.



Fields on Iraq's borders require joint operations

Guntis Moritis
Production Editor

A recent study advocates that the many fields that lie along Iraq's borders should be operated jointly with the adjacent country (Fig. 1).

The Centre for Global Energy Studies (CGES) conducted the study in reaction to February 2008 claims in the Iraqi press that neighbouring countries were stealing Iraq's oil.

These claims recall the assertions of Saddam Hussein's regime in 1990 that Kuwait was stealing oil from Iraq's South Rumaila field by excessive production from the Ratga field. This alleged theft was one of Saddam's justifications for invading Kuwait.

Also in 2001, Iraq claimed Kuwait's overproduction in the Ratga and Abdalli fields had led to about 50 million bbl moving into Kuwait from two Iraqi fields: South Rumaila and Safwan (part of the Zubair field complex).

Joint operations

The study suggested that an ideal approach is for two adjacent countries to undertake joint appraisal, planning, development, and production operations of fields on their common border, as well as for fields on either side of the border so that it can be verified that the fields are connected or are in separate reservoir systems.

Even for two separate fields, the study noted that a joint production system sharing some surface facilities might be preferable; however, technical and political expediency requires a high degree of cooperation and coordination.

The study further said that joint operations would benefit even border fields that were developed separately and produced for decades such as Naft Shahr-Naft Khaneh on the Iran-Iraq border, or Ratga-South Rumaila and Abdalli-Safwan-Zubair on the Kuwait-Iraq.

The CGES study reviewed and analyzed the oil and gas fields on or near the borders with Iran, Kuwait, Jordan, and Syria and suggested which field might continue across the borders.

Syria, Jordan borders

Fig. 2 shows the fields discussed in the study that are on Iraq's border with Syria and Jordan.

On the Syrian side are:

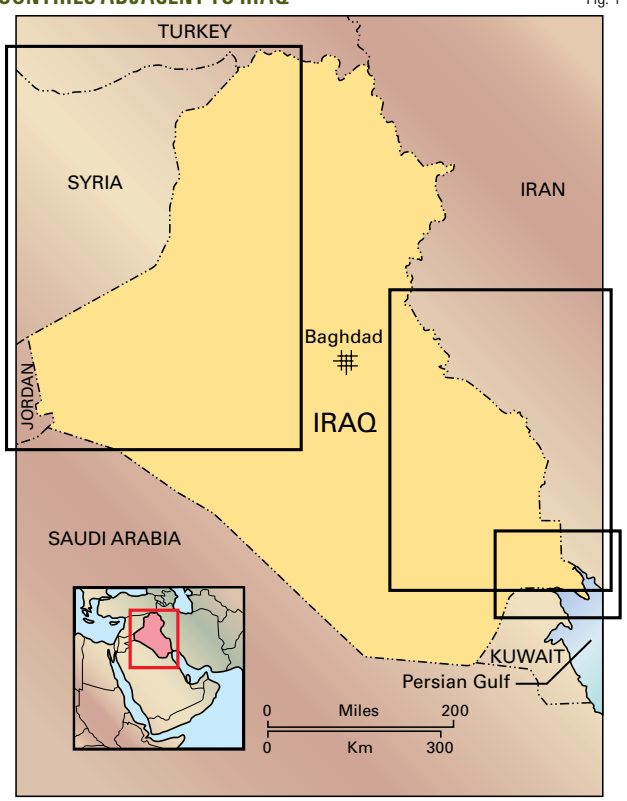
- Al-Hawl, gas discovery that could extend into the Qahtan structure in Iraq.
- Gbeibe, oil discovery that was producing in the 1980s.
- Ghouna, oil discovery and gas tested.
- Hamza, producing oil field.
- Jerribe, gas discovery that could extend into Jabal Sinjar structure in Iraq.
- Karachok, producing oil field that was the first oil field discovered in Syria.
- Swaidiayh, producing oil field that extends into the Sufaya in Iraq.

Fields on the Iraqi side include:

- Abtakh, potential oil discovery.

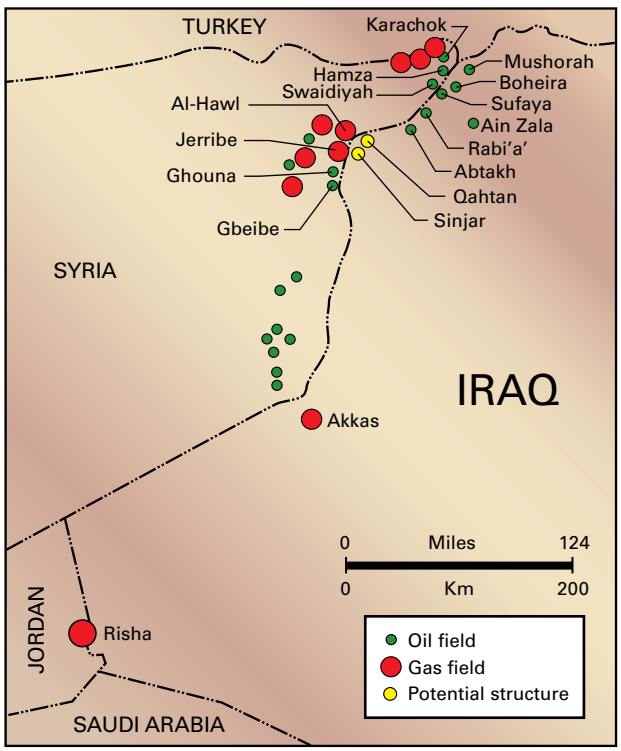
COUNTRIES ADJACENT TO IRAQ

Fig. 1



SYRIA-JORDAN BORDER FIELDS

Fig. 2



Note: The location of the borders and fields are approximate and are not to scale.

• Boheira, unevaluated oil discovery.
• Mushorah, unevaluated oil discovery.
• Rabi'a', potential oil discovery.
• Sufaya or Sfaiya, producing oil field.
• Jabal Sinjar, potential structure with gas.
• Qahtan, potential structure with gas.

On the Jordan border are:

• Risha, producing gas field on the Jordanian side that apparently extends into Iraq.
• Akkas, gas and oil discovery in Iraq's Western Desert. The field is closer to the Syrian border but gas properties are similar to those in the Risha field.

Iran border

Straddling the Iran-Iraq border are Naft Shahr-Naft Khaneh fields, nearly depleted oil fields on production since the 1920s.

Fields on the Iranian side include:

• Azadegan, producing oil field that is possibly connected with Majnoon in Iraq.
• Danan, producing oil field.
• Dehluran, producing oil field that is possibly connected with Abu Ghrab in Iraq.
• Yadavaran, producing oil field.
• West Paydar, producing oil field.

Fields on the Iraqi side include:

• Abu Ghrab, producing oil field.
• Badra, low potential oil field that possibly extends into Iran.
• Huwaiza, oil field awaiting development.
• Jabal Fauqi, Fauqi, or Al-Fakkah, producing oil field.
• Majnoon, producing oil field.
• Siba, undeveloped oil field that possibly extends into Iran.
• Chah Surkh, undeveloped gas field.
• Jaria Pika, undeveloped gas field.

Kuwait border

Fields on the Kuwaiti side include:

• Abdalli, producing oil field that is possibly an extension of Safwan in Iraq.
• East Abdalli, oil prospect that is possibly an extension of Umm Qasr in Iraq.
• Ratga, producing oil field that is an extension of South Rumaila in Iraq.
• Raudhatian, producing oil field.
• Sabriyah, producing oil field,
• West Abdalli, oil prospect.

Fields on the Iraqi side include:

• Jraishan, oil discovery.
• Rachi, producing oil field.
• South Rumaila, producing oil field.
• Safwan, producing oil field.
• Umm Qasr, producing oil field. ✦

Single-set CT straddle packers successful in Alaska

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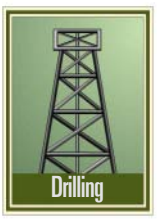


At Prudhoe Bay, Alas., nonrig tubing repairs have become a viable alternative to rig workovers (RWOs). This type of repair provides economic remediation for wells with production tubing by "A" annulus communication.

Wireline-set retrievable straddles can eliminate tubing communication at a significant cost savings. They are particularly attractive in areas where RWO cost is significant, such as offshore, remote, or arctic locations. The advantage of tubing straddle repair over a conventional RWO is that there is no need to pull tubing, resulting in the well being returned to service faster.

Typical straddle deployment costs are less than 5% of the costs for tubing replacement with an RWO. Single-set or "one-trip" straddles were used historically at Prudhoe Bay. However, starting in 1994, a less expensive, retrievable, two-run straddle design was adopted.

A 2006 study of 263 permanent and retrievable tubing straddles set in 181 wells at Prudhoe Bay showed that single-set straddles were far more successful and lasted longer than two-set straddles.[1]

This article describes the recent development, history, and success rate of a retrievable, single-set tubing straddle for 4½-in. and 3½-in. tubing. It details the modifications required to convert an hydraulic set straddle pack-off to a one trip wireline set system. Twenty-nine of these straddles have been set at Prudhoe Bay to date, improving the straddle program success rate to 80% from about 50%.

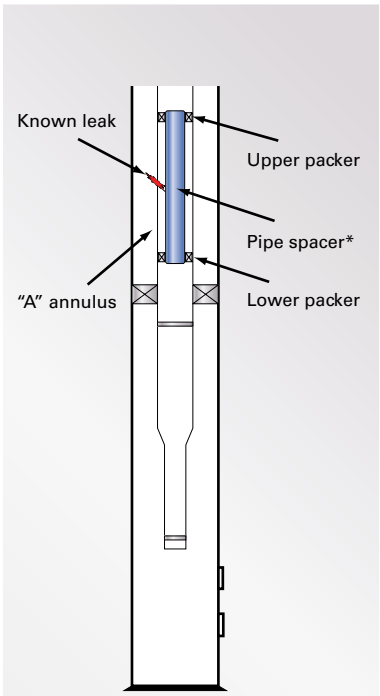
New solution

Prudhoe Bay is a mature, enhanced oil recovery/waterflood oil field. Mechanical problems with the original completions have traditionally been repaired with a rig to replace the tubing. The majority of these wells were completed with 4½-in. and 5½-in., L-80 carbon steel production tubing.

BP has made significant cost savings by deploying the alternative remediation technique discussed in this article, and the workovers may result in the recovery of additional reserves. Tubing straddles are designed to eliminate production tubing by "A" annulus communication (Fig. 1).

They consist of two sealing elements connected by a pipe spacer to straddle and isolate the source of tubing by "A" annulus communication. They can be installed in producers or injectors to isolate leaks in damaged gas lift mandrels (GLMs), jewelry, tubing collars, and eroded or corroded tubulars.

TUBING STRADDLE SCHEMATIC Fig. 1



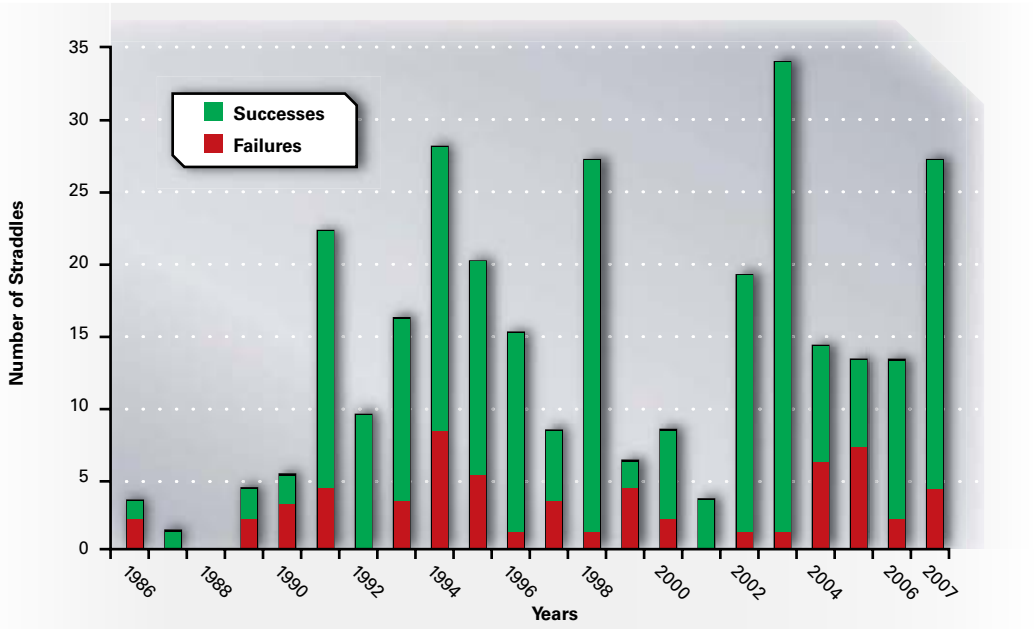
*The pipe spacer can be replaced with jewelry such as gas lift mandrels, profiles, sliding sleeves, etc.

Historical straddle analysis

The history of tubing straddles set at Prudhoe Bay from 1986 to 2005 is detailed in SPE 107069.[1] The paper also gives a complete description of prestraddle diagnostics and includes lessons learned from the 20-year straddle program. The number of straddles and the success rate have varied considerably over the years and are updated in Fig. 2 with data through 2007. A successful straddle is defined as one that has passed a successful

STRADDLE IMPLEMENTATION HISTORY

Fig. 2



poststraddle pressure test.

One unexpected outcome of the study is the clear difference in the straddle success rate between the single-set straddles compared to the two-run straddles (Fig. 3). Two-run straddles were introduced in mid-1994 and were appealing because of their lower cost. Although single-set straddles continued to be run, their use declined until 2002 when almost all of the straddles were the two-run style.

The study showed that the "old-style" single-set straddles had had a success rate of 82%, compared with the two-run straddles which were successful only 55% of the time. Initially, it was thought that this difference might be due to more aggressive candidate identification in wells which had corrosion damage. However, only 28% of straddles are set to isolate tubing holes due to corrosion.[1] The team felt that the extra seal in a two-set straddle was resulting in the increased failure rate.

This assessment has proven to be accurate, as 29 of the new single set straddles have been deployed and have a 79% success rate. This is a dramatic improvement in the success rate of 57% in 2004 and 46% in 2005. This significant increase in success rate is solely due to the development of the single-set straddle.

Single-set straddles

After evaluating the 1986-2005 historical straddle study results, BP asked Baker Oil Tools to design a one-trip, wireline-set, retrievable straddle packer system that would be modular in design. A modular system was requested to allow for variable straddle spacer lengths depending on each well's requirements. Additionally, the new system would allow jewelry (typically consisting of gas lift mandrels or sliding sleeves) to replace the spacer pipe.

The straddle length was initially required to be 35 ft between sealing elements. This is typically the longest conventional straddle that can be deployed due to lubricator length and fishing considerations.

Requirements of the single-set straddles included:

- One trip wireline deployed.
- Easily retrievable via slick line or coiled tubing.
- Modular design.
- 3½-in. ST-L connections.
- 3,500 psi pressure rating @ 230 °F.
- Set using Baker No. 10, E-4 wireline setting tool.
- Initial design to be 35 ft between sealing elements.

Single-set straddle operation

In single-run straddle deployment, both packers are set simultaneously, with a spacer pipe connecting them, to straddle the source of communication (Fig. 4).

The spacer pipe has a secondary tube through it to the bottom of the assembly. The tube transmits the setting force to the bottom packing element and extrudes it to the tubing wall to achieve a seal.

A standard hydraulic system was converted to a mechanical set system that is capable of deploying in one trip and packing off both sealing elements during setting. This requires that the two packers be mechanically connected to one another in such a way that as mechanical axial force is applied to the assembly, both sealing elements and lower slip are energized to allow packing off. To accomplish this, the system was converted from using internal hydraulic pistons (to apply compression to the assembly to induce slip setting and pack-off) to a mechanically induced axial compression load between the two pack-offs.

The packers were modified to make the originally fixed bottom ends "free floating." This allows axial forces to travel through, and between, the bot-

tom of the packers and into the slips/pack-off. Only one set of slips can be used in the system and the optimum placement for them is in the lower packer. This is necessary because of the axial movement of the assembly during setting. If the upper slips are in place, they will contact the tubing wall and prevent any additional axial movement down. This prevents the upper assembly and spacer tubes from moving down and energizing the lower pack-off. The lower assembly is unable to move up because it is retained by the lower slip.

The setting sequence design involves the following:

1. Shear up and set lower slip. This stops any additional axial movement up.
2. Shear down and pack-off lower element.
3. Shear down and pack-off upper element.
4. Shear setting tool.

The use of only one slip section to maintain the assembly in position downhole has been determined to be satisfactory for the straddle application. The assembly is pressure balanced above and below, thus no axial movement can be induced due to pressure variations. Pack-off energy is maintained in the upper and lower elements via body lock rings as originally designed.

The rubber elements consist of a 70 durometer center element and 90 durometer end elements. The Baker Model No. 10, E-4 setting tool is used to generate the required mechanical axial forces to squeeze the two packers into a set position. Setting rods run through the bore of the assembly and attach to a wireline adapter kit. The adapter kit is retained within a machined profile within the bottom sub of the lower packer. The straddles are rated to 3,500 psi. However, they have been tested in the shop, as well as on location, to as high as 4,000 psi.

Field operations

Baker set its first successful single-set straddle in January 2006 in 4½-in. tubing. Two months later, it successfully deployed a 3½-in. straddle. The operations were similar to previous straddle setting procedures. After performing prestraddle diagnostics, technicians rig up wireline on the well.[1] They arm the setting tools and make up the straddle. The tool string consists of:

- Electric-line head (the weak point and fishing neck in a small housing).
- Electronic release (disconnect).
- Casing collar locator.
- Baker-10 firing head.

On location, the operator test fires through the tool string to ensure continuity. The unit is then powered down and made up to the straddle that is horizontal on the ground. The assembly is pushed into the lubricator and a cap is screwed onto the lubricator bottom. The lubricator is picked up and stabbed onto the wellhead. The lubricator is pressure tested, the well is opened up, and the toolstring is run in at a maximum speed of 100 fpm.

