ON POINT

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GORDON ENERGY SOLUTIONS

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

IN THE NEWS

Libyan Contract Renewals

The contracts for Blocks NC115 and NC186 in Libya have been extended by 15 years and 10 years, respectively. As a result, Repsol OMV and Total will retain NC115 past 2017 and Repsol, Total, OMV and StatoilHydro will retain NC186 past 2023 until 2032.

The price of these extensions is high, consisting two key parts. A US$1billion signature bonus is payable over a three year period. Second, by converting to the EPSA IV format, the IOCs primary share of production is only 13% for NC115 and 12% for NC186.

As we have noted before, the cost of extending Libyan contracts is very high. The signature bonus is equivalent to US$13.51 per net boe. This is based on volumes projected to be produced from existing assets after the contracts were originally set to expire and from known projects that might not otherwise proceed. This does not include any contributions from remaining exploration potential on the blocks. However, it is also not adjusted for the lost net production volumes due to higher government take that would have been produced before the original contract expiration dates.

Chevron's LNG Program in Australia

Chevron expects to receive environmental approval for its expanded Gorgon project and complete FEED by 2009. The company has expanded the proposed LNG capacity from 10 to 15 mmtpa. In related news, the company has indicated that it may develop its Wheatstone and Iago discoveries jointly and include third party gas production as well.

Keystone Oil Pipeline Expansion Plans

TransCanada and ConocoPhillips have announced plans to increase Keystone capacity by 500 Mb/d with shipments to Port Arthur and potentially Houston, Texas. This US$7 billion program increases the total Keystone investment to US$12.2 billion. When complete, the project will have capacity to deliver 1.1 Mmb/d of Canadian crude to US refineries.

Major Strategic Moves in the M&A Market

In June and July we have seen critically important acquisitions that are part of an industry-wide re-structuring. This process will continue for the foreseeable future.

Several key points merit specific mention:

- North America is a focal point in this re-structuring but it is not exclusively a North American process.
- The driving goal of these deals is two-fold, depending on whether you are a buyer or a seller. From the sellers' perspective, there is a strategic shift of focus to very rapid exploitation of land positions that were acquired in recent years. From the buyers' perspective, the process we are describing is part of (1) a belated effort to gain access to emergent new business development areas or (2) a program of designed to consolidate and enhance already established positions in multiple plays
- The tools for achieving this re-structuring are heavily weighted towards the secondary markets (A&D and farm-ins).

The fact that these processes are industry-wide in scope has very significant and possibly dangerous implications. These implications are two-fold. First costs of access are rising, late-comers may overpay and renewed cost inflation is likely. Second, if we are correct that the goal is fundamentally rapid exploitation of land positions then there will inevitably be significant risks of a near and medium-term imbalance in supply and demand. This is clearly a risk to consider in North America but may also become a factor in other sectors. As this process proceeds and output responds there are likely to be strong impacts on performance not only in the North American plays but also in the broader international gas markets.

The degree to which this process is becoming universal in the industry is illustrated by two recent deals involving BP and Shell. These two cases reflect a fundamental shift underway in the new business development strategies of the global peer group. One central element of this shifting strategy is a re-emergent program to build North American asset positions.

The two deals are:

- BP's acquisition of Chesapeake's Woodford shale position in Oklahoma (these assets fit well with BP's existing Arkoma Basin position) and
- Shell's acquisition of Duvernay Oil and its positions in Alberta's Deep Basin and British Columbia's shale gas plays

Both of these transactions are discussed in some detail in the Mergers and Acquisitions section of this issue.

ConocoPhillips was the first company within this peer group to take action by acquiring Burlington Resources (BR) a full two years ago. The relative passivity of ConocoPhillips' efforts since that deal is perplexing to say the least.

Opportunities from the BR deal included:

- BR consolidated ConocoPhillips' position in a few existing core producing areas (San Juan being obvious) and the logic of this portion of the deal is clear
- An equally important aspect of the BR deal (we believe a more important element from a strategic perspective) is that BR provided a

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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.

By integrating the corporate and financial dimensions of strategy and performance with detailed project level analytics, we maintain a unique approach to your business. GES provides value to our clients through our forward-looking, critical analysis and unique perspective.

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number of relatively small but valuable bridgeheads in selected hot North American plays.

Exploiting these bridgeheads and building them to material size was both a central challenge and an opportunity for ConocoPhillips.

As North American land costs have escalated rapidly in the time since the BR deal, the value of these bridgehead positions has escalated as well.

