ON POINT

Vol 3, No. 4 April 2008

GORDON ENERGY SOLUTIONS

Candid, Forward-Looking Analysis of the Oil & Gas Industry

IN THE NEWS

Alaska Rejects Point Thomson Development Proposal

The Department of Natural Resources has rejected the latest development proposal for this 8 Tcf field on the grounds that it is not "credible" given previous failures to bring it on-line. Prospects for Alaskan gas supplies continue to be uncertain at best. This is despite the recent formation of a ConocoPhillips and BP joint venture to develop a pipeline proposal with hopes for an open season by 2010. This JV, Denali, plans to spend US$600 million in an effort to reach the open season milestone.

Brazil's Santos Basin Subsalt Play

Following intense speculation as to resource potential, Petrobras issued a "clarification" warning that substantial further exploration and appraisal work will be required on the Tupi and Carioca fields in Block BM-S-9.

Qatargas 4 Sales Contract with China

The Qatargas 4 LNG project (Shell, 30%; Qatargas, 70%) passed a significant milestone recently by signing a 25 year gas sales and purchase agreement (SPA) to supply 3 mmtpa of LNG to PetroChina. Qatargas 4 is designed to produce 7.8 mmtpa. In late 2007 Shell signed an SPA to take the full LNG volume from Qatargas 4. The agreement is also a significant indicator of continuing potential shifts in the role of LNG in the US market as project gas was originally intended primarily for the US and European markets.

ExxonMobil Malaysian PSC Extended

ExxonMobil and Petronas have signed the main principles associated with an extension of XOM's main oil producing PSC beyond its scheduled March 2012 expiration. This 1995 PSC includes seven oil producing fields. The agreement includes a commitment by the two companies to spend a minimum of US$2.1 billion for EOR, improvements to existing facilities and development of new reservoirs. It is not known if the agreement involves other cash payments by XOM or changes in JV working interests.

Central & Eastern Gulf of Mexico Lease Sales

The deepwater Gulf of Mexico (400 meters water depth or more) continues to be an area of intense competition to build acreage as leases from the prior boom of the last half of the 1990's are relinquished or expire. In Sales 206 and 224, held last month in the Central and Eastern regions, respectively, the industry budget for deepwater blocks was US$5.5 billion. Leading bidders are shown in Table 1 on page 3 with area detail and the value of total bids placed are shown in Figure 1 below.

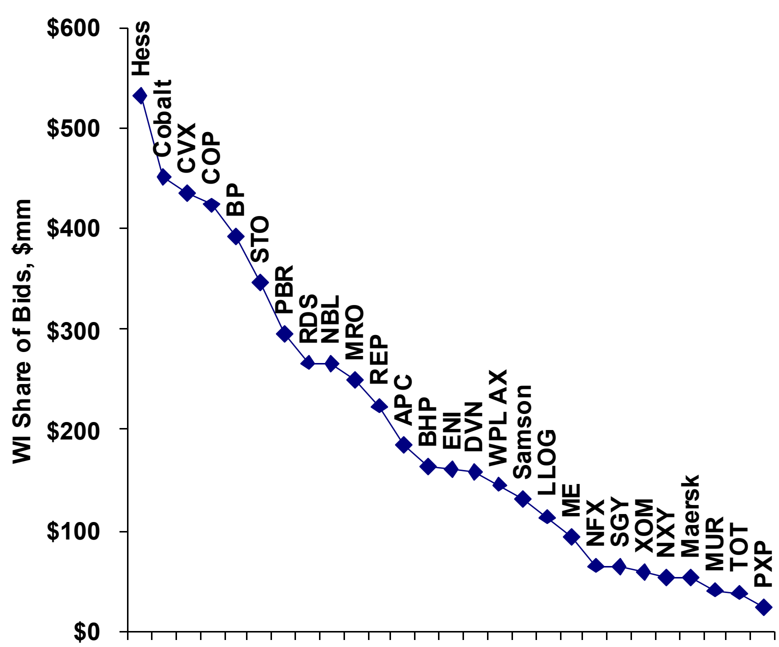
While bid levels were very high for a number of companies, unlike in the prior central sale, there is no single company that can be said to have clearly driven the sale. Shell, following its very high bidding in both last year's Central sale and, more recently, in the Chukchi Sea sale, significantly cut its bid budget this time around.

The relatively large budget ConocoPhillips brought to the sale is noteworthy. The company has been relatively conservative in its bidding for some time. However, in last year's sale ConocoPhillips was aggressive in selected specific block bids and in Sale 206 it rose to 4th largest deepwater budget.

Table 1 compares company bids placed by each area available. It is clear from Table 1 that Green Canyon, Keathley Canyon and Walker Ridge are major focal points of multiple companies. Combined, these three areas captured almost 72% of the total industry budget

Continued on Page 3

Figure 1: Capital Committed to Winning Bids and Money Left on the Table



CONTACTS

Gordon Energy Solutions is an energy consulting firm specializing in competitor analysis, strategic decisions, political risk analysis, and global issues concerning the international, integrated oil & gas industry. We anticipate future opportunities and challenges confronting our clients and assist in exploiting those opportunities.