Third-party cranes are required for longer straddles. Straddles are available in 5 ft increments up to 35 ft, but straddle length should be kept to a minimum length to ease handling requirements.

Results to date

The single set straddle program has been highly successful for both producing and injecting wells. To date, 29 straddles have been deployed in 26 wells. Four of these were set in 3.5-in. tubing and 25 were set in 4½-in. tubing. As shown in Fig. 1, overall success rate of the straddle program has increased to 79% from 52% over the last 4 years.

Nine single-set straddles were run in 2006 with two failures and a 78% success rate. Twenty were run in 2007 with an 80% success rate. Of the four failures in 2007, two are undiagnosed and "A" annulus fluid levels and other evidence suggest that there is likely a second leak and the straddle is holding.

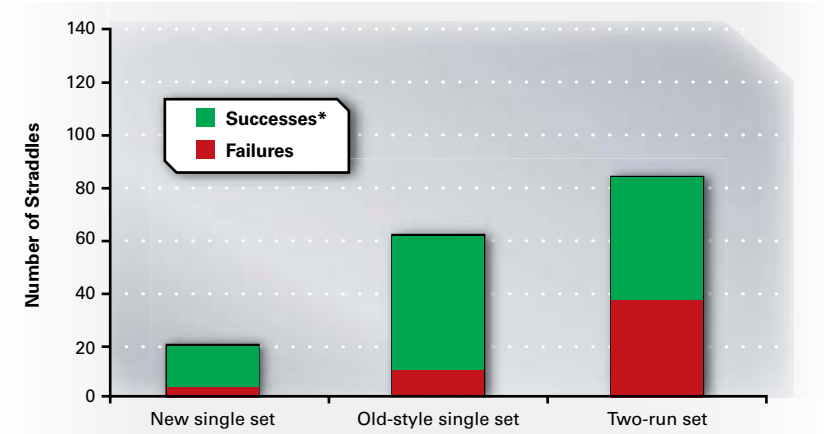
To date, there have been six wells that have not been returned to service after running a single-set straddle. Again, this may be straddle failure, or it may be due to a second hole.

Immediate failures

Of the six failures, four of them were set at the target depth, but a subsequent pressure test of the "A" annulus failed, as discussed below:

- *Well 1.* This 4½-in. straddle was set with no apparent problems after Baker had already successfully deployed five straddles successfully. The subsequent pressure test failed and a leak detection log identified a leak at the top of the straddle. The straddle was retrieved easily, and an intermediate length straddle was run, but still failed to solve the

FAILURE BY STRADDLE TYPE Fig. 3



*The new single-set straddles have a 79% success rate, the old-style single set (includes both permanent and retrievable straddles) have an 82% success rate, and the two-run set have a 55% success rate.

well's tubing by "A" annulus communication. The well is currently has a procedure planned to rerun a single-set straddle with a modified target depth.

• *Well 2: Undiagnosed failure.* This straddle was set over a damaged gas lift mandrel. The subsequent pressure test failed at a much smaller leak rate than prior to setting the straddle. A leak detection log is planned. It is suspected there is a second leak as a tubing caliper survey indicated the tubing had 46% wall loss above the straddle.

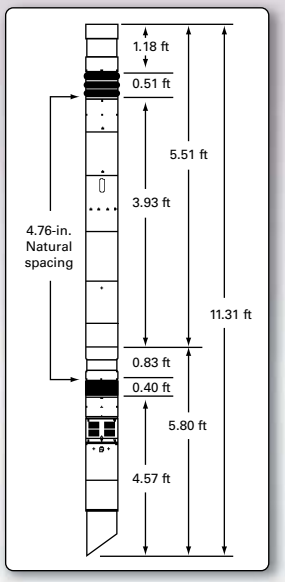
• *Well 3: Failure possibly temperature related.* Reset was successful. This 4½-in. single-set straddle was set over a damaged gas lift mandrel at 4,258 ft. Instead of a spacer pipe between packers, it had a 2⅜-in.special clearance gas lift mandrel to allow gas lifting through the straddled damaged mandrel. The poststraddle pressure test failed and a subsequent leak detection log indicated a leak at the straddle. After latching and jarring for 5½-in. hr with 0.125-in. slick line, and 1 hr 10 min with braided line, the straddle was successfully retrieved.

Inspection of the elements indicated that the center element (70 durometer) had been compressed. It was a little harder to discern that the two end elements (90 durometer) had been compressed (Figs. 5 and 6). However, the force the middle element was subject to was also transmitted to the outer elements. Both upper and lower packers should have seen a minimum of 11,000 lb of compressional force. A thorough inspection of the straddle confirmed the o-rings, shear ring, slips, and elements were in place and in good condition.

The temperature at the setting location was 35° F. and it is possible that although the end elements were subject to the same compressional force as the middle element, they weren't elastic enough to extrude due to cold temperatures. Prior to the second straddle attempt, 590 bbl of 180° F. seawater and 225 bbl of 190° F. diesel were pumped to warm the wellbore to assist the elastomers to pack-off. Baker set the straddle successfully and it is still in service.

SINGLE-SET STRADDLE OPERATION*

Fig. 4



	OD	ID	Length
Upper straddle packer 4-in. GS fishing neck up 3 ½-in. STL pin down 30,000 lb shear release H819634506 Eight, ¼-in. – 20 shear pins @ 11,320 lbs (third shear)	3.7 in.	2.37 in.	5.51 ft
Lower straddle packer 3 ½-in. box up WLEG down 30,000 lb shear release H819634506 Five, ¼-in. – 20 shear pins @ 7,075 lbs (first shear) Four, 5/16-in. – 18 shear pins @ 9,529 lbs (second shear)	3.7 in.	2.37 in.	5.80 ft

*Diagram of 4 ½-in. single-set straddle showing two packers connected by a spacer pipe. At Prudhoe Bay, either 3 ½-in. flush joint or 2 ⅞-in. collared pipe is used as the spacer pipe in 4 ½-in. tubing. In 3 ½-in. tubing, 2 ⅜-in. spacer pipe is used.

One mechanical change that was recommended, but not implemented was made to have a higher shear value for greater pack-off force. This would provide greater compressional force from the initial shear. A softer element could also be considered.

Although it is conjectured that temperature played a part in the failure of this straddle, a 4½-in. straddle was successfully set in the same well at 3,300 ft and would have been subject to similar cold temperatures. This second straddle is still in service after 1.4 years.

• *Well 4: Undiagnosed failure.* This well had a 4½-in. straddle set to isolate a tubing hole. A poststraddle pressure test failed, and a diagnostic leak detection log is planned. Fluid levels indicate a second leak above the straddle.

Stuck straddles

Of the 29 single-set straddles that Baker has run, two of them (7%) were stuck above the target depth prior to setting. This was significant because the 1986-2005 study of 263 straddles indicated that only six straddles (2%) had become stuck due to tight spots which were not noted in the prestraddle slickline drift.

• *Well 5.* Prior to setting this 4½-in. straddle from 12,295-12,310 ft, the well was drifted with a knuckle joint, 4½-in. gauge ring and 3.70-in. OD by 20 ft-long aluminum drift. The operational log noted some trouble at 10,625 ft and 11,256 ft. The area was worked with a 3.8-in. gauge ring, and a final drift run made three passes from 11,200-12,356 ft with the 20-ft drift.

An attempt was made to set a 35 ft long (element to element), 3.70-in. OD straddle. The overall tool string was 52 ft long. The straddle became stuck at 10,983 ft at a gas lift mandrel above the target setting depth. There was a 51° deviation at this gas lift mandrel, but no significant doglegs in the vicinity. After the straddle became stuck, the operator pulled off at the weak point. The straddle was fished and the well was redrifted with no problems noted.

A shorter straddle (21 ft, element to element, 37 ft tool string overall length) was then deployed. Although the tool string lost weight at 10,977 ft and continued to fall slowly, the straddle was set on depth. The shorter straddle was successfully deployed and pressure tested and is still in service. It was likely the problem with the first attempt was a

This bottom packer (left photo) was retrieved from Well 3 after an unsuccessful set; note position of elements and slips (Fig. 5). The elements of the lower packer (right photo) were retrieved from Well 3. It's clear that the middle element has been extruded, but not as obvious that the outer two elements have been extruded (Fig. 6).

downhole geometry issue.

• *Well 6.* This 25-ft long, 3½-in. straddle with a 2.74-in. OD became stuck at a subsurface safety valve (SSSV) nipple with an internal diameter of 2.75-in. and length of 3.22-in. The well had a history of tight tolerances at the SSSV nipple. Four months before the failed setting attempt, slick line was unable to pass the SSSV nipple with a 2.73-in. centralizer. Immediately prior to the straddle setting attempt, slick line drifted with a 2.74-in. dummy straddle with no problems. Later, the OD of the dummy straddle drift was questioned.

During the straddle setting operation, the 25-ft straddle sat down in the SSSV nipple. The wireline operator pulled up the slack and pulled out of the head prematurely. Surface inspection indicated the weak point was worn, causing two of the four wires to pull out, instead of break.

After fishing the tool string, slick line redrifted with a 32-ft long, 2.74-in. barbell assembly with another vendor's 2.74-in. straddle drift on bottom. The tool string was unable to pass the SSSV nipple. A swage turned down to 2.739-in. was able to work through the SSSV nipple with difficulty.

Baker was unable to turn down the 3½-in. straddle from 2.74-in. OD to 2.72-in. but did suggest a multiple run straddle system that could be turned down. A decision was made to use the other vendor's modified two-run straddle turned down to 2.72-in. The lower packer was run on wireline and the upper packer and pipe spacer were run on slick line. The subsequent pressure test of the "A" annulus failed at 1 bbl/min. A leak detection log identified a second tubing leak in the joint below the straddle. The straddle was pulled, and a procedure to run a longer straddle is pending.

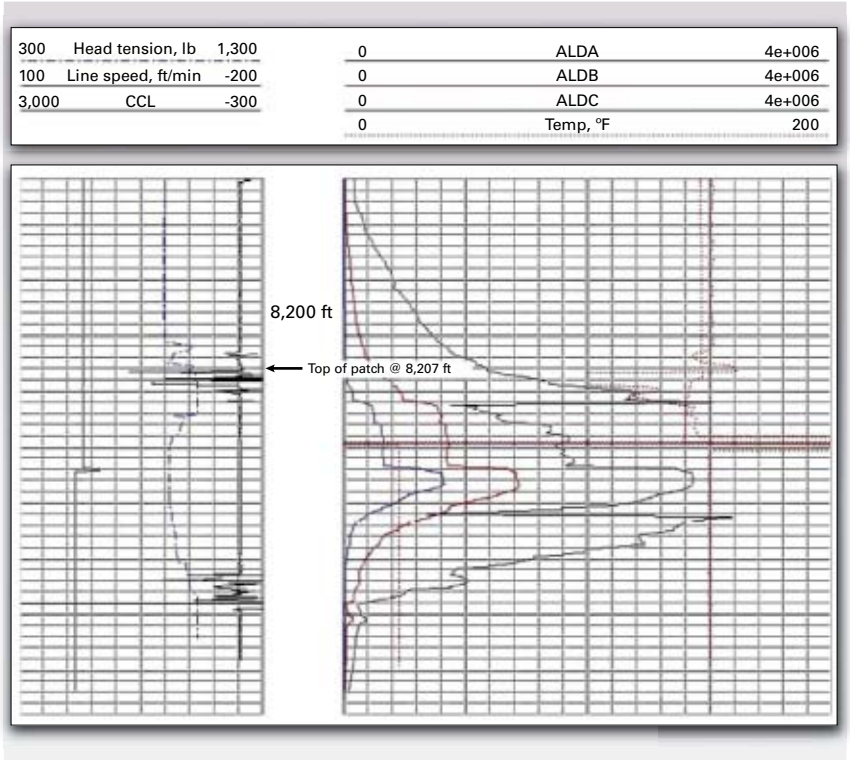
This example indicated that Baker's one trip 3½-in. straddle (or the other vendor's standard two-run straddle) is not ideal for wells with a 2.75-in. minimum restriction.

Until a few years ago, Prudhoe Bay had been operated by two different operating companies. The 2.75-in. SSSV nipples were more common in western operating area well completions and larger 2.81-in. nipples were used in the eastern operating area.

• *Importance of a prestraddle drift run.* The example above illustrates why it is important for slick line to run a dummy drift tha accurately mimics the actual straddle to ensure tight spots are not encountered. The wellbore should be free of debris for about 200 ft below the setting depth. If the drift or a tubing

ULTRASONIC LEAK DETECTION LOG, WELL 7*

Fig. 7



* Peaks show leak signature at top of upper straddle packer element and also at original tubing hole behind straddle.

caliper survey indicates tubing deposits, the straddle area should be brushed, scraped, or acidized so a better straddle seal can be obtained. The dummy straddle should also be the approximate length and the assembly should be run in the hole at the same speed the straddle will be run (typically 50-100 fpm). If the run is made at faster speeds, the slick-line tool string may sit down when going through tight spots, closing the spangs. This can allow the straddle dummy to "fall through" tight spots unnoticed. Wireline will not have this same capability, and the straddle may get stuck.

Well 7

Only one well with a single-set straddle has exhibited tubing by "A" annulus communication since the straddle tested successfully. This straddle was in service a total of 1.4 years before failing. An ultrasonic leak-detection log verified that there was a leak in the upper packer or a tubing leak immediately above the straddle. Becuase a subsequent caliper indicated that the tubing was in poor condition above the straddle, the straddle may still have integrity and the leak may be the result of a second tubing hole.

It's notable that the poststraddle leak detection log not only indicated the leak at or near the straddle, it also showed the original leak behind the straddle (Fig. 7). This commercially available log is able to detect leaks as small as 0.0025 gpm and has been used successfully in more than 65 wells on the North Slope.[2]

Fishing

There have been no problems fishing the single set straddles. On the two operations where straddles were stuck, wireline pulled out of the weak point and slick line subsequently fished the straddle. In retrospect, it may have been better to set the straddle where it was stuck and retrieve the setting tools, rather than pulling out at the weak point. Depending on wellbore configuration, setting the straddle may result in a much shorter, easier, one run fishing operation.

Observations

The high success rate of the single set straddle has increased confidence in straddle operations at Prudhoe Bay, with the following observations:

1. The single set tubing straddle developed to set in 3½-in. and 4½-in. tubing at Prudhoe Bay had an 80% success rate. This is a significant increase over the about 50% success rate it has had in the last few years.
2. Although there have been six failures, there is no single cause for failure. Continued analysis will improve candidate selection and prestraddle diagnostics.
3. Only one straddle has failed since successfully set, with a life of 1.4 years. The study of 263 straddles set between 1985 and 2005 indicates a conservative life of 3.5 years. It is likely that average life for single-set straddles will be at least that long.
4. A prestraddle drift that mimics actual straddle length and OD is very important to ensure a successful set, particularly for wells with tight tolerances.
5. The development of single set straddles for 5½-in. and 7-in. tubing will improve the straddle program.

Acknowledgments

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FACTS: 2007 LNG trade set record; Americas led regions

Shahriar Fesharaki
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In 2007, global LNG demand reached about 172.2 million tonnes, a rise of roughly 13 million tonnes (or 8%) compared with 2006. Fig. 1 shows the largest growth on a percentage basis occurred in the Americas (41%), followed by Asia (10%), while Europe (–7%) declined.

Interestingly, the situation was the reverse of 2006, when Europe experienced the largest growth rate in imports due to a cold winter and strong demand in the UK. The Americas, on the other hand, saw imports decline by more than 7% due to mild weather and ample storage, which stabilized prices and enabled cargoes to be directed to other higher value markets, particularly Asia. Asian imports posted strong growth rates of 10% in 2006 and 11% in 2007, further cementing the region as the most stable, high growth market in the world.

Asia-Pacific

In 2007, LNG demand in the Asia-Pacific reached 112.1 million tonnes. Moreover, the region accounted for the largest regional global growth in absolute numbers: 10.1 million tonnes over 2006 levels.

Japan, the world's largest LNG market for the second year running, led Asia-Pacific LNG importers in absolute growth. The rise in imports in 2007 can be attributed in part to economic recovery and attractive LNG prices compared with oil-based substitutes, which drove demand in the industrial sector.

In the power sector, demand for LNG expanded as power generation was affected by the closing of several nuclear power plants, most notably TEPCO's Kashiwazaki-Kariwa nuclear plant, as well as low utilization of hydropower capacity due to lower-than-average precipitation.

In Korea, imports increased marginally by about 0.3 million tonnes compared with 2006. The relatively flat level of imports can be attributed to seasonally mild temperatures, particularly in the first half of the year, although imports began to pick up in the second half, driven by stronger sales in the power sector. These increased sales were due to the lower generation unit cost of gas vs. oil, coupled with relatively strong electricity demand.

In Taiwan, LNG imports were up a healthy 7% to 8.3 million tonnes year-on-year. The rise in imports was driven by the power sector and to a lesser extent the industrial sector, followed by the residential sector. Taiwan imports from the Atlantic Basin totaled about 1.21 million tonnes, with the largest supplies stemming from Equatorial Guinea, followed by Egypt and Nigeria.

The Atlantic Basin accounted for nearly 15% of Taiwan's portfolio in 2007, a significantly higher share than that of the Asia-Pacific region as a whole, which stood at 7%.