Land Acquisition Costs in Selected Onshore North American Plays

We are routinely following land acquisition cost sources in plays throughout the world. North American onshore plays have become extremely hot this year. We have commented on this process previously.

Figure 1 shows some selected results from our databases for the Barnett, Woodford and Haynesville shale gas plays. The charts combine the results of competitive lease auctions on the left hand side and recent acquisition deals on the right hand side. In the Haynesville and Woodford cases, the competitive bidding data are from public land auctions. Barnett data reflect the results of negotiated deals between companies and neighborhood coalition groups in the area.

The left graphic in Figure 1 compares winning bids on a $/Acre bonus paid basis. The graphic on the right shows the cost of recent acquisitions in these plays on a $/Net Acre acquired basis.

Royalty rates in the Haynesville shale play are ranging from 25% to 30% with 25% being the most common. As a footnote, land costs data in the Marcellus Shale are more spotty. XTO and Whitmar Exploration struck a deal with a coalition in Broome and Delaware Counties in New York. The deal includes US$2,411 signature bonus per acre and a 15% royalty rate.

Coming Up: Bossier City and Shreveport are expected to offer sizeable blocks of acreage for competitive bid in the October Louisiana Mineral Board Auction. Bossier City will offer 3,300 acres and Shreveport will offer 2,700 acres. By contrast, the average block size in the Haynesville auction results in Figure 1 is only 219 acres. Minimum acceptable bids are US$27,500 and US$22,500 per acre for the respective cities. Both also require a minimum 25% royalty.

Elsewhere: In the Marcellus play, Pennsylvania's Department of Conservation and Natural Resources will announce the results of bidding on 75,000 acres. The acreage is located in three state forests (Loyalsock, Tiadaghton and Tioga State Forests) in Tioga and Lycoming Counties.

Williams is reported to be seeking leases in the Marcellus, offering $2,500 per acre plus a 15% royalty.

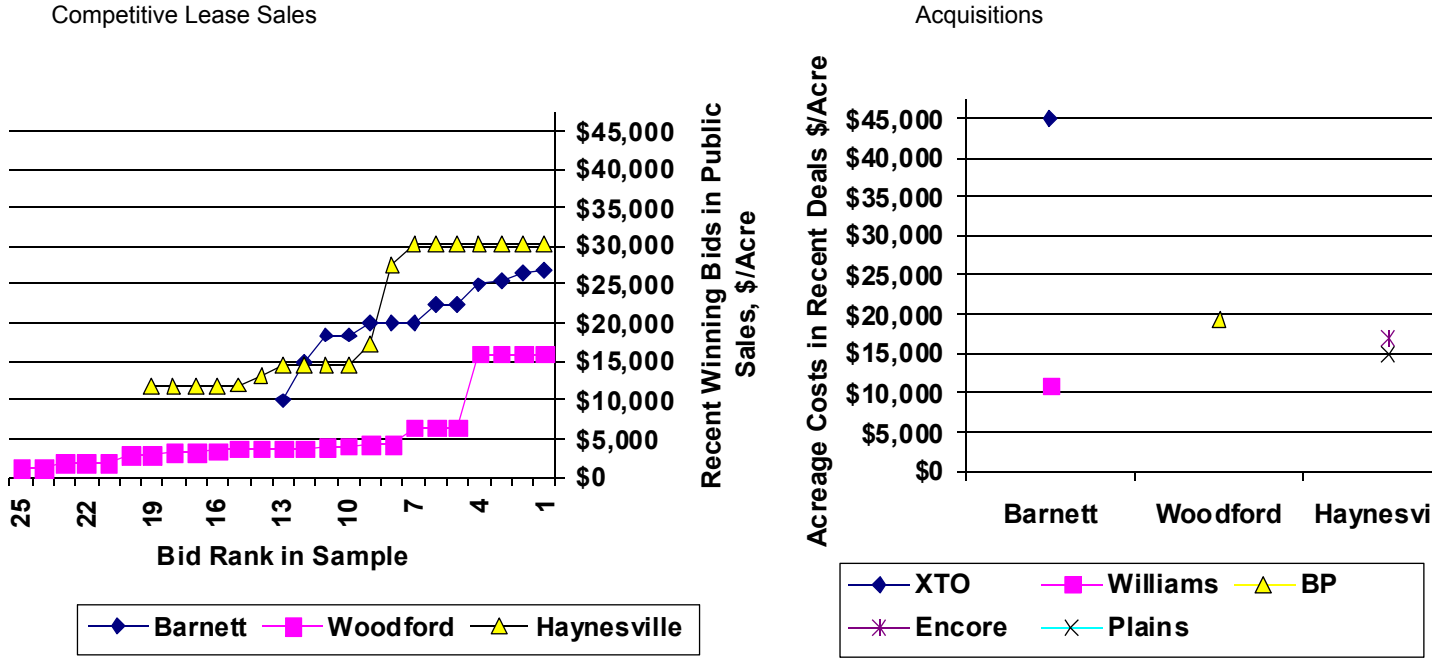
Also in the Marcellus, Quest Resource just completed the purchase of PetroEdge Resources for US$142 million. The per acre cost of the deal is US$1,820.