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Table 1: Working Interest Capital Bid on Deepwater Blocks, $mm

	Atwater Valley	*De Soto Canyon*	*Ewing Bank*	*Garden Banks*	*Green Canyon*	*Keathley Canyon*	*Lloyd Ridge*	*Miss. Canyon*	*Sigsbee Escarp.*	*Walker Ridge*	*Total*
Hess				$158.9	$84.5	$98.6				$189.1	$531.2
Cobalt	$10.7			$35.5	$214.5	$108.6		$54.3		$27.2	$450.8
CVX	$18.1			$46.9	$190.5	$151.1				$27.9	$434.5
COP				$109.5	$49.0	$190.2				$74.2	$423.0
BP	$56.9	$2.1		$33.8	$143.6	$16.1		$90.0	$0.5	$48.2	$391.2
STO					$99.7	$185.0				$61.9	$346.7
PBR	$10.6			$0.8	$69.9	$52.6		$59.5		$102.6	$296.0
RDS	$62.7	$2.2			$2.3	$134.1	$2.8			$62.7	$266.7
NBL				$6.9	$107.8			$137.8		$13.2	$265.7
MRO	$9.1				$80.1	$55.6		$27.9		$76.9	$249.5
REP	$19.7				$92.1	$83.9		$4.6		$23.7	$224.0
APC	$25.5			$43.3	$43.2	$45.2	$19.8	$8.5			$185.5
BHP	$0.5	$78.4			$83.5			$2.1			$164.5
ENI	$3.0	$3.4			$26.2	$21.0	$1.1	$26.1		$80.1	$160.9
DVN	$5.9			$12.7	$71.7	$17.3		$18.9		$31.7	$158.1
WPL.AX	$27.1			$6.1	$17.8	$36.1				$58.7	$145.9
Samson	$11.3			$1.6	$41.5	$21.0		$3.3		$52.0	$130.7
LLOG				$19.7	$6.6			$87.5			$113.8
ME			$0.9	$21.2	$29.1	$25.0		$17.9			$94.0
NFX	$0.6			$24.3	$33.1			$7.2			$65.2
SGY	$0.7			$6.0	$20.6			$17.4		$19.4	$64.2
XOM	$5.8			$3.4	$11.6	$5.5		$1.3		$30.9	$58.5
NXY	$8.6	$2.9		$5.0	$28.5	$3.8		$5.0			$53.8
Maersk					$1.5					$51.5	$53.0
MUR		$0.3			$36.0		$5.0				$41.2
TOT				$13.0		$1.3				$24.5	$38.8
PXP					$24.8						$24.8
Century			$23.7								$23.7
Hunt				$2.2	$0.9	$4.1				$3.1	$10.3
Total	$276.9	$89.2	$24.6	$550.8	$1,610.6	$1,256.0	$28.7	$569.2	$0.5	$1,059.6	$5,466.0

Note: Some relatively small bidders are excluded since their bids do not materially alter conclusions.

for deepwater acreage. Of these three areas, Green Canyon captured the biggest budget allocation by far and, as can be clearly seen from the table, had the broadest base of companies engaged in the bids. Mississippi Canyon and Garden Banks held roughly equal second place positions but this was due to a small number of companies focused in these two areas.

Shell substantially reduced its bid budget this time around while Hess very substantially increased its budget. BHP is noteworthy for its relatively modest budget overall but very significant allocation of that budget to De Soto Canyon blocks. BP also is noteworthy for its bidding in De Soto Canyon. The company was clearly trying to build in the area (placing multiple bids on blocks also sought by BHP) but hoped or expected to be able to do it with very low bids.

Windfall Profits Taxes

Venezuela -- Many are talking about it but Venezuela has done it. Specifically, the government has approved a price-linked windfall tax on oil producers. When Brent exceeds $70/barrel, a 50% tax on the excess is levied. If Brent rises above $100/barrel an additional 10% tax is levied.

The net effect, as shown in Figure 2, is a price-responsive royalty rate mechanism somewhat similar to the system in Alberta. The effective royalty rate is 33.33% at or below $70 Brent, rising to as high as 60% when Brent is $135.

The significance of this latest tax is two-fold. First, President Chavez continues to drain cash flows out of the Venezuelan industry (including PdVSA). This cash flow drain, combined with the large cash outlay demands on PdVSA that are irrelevant to its function as an oil and gas company is making it more and more likely that PdVSA cannot sustain production capacity. Second, the windfall tax is also significant because it erodes incentives for IOCs or other NOCs to invest in Venezuela's industry.

The tax is a royalty and, like all royalties, it is regressive. The additional burden on Venezuela's high cost, long lead-time project base is severe and will become particularly onerous as cost inflation progresses.

The impact of Venezuela's WPT will likely extend to other countries looking to generate additional revenues from oil and gas operations.

Venezuela's emerging meltdown as an oil producer is clearly not unique but, in fact, is part of a broader erosion of oil supply capability that has a high likelihood of becoming global in scope. In particular, supply problems in Mexico and now Russia will likely compound the problem.

The IEA recently estimated that Russian oil output fell in the 1st quarter of 2008. To see how Russia is pointing the way to Venezuela's future note that Putin's administration has imposed remarkably similar price-linked taxes on oil production for years. The fact that Russia is now contemplating a reduction in these taxes (albeit relatively minor) appears to have been lost on Venezuelan policy makers.