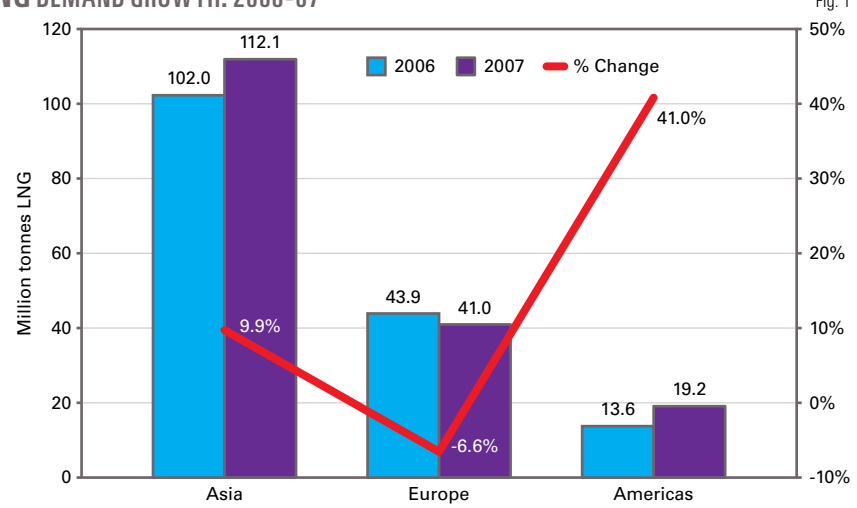
Indian LNG imports totaled about

LNG IMPORTS IN ASIA Table 1

Importers	2006 – Million tonnes –	2007	Change, %
Japan	62.1	66.8	7.6
Korea	25.3	25.6	1.2
Taiwan	7.8	8.3	7.0
India	6.2	8.4	35.9
China	0.7	2.9	324.0
Total	**102.0**	**112.1**	**9.9**

Source: FGE, Honolulu

LNG DEMAND GROWTH: 2006-07 Fig. 1



8.4 million tonnes in 2007, a substantial 36% increase from 2006, driven by strong demand in the industrial and residential sectors and substitution for naphtha in fertilizer production. India continues to be an active player in the spot market, importing about 42 cargoes in 2007. While a significant amount of these cargoes came from Qatar, roughly 1.2 million tonnes came from the Atlantic Basin, particularly Nigeria (0.69 million tonnes) and Algeria (0.37 million tonnes).

China National Offshore Oil Co.'s (CNOOC's) Guangdong terminal received its first Australian cargo in late May 2006. Imports grew rapidly in 2007 and totaled 2.9 million tonnes by yearend. China also made its entry into the spot LNG market receiving its first cargo from Oman in April 2007 and six additional cargoes during the remainder of the year, with the bulk coming from Algeria.

Europe

In 2007, European LNG imports were down 2.9 million tonnes (or 6.6%) compared with 2006 (Table 2). Exceptionally warm temperatures since autumn 2006 curbed demand for heating in most Western European countries last winter, whereas first-quarter 2006 was colder than average. Moreover, hydropower generation increased in many European countries during first-half 2007 thanks to heavier rainfalls.

In Spain, the largest LNG market in Europe, LNG imports in 2007 were essentially flat compared with 2006. Imports decreased by about 0.1 million tonnes, or less than 1%. Natural gas demand dropped in the first quarter, primarily due to a mild winter and to robust hydropower generation following high precipitation in 2006 and early 2007.

The situation reversed itself, however, and LNG demand was especially strong in the last quarter as the country experienced colder temperatures, low hydropower generation (the rest of 2007 turned out to be dry), and maintenance at nuclear power plants.

In Belgium, Algerian LNG imports of less than 3.3 million tonnes/year (tpy), long-term contract have ceased and been replaced since April 2007 by a 2-million-tpy long-term contract between RasGas II and Distrigas. Low gas prices at the Zeebrugge Hub, however, have been unable to attract more than a couple of complementary spot cargoes and, consequently, LNG imports decreased by 1.2 million tonnes or 36% year-on-year.

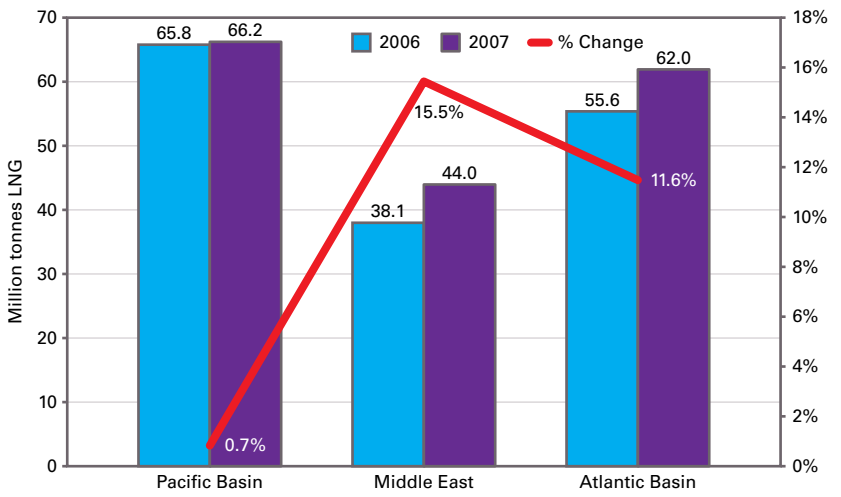
In the UK, the start of two new pipelines at the end of 2006 (Langeled, 2.4 bscfd from Norway in September 2006; and the 1.5 bscfd Dutch Interconnector in December 2006) opened additional natural gas supply routes to the country.

This contributed to the fall of UK gas prices (which averaged around $6.00/MMbtu in 2007), deterring LNG imports despite the start of Excelerate's Teesside onboard regasification terminal in February 2007. Total imports only reached 1.1 million tonnes for the year, a drop of more than 55% compared with 2006 and leaving the Teesside terminal empty during the whole year.

In 2007, only three southern European countries (Turkey, Portugal, and Greece) increased their LNG imports. Turkey's imports rose about 25% (or nearly 0.8 million tonnes). The country experienced strong demand growth in the power and industrial sectors and had to make up for lost volumes due to pipeline supply disruptions from Iran in the last quarter, as Iran was experiencing one of the coldest winters on record.

LNG imports into Portugal and Greece in 2007 rose by roughly 0.4 million tonnes and 0.3 million tonnes, respectively, from 2006. Greece completed the expansion of DEPA's Revithoussa terminal in September 2007 and received one additional cargo from

LNG SUPPLY GROWTH: 2006-07 Fig. 2



LNG IMPORTS IN EUROPE Table 2

Importers	2006 – Million tonnes –	2007	Change, %
Spain	19.0	18.9	–0.4
France	11.2	9.9	–13.0
Turkey	3.4	4.2	24.6
Italy	2.4	2.1	–10.9
Belgium	3.2	2.0	–36.0
Portugal	1.7	2.1	21.6
Greece	0.4	0.7	71.6
UK	2.6	1.1	–55.6
Norway	0.1	—	–100.0
Total	**43.9**	**41.1**	**–6.6**

Source: FGE, Honolulu

LNG IMPORTS IN AMERICAS Table 3

Importers	2006 – Million tonnes –	2007	Change, %
US	12.2	16.2	32.1
Puerto Rico	0.5	0.6	2.9
Dominican Republic	0.2	0.5	92.0
Mexico	0.6	2.0	237.8
Total	**13.6**	**19.2**	**41.0**

Source: FGE, Honolulu

Algeria in the same month. The country has not, however, signed any additional supply contract so far to feed the additional capacity in the terminal.

Americas

Warm weather in Western Europe led to record levels of LNG imports in the Americas, particularly through August, as the US confirmed its position as the market of last resort. As a result, LNG demand in the Americas increased by 5.6 million tonnes or 41% year-on-year driven primarily by US demand, which increased to 16.2 million tonnes.

In Mexico, the Altamira terminal, which received its first LNG cargo in August 2006, imported 2.0 million tonnes in 2007 from Nigeria, Egypt, and Trinidad. Imports will increase this year with the commencement of the Costa Azul terminal, though it remains to be seen how much LNG will be attracted to the West Coast terminal given strong demand in Asia.

Demand in the Dominican Republic also increased slightly due to the relaxation of tensions on Atlantic Basin supply.

LNG supply

In 2007, global LNG supply grew by about 13 million tonnes or 8% year-on-year. As was the case in 2006, production levels did not meet expected targets due to projects delays (NLNG Train 6), technical problems (Snohvit), feedstock shortages (SEGAS and Bontang), as well as unplanned outages (NWS). As Fig. 2 shows, the largest supply growth occurred in the Middle East at 15.5%, followed by the Atlantic Basin at 1.16%, and Pacific Basin at 0.7%.

LNG supply from the Middle East continues to grow on the increased output from Qatar and smaller increases from Oman and Abu Dhabi. Since 2006, Qatar has replaced Indonesia as the world's largest LNG producer accounting for 29.4 million tonnes of exports in 2007. The incremental growth of 5 million tonnes year-on-year is primarily due to the start of RasGas Train 5 in December 2006.

LNG supply from Oman and Abu Dhabi also increased by 5.3% and 8.3%, respectively, during the same period. However, LNG production from Oman LNG and Qalhat LNG remain less than the liquefaction total capacity of 11 million tpy, as the country faces a domestic demand surge and gas supply crunch.

Algeria continues to be the largest producer in the Atlantic Basin with exports increasing by nearly 4% to 18.7 million tonnes. Nigeria, now the region's second largest supplier, posted the largest growth (3.3 million tpy), primarily due to steadier production from NLNG Trains 4 and 5, which experienced production shortfalls in 2006.

Trinidad and Tobago also posted solid growth of 1.7 million tonnes year-on-year with production levels increasing to 14.4 million tonnes in 2007. Libyan exports were essentially flat year-on-year, whereas Egyptian production dropped by about 4% due to growing domestic demand and technical difficulties, which led to gas supply cuts to the Damietta plant.

Finally, the Atlantic Basin witnessed the entrance of two new LNG exporters in 2007, with the commencement of exports from Equatorial Guinea in May and Snohvit in October.

The Pacific Basin posted the smallest nominal increase (0.4 million tonnes). Australia represented the largest growth in LNG supply in the region for 2007 (averaging 8.5%/year). LNG supply from Australia increased to 15.1 million tonnes in 2007 from 13.9 million tonnes in 2006 because of a ramp up in the Darwin liquefaction plant. In Malaysia, LNG production from Bintulu was up 7% in 2007.

Indonesian LNG supply experienced a total decline in production of 1.7 million tonnes during 2006-07. The country continues to face production problems and has fallen to the third rank (after Qatar and Malaysia), down from being the world's largest LNG producer. Finally, Brunei decreased its LNG supply by 0.4 million tonnes during 2007, when compared with 2006.

Table 4 illustrates global LNG supply by country in 2006-07.

GLOBAL LNG SUPPLY

Table 4

Exporter	2006 – Million tonnes –	2007	Change, %
Alaska	1.2	0.9	–23.5
Australia	13.9	15.1	8.5
Brunei	7.4	7.6	2.8
Indonesia	22.4	20.7	–7.3
Malaysia	21.0	22.0	4.7
Total Pacific Basin	**65.8**	**66.2**	**0.7**
Abu Dhabi	5.3	5.7	8.3
Qatar	24.4	29.4	20.6
Oman	8.5	8.9	5.3
Total Middle East	**38.1**	**44.0**	**15.7**
Algeria	18.0	18.6	3.8
Libya	0.5	0.6	18.4
Egypt	10.8	10.4	–3.9
Trinidad	12.8	14.8	12.0
Nigeria	13.5	16.1	25.0
Equatorial Guinea	—	1.5	NA
Norway	—	0.1	NA
Total Atlantic Basin	**55.6**	**62.2**	**11.6**
Total world	**159.4**	**172.2**	**8.0**

Source: FGE, Honolulu

New LNG supply

Qatar is expected to boost its liquefaction capacity with its new 7.8-million-tpy liquefaction trains. The first train of RasGas III is to be completed in October of this year. Qatargas II is also to commence its LNG supply from the first train in third-quarter 2008. With completion of these two mega trains by yearend 2008, total Qatari liquefaction capacity will jump to 45.9 million tpy from 30.3 million tpy.

LNG supply from the Atlantic Basin will see a large increase after completion of the new Nigeria LNG Train 6 and ramp up of LNG supply from Equatorial Guinea. Production from the Snohvit plant in Norway resumed in February 2008 and production should slowly ramp up this year.

In Asia-Pacific, Australian liquefaction capacity is to increase by 4.4 million tpy after completion of NWS Train 5 in late 2008. In Indonesia, Train 1 of the Tangguh LNG project is to be completed in late 2008. The BP-led Tangguh LNG project, however, is targeting next year for first exports from its two

NEW LIQUEFACTION CAPACITY, 2008 Table 5

Location	Project	Capacity, million tpy	Start-up date in 2008
Nigeria	Nigeria LNG (Train 6)	4.1	First qtr.
Qatar	Qatargas II (Train 1)	7.8	Third qtr
Qatar	Rasgas III (Train 1)	7.8	Fourth qtr.
Australia	NWS (Train 5)	4.4	
Indonesia	Tangguh (Train 1)	3.8	Fourth qtr.
Total		**27.9**	

Source: FGE, Honolulu

production trains.

FGE understands that start-up for Tangguh's first train is currently scheduled for Oct. 17, 2008, with the first cargo of LNG expected to emerge 3 months later. The second train of Tangguh is due for start-up on Mar. 17, 2009, with first export cargo to follow on June 17, 2009.

In general, for 2008, a total of 27.9 million tonnes of new LNG capacity is expected to come on stream worldwide (Table 5).

Strong LNG demand

In Asia-Pacific, FGE expects an average 9.3% in LNG demand growth in 2008 in our base-case demand scenario for the region. China and India are to increase their LNG imports significantly.

In China, LNG demand is to grow to 3.5 million tonnes this year from 2.9 in 2007.

In the Americas, construction of five new LNG terminals is to be completed by yearend 2008, bringing total regasification capacity to 101.5 million tpy by yearend 2008. The annual growth rate for LNG imports is to be lower than other regions. FGE's base-case average growth estimation for 2007-08 indicates a 3.3%/year increase in LNG demand in the Americas.

For Europe, FGE's forecasts in its base case is an average of 18.9%/year in LNG imports, as demand in northern Europe is to pick up compared with 2007 levels.

Currently, about 18.2 million tonnes of LNG regasification capacity is under construction in Europe and expected to come on stream by the end of this year. The Fos Cavaou terminal in France is currently under construction and expected to start its operations in late 2008 or early 2009. The terminal will receive Egyptian LNG supply.

In the UK, two LNG terminals are currently under construction. The UK is to be ready to receive its first cargo from Qatargas II after completion of its 7.8-million-tpy South Hook terminal at Milford Heaven.

In FGE's base-case demand scenario, global LNG demand will increase to 191.2 million tonnes in 2008.

Although five new LNG production projects are to come on stream during 2008, supply will still have a hard time keeping up with growing demand pressure and LNG markets will likely continue to show high prices. ✦

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Gulf LNG terminals will see completion 2008-09

Warren R. True
Chief Technology Editor—LNG/Gas Processing

Terminal commissioning has been ongoing at two Texas Gulf Coast LNG terminals this month, as the region begins to complete and start up the first wave of new US import capacity.

Freeport LNG Development LP's Quintana terminal, about 70 miles south of Houston, began receiving its first cool-down shipment from the 138,000-cu m Excelsior on Apr. 15. Cheniere Energy's Sabine Pass terminal, in Cameron Parish, La., along the Sabine River border near Port Arthur, Tex., received its first cargo for commissioning on Apr. 11 from the 145,000-cu m Celestine River.

Two other terminals in the area will begin commissioning later this year or in first-quarter 2009.

ExxonMobil's Golden Pass terminal lies across the Sabine River from Cheniere's facility. And east of Sabine Pass, in Hackberry, La., on the Calcasieu Channel 18 miles from the Gulf of Mexico, Sempra Energy subsidiary Sempra LNG is in the final months of building its Cameron LNG terminal.

Fig. 1 shows the relative location of each terminal.

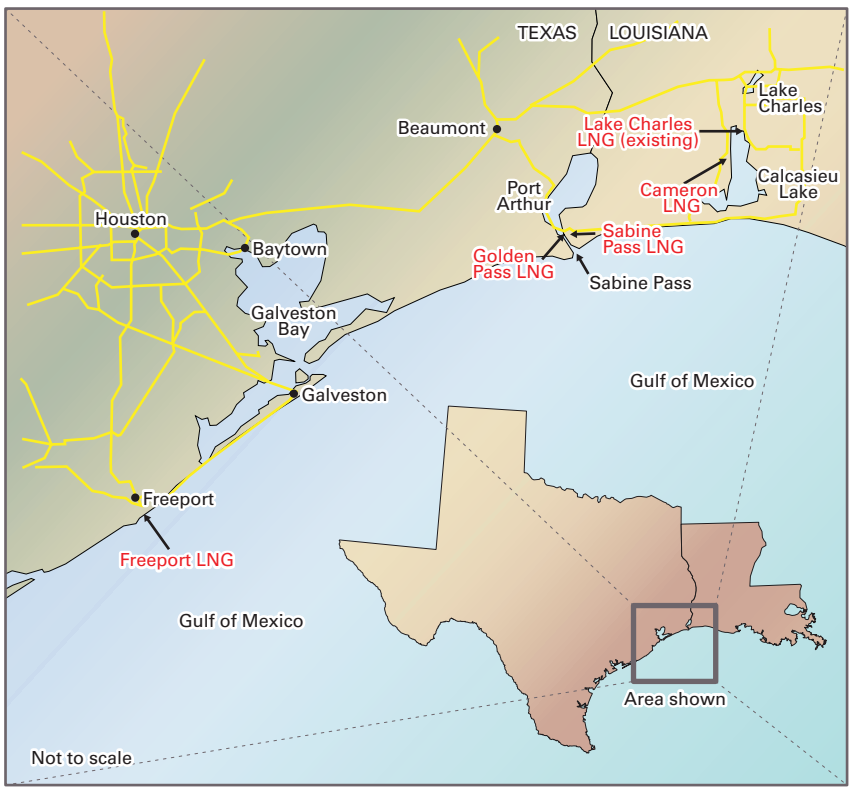
Freeport LNG

Start-up at Freeport LNG will occur later this year, according to FLNG Vice-Pres. Bill Henry.