Karachaganak Export Tax Exemptions Repealed by Kazakh Government

Kazakhstan has repealed the export tax exemption on liquids production from the Karachaganak project. There are also reports that the government may also impose export tax on Tengiz.

The government's action is, in some respects, remarkably similar to Australian policy makers recent decision to impose tax on NW Shelf condensates. The link in both cases (and the warning that should be taken seriously by companies participating in such projects) is clear. Concessions to encourage specific major projects are not safe from re-negotiation in today's high price environment.

Figure 1: Comparative Land Acquisition Costs in 2008



However, there is more to it than this. The Kazakh government's behavior is increasingly moving down the same road that Russia has taken.

- Like in Russia, the oil export tax is a tool for subsidizing domestic oil prices. The sliding scale tax rate based on oil prices makes this clear.
- Also, Kazakhstan is increasingly mimicking Russia in its reliance on excise taxes (the export tax and the production tax) as a source of revenues. This is despite the clear damage that such taxes do to investment incentives, the inherent rigidities and inconsistencies that they create, and the resulting future need to correct distortions that inevitably arise.

Moreover, dependence on these excise taxes will increase if draft changes are implemented.

- There has been discussion of a substitution of the minerals production tax for the royalty with rates of taxation varying with production rates from 5% to 20%.
- With respect to the oil export tax the rate of taxation may be increased from a range of 0% to 33% to a range varying from 22% to 57%.

In both cases, it has been hinted that the base for computing the taxes will be revised to eliminate adjustments for transportation costs. Recognizing the very substantial discounting of Kazakh crude at the point of production that are made necessary by large transport costs, the effective burden of these taxes will be considerably greater than their nominal rates might suggest.

Occidental Expands Permian EOR Program

In late June Oxy announced an agreement with SandRidge Energy involving construction of a US$1.1 billion gas processing facility in Pecos County, West Texas, and a pipeline.

The processing facility, Century Plant, will be owned and operated by Oxy over a 30-year contract term. The facility will process high CO2 content gas produced by SandRidge. SandRidge produces from the West Texas Overthrust area including the Pinon field. Century Plant will yield an expected 450 Mmcf/d of CO2 to be retained by Oxy for EOR injection and 350 Mmcf/d of methane that will be retained by SandRidge.

Oxy estimated that the deal will enable it to generate 3.5 Tcf of CO2. This will be used to:

- Increase Permian Basin recoverable reserves by 500 Mmbbls and
- Generate 50 Mb/d oil output by 2013

The Century Plant and pipelines are expected to be online in 2011.

SandRidge has been actively re-adjusting its asset portfolio this year. In addition to the agreement with Oxy, the company

- Sold 24,000 net acres in the Piceance Basin to Williams (more on this deal can be found in the Mergers and Acquisitions section of this issue)
- Sold 10,000 net acres in the Barnett to Williams
- Has announced its intent to divest 32,000 net acres in the East Texas Cotton Valley trend (including rights to the Haynesville shale)

BP Acquires Chesapeake's Woodford Shale Position

In a US$1.75 billion deal, BP has acquired 90,000 net acres in the Woodford shale play. The assets are located in Oklahoma's Coal, Hughes and Pittsburg counties in the Arkoma Basin.

This acquisition marks a major extension of BP's North American program into the hot onshore gas resource plays. The acquired position fits well with BP's existing Arkoma Basin assets which date back to the company's acquisition of Amocol.

Figure 1 compares BP's cost per acre to the cumulative percentile distribution of winning bids for acreage in the target counties in public sales in 2007 and 2008.