US -- Meanwhile, in the US both Clinton and Obama call for a windfall profits tax on oil to pay for other energy programs. Clinton goes so far as to call for a US$50 billion Strategic Energy Fund to provide a source of capital for investment in alternative energy. This will be financed by a windfall profits tax and "removing special tax breaks for oil and gas companies".

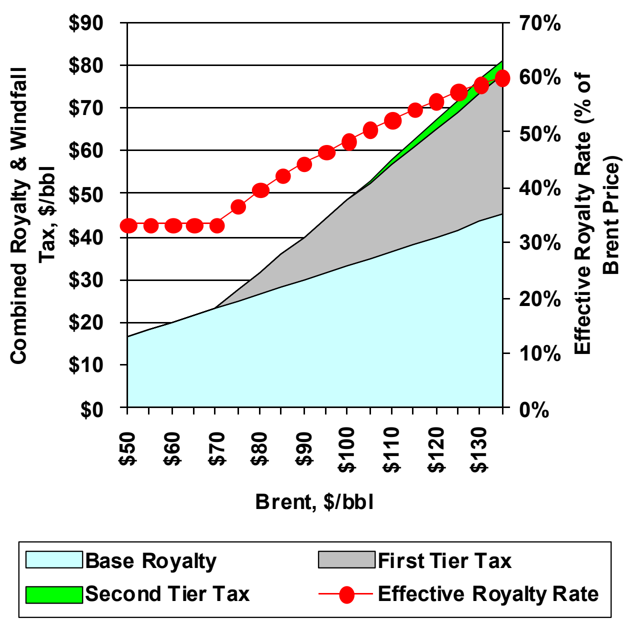
Unconventional Gas

Hungary -- ExxonMobil farmed into two acreage positions within Hungary's Mako Trough area. The first deal gives XOM a 50% interest in MOL's Blocks 106 and 107 (JV acreage of 387,000 acres). The JV will undertake a two to three year test of unconventional gas potential. Financial terms of the XOM/ MOL deal were not announced. The second farm in was announced two days later with Falcon Oil and Gas Limited, another major land holder in the Mako Trough. XOM will acquire a 67% interest in 184,000 acres with Falcon retaining 33%. XOM will pay Falcon US$25 million in cash and spend US$50 million as part of an initial work program to test the acreage. If XOM chooses to move beyond this first phase program it will pay Falcon an additional US$50 million and spend US$100 million in further work efforts. If the Falcon/XOM venture proceeds to development, XOM will pay Falcon another US$75 million. XOM appears to have assigned half of its interest in the Falcon acreage to MOL.

If development progresses, the partners in these two ventures propose to use the same multiple zone stimulation technology that XOM is applying in its Piceance Basin project in the US. In that project, XOM proposes to further develop its 29,000 acre position by drilling wells from up to 120 multiple well pads having up to 9 wells on each well pad.

If the Mako Trough project proves to be feasible, the JV partners currently anticipate 80 to 120 acre well spacing with a total of as many as 2,000 wells to be drilled over the 30 year life of the project. Well depths are projected to range from 8,200 feet to 18,000 feet and costs are expected at this time to range between US$8 to US$12 million each. Average Expected Ultimate Recovery (EUR) per well could range from 5.3 to 7.9 Bcfe implying ultimate reserves from the Mako Trough before royalties of 10 to 16 tcf. Future production, if the

Figure 2: Venezuelan Royalty Rates after the Windfall Tax



Note: It is assumed that the Second Tier Tax is incremental, I.e., it applies to the price incremental over $100/barrel.

project proceeds, is subject to a modest 12% royalty rate.

Like BP's recent deal to evaluate the potential of developing tight gas fields in Oman, XOM's move into Hungary is a significant illustration of the potential broader scope of unconventional gas technology outside North America. Key differences between the two deals are (1) BP will likely be selling gas into a discounted price environment while XOM Mako Trough gas is likely to capture relatively high prices and (2) the timing of Omani gas development is likely to be contingent on factors outside BP's control.

British Columbia – Apache reported strong initial production results from three horizontal wells in the British Columbia shale gas play. Eighteen fracture stimulations were used in the three wells yielding test flows of 8.8, 6.1 and 5.3 Mmcf/d from the respective wells. EnCana has also drilled two horizontal wells in the play with results that are not yet known. Apache reported that its net share of gas from the emerging play could range from 9 to 16 Tcf.

The British Columbia shale play could have a critical significance that extends well beyond the obvious benefits to Apache, EnCana and the other companies holding substantial acreage positions. Specifically, the future of oil sands potential in Alberta is dependent, among other factors, on gas supplies. As the Mackenzie gas project continues to languish and natural gas production in Canada's more traditional plays falls, the emergence of a world class shale gas play in British Columbia could serve as a critical enabler of future oil sands development projects.

Results from the EnCana wells plus the progress of Murphy's program in the shale gas play will help to further evaluate the potential.