Possibly the first to first to start up among the four under construction, the terminal on Quintana Island just south of Freeport, Tex., will have Phase 1 nominal sendout capacity of 1.5 bcfd with peak capacity of 1.75 bcfd. Phase 2 plans, unapproved as recently as early April, would add 2.25 bcfd of addition-

US GULF COAST LNG TERMINALS

Fig. 1



Fan installation proceeds in late 2007 for the ambient-air vaporizers at Freeport LNG. The site will be the first terminal in North America to employ the technology (Fig. 2; photo from Freeport LNG; photo by John Smallwood, Houston).

al sendout capacity.

The terminal began construction in January 2005, the first of the three other LNG terminals in Texas whose construction has also been taking place over the last 2-3 years. It has been built under a "fixed-price, date-certain, turnkey" contract by a consortium consisting of Technip USA Corp., Zachry Construction Corp., and Saipem Technigaz SA.

Unlike the four existing US land terminals that use submerged-combustion vaporization—at Everett, Mass.; Cove Point, Md.; Elba Island, Ga.; and Lake Charles, La., Freeport LNG employs an ambient-air system designed to draw heat from the air to regasify the LNG. The process employs towers similar to cooling towers commonly used in many industries, says the company. The towers consist of seven vaporizers with one installed spare employing vertical shell-and-tube exchangers of 250 MMcfd each. The heating medium is glycol and water (Fig. 2)

The technology, says the company, allows Freeport LNG to operate its plant within the Houston-Galveston nonattainment area because the towers emit no NOx. During cooler weather, FLNG converts its vaporization process to heaters similar to those used at other LNG terminals.

Phase 1 has installed two, 160,000-cu m LNG storage tanks (3 bcf equivalent in each tank) and an LNG carrier berth that can accommodate the largest carrier envisioned. Phase 2 would add a third 160,000-cu m tank and separate berthing facilities for a second carrier.

In addition, the company has laid a 9.6-mile, 42-in. pipeline from the terminal to natural gas salt-dome storage at Stratton Ridge (LNG Observer, January-March 2007) where it has contracted for 7 bcf of storage. Three storage tanks in both phases combined with the salt dome storage effectively give the terminal as much as 16 bcf of storage.

The terminal's first cool-down cargo arrived aboard the LNG regasification vessel (LNGR) Excelsior; the vessel is chartered to Excelerate Energy.

Freeport LNG Development is managed by a general partner owned 50% by Michael S. Smith and 50% by ConocoPhillips. Limited partners with "economic interests," according to company material, are Michael S. Smith, Cheniere Energy, Dow Chemical Co., and Osaka Gas. Company material says ConocoPhillips has agreed with Freeport LNG for capacity rights of up to 1 bcfd. Dow has also contracted to receive 500 MMcfd.

Sabine Pass

Running close to the construction schedule of Freeport LNG has been Cheniere Energy's Sabine Pass terminal in Louisiana, near Port Arthur, Tex., along the Sabine River border with Texas. The company held an opening ceremony—not a commissioning, company officials were at pains to say—only last week.

The terminal sits at the widest point on the Sabine River Navigation Channel, 3.7 nautical miles from open water and 23 nautical miles from the outer buoy. The channel is maintained at 40 ft deep and not subject to tidal limitations, says the company. The terminal's two berths are recessed far enough so that no part of the LNG vessel will protrude into the open waterway while docked, says company material.

Phase 1 of terminal construction, nearing completion, has built 10.1 bcf of LNG storage in three tanks, each with an LNG capacity of 160,000 cu m and a maximum continuous regasification rate of 2.6 bcfd, the largest of any US terminal. Vaporization will take place in 16 high-pressure submerged combustion vaporizers (SCVs; Fig. 3). Takeaway is provided by a 16-mile, 42-in. pipeline.

At the opening ceremony last week, company officials celebrated the end of construction of Phase 1. The 145,000-cu m Celestine River was in berth, having arrived on Apr. 11 with a cargo from Nigeria LNG to begin commissioning of the terminal. The vessel is owned and operated by Kawasaki Kisen Kaisha Ltd.

A company spokesperson said two or three more cargoes, from suppliers she declined to name, will be necessary to complete the cool-down process. Commercial operations are likely to start in May or early June, again with no supply sources named by the company.

Phase 2, already well under way, will add 1.4 bcfd with three more 160,000-cu m single-containment tanks, 16 ambient-air vaporizers, each with a high-pressure sendout pump, 8 more SCVs, also aided by a high-pressure sendout pump, and two 30-in. take-away pipelines to metering sites.

Phase 2 will be built in stages. The first stage is adding fourth and fifth storage tanks and more vaporizers that will bring the maximum continuous regasification rate up to 4.0 bcfd with a peak sendout capacity of 4.3 bcfd. Future stages of Phase 2 may add a sixth storage tank and related facilities to bring the total LNG storage volume to 20.2 bcf.

Vaporization at Cheniere's Sabine Pass terminal will be handled by 16 high-pressure submerged combustion vaporizers (Fig. 3; photo from Cheniere LNG).

An aerial view last year of Sempra LNG's Cameron, La., terminal shows the site well along toward completion in late 2008 or early 2009 (Fig. 4; photo from Sempra LNG).

2009 completions

Also under construction is ExxonMobil's Golden Pass terminal, across the Sabine River in Texas from Cheniere's terminal and about 10 miles south of Port Arthur in Jefferson County. At the end of April, said ExxonMobil, the first phase of terminal construction is about 50% complete and will be fully completed by mid-2009. The second phase of the terminal will be completed in 2010.

At the end of two construction

phases, Golden Pass LNG plans to import LNG to move about 2 bcfd (2.7 bcfd peak) to Texas and US markets. The project includes dock and unloading facilities for double-hulled LNG carriers; five full-containment 155,000-cu m LNG tanks; 10 shell-and-tube heat transfer fluid heat exchangers (5 in Phase 1 and 5 in Phase 2) for vaporization; and associated pipelines.

The initial filing with the US Federal Energy Regulatory Commission listed:

- A 77.8-mile, 36-in. mainline (the Golden Pass LNG pipeline) from the terminal to an interconnection with a Transco mainline near Starks, La.
- A 42.8-mile, 36-in. loop beside the mainline from the terminal to an interconnection with Texoma pipeline in Orange County, Tex.
- A 1.8-mile, 24-in. lateral from the mainline in Jefferson County, Tex., to industrial customers in Beaumont-Port Arthur, including ExxonMobil's Beaumont refinery.

Golden Pass's dedicated slip, berths, and unloading facilities will accommodate two LNG carriers of 125,000-250,000 cu m and tugboat operations, says the company's initial FERC filing. The berths will also consist of four 16-in. unloading arms and on 16-in. vapor-return arm.

Golden Pass LNG LLC, owner of the terminal, is 70% owned by an affiliate of Qatar Petroleum, with affiliates of ExxonMobil and ConocoPhillips each owning a share in the balance of the interest in the terminal. LNG for Golden Pass will be supplied primarily from RasGas 3, Trains 6 and 7, and Qatargas 3.

East of the Sabine Pass area, in Hackberry, La., 18 miles north of the gulf and on the Calcasieu Channel, Sempra Energy subsidiary Sempra LNG is building the Cameron LNG terminal (Fig. 4).

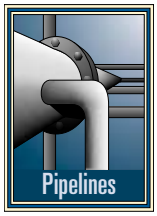
With total investment, according to Sempra, of about $750 million, the terminal will have 1.5 bcfd of initial sendout capacity with room for expansion up to 2.65 bcfd. The terminal is installing NGL recovery to allow it to meet btu-content specifications of receiving pipelines.

Construction began in 2005, with completion expected late this year. Start-up is planned for first-quarter 2009, said a company spokesperson, but had no details on commissioning cargoes, vessels, or sources.

The location consists of three 160,000-cu m full-containment LNG storage tanks; the planned 1.15-bcfd second phase will add another tank. Vaporizing will take place in 12 SCVs, each sized for 150 MMcfd.

Another Sempra Energy unit, Sempra Pipelines & Storage, has built a 35.4-mile, 36-in. sendout pipeline to connect with major interstate systems north of the terminal. ✦

US NATURAL GAS—1



Gulf-region transport bottlenecks pose future supply, price dislocation

Porter Bennett
E. Russell Braziel
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Between 2010 and 2012, barring a drastic decline in the price of natural gas that would curtail the current growth trajectory of US production, incremental domestic production, combined with some nominal volume of increased LNG imports could exceed pipeline capacity out of the Southeast-gulf region.

It is possible that capacity use out of the region could reach 100%, resulting in a market scenario similar to the which affected Rockies pricing during summer 2007, displacing gas supplies that have traditionally moved into the Southeast-gulf region from the Midcontinent and West Texas into lower-value markets in the western US.

This first part of two articles outlines the infrastructural developments that will bring this about. The second, concluding article (May 12) will provide a detailed time line of projects in the region and explain how each will play into the potential for basis dislocation suggested here.

Background

The unprecedented natural gas infrastructure investment occurring in the Southeast US-Gulf Coast region has major implications not only for that region, but also for markets across North America and ultimately the world. The addition of such a large amount of new pipeline, LNG, and gas storage will affect flow patterns, commodity values, asset values, trading economics, and hedging strategies both in the near term and for decades to come.

While this development period will continue for several years, numerous projects are slated to enter service this year and during first-half 2009. Twenty-five natural gas pipeline projects totaling 18.6 bcfd of capacity and four LNG terminals with 7.1 bcfd of sendout capability are coming online between now and mid-2009. Another 11 new storage projects will add 6.3 bcfd of new deliverability to the growing capacity surplus.

An inadequate amount of regional takeaway in the face of this expected influx of new supply could lead to both supply and pricing dislocations, similar to what has occurred for the past several years in the Rocky Mountain region.

With winter 2006-07 and summer 2007 as reference periods, current maximum capacity out of the Southeast-gulf region totals 22.5 bcfd. An average of about 16.0 bcfd moves out of the region, increasing to 19.4 bcfd in peak periods. Ignoring the effect of variability in local demand, this implies room to move about an additional 6.5 bcfd on average days and 3.1 bcfd on peak days.

Fig. 1 suggests that even 6.5 bcfd of spare outbound capacity, however, may not be enough. Total new inbound pipeline capacity measures 6.6 bcfd, with supplies provided by feeder pipelines west of the region totaling 7.4 bcfd. New LNG terminal sendout adds 7.1 bcfd, with 3.6 bcfd of this from the Sabine Pass and Cameron facilities, both inside the region. While current domestic supplies will be inadequate to fill new pipeline capacity and there is considerable doubt as to the availability of LNG supplies to fill new terminal capacity, the potential for a significant surplus of gas supply into the region is increasing. The 11 new storage projects further exacerbate this risk.

Even though Table 1 shows 4.2 bcfd of new outbound pipeline capacity, most of this is subject to downstream constraints. In an extreme case, the total capacity from new inbound pipeline projects, LNG sendout, and storage deliverability (16.5 bcfd) could exceed the 6.5 bcfd capacity out of the region

by more than two and a half times.

This scenario exaggerates the magnitude of the outbound capacity problem, since it excludes the effect of local demand, the likelihood of noncoincident demand peaks on different pipeline systems, curtailments of receipts from the East and South Texas corridors, and similar market developments. The numbers, however, still clearly show that intense competition will emerge between new and existing facilities for capacity out of the region.

Production limits

Production in the four basins driving much of the growth in pipeline infrastructure—the Fort Worth, East Texas, Arkoma, and Arkla basins—reached more than 10.7 bcfd in 2007 from 5.5 bcfd in 2001. Bentek projects production from these basins will reach 13.2 bcfd in 2009.

Four of the seven pipeline projects bringing gas into the region run roughly through the corridor between Carthage, Tex., and Perryville, La. These projects will add 5.8 bcfd of transportation capacity by mid-2009.

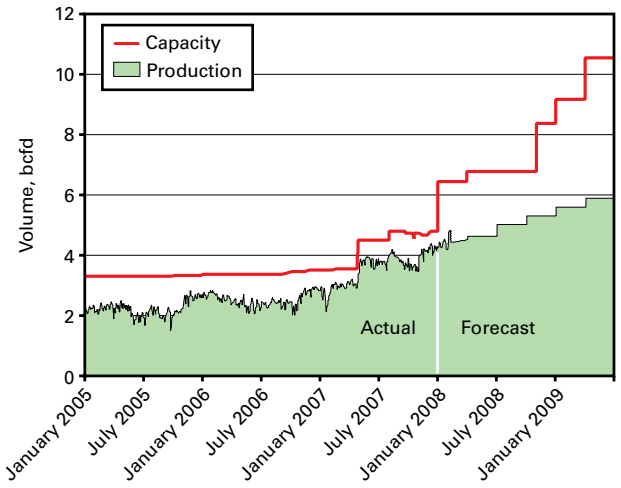
Fig. 1 brings these two assessments together, showing the relationship between flow and capacity between Carthage and Perryville through mid-2009. The blue line represents flows on the corridor. The red line depicts actual and projected capacity. The green area represents historical and forecast production.

Fig. 1 shows a lack of new incremental production available to fill the new capacity between Carthage and Perryville during 2008 to mid-2009. This production deficit has three important market implications:

- Demand for gas at the west (Carthage) end of the corridor to fill surplus capacity will drive up relative prices in this area. Holders of capacity on the new pipelines will bid up prices in East Texas markets to secure volumes to fill the new pipeline capacity. This pattern has already become apparent in the spot market following start-up of Gulf South's East Texas-to-Mississippi expansion in February and March 2008.
- Capacity holders on the new pipelines may bid prices high enough to pull gas from other pipelines already operating in the region.
- While limits exist on the availability of incremental production to fill new pipeline capacity, enough new gas supplies will reach the eastern (Transco Station 85) end of the region to put downward price pressure on the premium Southeast market. Given downstream constraints from that region, this pressure could threaten Transco Zone 4's traditional pricing premium, particularly after first-quarter 2009 completion of the Gulf Crossing pipeline. At that point the difference between inbound capacity and outbound capacity will reach its highest level (Fig. 2).

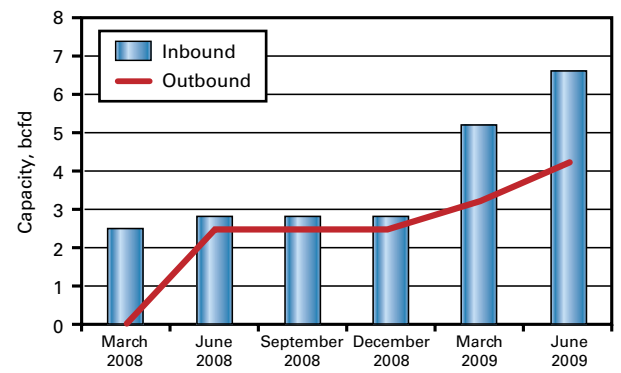
NATURAL GAS FLOW INTO SOUTHWEST-GULF REGION

Fig. 1



SOUTHEAST-GULF PIPELINE PROJECTS, CUMULATIVE

Fig. 2



Costs, differentials

Efficiencies of the new, large diameter pipeline projects and the rate design benefits that frequently reflect those efficiencies will lower the average cost of moving gas through most sectors of the region, particularly northern sectors where most of the new construction is taking place. The weighted average incremental cost to move gas on the new pipelines from Carthage to Perryville is $0.107/MMbtu, 30% lower than the $0.155/MMbtu average of traditional pipelines in the region.

An even more dramatic shift will occur between Perryville and the premium Southeast market. A total of 4 bcfd will be added on this route, increasing total capacity by almost seven times. The average ITC on this new capacity is only $0.105/MMbtu, 50% below traditional pipelines.

The sector between the Houston ship channel and Henry Hub has run consistently full since autumn 2007. New construction will increase capacity on that sector by just 0.8 bcfd.

Since most of the new pipeline capacity consists of additions to the northern route (Carthage-Perryville) and the southern route is at capacity on most days, the northern route will emerge as the primary path for

incremental production to move from Texas into the Southeast.

To the extent that new supplies are available to fill the capacity, these supplies will flow to new pipelines in the northern sectors. When the 4.2 bcfd of new pipeline capacity enters service between Perryville (and Carthage) and Southeast consuming markets in summer 2009, there will only be about 2.0 bcfd of new production to fill it, leaving 2.2 bcfd of demand (spare capacity) in East Texas.

This development will further reinforce the increase in new demand for supplies in the Carthage area, but will also add enough new supply to the Southeast to pressure those prices, resulting in a reduction in the price differential between the two points.

Terminology

The Southeast US-Gulf Coast region can be viewed as a dense web of interconnected pipeline systems that crisscross in a network that defies traditional analyses of natural gas flows and capacities. Bentek has developed a simplifying model to help understand Southeast-gulf flows and capacities. The resulting flow structure resembles a horizontally stretched letter I (Fig. 3). The I model simplifies analysis by assigning each existing and new pipeline segment in the region to one of five regional pipeline sectors.

Sector I-1 runs west-to-east from Carthage, Tex., through Perryville, La. Sector I-2 includes pipelines that move gas in a west-to-east flow from the Houston ship channel area into the region around Henry Hub in Louisiana.

Sector I-3 runs from South Louisiana north to Perryville and includes some pipelines that can flow gas south from Perryville to South Louisiana. Sector I-4 extends from North Louisiana eastward to Transco Station 85 in Choctaw, Ala. Sector I-5 extends from the Henry Hub area in South Louisiana to pipeline connections in the premium Southeast, including Florida Gas Transmission Zone 3.