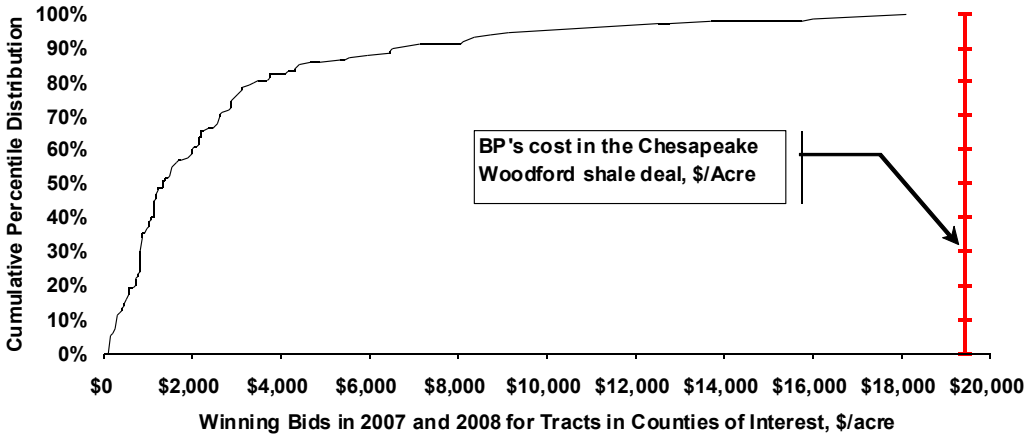
The inflation of land values in these gas resource plays has been a key process underway for some time. The extent of the land cost pressures is evident when we consider that BP is paying a very high US$19,444 per acre. This high land cost is likely due to three factors.

- First, BP has acquired a very large acreage position and is paying a premium for the size of the position compared to many of the leases included in Figure 1 which are small.
- Second, the sample of leases is limited and does not incorporate other transfers of interests and the related values implicit in these deals.
- Third, the assets are producing 50 Mmcf/d. Based on EnergyNet estimates of recent average US acquisition costs per daily boe output, approximately US$320 million of the acquisition cost (18%) is allocable to this production. If we adjust the acreage cost down on this basis, BP's per acre cost is $15,900 -- still high but at least within the upper range of the distribution range Figure 1.

Nevertheless, and as we would expect, BP's costs are clearly high compared to earlier entrants.

Table 1 shows the estimated cost of the acquisition. Results are based on BP's reserve estimates and All In Costs are based on GES estimates of future

Figure 1: BP Land Acquisition Cost and Comparative Public Lease Sale Results



The chart shows winning bid values in 2007 and 2008 public lease sales in Coal, Hughes and Pittsburg counties. The horizontal axis shows per acre winning bid values; the vertical axis shows the cumulative percentage of all blocks won at or below each bid value. The vertical axis intersects at BP's per acre cost.

Table 1: BP Woodford Shale Acquisition Metrics

		Acquisition Price $mm	*LT Debt Assumed $mm*	*Other Outlays $mm*	*Future Development Cost $mm*	*All In Costs $mm*
Net Reserves mmboe		**$1,750.0**			**$2,896.6**	**$4,646.6**
Proved	**15.2**					
Proved & Probable	**333.3**					
Buyer Share	**100%**					
Proved mmboe	**15.2**					
Proved & Probable mmboe	**333.3**					
$/boe Proved		**$115.38**	**$0.00**	**$0.00**	**$190.98**	**$306.37**
$/boe Proved & Probable		**$5.25**	**$0.00**	**$0.00**	**$8.69**	**$13.94**

Proved and Probable reserves are based on BP's stated estimate of potential reserves associated with the acquired acreage. This information is combined with GES data on the likely per well Expected Ultimate Recovery in the Woodford and per well drilling and completion costs to estimate probable future development costs and, therefore, the All In cost of the deal.

development costs. BP's All In costs are expected to be US$13.94 per boe ($2.32 per Mcfe). While high, this unit cost is clearly viable at recent natural gas prices.

What remains to be seen is how much further BP is prepared to go to build its onshore North American position -- a very large and ongoing source of earnings and cash flows.

Shell Acquires Duvernay Oil

Just a few days before the BP deal, Shell announced an all cash deal to acquire Duvernay Oil.

Shell agreed to pay a 36% premium on Duvernay shares with total costs estimated at US$5.3 billion plus US$446 million in assumed debt.