US, Fayetteville Shale – XTO acquired 55,631 net acres in the Fayetteville shale play from Southwestern Energy for US$520 million. The transaction strengthens XTO's position in the play (increasing the company's position to more than 300,000 net acres and adding, by XTO's estimates 1 Tcf of potential resources). Moreover, Southwestern's land-rich status is strengthened by the cash as a means to further drilling. More on these deals is provided later in this issue.

As we noted in our recent presentation at the Developing Unconventional Gas conference, deals such as this are part of a reshuffling of land positions. XTO's acquisition of Linn Energy's Marcellus shale acreage is another example. This process will continue to be a driving force behind the future of unconventional gas.

More bluntly, the unconventional gas business is at a critical juncture. At this time, acquisitions, joint ventures and farm ins will be essential tools for (1) building long-term positions that will reshape company portfolios and (2) enable land-rich companies and to undertake more effective and more timely exploitation of their resource potential in the near and medium-term.

Coal Bed Methane in Australia -- Santos indicated that it is in discussions to sell an interest in its Gladstone LNG project proposal. Still in a very early stage, FEED is expected to begin by the end of this year or early in 2009.

The plans call for Gladstone to be supplied from CBM. Estimated development cost in real terms is currently pegged at A$7.7 billion. Santos anticipates drilling 540 wells in the period leading to LNG startup and another 600 wells over the remaining life of the project.

Chevron's Global Gas

The company's global gas operations are being counted on to contribute significant volume and earnings in the medium to long-term. Gorgon LNG is a major part of this. Two items of note emerged recently concerning other assets.

- The company announced that its 4.5 Tcf Wheatstone (CVX 100%) gas discovery in Australia's Carnarvon Basin will be developed as a greenfield LNG and domestic supply source. The project will include at least one 5 mmtpa LNG train. This is instead of developing the field as an add on to Woodside's nearby Pluto LNG project. FEED is expected to commence in 2009.

- PetroChina is reported to be pressuring the company to begin production from the high sulfur Chuandongbei field in Sichuan province.

Qatar Petroleum Expanding International Role

Total has sold a 20% WI in the Taoudenni Ta7 and Ta8 licenses to Qatar Petroleum International. Total retains a 60% WI after the sale. Earlier this year Total assigned a 20% WI in the blocks to Sonatrach.

The transaction is significant for two reasons:

- Qatar Petroleum is entering international upstream competition with the IOCs and
- Total, through these two agreements, appears to be following a strategy of aligning itself to national oil companies (NOCs) as they look to build international upstream positions

Ta7 and Ta8 are very large (58,000 sq km combined) onshore blocks in Mauritania's interior. Total won the blocks in early 2005.

Deepwater Gulf of Mexico

Itochu Acquires 50% of Entrada Project

Callon and Cieco Energy (a subsidiary of Itochu) announced that Cieco acquired a 50% share of the deepwater Gulf of Mexico Entrada field. Total consideration includes US$155 million plus a contingent payment to BP of US$20 million. A contingent payment of $2.50 per boe is also payable to Callon once cumulative gross recovered reserves passes 30 mmboe to be paid through 2018. Cieco also agreed to pay US$12.6 million as reimbursement for 50% of capital spent this year.

In an interesting twist to the deal, Cieco will lend Callon US$150 million to fund Callon's expected development costs for Entrada. Key terms of the loan are: (1) interest rate at LIBOR plus 375 basis points, (2) 5 year term beginning with production startup and (3) semi-annual payments linked to anticipated production.

In April 2007 Callon acquired BP's 80% interest in the field for US$150 million plus a US$40 million payment to be paid once cumulative output reaches 12.5 mmboe. At the time Callon estimated net proved reserves for the full field interest of 31.25 mmboe and 55.25 mmboe net proved and probable reserves. Estimated unit costs of the deal are shown in Table 1.

Competition for Anadarko's 25% WI in Kaskida

In early March Anadarko announced that it accepted StatoilHydro's unsolicited offer to purchase their 50% interest in the Peregrino field offshore Brazil and 25% interest in the Kaskida discovery in the ultra-deepwater Gulf of Mexico.

StatoilHydro agreed to pay Anadarko USD $1.8 Billion with an additional USD $300 million pre-tax to be earned by 2020 related to the Peregrino field conditioned on future oil prices remaining above a pre-determined level.

The Peregrino acquisition gives StatoilHydro a 100% working interest and operatorship. The field is located offshore in the Campos Basin in 100 meters of water. The project is scheduled to come online in 2010 and pump 100,000 b/d of 14° API crude via an FSPO and two platforms. Reserves are estimated at 500 million barrels based on a 20% recovery factor. The development concept calls for 30 horizontal production wells and 7 water injection wells.

The Kaskida acquisition would have given StatoilHydro a 25% non-operated interest. Anadarko's partners in the discovery were BP with a 55% operated-interest and Devon with the remaining 20%. Devon has announced that it will pre-empt the Kaskida deal, exercising its right to buy its proportional share of Anadarko's working interest (6.67%). BP also exercised its pre-emptive rights, increasing its share from 55% to 73.33%

The details on Kaskida are very limited, but are believed to be in line with other discoveries in the lower tertiary such as St. Malo, Jack, and Julia. The full value of Kaskida will be realized as further discoveries are made in the vicinity and tied-back to the infrastructure.