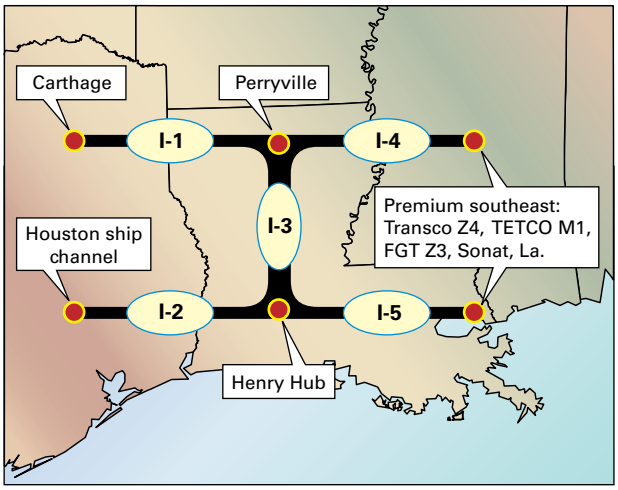
Premium Southeast refers to a number of key trading hubs that typically enjoy relatively high pricing, including Transco Zone 4, Texas Eastern Zone M1, Florida Gas Zone 3, and Sonat Louisiana.

Inbound surplus

New Southeast-gulf pipelines and LNG terminals—totaling 25.4 bcfd—will add inbound capacity exceeding takeaway capacity out of the region. Another 6.3 bcfd of new storage deliverability will add to surplus. Current capacity out of the Southeast-gulf averages 22.5 bcfd. Average utilization of capacity out of the region equals about 71%, increasing to 90% on peak winter days and

Regional gas flow pattern

Fig. 3



US SOUTHEAST-GULF NATURAL GAS TRANSPORTATION, STORAGE PROJECTS*

Table 1

Category	Number of projects	Capacity, bcfd	Description
Feeder pipelines, outside southeast-gulf region	13	7.4	Primarily designed to move gas out of the field and into pipelines delivering gas into new or existing southeast-gulf pipelines.
Inbound pipelines	7	6.6	Some of the region's largest inbound pipeline system additions bring gas from Carthage, Tex., to Perryville, La. and beyond, including Gulf South's Southeast Expansion, Boardwalk's Gulf Crossing, and Kinder Morgan's Midcontinent Express.
Storage facilities	11	6.3	All but one of these storage projects are high-deliverability salt-dome facilities, mostly located within 200 miles of the gulf coast.
LNG terminals	4	7.1	LNG terminals should be viewed similar to storage facilities in that they can deliver large volumes of gas quickly into the pipeline grid.
Total inbound	**22**	**20**	
Outbound pipelines	5	4.2	Three new pipeline systems will move gas from supply areas in northeast Texas and Oklahoma to Transco's Station 85 in Choctaw County, Ala.: Gulf South's Southeast Expansion, Boardwalk's Gulf Crossing, and Kinder Morgan's Midcontinent Express. Spectra-CenterPoint's Southeast Supply Header will move gas from Perryville into Florida.
Total, all projects	**40**	**31.6**	

*Planned for completion by mid-2009.

93% on peak summer days.

This pattern will change dramatically as 25 natural gas pipeline projects, four LNG terminal facilities, and 11 storage projects come online in 2008 and first half 2009. Thirteen pipeline projects to the west of the Southeast-gulf region will deliver new Barnett, Woodford, Fayetteville, and Bossier Sands production into pipelines feeding the Southeast-gulf. Boardwalk Pipeline Partners Gulf South pipeline expansion and Gulf Crossing pipeline, the MidContinent Express pipeline, and other projects will add 6.6 bcfd moving new gas into Perryville and to markets farther east.

LNG and storage projects will add 13.7 bcfd of additional gas supply. Pipeline projects to move gas across and out of the region, however, total only 4.2 bcfd. To the extent that gas supplies are available to fill the net new capacity in the region, peak deliverability could exceed current takeaway capacity by more than two-and-one-half times.

New LNG terminals and associated storage projects started development a few years ago when it was widely determined that existing supply sources in North America would be inadequate to meet demand over the long term because of steady growth in the residential and commercial sectors and even greater growth in the power generation sector. The same price signals that triggered initial interest in additional LNG and storage capacity also prompted rapid development of unconventional domestic gas resources. Many of the new pipeline projects will handle production growth from shales, tight sands, and other unconventional gas plays.

Price differentials

While these new pipeline projects will bring additional gas into the region, the ability to move incremental gas out of the region will remain constrained, at least for the next 2-3 years. Operators are only developing 4.2 bcfd out of the region, 2.4 bcfd less than inbound capacity. Net capacity additions to the region will come in successive waves, with an increment of inbound capacity coming online in one time frame and a lesser increment of outbound capacity coming online at a later date. The resulting oscillation of changes in net pipeline capacity, combined with supply variations, will create volatility in regional price differentials.

Eastward deliverability

GulfSouth's Southeast Expansion and Gulf Crossing pipelines and KinderMorgan-Energy Transfer Partners' Midcontinent Express project terminate at Transco Station 85 in Choctaw County, Ala., in Transco Zone 4. While these pipelines will bring a total of more than 3 bcfd into Station 85, downstream capacity there is constrained on most days during the winter.

Downstream capacity on Transco at Station 180, just before Transco reaches densely populated areas in Virginia and Maryland, experiences near 100% utilization most of the time. This constraint effectively prevents incremental flows from reaching northern markets. Until Transco expands capacity north of those constraints, any new supplies that come into Transco Zone 4 will displace traditional pipeline flows into the area. Similar downstream constraints will affect flows from the Centerpoint-Spectra Southeast Supply Header project into Florida.

Incremental production

Although rapid production in the Southeast-gulf region is driving much of the region's pipeline expansion, in the short and medium term there will not be enough incremental supplies to fill the new capacity. Several of the new pipeline projects with favorable tariff structures for commodity and fuel rates will displace gas from traditional pipe-

lines that deliver gas into and across the region.

The surge of new natural gas infrastructure development to move gas west-to-east across the Southeast-gulf region will initially exceed the volume of supplies available to fill that capacity, causing the differential between gas prices in the Barnett, Woodford, and Fayetteville shales and the Bossier sands region to narrow relative to the premium Southeast markets at Transco Zone 4, TETCO M1, FGT Zone 3, and Sonat, La.

Completion at the same time of the Rockies Express pipeline into Lebanon and Clarington, Ohio, will provide another boost to Rockies prices, put downward pressure on Ohio Valley prices, and displace gas that has traditionally moved from the Southeast-gulf region. These developments will combine to flatten basis differentials across the Southeast and into the Ohio valley area (OGJ, Apr. 2, 2007, p. 56).

Henry Hub

New pipeline capacity being built from northeast Texas around Carthage into eastern Louisiana near Perryville will exceed new capacity being built to move gas eastward from Perryville. Surplus Perryville supplies can move either north into the Midwest and Ohio valley, or south by either physical movement or displacement, into pipelines along the South Louisiana corridor to the Henry Hub, and then north and east to premium markets.

These capacity developments, in conjuction with unpredictable market conditions, will tend to make pricing flip-flop between the northern and southern pipeline corridors. Production growth will eventually fill available capacity into Perryville, increasing surplus supplies at that location. Capacity limitations to move gas north and east out of Perryville will then reverse some flows that have traditionally moved north out of South Louisiana. Those flows will instead move south into the Henry Hub and surrounding pipelines.

Four new LNG terminals are also scheduled to be completed in the Southeast-gulf region within the next 18 months, adding 7.1 bcfd of send-out capacity on the Louisiana and Texas coast. Two of the new facilities, plus the existing Lake Charles terminal, will add 6.0 bcfd of peak LNG sendout capacity within 75 miles of Henry Hub.

Whether more than a few token deliveries of LNG arrive at US Gulf Coast terminals over the next few years remains uncertain. But any cargoes which do arrive will likely do so in the summer, when demand in Europe and Asia is at its lowest.

When surplus LNG arrives in the Southeast-gulf region, the gas may either move immediately into the pipeline grid and presumably on to market-area storage, move into existing and new high-deliverability gulf-region storage, or some combination of the two. More than enough pipeline capacity should exist to handle LNG volumes delivered into gulf-region storage. Withdrawals, however, are another matter. Market conditions will encourage withdrawals from existing and new storage facilities during relatively narrow time frames, resulting in excess demand for pipeline capacity out of the region.

Incremental costs

Most of the new pipeline projects are large diameter, high-capacity lines, which translate into lower charges for fuel and lost and unaccounted for gas in the pipelines' tariffs. Lower incremental gas transportation costs translate into more competitive pricing for new pipeline supplies, a situation already seen regarding Rockies Express' start-up (OGJ, Apr. 2, 2007, p. 56). Several of the major pipelines traversing the Southeast-gulf region, however, have postage stamp rates, such as Florida Gas Transmission, or feeder-cost arrangements that economically favor already operating Southeast pipelines.

Henry Hub's location at the pivot point of new domestic and LNG supplies will increase near-term price volatility both there and at surrounding pricing hubs when LNG imports enter the region. The tendency of new transportation and storage capacity to compress regional price differentials and dampen the volatility of price differentials across the entire market will offset this trend. When combined, these diverging developments suggest basis as measured by the difference between Henry Hub and other market regions will become more volatile and more heavily influenced by localized market forces in the Southeast-gulf region. ✦

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Equipment/Software/Literature

Drilling sites are focus of application reports

A series of application reports focuses on worldwide drilling sites.

Three recent additions to these 2-4 page educational reports look at the utilization of truck-mounted rotary rigs used in coalbed methane and natural gas production.

Application reports 7, 8, and 9, respectively, include a tribute to Noah Horn of Noah Horn Well Drilling Inc., Vansant, Va.; documented use of rigs in rural Missouri by Pense Bros. Drilling Co. Inc., Fredericktown, Mo.; and rig operations in Alberta by the drilling division of BlackWatch Energy Services Trust, Calgary. The reports include location photos and comments from site supervisors.

Source: **Atlas Copco Drilling Solutions LLC,** Box 462288, Garland, TX 75046-2288.

New memory sensor for coiled tubing operations

DataCoil, a new memory sensor for coiled tubing use, combines multiple sensors into a compact module.

The module accompanies the bottomhole assembly (BHA) and monitors parameters such as pressure, temperature, inclination, compression, and tensile and impact loads.

The system was deployed recently in Alaska, where it was subjected to 24,000 impacts greater than 10,000 lb each over a 30-min interval during a high-profile fishing operation. During vibratory impacting, the tool continued to acquire pressure, temperature, and strain data, performing without interruption, the firm reports. The tool has been used on more than 12 wells for various applications since. The system can be deployed "in field" for extended periods of time on a single battery charge, typically more than 6 months, the firm says.

The system can be applied in the following BHA configurations:

- Perforating.
- Fracturing.
- Inflatable packer setting.
- Bridge/plug setting/retrieval.
- Heavy duty fishing operations.
- Milling operation.
- Vibratory hammers.
- Hydraulic single shot hammers.
- Tractor deployment/measurement.
- Sliding sleeve manipulation and confirmation.

It supplies information as follows:

- Data analysis of coil tubing loads.
- Surface tensile vs. BHA loading.
- Surface applied pressure vs. actual BHA pressures.
- Actual BHA inclination for friction analysis.
- Actual forces applied during impacting with the ability to monitor change with pressure analysis.

Source: **Impact Guidance Systems Inc.,** 519 E. Oak Hill Dr., Spring, TX 77386.

Services/Suppliers

Martin International,

Martin

LaPlace, La., named Russell D. Martin its new CEO. He started in the business as an ordinary seaman with Otto Candies in Des Allemands, La., later moving to Seahorse in Morgan City, La. Martin worked his way up to a Master 500 Gross Tons license in the Gulf of Mexico and off Africa. He then went to work for Zapata Gulf Marine, where he earned his Master 1,000 Tons Freight and Towing license and became Zapata's director of crew coordination. That was followed by a stint at Tidewater in New Orleans, where Martin earned a Master 3,000 Gross Tons Any Oceans license, working off Alaska. For the last 10 years he has instructed at Martin International. Recently, Martin became Captain of the company when he purchased it from his family and became the majority shareholder.

Martin International provides a range of US Coast Guard license training for personnel working on offshore installations and mobile drilling units.

Geotrace,

Houston, has named Scott Humphrey manager, Latin America marketing. His responsibilities include sales of Geotrace's reservoir seismic and reservoir services to new and existing customers, as well as expanding Geotrace's presence geographically throughout the Latin America region. Humphrey comes to Geotrace with more than 20 years of experience in the seismic industry. Previously, Humphrey held management positions with GX Technology, Landmark Graphics, and Digicon Geophysical.

Geotrace is a leading reservoir services company that provides subsurface imaging solutions to the oil and gas industry worldwide.

Domain Engineering,

Tulsa, has promoted Hussein Sallak to president after he recently joined the firm. His background includes 37 years in project management and engineering design for gas processing plants, refineries, and pipelines. Domain's previous president and founder, Dan Lansdown, will remain active in the firm as its CEO. In addition, Domain appointed Scott Brown vice-president, refining and chemicals. Brown worked 11 years with Exxon Chemical Co. in technology development and industrial manufacturing prior to joining Domain Engineering in 1998. Domain also named Brad Young vice-president, gas processing. Young brings 20 years of domestic and international experience in process design and project management. He joined Domain Engineering in 2000.

Domain Engineering is an engineering consulting firm specializing in refining, gas processing, chemicals, and biotechnical industries worldwide.

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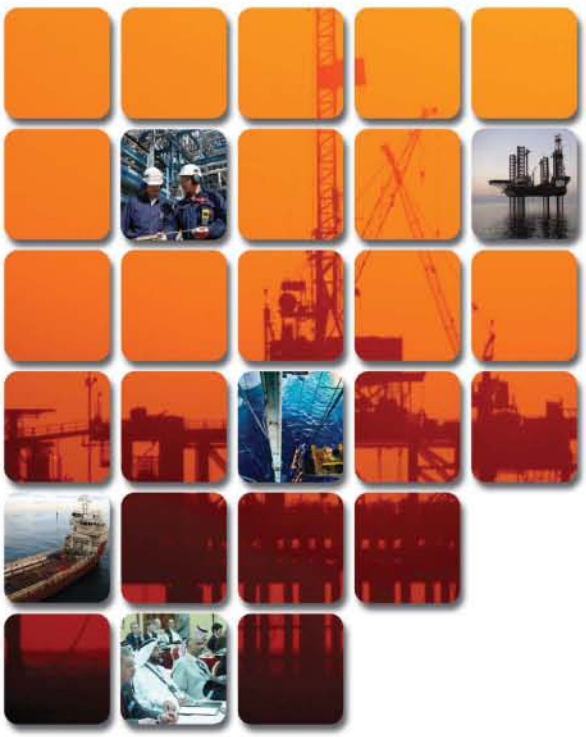

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Imports of crude and products

	Districts 1-4		District 5		Total US		
	4-11 2008	4-4 2008	4-11 2008	4-4 2008	4-11 2008	4-4 2008	*4-13 2007
	1,000 b/d						
Total motor gasoline	946	800	4	107	950	907	1,039
Mo. gas. blending comp.	682	393	—	86	682	479	568
Distillate	204	161	56	—	260	161	263
Residual	298	368	18	18	316	386	488
Jet fuel-kerosine	175	137	143	66	318	203	336
Propane-propylene	147	180	12	12	159	192	89
Other	477	1,006	(12)	(98)	465	908	749
Total products	**2,929**	**3,045**	**221**	**191**	**3,150**	**3,236**	**3,532**
Total crude	**7,966**	**7,750**	**913**	**1,162**	**8,879**	**8,912**	**9,919**
Total imports	**10,895**	**10,795**	**1,134**	**1,353**	**12,029**	**12,148**	**13,451**

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

Purvin & Gertz LNG netbacks—Apr. 18, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	8.51	6.17	7.57	6.05	6.85	7.48
Everett	8.72	6.64	8.32	6.48	7.06	9.05
Isle of Grain	10.36	7.84	10.16	7.71	8.53	9.62
Lake Charles	7.43	5.22	7.16	5.43	5.76	8.18
Sodegaura	6.69	8.42	6.63	8.43	7.68	5.64
Zeebrugge	8.87	5.60	7.20	5.54	6.29	7.20

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		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	15,954	58,993	32,355	8,988	30,123	13,479	2,129
PADD 2	64,389	49,929	17,558	7,614	28,527	1,317	8,798
PADD 3	167,462	70,002	32,745	12,773	31,402	17,231	13,580
PADD 4	13,799	6,252	1,791	536	3,221	262	[1]760
PADD 5	52,056	30,575	23,346	9,798	12,806	6,050	—
Apr. 11, 2008	**313,660**	**215,751**	**107,795**	**39,709**	**106,079**	**38,339**	**25,267**
Apr. 4, 2008	**316,016**	**221,268**	**110,805**	**38,510**	**106,027**	**39,258**	**25,250**
Apr. 13, 2007[2]	**332,405**	**197,007**	**91,204**	**40,686**	**117,327**	**40,803**	**25,975**

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

Refinery report—Apr. 11, 2008

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,348	1,394	1,767	84	418	161	57
PADD 2	3,032	3,015	2,242	177	877	49	180
PADD 3	6,784	6,779	3,145	682	2,020	225	628
PADD 4	569	557	288	27	174	13	[1]137
PADD 5	2,583	2,491	1,399	433	540	198	—
Apr. 11, 2008	**14,316**	**14,236**	**8,841**	**1,403**	**4,029**	**646**	**1,002**
Apr. 4, 2008	**14,603**	**14,349**	**8,896**	**1,441**	**3,990**	**610**	**1,089**
Apr. 13, 2007[2]	**15,781**	**15,444**	**8,664**	**1,348**	**4,217**	**673**	**1,047**
	17,588 operable capacity		**81.4% 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.