Key Duvernay assets include:

- Significant acreage positions in Alberta's Deep Gas play and British Columbia's Doig trend plus an estimated 250 to 500 future well locations in the Montney shale gas play. Duvernay holds 449,000 net acres in Alberta and British Columbia (65% and 44% developed, respectively).
- Net 2007 output averaged 21 Mboe/d (89% natural gas)

Figure 2: Shell Land Acquisition Costs in the Duvernay Deal versus Comparable Public Sale Values

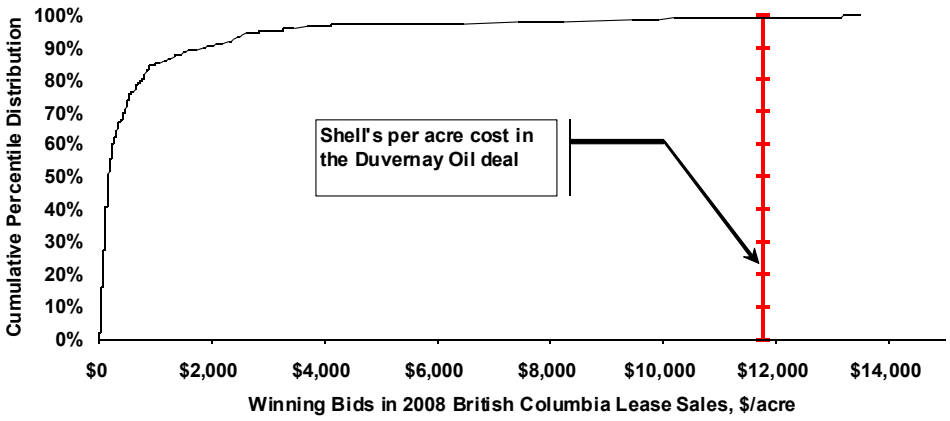


Table 2 shows the key metrics of this deal. After adding possible reserves and estimated associated development costs, the reserve cost per Mcfe is US$3.23. Because the reserve potential hinges critically on well spacing and proving up the Montney acreage position, the ultimate cost can vary considerably from this figure.

Divestiture of some of the acquired assets also seems likely.

An alternative metric, $/acre cost, is US$11,770 per acre. Figure 2 compares Shell's per acre cost and the year to date winning bid results in British Columbia's 2008 lease sales.

As in the BP deal, Shell has paid a very large premium to build its Western Canada natural gas portfolio quickly. Also, like the BP deal, this high cost is clearly due in no small part to the fact that Shell is coming late to the Montney party.

We suspect that the company's willingness to pay this premium also has a lot to do with its hoped for expansion of oil sands production in the coming years and a desire to balance its Canadian portfolio.

Moreover, adverse international results in recent years have pushed Shell into an aggressive land acquisition strategy elsewhere (the Chukchi Sea sale, Gulf of Mexico, and now onshore North America).

Table 2: Shell Duvernay Oil Acquisition Metrics

		Acquisition Price $mm	*LT Debt $mm*	*Other Costs $mm*	*Future Development Cost $mm*	*All In Costs $mm*
Net Reserves mmboe		**$5,287.5**	**$445.5**		**$2,803.8**	**$8,536.8**
Proved	**96.0**					
Proved & Probable	**148.2**					
Buyer Share	**100%**					
Proved mmboe	**96.0**					
Proved & Probable mmboe	**440.5**					
$/boe Proved		**$55.10**	**$4.64**	**$0.00**	**$29.22**	**$88.96**
$/boe Proved & Probable		**$12.00**	**$1.01**	**$0.00**	**$6.36**	**$19.38**

Proved reserve estimates are as reported by Duvernay. Proved and probable reserve estimates from Duvernay are 148.2 mmboe. GES has increased these reserve estimates using data on well locations previously reported by Duvernay and GES data on per well expected ultimate recovery and drilling and completion costs in the key plays.

MERGERS, ACQUISITIONS, & DIVESTITURES

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Quicksilver Barnett Shale Acquisition

In a cash and stock deal Quicksilver acquired Barnett Shale assets from private parties including Chief Resources, Hillwood Oil & Gas and Collins and Young. The estimated US$1.3 billion cost of the acquisition included US$1 billion in cash and Quicksilver stock valued at an estimated US$307 million.

The deal includes leases (both producing and undeveloped), royalty and midstream assets. Key upstream assets are:

- 13,000 net acres in northern Tarrant County and southern Denton county
- 350 Bcf proved reserves (40% developed)
- Estaimated 650 Bcf of additional resource potential
- 45 Mmcf/d of current production

The acquisition increased Quicksilver's proved Barnett Shale reserve base by 29% compared to end of year 2007. It also extends the company's Barnett Shale position into generally contiguous blocks of acreage in Tarrant and Denton counties.

Excluding effects of costs allocated to royalty interests and midstream assets, the estimated acquisition cost is US$7.84 per boe of proved and probable reserves. Factoring in GES estimates of future development costs the All In cost of the deal is an estimated US$13.65 per boe ($2.28 per Mcf).