CNOOC Acquires 50% WI in Madura Straits PSC

Husky sold a 50% WI in its Madura Straits PSC to CNOOC for US$125 million.

The block includes the BD and MDA gas fields. Husky estimates gross reserves associated with BD at 515 Bcf and 23 mmbbls condensate. MDA is estimated to hold 150 Bcf. Husky anticipates production startup in 2010 following the signing of three gas sale and purchase agreements (SPA) for 100 Mmcf/d from BD. The gas will be shipped to Java and used domestically.

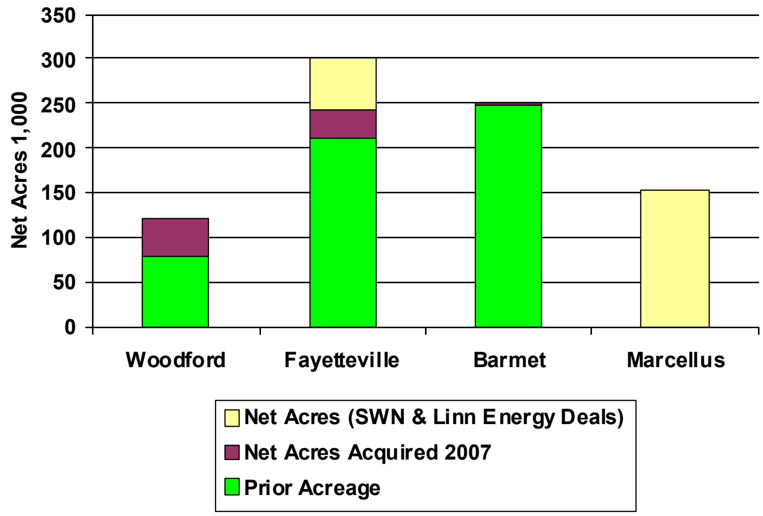
Table 1: Entrada Acquisition Metrics

		Acquisition Price $mm	***Contingent Payment $mm***	***YTD 2008 Capex $mm***	***Future Development Cost $mm***	***All In Costs $mm***
Net Field Reserves mmboe		$155	$20.0	$12.6	$150.0	$337.6
Proved	31.3					
Proved & Probable	55.3					
Cieco Share	50%					
Proved mmboe	15.6					
2P mmboe	27.6					
$/boe Proved		$9.60	$1.28	$0.81	$9.60	$21.61
$/boe Proved & Probable		$5.43	$0.72	$0.46	$5.43	$12.22

The SPA were signed in 2007 with PT Parna Raya and PT Inti Alasindo Energy (each buying 40 Mmcf/d) and with PGN for 20 Mmcf/d. The initial gas price under each of the contracts is US$4.20 per mmbtu although the contracts include escalation provisions over the 20 year term of the contracts.

The field will be developed using a floating production unit with a 60 km pipeline to shore. Based on GES estimates, the project yields CNOOC roughly a 17% internal rate of return in the $50 WTI mid-cycle case. This estimate is subject to considerable estimation error due to limited information on development cost and escalation terms under the SPA.

Figure 4: XTO Shale Gas Acreage Acquisition Program



XTO Continues its Acquisition Program in Gas Shale

XTO has added more gas shale acreage through two deals in the Fayetteville and the Marcellus plays.

Following up on our February coverage of XTO, Figure 4 updates the graphic from that issue. It shows XTO's growing acreage position in these plays as a result of known acquisitions. These include deals announced at the end of last year as well as the two most recent deals.

In the latest deals XTO acquired 55,631 net acres from Southwestern Energy in a US$520 million deal. XTO also acquired 152,000 net acres in the Marcellus shale play in Western Pennsylvania and West Virginia from Linn Energy for US$600 million.

Linn Energy estimated proved reserves on its Marcellus acreage at 197 Bcfe with output at 25 Mmcfe/d. XTO stated that it believes the acreage could hold resources of 2 to 4 Tcf. XTO estimates the resource potential of the SWN acreage at 1 Tcf or more.

XTO's per acre costs are $9,347 and $3,618 in the Fayetteville and Marcellus deals, respectively.

The company's aggressive expansion program includes a recent US$2 billion senior notes issuance to fund the acquisitions and pay down commercial paper. .

GEPetrol Acquires Devon's Assets in Equatorial Guinea

GEPetrol, the national oil company of Equatorial Guinea will pay US$2.2 billion for Devon's interest in three offshore blocks. These assets include

- Devon's 24% working interest in the Block B Zafiro field with estimated net reserves of 55 mmbbls oil and net output of 20 Mb/d,
- Esmeralda discovery reported to have gross unrisked resource potential of 302 Mmbbls condensate
- Block P, site of the Venus discovery (100 Mmbbls resource potential) that has been declared commercial
- Block C, site of the Langosata gas and condensate prospect that was expected to be drilled in late 2007 with potential of 400 Mmbbls

Anadarko Sells Venezuelan Assets

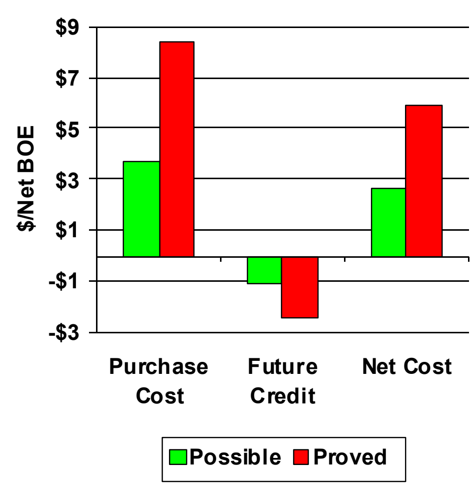
PetroFalcon (owned 42% indirectly by Lundin Petroleum) acquired Anadarko's Venezuelan operations including its 18% WI in Petroritupano for US$200 million. The assets include 2P net reserves of 23.9 mmboe, estimated net output of 5 Mboe/d (92% oil) and a US$58 million credit.