OGJ crack spread

	*4-18-08	*4-20-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	126.40	81.74	44.66	54.6
Brent crude	112.08	66.29	45.79	69.1
Crack spread	14.32	15.45	–1.13	–7.3
FUTURES MARKET PRICES				
One month				
Product value	128.36	83.41	44.95	53.9
Light sweet crude	114.41	63.01	51.40	81.6
Crack spread	13.96	20.40	–6.44	–31.6
Six month				
Product value	123.14	79.64	43.50	54.6
Light sweet crude	111.21	67.60	43.61	64.5
Crack spread	11.92	12.04	–0.11	–0.9

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

OGJ GASOLINE PRICES

	Price ex tax 4-16-08	Pump price* 4-16-08	Pump price 4-18-07
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	302.1	341.8	274.1
Baltimore	288.5	330.4	279.8
Boston	283.5	325.4	270.1
Buffalo	286.7	346.8	286.2
Miami	302.8	353.1	293.0
Newark	284.9	317.8	259.3
New York	268.7	328.8	278.2
Norfolk	286.1	323.7	270.8
Philadelphia	284.3	335.0	284.2
Pittsburgh	282.6	333.3	274.2
Wash., DC	299.7	338.1	287.5
PAD I avg.	288.2	334.0	271.2
Chicago	320.0	370.9	307.8
Cleveland	288.0	334.4	273.9
Des Moines	291.9	332.3	269.9
Detroit	287.0	336.2	277.1
Indianapolis	293.6	338.6	278.9
Kansas City	290.7	326.7	264.1
Louisville	308.9	345.8	280.7
Memphis	293.1	332.9	268.9
Milwaukee	288.9	340.2	287.6
Minn.-St. Paul	288.2	328.6	269.3
Oklahoma City	290.0	325.4	265.0
Omaha	289.2	335.6	275.1
St. Louis	291.6	327.6	270.8
Tulsa	284.6	320.0	266.9
Wichita	279.8	323.2	269.0
PAD II avg.	292.4	334.5	267.2
Albuquerque	291.8	328.2	275.8
Birmingham	297.8	336.5	269.9
Dallas-Fort Worth	294.5	332.9	274.7
Houston	292.8	331.2	270.8
Little Rock	294.3	334.5	268.0
New Orleans	294.0	332.4	267.9
San Antonio	286.4	324.8	256.0
PAD III avg.	293.1	331.5	261.0
Cheyenne	288.1	320.5	259.0
Denver	296.4	336.8	270.9
Salt Lake City	286.7	329.6	264.3
PAD IV avg.	290.4	329.0	260.8
Los Angeles	305.7	364.2	325.4
Phoenix	281.7	319.1	287.0
Portland	309.5	352.8	303.3
San Diego	316.3	374.8	335.3
San Francisco	329.0	387.5	349.6
Seattle	308.8	361.2	311.0
PAD V avg.	308.5	359.9	318.6
Week's avg.	**293.6**	**337.1**	**280.3**
Mar. avg.	**276.1**	**319.7**	**254.0**
Feb. avg.	**259.5**	**303.1**	**228.0**
2008 to date	**269.3**	**312.9**	—
2007 to date	**199.3**	**242.9**	—

*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

	4-11-08 ¢/gal		4-11-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	270.46	New York Harbor	325.65
Gulf Coast	271.96	Gulf Coast	315.28
Los Angeles	301.21	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	NA	ARA	333.54
Singapore	281.95	Singapore	326.95
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	280.21	New York Harbor	189.00
Gulf Coast	293.21	Gulf Coast	191.00
Los Angeles	307.21	Los Angeles	207.30
		ARA	211.29
		Singapore	203.37

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

BAKER HUGHES RIG COUNT

	4-18-08	4-20-07
Alabama	5	3
Alaska	6	8
Arkansas	43	42
California	39	35
Land	38	34
Offshore	1	1
Colorado	122	114
Florida	0	0
Illinois	0	0
Indiana	2	2
Kansas	12	14
Kentucky	12	2
Louisiana	142	189
N. Land	51	62
S. Inland waters	19	30
S. Land	19	33
Offshore	53	64
Maryland	0	0
Michigan	0	2
Mississippi	10	18
Montana	12	22
Nebraska	0	0
New Mexico	82	76
New York	7	6
North Dakota	56	32
Ohio	12	13
Oklahoma	214	178
Pennsylvania	22	14
South Dakota	2	2
Texas	883	836
Offshore	8	11
Inland waters	2	1
Dist. 1	23	22
Dist. 2	35	37
Dist. 3	55	54
Dist. 4	93	89
Dist. 5	187	169
Dist. 6	120	126
Dist. 7B	32	45
Dist. 7C	68	60
Dist. 8	130	111
Dist. 8A	22	24
Dist. 9	35	31
Dist. 10	73	56
Utah	41	43
West Virginia	23	32
Wyoming	68	71
Others—AZ-1; NV-3; OR-1; TN-3; VA-4	12	9
Total US	**1,827**	**1,769**
Total Canada	**96**	**98**
Grand total	**1,923**	**1,867**
Oil rigs	355	292
Gas rigs	1,461	1,473
Total offshore	63	76
Total cum. avg. YTD	**1,780**	**1,737**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	4-18-08 Percent footage*	Rig count	4-20-07 Percent footage*
0-2,500	71	5.6	52	5.7
2,501-5,000	123	51.2	100	55.0
5,001-7,500	204	17.6	209	22.9
7,501-10,000	420	2.3	432	3.0
10,001-12,500	469	4.0	429	3.7
12,501-15,000	292	—	268	0.3
15,001-17,500	118	—	111	0.9
17,501-20,000	73	—	68	—
20,001-over	36	—	37	—
Total	**1,806**	**7.3**	**1,706**	**8.0**
INLAND	29		34	
LAND	1,719		1,611	
OFFSHORE	58		61	

*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]4-18-08	[2]4-20-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	16	20
Alaska	713	745
California	651	668
Colorado	44	66
Florida	5	5
Illinois	25	26
Kansas	94	98
Louisiana	1,352	1,333
Michigan	14	17
Mississippi	52	48
Montana	93	86
New Mexico	163	164
North Dakota	114	118
Oklahoma	171	169
Texas	1,339	1,343
Utah	45	50
Wyoming	144	146
All others	62	70
Total	**5,097**	**5,173**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	4-18-08 $/bbl*
Alaska-North Slope 32°	88.35
South Louisiana Sweet	118.50
California-Kern River 13°	104.15
Lost Hills 30°	112.55
Southwest Wyoming Sweet	108.19
East Texas Sweet	112.75
West Texas Sour 34°	105.75
West Texas Intermediate	113.25
Oklahoma Sweet	113.25
Texas Upper Gulf Coast	109.75
Michigan Sour	106.25
Kansas Common	112.25
North Dakota Sweet	109.50

*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

	4-11-08 $/bbl[1]
United Kingdom-Brent 38°	107.00
Russia-Urals 32°	101.84
Saudi Light 34°	103.37
Dubai Fateh 32°	99.53
Algeria Saharan 44°	108.27
Nigeria-Bonny Light 37°	109.38
Indonesia-Minas 34°	105.25
Venezuela-Tia Juana Light 31°	103.25
Mexico-Isthmus 33°	103.14
OPEC basket	104.60
Total OPEC[2]	103.17
Total non-OPEC[2]	103.27
Total world[2]	103.22
US imports[3]	101.22

[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]

	4-11-08	4-4-08	4-11-07	Change, %
		bcf		
Producing region	503	498	638	–21.2
Consuming region east	582	563	675	–13.8
Consuming region west	176	173	246	–28.5
Total US	**1,261**	**1,234**	**2,559**	**–19.1**
	Jan. 08	**Jan. 07**	**Change, %**	
Total US[2]	**2,055**	**2,379**	**–13.6**	

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

Statistics

World oil balance

	2007 4th qtr.	2007 3rd qtr.	2007 2nd qtr.	2007 1st qtr.	2006 4th qtr.	2006 3rd qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	21.00	21.03	20.97	21.07	21.09	21.25
Canada	2.38	2.38	2.28	2.34	2.29	2.31
Mexico	2.08	1.98	2.07	2.05	2.00	1.96
Japan	5.22	4.67	4.61	5.39	5.29	4.75
South Korea	2.31	2.06	2.12	2.35	2.32	2.04
France	2.00	1.93	1.85	1.97	1.95	1.93
Italy	1.72	1.63	1.67	1.69	1.71	1.68
United Kingdom	1.73	1.75	1.78	1.80	1.81	1.78
Germany	2.56	2.56	2.40	2.39	2.71	2.75
Other OECD Europe	7.56	7.54	7.26	7.36	7.54	7.46
Australia & New Zealand	1.12	1.09	1.07	1.09	1.10	1.07
Total OECD	**49.68**	**48.62**	**48.08**	**49.50**	**49.81**	**48.98**
NON-OECD						
China	7.97	7.69	7.62	7.43	7.53	7.24
FSU	4.44	4.34	4.45	4.37	4.43	4.35
Non-OECD Europe	0.79	0.73	0.78	0.85	0.78	0.72
Other Asia	8.95	8.65	8.84	8.75	8.82	8.54
Other non-OECD	14.97	15.26	14.94	14.67	14.46	14.69
Total non-OECD	**37.12**	**36.67**	**36.63**	**36.07**	**36..02**	**35.54**
TOTAL DEMAND	**86.80**	**85.29**	**84.71**	**85.57**	**85.83**	**84.52**
SUPPLY						
OECD						
US	8.56	8.40	8.53	8.43	8.40	8.38
Canada	3.33	3.35	3.33	3.42	3.39	3.31
Mexico	3.35	3.46	3.61	3.59	3.52	3.71
North Sea	4.57	4.28	4.49	4.80	4.76	4.51
Other OECD	1.58	1.56	1.54	1.50	1.55	1.55
Total OECD	**21.39**	**21.05**	**21.50**	**21.74**	**21.62**	**21.46**
NON-OECD						
FSU	12.67	12.55	12.60	12.61	12.48	12.26
China	3.86	3.87	3.96	3.92	3.81	3.85
Other non-OECD	11.40	11.47	11.22	10.87	11.21	11.37
Total non-OECD, non-OPEC	**27.93**	**27.89**	**27.78**	**27.40**	**27.50**	**27.48**
OPEC*	**36.19**	**35.41**	**35.09**	**35.01**	**35.49**	**36.20**
TOTAL SUPPLY	**85.51**	**84.35**	**84.37**	**84.15**	**84.61**	**85.14**
Stock change	**–1.29**	**–0.94**	**–0.34**	**–1.42**	**–1.22**	**0.62**

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

OECD total net oil imports

	Dec. 2007	Nov. 2007	Oct. 2007	Dec. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,288	–1,296	–1,217	–1,537	249	–16.2
US	11,484	11,569	11,628	11,556	–72	–0.6
Mexico	–1,258	–1,520	–1,217	–1,469	211	–14.4
France	1,952	1,951	1,792	1,965	–13	–0.7
Germany	2,266	2,167	2,289	2,334	–68	–2.9
Italy	1,721	1,641	1,689	1,712	9	0.5
Netherlands	1,212	1,204	790	1,009	203	20.1
Spain	1,627	1,514	1,539	1,584	43	2.7
Other importers	4,005	4,205	4,252	3,847	158	4.1
Norway	–2,296	–2,030	–2,165	–2,236	–60	2.7
United Kingdom	–90	168	84	–4	–86	2,150.0
Total OECD Europe	**10,397**	**10,820**	**10,270**	**10,211**	**186**	**1.8**
Japan	5,727	5,101	4,821	5,299	428	8.1
South Korea	2,281	1,909	2,194	2,250	31	1.4
Other OECD	673	856	913	880	–207	–23.5
Total OECD	**28,016**	**27,439**	**27,392**	**27,190**	**826**	**3.0**

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

OECD* total gross imports from OPEC

	Dec. 2007	Nov. 2007	Oct. 2007	Dec. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	397	412	394	395	2	0.5
US	6,310	6,102	5,837	5,841	469	8.0
Mexico	40	32	31	43	–3	–7.0
France	925	792	766	913	12	1.3
Germany	484	360	420	337	147	43.6
Italy	1,306	1,272	1,255	1,372	–66	–4.8
Netherlands	774	555	537	603	171	28.4
Spain	691	562	730	832	–141	–16.9
Other importers	1,201	1,281	1,296	1,355	–154	–11.4
United Kingdom	273	257	273	182	91	50.0
Total OECD Europe	**5,654**	**5,079**	**5,277**	**5,594**	**60**	**1.1**
Japan	4,442	4,419	4,326	4,622	–180	–3.9
South Korea	2,490	2,158	2,549	2,245	245	10.9
Other OECD	766	692	803	768	–2	–0.3
Total OECD	**20,099**	**18,894**	**19,217**	**19,508**	**591**	**3.0**

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

US petroleum imports from source country

	Dec. 2007	Nov. 2007	Average YTD 2007	Average YTD 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	600	447	670	657	13	2.0
Angola	439	415	507	513	–6	–1.2
Kuwait	158	154	183	185	–2	–1.1
Nigeria	1,271	1,306	1,132	1,114	18	1.6
Saudi Arabia	1,686	1,620	1,489	1,463	26	1.8
Venezuela	1,387	1,381	1,362	1,419	–57	–4.0
Other OPEC	568	618	640	166	474	285.5
Total OPEC	**6,109**	**5,941**	**5,983**	**5,517**	**466**	**8.4**
Canada	2,360	2,431	2,426	2,353	73	3.1
Mexico	1,322	1,581	1,533	1,705	–172	–10.1
Norway	110	100	141	196	–55	–28.1
United Kingdom	238	210	278	272	6	2.2
Virgin Islands	387	414	346	328	18	5.5
Other non-OPEC	2,329	2,518	2,732	3,336	–604	–18.1
Total non-OPEC	**6,746**	**7,254**	**7,456**	**8,190**	**–734**	**–9.0**
TOTAL IMPORTS	**12,855**	**13,195**	**13,439**	**13,707**	**–268**	**–2.0**

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

Oil stocks in OECD countries*

	Dec. 2007	Nov. 2007	Oct. 2007	Dec. 2006	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	184	177	176	192	–8	–4.2
Germany	275	272	275	283	–8	–2.8
Italy	133	130	132	133	—	—
United Kingdom	98	98	103	109	–11	–10.1
Other OECD Europe	682	667	661	670	12	1.8
Total OECD Europe	**1,372**	**1,344**	**1,347**	**1,387**	**–15**	**–1.1**
Canada	200	202	207	180	20	11.1
US	1,662	1,686	1,707	1,720	–58	–3.4
Japan	621	622	629	631	–10	–1.6
South Korea	143	149	159	152	–9	–5.9
Other OECD	107	106	112	103	4	3.9
Total OECD	**4,105**	**4,109**	**4,161**	**4,173**	**–68**	**–1.6**

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

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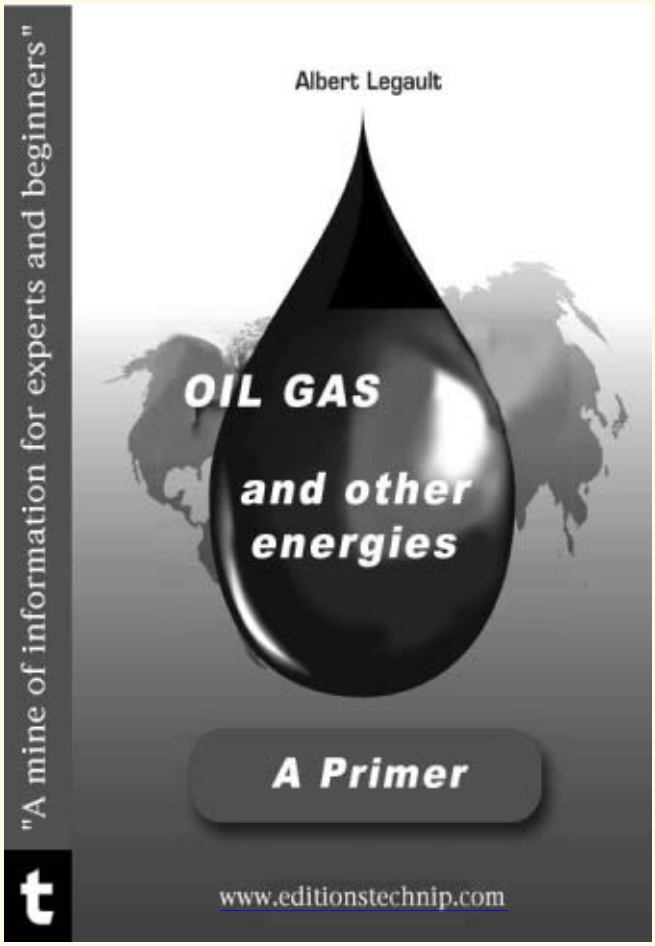

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Bush attempts climate-change damage control

The climate-change proposal by US President George W. Bush deserves credit for damage control.

On Apr. 16, Bush announced a goal of halting the growth greenhouse-gas emissions by 2025.

The plan emphasizes technology, appeals for parallel efforts in all economically growing countries, asserts the need for accelerated cuts in power-plant emissions,

The Editor's Perspective

by Bob Tippee, Editor

and relies on incentives, including for nuclear energy.

Because it spurns mandates, the proposal drew criticism from advocates of aggressive climate-change response.

And because it presumes the need for response, the plan alarmed observers who remain doubtful about the ability of politics to influence climate and worried about the economic effects.

Bush disclosed at least part of his motivation by citing "a growing problem here at home": court rulings authorizing regulators to limit greenhouse-gas emissions under air-quality and other environmental laws.

"If these laws are stretched beyond their original intent," he said, "they could override the [energy] programs Congress just adopted and force the government to regulate more than just power-plant emissions."

The president rejected tax increases but didn't mention cap-and-trade schemes such as the one proposed in a bill the Senate is expected to consider soon (OGJ Online, Apr. 8, 2008).

That's appropriate. Economically, they do the same thing: raise the cost of energy use. With a direct tax, energy users see what's happening to them. Cap-and-trade schemes camouflage the effects.

Either way, the costs are real.

A week before Bush spoke, the Congressional Budget Office estimated costs of the Senate bill—"revenues," in the language of fiscal politics: $1.2 trillion during 2009-18 net of income and payroll tax offsets. And meeting mandates in the legislation would cost private companies an estimated $90 billion/year during 2012-16, CBO says.

The average cost is $165 billion/year. As a share of last year's gross domestic product, that's 1.3%. For perspective: Receipts from the federal income tax this year, according to an estimate by the Heritage Foundation, will be 8.5% of GDP.