Occidental Re-Enters Canadian Upstream

In an interesting move back into the Canadian upstream sector Occidental acquired a 15% interest in the Joslyn Oil Sands project from Enerplus Resources Fund.

Occidental paid Enerplus C$500 (US$495) million for an estimated 370 million barrels of net recoverable reserves. The company reported that its share of future development costs will be US$2 billion, implying an All In cost of US$6.74 per barrel.

Occidental effectively exited the Canadian upstream in early 2000. This was accomplished by selling its shares in Canadian Occidental (now Nexen) to Canadian Occidental and the Ontario Teachers' Pension Plan for C$1.2 billion.

In broad terms an interest in Joslyn fits with Occidental's focus on enhanced recovery in the Permian Basin. The mining portion of the project is currently estimated to come on-line in 2014 and will add 31 Mb/d net to Occidental output when peak output is achieved.

Marcellus Shale Land Costs

In a US$552 million deal Antero Resources acquired Dominion's Marcellus Shale drilling rights on 205,000 net acres. The acreage is in western Pennsylvania and West Virgina.

Dominion retains drilling rights to other formations and a 7.5% royalty interest in future Antero output from the Marcellus Shale.

At a cost of US$2,693 per acre, the Antero deal is competitive with recent land acquisition costs in the Marcellus and Utica shale plays:

- XTO, 15 April 2008: US$3,618/ acre. US$600 million deal (including US$50 million allocated to pipeline and gathering infrastructure) for Linn Energy's 152,000 net acres in western Pennsylvania and West Virginia
- XTO, May 2008: US$2,411 per acre with a 15% royalty. With Whitmar Exploration signed a US$90 million bonus to acquire rights to 37,000 acres in eastern Broome and western Delaware counties in New York
- Gastem, 27 February 2008. Farmed into 29,000 acres in New York held by Utica Energy. Gastem will earn a 65% interest by drilling five vertical wells and one horizontal well (all in the Utica Shale but with testing also of the Marcellus and Oneida).

In recent action, Pennsylvania's Department of Conservation and Natural Resources has opened up 74,000 acres in three state forests for bid. Bids on the 18 tracts will continue until 3 September 2008. The acreage is being offered on a ten year lease with a 16% royalty.

ExxonMobil Opts to Buy Piceance Assets

ExxonMobil and Williams participate in an area of mutual interest (AMI) in the Piceance Basin.

Under the terms of this AMI, ExxonMobil has exercised its option to buy a 49% interest in a portion of acreage acquired by Williams from SandRidge Energy in May. ExxonMobil will pay US$71 million to acquire approximately 7,000 net acres (roughly 2/3rds of the 24,000 net acres that were acquired by Williams was subject to the AMI). The acreage is located in Rio Blanco County and was reported by Williams to be contiguous to its existing 17,500 net acre position in the this Piceance Highlands area.

The estimated cost of the Williams deal is $10,417 per net acre. Williams estimated 1,900 Bcf probable and possible reserves, assuming 10 acre spacing is approved on the acquired lands. The cost of acquiring the probable and possible reserves is only $0.79 per boe. GES estimates of All In Costs of the deal range from a low of US$6.79 per boe, a mid-range case of US$11.37 per boe, and a high case of US$31.11 per boe.

Haynesville Shale

EnCana increased its Haynesville acreage position through a deal with Indigo Minerals LLC. Indigo sold 89,500 acres (including some fee mineral rights) to EnCana for US$457 million.

In another deal, Chesapeake announced that Plains will farm into a 20% share in Chesapeake's 550,000 net Haynesville shale acres.

Plains is paying US$1.65 billion in cash ($15,000 per acre and US$2.13 per boe 2P reserves) and will fund half of Chesapeake's share of future development costs up to another US$1.65 billion. Under the terms of this agreement, Plains' All In Cost including its share of development costs plus the carry of part of Chesapeake's costs is estimated to be US$15.82 per boe.