Petroritupano produces 16 degree API oil, sold at 75% of WTI. It is unclear whether gas output is sold or used in the field operations. PetroFalcon estimates unrisked possible reserves of up to 30 mmboe net to Anadarko's share.

The estimated per boe cost of the deal is shown in Figure 5. These estimates do not include future exploration or development costs and, therefore, the per boe cost of the "Possible Reserve" case is understated.

Lundin is guaranteeing the deal and, as a result, will receive an additional 17.1 mm shares of PetroFalcon.

Figure 5: Petroritupano Per BOE Acquisition Cost



US Asset Sale Value Indicators

EnergyNet Regional Sales Data 2006

Working Interests 6:1

	Average $/BOE/D	Average $/MCFE/D	Average Multiple (Average Income)	Average Multiple (Last Income)
Appalachians	$73,565	$12,261	43.62	50.38
Central Texas	$48,902	$8,150	37.81	40.12
East Texas	$62,972	$10,495	44.78	49.16
Gulf Coast	$45,285	$7,248	37.19	45.30
Michigan Basin	$44,347	$7,391	41.24	40.58
Mid Continent	$52,819	$9,148	50.14	54.44
Panhandle	$43,592	$7,028	43.84	51.81
Permian Basin	$62,599	$10,433	45.32	46.10
Rockies	$66,418	$11,070	45.93	68.58
South Texas	$37,688	$5,484	34.34	44.28
National Average	**$53,819**	**$8,871**	**42.4**	**49.1**

EnergyNet Regional Sales Data 2007

Working Interests 6:1

	Average $/BOE/D	Average $/MCFE/D	Average Multiple (Average Income)	Average Multiple (Last Income)
Appalachians	$47,237	$7,873	38.72	34.44
Central Texas	$52,151	$8,281	45.56	44.93
East Texas	$49,862	$6,599	50.39	56.93
Gulf Coast	$32,371	$12,734	37.56	44.08
Michigan Basin	$50,574	$8,429	31.79	75.45
Mid Continent	$55,110	$8,491	52.60	58.43
Panhandle	$39,728	$6,621	45.60	50.09
Permian Basin	$49,800	$7,609	51.07	47.98
Rockies	$43,093	$7,182	40.92	41.95
South Texas	$33,828	$5,032	38.56	50.07
National Average	**$45,375**	**$7,885**	**43.3**	**50.4**

EnergyNet data on US deal metrics is shown on the following page.

EnergyNet provides a way to high-grade a portfolio of assets, maximizing value for each individual property or field, without expending significant time and effort. EnergyNet maximizes value by efficiently offering the elemental properties (single well, lease, or field) to the largest audience of qualified and accredited oil and gas investors. There are simply more Buyers in the marketplace capable of competing to win a $1MM property than a $100MM package of properties, and EnergyNet has established relationships with over 12,500 Buyers. Geographically diverse packages benefit by being broken down into their elemental parts. By marketing and selling properties in the most logical, elemental pieces, Sellers maximize value for each part of the package and do not exclude Buyers from the process.

EnergyNet can prepare, market, and close a set of property transactions much faster than any other divestment-focused company in the industry. The Continuous Model allows EnergyNet to handle as much for a company as requested, including gathering data, preparing properties, filing the conveyance documents, escrow and post-closing services.

For More Information Contact EnergyNet, Inc.: Toll Free: 877.351.4488
E-mail: energy@energynet.com Or visit their website: www.energynet.com

Comments on 1st Quarter Inflation

Drilling costs continue to fall compared to the same time last year. Beginning in the last quarter of 2007, oil and gas support activities costs have been essentially unchanged. However, oil field machinery cost inflation has been stuck at a roughly 5% rate since 4th quarter 2007 and preliminary estimates for March 2008 show a significant upturn.

Upgrades in Cost Coverage

Beginning with this issue, we are expanding cost coverage in two important ways.

First, the cost indices routinely followed here will be used to generate a weighted estimate of the cost of drilling and equipping oil and gas wells. The results are shown on page 10. Percent changes in the GES Composite US Onshore Drilling and Completion Cost index are compared to the percentage changes in component cost indices. The cost of drilling wells has been declining significantly on a year over year basis since April 2007. However, factoring in the costs of equipment and services, the composite cost of wells has been declining only slightly. The difference is rooted in the fact that the costs of support activities have fallen only modestly and oil field machinery costs have continued to rise. Looking forward you should note that preliminary March results suggest that machinery cost inflation may be ratcheting back up.