The cap-and-trade proposal by the Senate thus represents a hard punch to a jittery economy. The pain is just harder to see coming than that of a direct tax.

(Online Apr. 18, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Weak dollar buoys oil prices

The US dollar at record lows against the euro, China's robust demand for diesel, and market concerns about supply and demand have pushed up oil prices more than 18% so far this year, said analysts in the Houston office of Raymond James & Associates Inc. in mid-April.

At Barclays Capital Inc., London, Paul Horsnell reported, "The drift up in prices and the continuation in the reduction of resistance to higher prices along the curve are still very much a function of perceived imbalances into the future. If we are correct in our view that non-OPEC supply will be at best very weak in 2008 and is likely to fall, despite a decade of rising prices, the impact on perceptions of the long-term clearing price is likely to be a powerful one and likely to be more powerful than any perceived position in the short-term economic cycle." He predicted, "The price highs of the year are not yet in."

Adam Sieminski, global energy economist for Deutsche Bank, said, "We believe the oil price remains mesmerized by the course of the US dollar. If as we expect [the euro] hits $1.62, it would imply the oil price rising to $118/bbl. However, it would require oil prices hitting $145/bbl for the market capitalization of energy companies on the Standard & Poor's 500 to represent a similar share as tech stocks at the peak of the internet bubble."

The weak dollar has lowered the cost of oil to many foreign buyers and has encouraged investments in crude as a hedge against the falling value of US currency and fears of inflation.

As for natural gas, the current difference between gas prices in the US and UK markets "will discourage flows to the US," said Sieminski. "While two new LNG terminals took first deliveries this week and another is coming on soon, we expect utilization rates at these facilities will stay low unless US gas prices rise. We remain bullish on price."

Refinery outages

Input of crude into US refineries was down 113,000 b/d to 14.2 million b/d in the week ended Apr. 11, with refineries operating at 81.4% of capacity. Jacques H. Rousseau at Soleil-Back Bay Research said total refined product inventories—including gasoline, distillate, and jet fuel—declined more than 4 million bbl (1.1%) during the week, due primary to lower supply. "We expect this trend of lower supply and seasonally improving demand to continue in the coming weeks, but we remain concerned that high retail gasoline prices will slow consumption growth during the summer driving season," Rousseau said.

In addition to planned maintenance and the seasonal turn-around efforts at several refineries, several have experienced unexpected disruptions of production. BP PLC began Apr. 14 restarting an alkylation unit at its 460,000 b/d Texas City, Tex., refinery. Just a day earlier, ExxonMobil Corp. began the restart of a CO boiler at fluid catalytic cracking unit No. 3 at its 53,000 b/d Baytown, Tex., refinery.

An Apr. 10 fire at an electrical substation at Marathon Oil's 239,000 b/d refinery in Catlettsburg, Ky., forced the closure of the FCCU.

Sunoco Inc.'s 194,000 b/d Marcus Hook, Pa., refinery was in restart mode Apr. 9 following an Apr. 7 power failure, according to a recent report by Dow Jones Newswires, compiled from both official and unofficial sources. Valero Energy Corp.'s 255,000 b/d Aruba refinery is expected to operate at a reduced rate through April, pending completion of repairs to a crude vacuum unit following a fire on Jan. 25. Coker repairs began in late March at Valero's 210,000 b/d Delaware refinery and are expected to continue through early May.

At Lyondell Chemical Co.'s 268,000 b/d refinery in Houston, an FCCU was shut down Mar. 19 due to a compressor failure and is expected to restart in April. A 20,000 b/d FCC unit was shut in at Valero's 340,000 b/d Corpus Christi refinery. The company's 325,000-b/d Port Arthur refinery is operating at 260,000-270,000 b/d during repairs to drum cracks on a coking unit.

A 43,000 b/d hydrocracker was shut down Apr. 12 at BP's 260,000 b/d Carson, Calif., refinery following a fire at an associated compressor. Exxon restarted a hydrotreater that was idled Apr. 4 due to a fire at its 152,500 b/d Torrance, Calif., refinery. A 36,000 b/d hydrocracker was shut in Apr. 2 to repair a heat exchanger at Valero's 165,000 b/d Benecia, Calif., refinery.

(Online Apr. 21, 2008; author's e-mail: samf@ogjonline.com)

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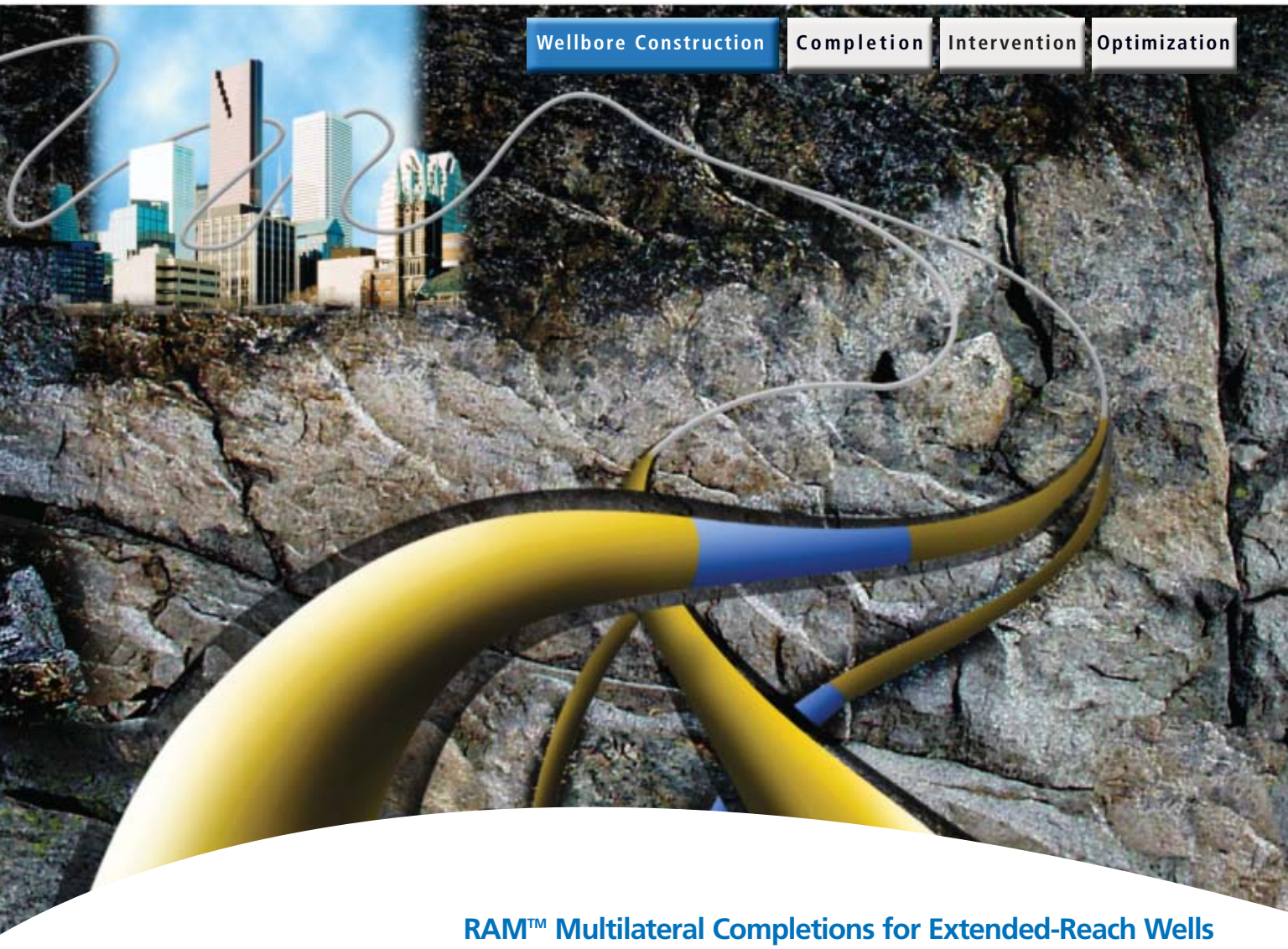

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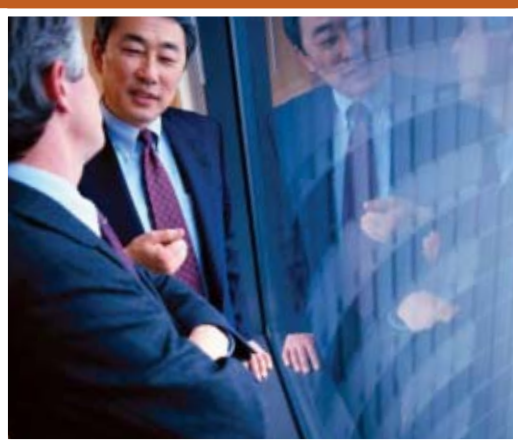

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The mission of the Oil Sands and Heavy Oil Technologies Conference & Exhibition is to provide an annual forum that addresses the technical challenges to safely and cost-effectively develop oil sands and heavy oil resources and that encourages the development of young professionals within the industry. The conference is organized to facilitate the open exchange of technology, ideas, best practices, and experiences that impact oil sands and heavy oil projects and operations.

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INNOVATION OPENS THE DOOR

The oil sands of Alberta in western Canada are undergoing an investment boom worth more than $100 billion. From 2007 to 2016, the Alberta Energy and Utilities Board (EUB) projects total real investment in Alberta's oil sands (surface mining, upgrading, in situ, and support services) to reach Canadian $118 billion. Oil sands output is set to rise from about 1.2 million barrels a day to an expected 3 million b/d by 2016, and perhaps 4 million plus by 2020. That could make Canada the world's fourth-biggest oil producer after Saudi Arabia, Russia and the United States.

The Alberta oil sands and heavy oil industry is both a globally important and growing source of oil supply as well as a vital breeding ground for production and environmental technology. As the boom continues, share your ideas, experiences, technology, and expertise with major industry players who must react quickly to the rapid expansion. Plan to attend the second annual Oil Sands and Heavy Oil Technologies Conference & Exhibition, July 15 – 17, 2008 at the Calgary TELUS Convention Centre in Calgary, Alberta Canada.

WHO SHOULD ATTEND

The Oil Sands and Heavy Oil Technologies Conference & Exhibition is a forum for senior-level industry experts. It provides a rich environment for learning and networking through topic-specific exhibits and presentations of industry-leading technology.

Experts from around the world will be present to explain the technologies and services that are a critical component of success in this complex industry.

And experts from all phases of operations will be in attendance to learn and make business contacts – including engineers, managers, supervisors, consultants and business development managers.

PLAN TO ATTEND IF YOUR RESPONSIBILITIES INCLUDE:

- Project identification
- Project development
- Production, processing, and transportation
- Power generation

EVENT OVERVIEW

- A unique gathering of the world's leading executives, managers, and engineers from major and independent E&P companies
- Original reports on the current and future state of technology in this frontier environment delivered by key personnel involved in groundbreaking projects
- A renewed focus on oil sands and heavy oil technologies and equipment, viewed at the strategic level with case studies and reports on application technologies
- Geopolitical and economic evaluations of the future of oil sands and heavy oil around the globe with input from major, independent, and state-owned operators

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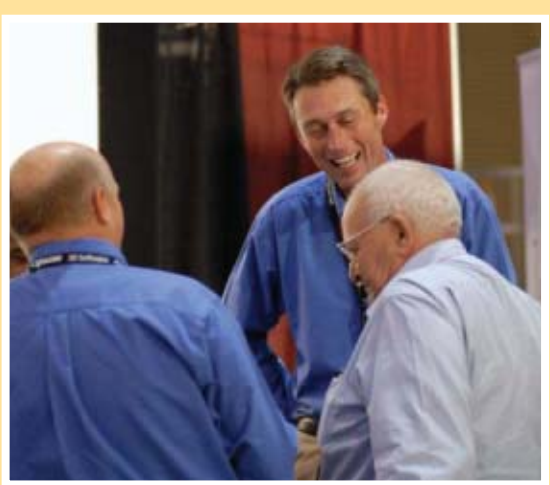

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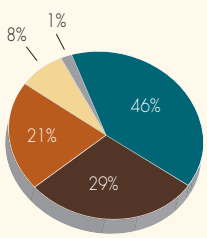

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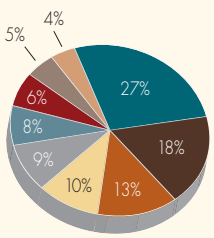

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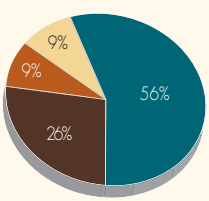

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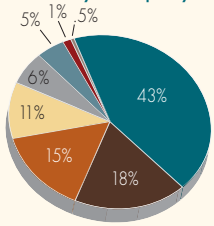

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OIL SANDS HEAVY OIL TECHNOLOGIES

TUESDAY, JULY 15, 2008	
8:00 – 1:00 p.m.	PRE-CONFERENCE WORKSHOP – An Introduction To Oil Sands And Heavy Oil Technologies Instructor: Len Flint – *LENEF Consulting (1994) Limited*
3:00 – 5:00 p.m.	OPENING SESSION – Oil Sands and Heavy Oil Technologies Overview Robert Fryklund – *IHS* Tom Wise – *Purvin & Gertz*
5:00 – 7:00 p.m.	EXHIBITION HALL NETWORKING RECEPTION
WEDNESDAY, JULY 16, 2008	
7:30 a.m.	NETWORKING BREAKFAST *Sponsored by:* HSL Hatch – Sargent & Lundy A JOINT VENTURE
8:00 – 10:00 a.m.	KEYNOTE SESSION
8:00 – 8:15 a.m	WELCOME & INTRODUCTION Bob Tippee – Conference Director
8:15 – 8:20 a.m	SAFETY MESSAGE – TELUS Convention Centre Manager
8:20 – 10:00 a.m.	KEYNOTE Eddy Issacs – *AERI* Shannon Flint – *Alberta Environment*
SESSION 1	
TRACK 1:	ENVIRONMENTAL CHALLENGES
10:30 – 12:00 noon	WATER Chair: Peter McAleer – *Tundra Solutions* Co-Chair: Randy McGill – *Siemens Canada Limited*
	A Broad Portfolio of Innovative Solutions for the Technical Challenges of the Oil Sands Mark Wilson – *GE Water & Process Technologies* *This discussion addresses new, innovative technologies bundled as a portfolio solution and focused on utility and produced water treatment, water reuse and ZLD, wastewater management, process treatment, system upgrades and retrofits as well as financing opportunities for the oil sands.*
	Improving Water Intake System & Eliminating Heat Exchanger Fouling & Sealing to Improve Plant Performance Kaveh Someah – *Eimco Water Technologies*
	Produced Water Treatment Options for SAGD Keith Minnich – *Veolia Water Solutions & Technologies* *New developments in produced water treatment for SAGD will reduce the carbon footprint, OPEX, and CAPEX over conventional evaporation processes.*
TRACK 2:	POWER, FUEL & INFRASTRUCTURE
10:30 – 12:00 noon	ALTERNATIVE POWER Chair: Frank Forte – *Jacobs Canada* Co-Chair: Teresa Hansen – *Power Engineering*
	Evaluation of Cogeneration for an Upgrading Facility Brent Stang – *Fluor Canda Ltd.* *An economic and emissions evaluation to determine the impact of installing a "fit-for-purpose" cogeneration unit versus generating steam via utility boilers and importing power.*
	Paper Title & Speaker TBD
	Nuclear Applications in the Oil Sands Catherine Cottrell – *AECL*

CONFERENCE PROGRAM DETAIL

OIL SANDS HEAVY OIL TECHNOLOGIES

TRACK 3:	**UPGRADING METHODS**
10:30 – 12:00 noon	UPGRADING 1 Chair: Keng Chung – *Well Resources* Co-Chair: Tom Prokop – *Suncor Energy*
	Catalytic Gasification of Coal and PetCoke to Synthetic Natural Gas Don Anthony – *Great Point Energy*
	UOP Introduces Slurry Hydrocracking Solution for Heavy Oil Upgrading Robert Haizmann – *UOP LLC* *The benefits of UOP Slurry Hydrocracking for conversion of bitumen and vacuum residue are described including high conversion to distillates, flexible flow scheme options and attractive economics.*
	Emerging Technologies to Produce Paraffins, Olefins and Aromatics for the Petrochemical Industry in Alberta Dr. Michael Oballa – *NOVA Chemicals Corp* *This paper summarizes efforts by NOVA Chemicals, to date, on the development of two new technologies, which start with bitumen-derived gas oils, and transform them into paraffins (ethane, propane, butane), olefins (ethylene and propylene) and aromatic compounds (benzene, toluene and xylene), all of which are valuable feedstock to petrochemical plants.*
12:00 – 1:30 p.m.	LUNCH
SESSION 2	
TRACK 1:	**ENVIRONMENTAL CHALLENGES**
1:30 – 3:00 p.m.	EMISSIONS 1 Chair: Derek Macdonald – *Alstom Canada Limited* Co-Chair: Peter McAleer – *Tundra Solutions*
	Alstom SCR Technology John Buschmann – *Alstom* *This paper will outline the design, operating and performance features for SCR as applied to boilers fired by conventional fuels and highlight some of the areas that may need attention in developing a design that will be appropriate for high sulfur heavy oil.*
	CFD Analysis for NO_x Control in Refinery Rudolf Schick – *Spray Analysis & Research Services*
	Paper Title & Speaker TBD
TRACK 2:	**POWER, FUEL & INFRASTRUCTURE**
1:30 – 3:00 p.m.	INFRASTRUCTURE 1 Chair: Jim Hyne – *HYJAY Research & Development* Co-Chair: Jerry d'Aquin – *Con-Sul Inc.*
	Update on Design Considerations for the Combustion of Bitumen-Based Fuels – Based on Recent Test Burn Results William Rosenquist – *Sargent & Lundy*
	Paper Title & Speaker TBD
	Paper Title & Speaker TBD
TRACK 3:	**UPGRADING METHODS**
1:30 – 3:00 p.m.	UPGRADING 2 Chair: Chris Lehecka – *ConocoPhillips* Co-Chair: Frank Forte – *Jacobs Canada*
	A Process Using Heated Pressurized Hydrogen Fluidized Bed Producing High Grade SCO from Oil Sand, Heavy Oil, Bitumen, and Oil Shale Martin Karpenski and Anthony Howarth – *Chattanooga Corp.* *This demonstrated pressurized fluid bed hydrogen reactor converts unconventional resources in a low temperature, non-combustion environment and has the flexibility to use process off-gasses and recovery of waste heat, power co-generation and the utilization of the light HC gases as feedstock in its hydrogen plant and as fuel for the fired heater making the process virtually self sufficient.*