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US Asset Sale Value Indicators
Trailing 12-Month Period, June 2007-June 2008

Non-Operated Working Interests 6:1

	Average (Mean) $/BOE/D	Average (Weighted) $/BOE/D	Average Multiple (Average Income)	Average Multiple (Last Income)
Appalachians	$45,873	$28,278	38.50	35.19
Ark-La-Tex	$42,975	$34,667	47.56	50.36
Gulf Coast	$35,729	$23,611	35.62	45.01
Michigan Basin	$37,138	$26,415	40.11	55.73
Mid Continent	$47,948	$41,969	51.24	55.85
Permian Basin	$74,420	$75,092	56.99	51.72
Rockies	$48,652	$56,898	44.52	42.26
South Texas	$36,738	$31,067	35.53	39.14
West Coast	$42,260	$27,675	44.73	44.48
Column Average	**$45,748**	**$38,408**	**43.87**	**46.64**

Operated Working Interests 6:1

	Average (Mean) $/BOE/D	Average (Weighted) $/BOE/D	Average Multiple (Average Income)	Average Multiple (Last Income)
Appalachians	$85,524	$56,867	45.70	54.69
Ark-La-Tex	$32,972	$28,431	29.47	32.74
Gulf Coast	$31,344	$23,493	26.30	48.76
Michigan Basin	$44,967	$44,967	31.40	41.35
Mid Continent	$56,945	$28,516	53.39	51.61
Permian Basin	$45,293	$51,050	54.59	45.04
Rockies	$39,791	$46,338	38.03	44.97
South Texas	$23,632	$21,145	36.68	54.64
Column Average	**$45,058**	**$37,601**	**39.44**	**46.73**

EnergyNet data on US deal metrics over the 12-month period from June 2007 through June 2008 are shown here.

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.

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June Cost Inflation Results

UPSTREAM

Drilling costs in 2008 continue to be down relative to the same time last year. However, month to month changes in 2008 have turned positive, suggesting that the downward pressures have diminished.

Inflationary pressures are considerably stronger in the oil field machinery sector. On a year to date basis, oil field machinery costs are up 7.1%. Rotary drilling machinery costs are up 4.7% thus far in 2008.

The relative distribution of inflationary or deflationary cost pressures will tend to reflect the shifts in the focus of industry activities. This cost reaction will, however, tend to lag.

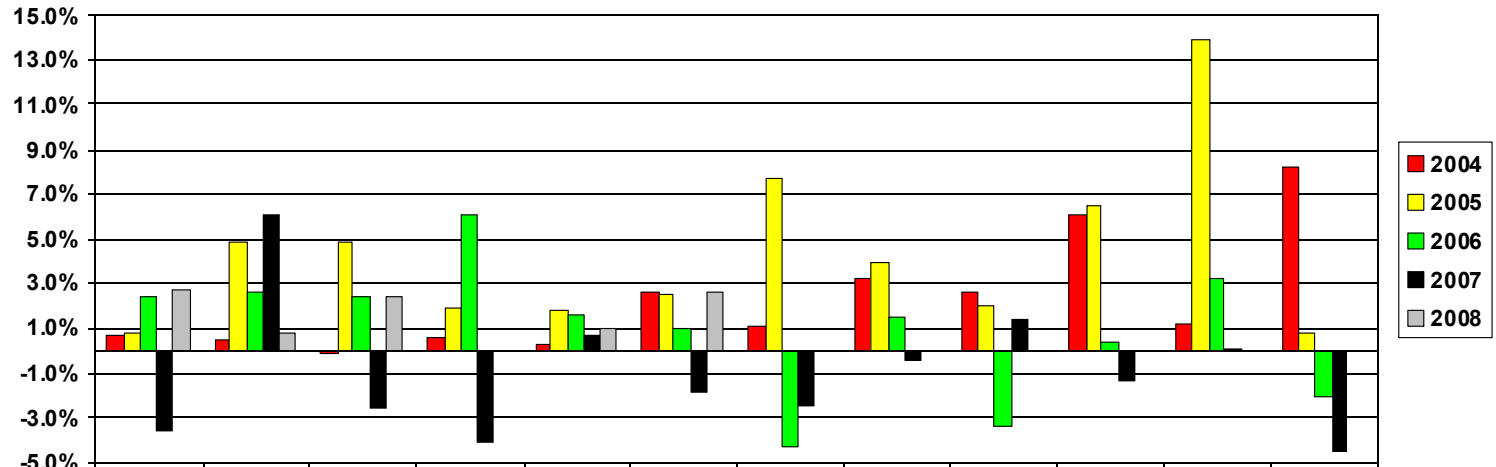
A growing consensus strategy within the industry (at least in North America) is to monetize land positions, I.e, focus on production. It should not, therefore, be too surprising that the transition of industry activities towards a heavier weighting on development, inflationary pressures are particularly strong in the production machinery sub-sector. Here, year to date cost inflation is estimated at 11% and month to month cost increases since February have ranged from 12% to nearly 17% in June.