A second change that will be implemented in coming issues is the inclusion of other cost factors relevant to the industry. Initial coverage of these other factors will be more qualitative in

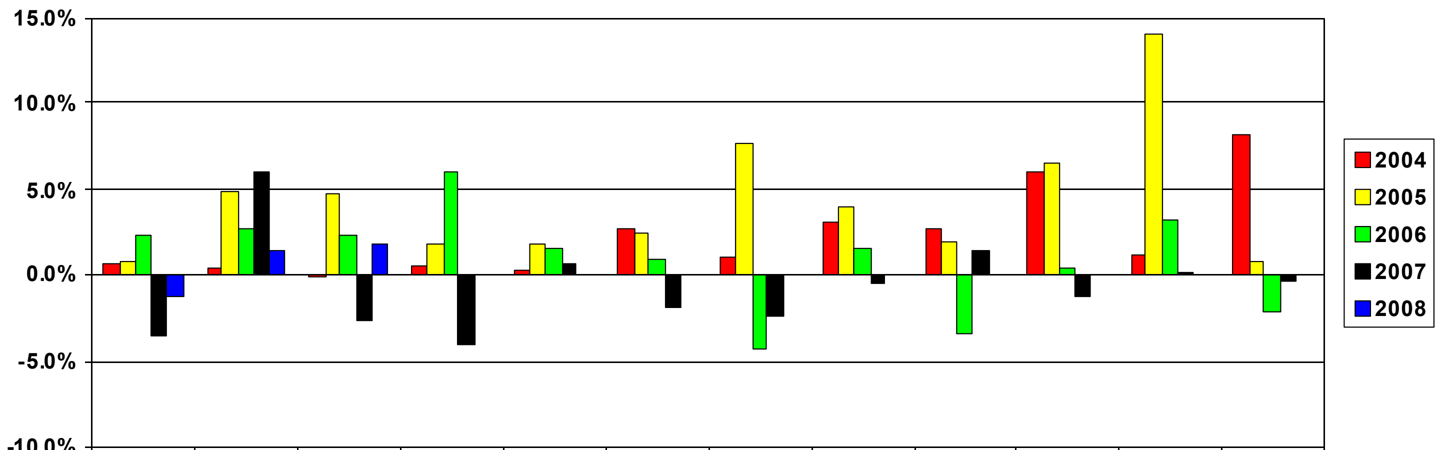
UPSTREAM

Annualized Cost Inflation Rates: 2006, 2007 and 2008 YTD

Cost Component	2006/2005	2007/2006	2008 YTD/ 2007
Drilling Cost	**37.8%**	**-4.3%**	**-7.6%**
O&G Support Activities	**13.1%**	**3.6%**	**-0.2%**
Oil Field Machinery	**8.7%**	**7.0%**	**6.1%**
Rotary Drilling Machinery	**11.5%**	**9.0%**	**3.9%**

Note: 2007 & 2008 YTD inflation estimates subject to revision

US Producer Price Index: Monthly Percentage Change in the Cost of Drilling Oil & Gas Wells