CONFERENCE PROGRAM DETAIL

TRACK 3:	**UPGRADING METHODS CONTINUED...**
1:30 – 3:00 p.m.	Development of a Thermally – Intensive Reactor and Process for Upgrading Heavy Crude Oil Dr. Edward Hauptmann – *Refinery Science Corp.* *A very high thermal flux reactor having short residence time for upgrading heavy crude has been developed and tested in a 15 bpd pilot plant with promising results.*
	Catalytic Cracking of Bitumen and Heavy Oil Feedstock During the Upgrading Process James Miller – *OptiFuel® Technology Group, LLC* *This paper presents test results for an innovative technology that adds a catalytically-enhanced set of chemical cracking reactions to the thermal cracking and coking processes that are currently occurring in upgrading units.*
3:00 – 3:30 p.m.	COFFEE BREAK
SESSION 3	
TRACK 1:	**ENVIRONMENTAL CHALLENGES**
3:30 – 5:00 p.m.	EMISSIONS 2 Chair: Derek Macdonald – *Alstom Canada* Co-Chair: Randy McGill – *Siemens Canada Limited*
	Multi-Pollutant Control Options for the Combustion of Bitumen-Based and Related Fuels: 2008 Update William DePriest – *Sargent & Lundy* *This paper will explore emissions control technologies suitable for meeting the recent developments in the SO_2, NO_x, and particulate emission requirements for the combustion of bitumen based fuels in the Province of Alberta.*
	Skidded Combination Scrubber/WESP Offers Low Cost/High Efficiency SO_2 and Particulate Removal for Bitumen Fired Boilers Steven Meyer – *MECS, Inc.*
	Syncrude Emissions Reduction Project Mark Fiedler – *Alstom* *The Syncrude Emissions Reduction Project is a multi-year engineering and construction project to reduce the air emissions from oil extraction and upgrading operations at the Mildred Lake facility.*
TRACK 2:	**POWER, FUEL & INFRASTRUCTURE**
3:30 – 5:00 p.m.	INFASTRUCTURE 2 Chair: Chris Lehecka – *ConocoPhillips* Co-Chair: Paul Brown – *Colt WorleyParsons*
	Reduced Labor and Condensed Schedules with Cellular Concrete Solutions Doug Lavis – *CEMATRIX (Canada) Inc.* *Properties, case studies, and advantages of Cellular Concrete insulation and light weight fill are discussed as an innovative solution to reducing labor and increasing the speed of construction.*
	Paper Title & Speaker TBD
	The Integration of CO_2 Transportation and Sequestration Chuck Szmurlo – *Enbridge, Inc.* *This presentation examines the strategic drivers, costs and operational considerations for integrating key elements of an integrated carbon sequestration and transportation system.*
	ALTERNATE: Practical Application of Passive Sonar Technology to Long Standing Measurement Challenges in Oil Sands and Heavy Oil Processes John Viega – *CiDRA Corp.*
TRACK 3:	**UPGRADING METHODS**
	UPGRADING PANEL DISCUSSION Chair: Shunlan Liu – *AERI* Co-Chair: Keng Chung – *Well Resources*
	Panel Members TBD
5:00 – 6:00 p.m.	EXHIBITION HALL NETWORKING RECEPTION

CONFERENCE PROGRAM DETAIL

OIL SANDS HEAVY OIL TECHNOLOGIES

THURSDAY, JULY 17, 2008

SESSION 4

TRACK 1:	SULFUR	*Sponsored by:* SANDVIK
8:30 – 10:00 a.m.	SULFUR 1 Chair: Jim Hyne – *HYJAY Research & Development* Co-Chair: Bob Tippee – *Oil & Gas Journal*	
	World Sulfur Perspective and its Impact on Canadian Sulfur Bill Kennedy – *retired from Shell Canada* *Despite the present astronomical price of sulfur, which was unexpected by all, forecasts indicate a substantial oversupply of this essential material is expected within a few years - this paper will explore such issues and its impact on the Alberta sulfur industry.*	
	Sulphur Output from Oilsands – Changing Alberta's Sulfur Balance Jerry d'Aquin – *Con-Sul, Inc.* *A review of oil sands projects with their possible sulfur production, combined with an outlook for gas-derived sulfur output, yields one possible estimate of sulfur availability in Alberta for the coming decade*	
	Logistical Alternatives and Challenges Facing Alberta's Changing Sulfur Geography C. Doug Houston – *Kinder Morgan Canada Terminals Ltd.* *Alberta's oil sands processing investments and declining sour gas reserves will shift the centre of sulfur production from southern to the northern Alberta centre, requiring new storage, forming and logistical infrastructure to support the outflow of product.*	
TRACK 2:	EXTRACTION METHODS	
8:30 – 10:00 a.m.	PRODUCTION 1 Chair: Mike Freeman – *M-I SWACO* Co-Chair: Guntis Moritis – *Oil & Gas Journal*	
	Development of a Chemical Treatment for the Management of Wellbore Tar Adhesion Dr. Gregory Perez – *Halliburton* *Rather than solvate the tar into the mud, an aqueous polymeric treatment has been developed aiming to effectively minimize the inherent adhesive properties of the bitumen allowing for conventional solids control equipment to remove the encapsulated bitumen as a firm solid*	
	Slotted Pipes for Steam Assisted Gravity Drainage (SAGD), Experimental Testing & Numerical Modeling under Torsion & External Pressure Loads Luciano Mantovano – *TENARIS*	
	Electro-Enhanced Oil Recovery (EEOR) Using Direct Current Dr. Kenneth Wittle – *Electro-Petroleum, Inc.* *Field demonstrations of Direct Current stimulation of heavy oil fields showed changes in the produced fluids including an increased in oil production rates, reduced produced oil viscosity, reduction in water cut, reduced H_2S production, increased gas production, increased produced gas energy (heavy gas) content and reduced PAH concentration which can be explained by well known electrochemical and electro kinetic processes.*	
TRACK 3:	UPGRADING METHODS	
8:30 – 10:00 a.m.	UPGRADING 3 Chair: Shunlan Liu – *AERI* Co-chair: Keng Chung – *Well Resources*	
	Bitumen Upgrading by Supercritical Water Cracking Coupled with SAGD Process Jun Abe – *JGC Corp.* *Extra heavy oil such as Canadian bitumen is highly viscous and difficult to transport through pipeline. We have been developing an upgrading process of bitumen by supercritical water cracking coupled with SAGD process.*	
8:30 – 10:00 a.m.	HTL Upgrading Value Proposition for Oil Sands Edward Koshka – *Ivanhoe Energy*	

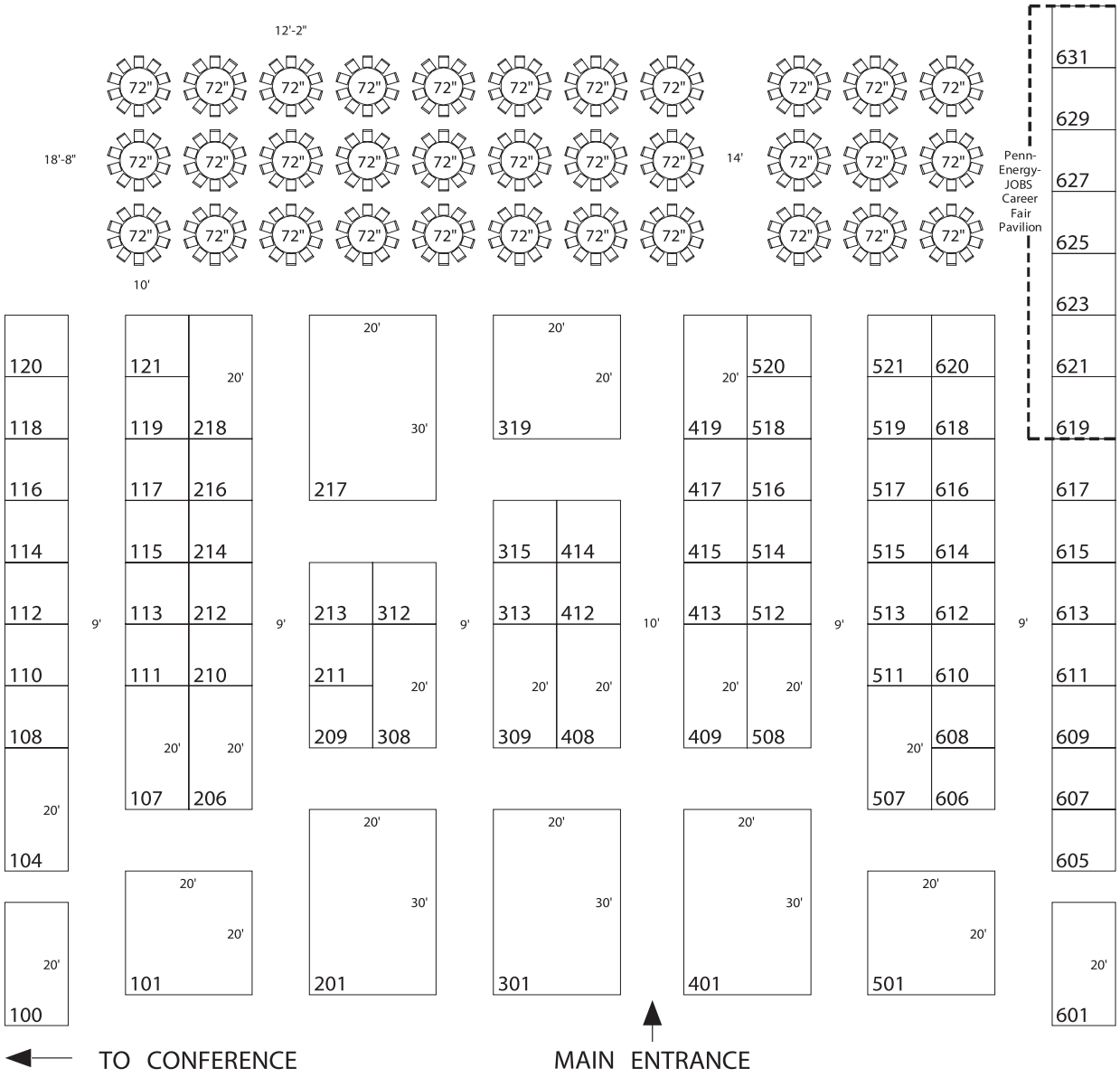
CONFERENCE PROGRAM DETAIL

OIL SANDS HEAVY OIL TECHNOLOGIES

TRACK 3:	UPGRADING METHODS CONTINUED...
	Cost-Effective Upgrading of Coker Off-Gas With Alkylation Dr. James Nehlsen – *Exelus Inc.* *A new solid-acid alkylation technology can economically convert fuel-grade coker off-gas streams to high-octane transportation fuel without the costs and hazards associated with liquid acids and their regeneration.*
10:00 – 10:30 a.m.	COFFEE BREAK
SESSION 5	
TRACK 1:	SULFUR *Sponsored by:* SANDVIK
10:30 – 12:00 noon	**SULFUR 2** Chair: Jerry d'Aquin – *Con-Sul, Inc.* Co-Chair: Guntis Moritis – *Oil & Gas Journal*
	Long-Term Management Strategies for Sulfur Associated with Fossil Fuel Development Paul Davis – *Alberta Sulphur Research Ltd.* *Storage options and other developments in the utilization of sulfur and/or related sulfur compounds produced during fossil fuel processing are being investigated in order that future production amounts, that could be in significant excess of demand by present and new uses of this important resource, can be suitably managed.*
	Regulatory and Environmental Issues Speaker TBD
	Open Forum and Q&A
TRACK 2:	EXTRACTION METHODS
10:30 – 12:00 noon	**PRODUCTION 2** Chair: Tom Prokop – *Suncor Energy* Co-Chair: Shunlan Liu – *AERI*
	Hollow Sucker Rod for PCP Systems Jose Antonio Villasante – *TENARIS* *A new innovative product called hollow sucker rod was developed to be used for rotating pumping or PCP systems in order to work more efficiently.*
	BioTiger™, A Natural Microbial Product for Enhanced Hydrocarbon Recovery from Oil Sands Dr. Robin Brigmon – *Savannah River National Laboratory*
	Borehole Mining of Oil Sands - Does It Have A Future? Mike Dibble – *Rail-Veyor Systems, Inc.* *The borehole mining process successfully extracted +80 meter deep sedimentary phosphates - can the lessons learned be applicable to recovery of Oil Sands?*
TRACK 3:	CO_2
10:30 – 12:00 noon	**CO_2 Handling** Chair: Derek Macdonald – *Alstom Canada* Co-Chair: Teresa Hansen – *PowerEngineering*
	Chilled Ammonia Process for CO_2 Capture Sean Black – *Alstom* *Overview of Alstom's development and commercialization program, including details on current pilot and demonstration projects in operation and development.*
	Impact of Carbon Dioxide Removal Systems on Fossil-Fired Power Plants for the Oil Sands Industry Chris Wedig – *The Shaw Group* *This paper will provide an overview of the design and operation maintenance impact of carbon dioxide (CO_2) removal systems on fossil-fired power plants for the Oil Sands industry.*
	The Siemens Fuel Gasification Technology: Application in the Oil Sands Industry Harry Morehead – *Siemens Power Generation, Inc.* *This paper will review Siemens' Fuel Gasification technology, its active projects and their relevance to oil sands industry applications to produce H_2, steam and power.*
12:00 – 1:00 p.m.	LUNCH
1:00 - 2:30 p.m.	CONFERENCE SUMMARY LOOK AHEAD PANEL DISCUSSION AND LIVE WEBCAST CLOSING REMARKS

OIL SANDS AND HEAVY OIL TECHNOLOGIES CONFERENCE & EXHIBITION

2008 Floor Plan
July 15 – 17, 2008
Calgary TELUS Convention Centre
Calgary, Alberta, Canada



REGISTRATION HOURS:

MONDAY, JULY 14	12 noon – 6:00 p.m.
TUESDAY, JULY 15	8:00 a.m. – 7:00 p.m.
WEDNESDAY, JULY 16	7:30 a.m. – 6:00 p.m.
THURSDAY, JULY 17	7:30 a.m. – 1:00 p.m.

EXHIBITION HOURS:

TUESDAY, JULY 15	5:00 p.m. – 7:00 p.m.
WEDNESDAY, JULY 16	10:00 a.m. – 6:00 p.m.
THURSDAY, JULY 17	10:00 a.m. – 1:00 p.m.

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CONFERENCE RATES AVAILABLE

Single/Double:	$219.00
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For more information visit or to check room availability visit:

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OIL SANDS AND HEAVY OIL TECHNOLOGIES CONFERENCE & EXHIBITION

2008 Registration Form
July 15 – 17, 2008
Calgary TELUS Convention Centre
Calgary, Alberta, Canada

First Name: _____ Last Name: _____

Title/Position: _____

Company: _____

Address: _____

City/State/Zip: _____ Country: _____ Postal Code: _____

Telephone: _____ Fax: _____

Email: _____

Registration confirmation will be sent via-email, if a unique email address is provided above.

1. Type of Company or Organization:
- ❑ 10 Oil/Gas company
- ❑ 20 Consulting Company
- ❑ 30 Contractor
- ❑ 40 Engineering/Construction
- ❑ 50 Financial
- ❑ 60 Service/Supply
- ❑ 65 Government/Library/Education
- ❑ 70 Other _____

2. Job Function:
- ❑ 02 Management (CEO, Pres.VP)
- ❑ 05 Engineering/Technical/Geoscience
- ❑ 06 Superintendent/Field Professional/Foreman
- ❑ 10 Purchasing/Consulting
- ❑ 12 Other _____

3. Areas of Interest/Involvement:
- ❑ 10 Exploration
- ❑ 05 Drilling
- ❑ 01 Production
- ❑ 29 Gas Processing
- ❑ 23 Pipeline/Transportation
- ❑ 15 Refining
- ❑ 19 Petrochemical
- ❑ 39 Financial
- ❑ 46 Other _____

4. Purchasing Role: ❑ Specify ❑ Recommend ❑ Approve ❑ None

For Information on corporate packages for 11 or more attendees, contact Registration:
Phone +1 918 831 9160
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- Delegate Lunch on Thursday and Friday (Ticketed)

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2. Corporate Plan (5 delegates)
Includes:
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- Access to Exhibition Hall, including any scheduled receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Thursday and Friday (Ticketed)

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4. ❑ Student Conference Delegate ..... US$ 50
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- Access to Exhibition Hall, including any scheduled receptions
- Coffee Breaks in Exhibition Hall
- Luncheon on corresponding day (Ticketed)

❑ Wednesday, Paid By June 13, 2008 ..... US$ 565
❑ Wednesday, Paid After June 13, 2008 ..... US$ 665
❑ Thursday, Paid By June 13, 2008 ..... US$ 565
❑ Thursday, Paid After June 13, 2008 ..... US$ 665

6. ❑ Exhibit Visitor ..... US$ 25
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❑ Friday ..... ( ) @ US$ 40/day

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Cancellation: Cancellation of registration must be received in writing. Any individual, exhibitor, or corporate registrations cancelled in writing before June 13, 2008 will receive a 50% refund of registration fee. After June 13, 2008, no refunds will be permitted. Substitutions may be made at any time by contacting the registration office.

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