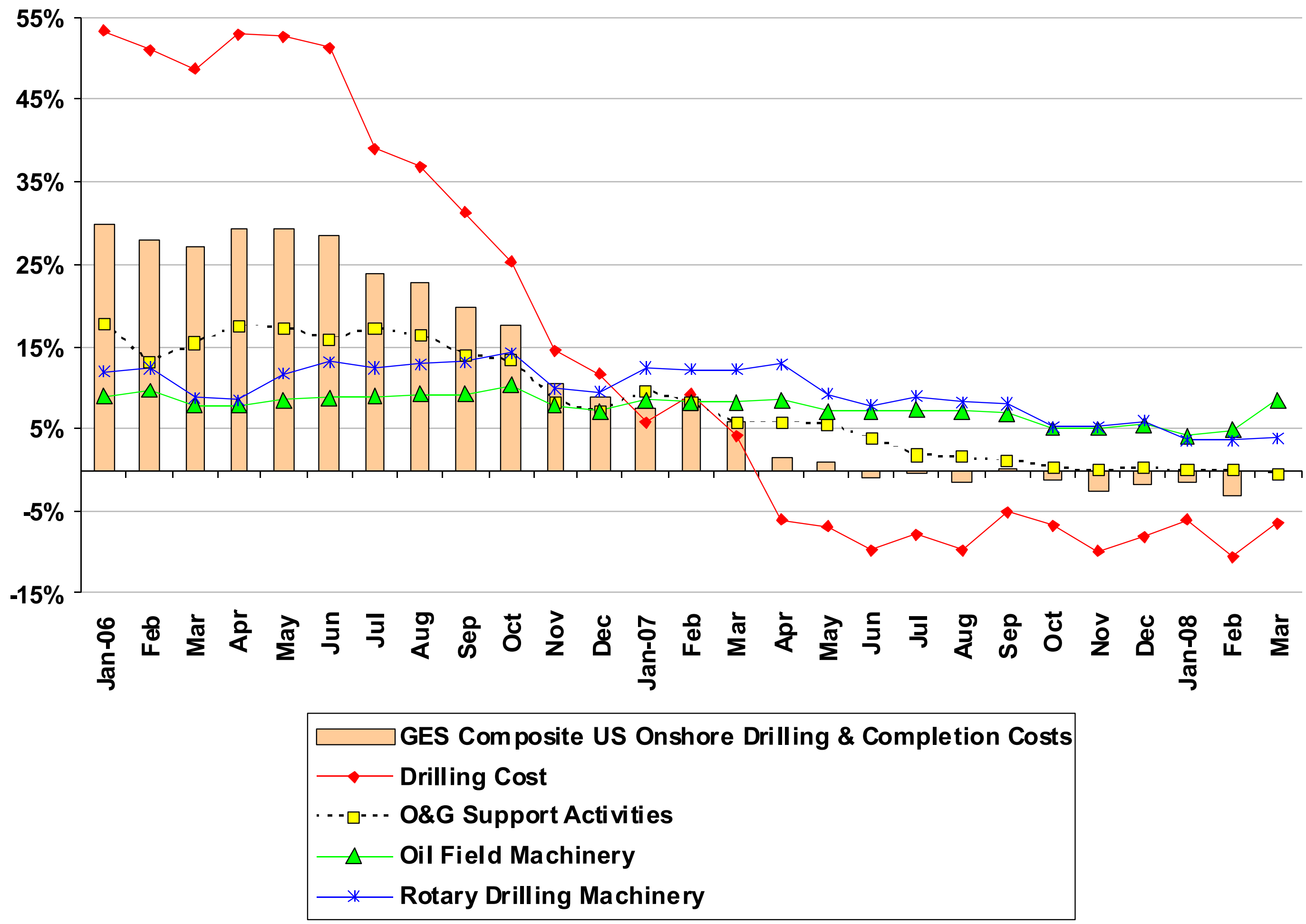
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004	0.70%	0.50%	-0.10%	0.60%	0.30%	2.70%	1.10%	3.20%	2.70%	6.10%	1.20%	8.20%
2005	0.80%	4.90%	4.80%	1.90%	1.80%	2.50%	7.70%	4.00%	2.00%	6.50%	14.00%	0.80%
2006	2.40%	2.70%	2.40%	6.10%	1.60%	1.00%	-4.30%	1.50%	-3.40%	0.40%	3.30%	-2.10%
2007	-3.50%	6.10%	-2.60%	-4.10%	0.70%	-1.80%	-2.40%	-0.40%	1.40%	-1.30%	0.10%	-0.30%
2008	-1.30%	1.40%	1.80%									

Year over Year Percentage Change

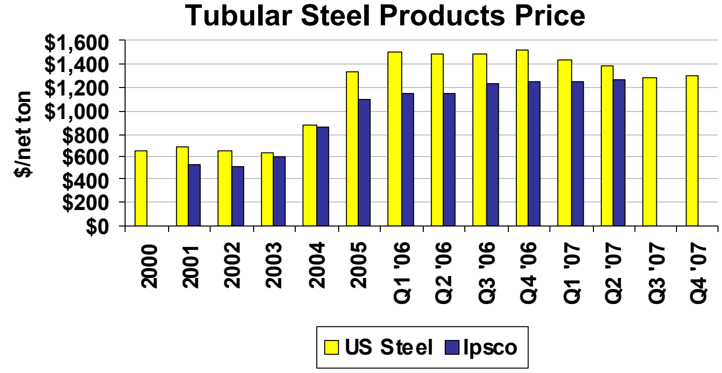
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2006	53.3%	51.1%	48.7%	53.0%	52.7%	51.3%	39.2%	36.7%	31.3%	25.2%	14.5%	11.6%	37.8%
2007	5.7%	9.1%	4.2%	-6.1%	-7.0%	-9.8%	-7.9%	-9.8%	-5.0%	-6.7%	-9.9%	-8.1%	-4.3%
2008	-6.0%	-10.7%	-6.4%										

COST WATCH

Monthly Year over Year Inflation of Selected Industry Costs



Tubular Steel Products Price



nature but will be expanded to include quantitative cost indices. Look, in particular, for estimates of deep water drilling costs as reflected in day rates and contract values.

Emerging Cost Drivers

There are at least two key cost drivers to watch as we go forward. First, while the cost of tubular steel products stabilized in 2006 and even fell slightly in 2007, conditions in the metallurgical coal market are not favorable at this time. BHP Billiton recently announced that FOB prices of metallurgical coking coal products are expected to increase in 2008 by 206% to 240% over 2007 levels. Also, Tokyo-based JFE Steel has agreed to a tripling of its coal prices from US$98 to US$300 per ton. Unless economic conditions deteriorate on a global scale it is likely that steel prices will again be pressured upward.

The second cost driver is labor costs. Up to this point, the costs of skilled labor in the industry have been climbing largely due to demand-pull pressures, I.e., rising industry demand for labor. However, inflation rates are rising worldwide and spreading to key non-energy sectors. As this occurs, you may expect rising labor cost pressures as compensation demands respond to rising living costs. This inflation driver will have two clear effects on oil and gas company cost structures. First, internally companies will face rising compensation pressures from corporate staff costs through oil field labor. Second, this process will also cut across all sectors and industries supplying the oil and gas industry.