Annualized Cost Inflation Rates: 2006, 2007 and 2008 YTD

Cost Component	2006/2005	2007/2006	2008 YTD/ 2007
Drilling Cost	37.8%	-4.6%	-4.2%
O&G Support Activities	13.1%	3.6%	-0.1%
Oil Field Machinery	8.7%	7.0%	7.1%
Rotary Drilling Machinery	11.5%	8.9%	4.7%

Note: 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%	-4.50%
2008	2.80%	0.80%	2.40%	0.00%	1.00%	2.70%						

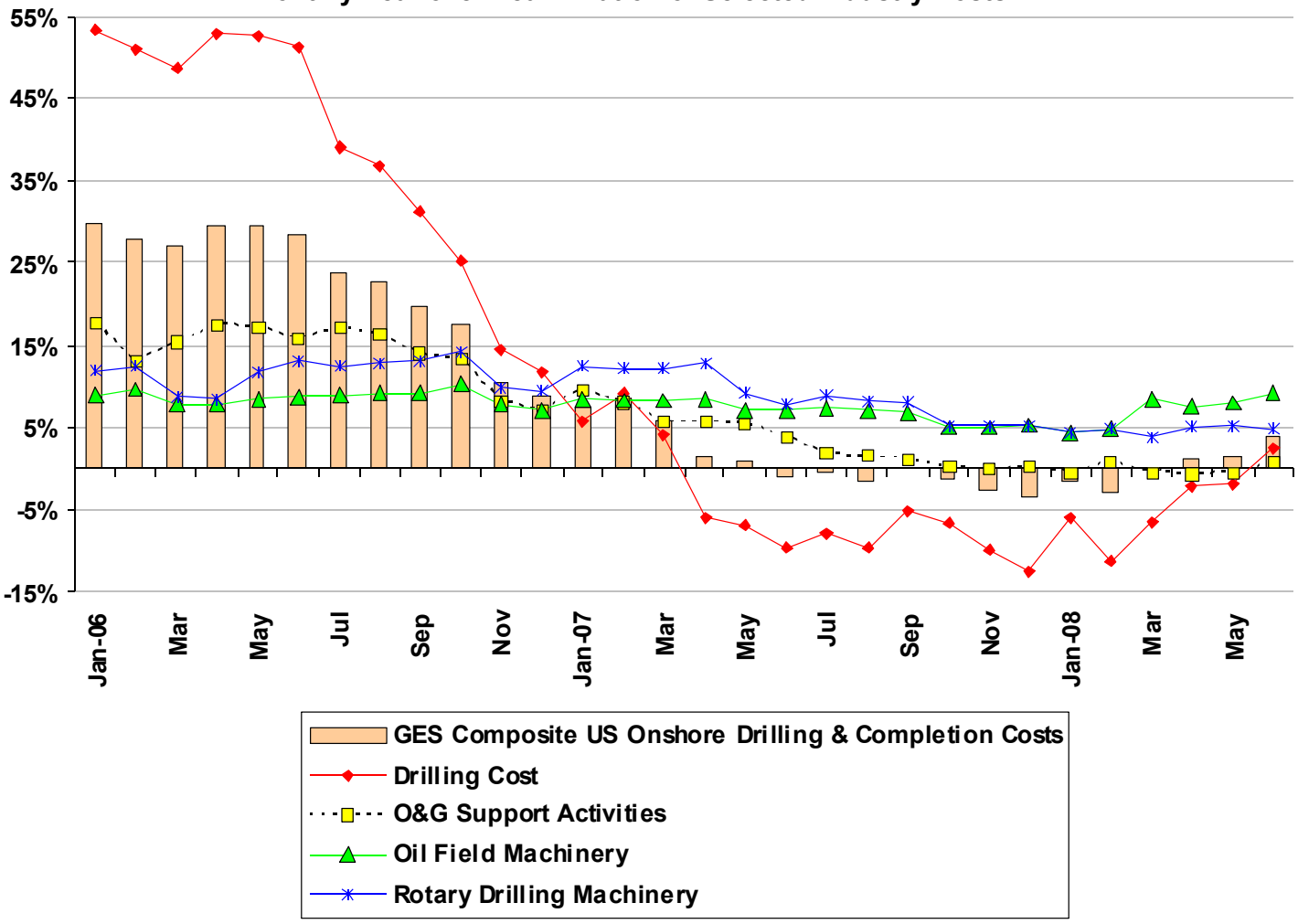
Year over Year Percentage Change

	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%	-12.4%	-4.6%
2008	-6.1%	-11.3%	-6.4%	-2.2%	-1.9%	2.5%							

COST WATCH

GORDON ENERGY SOLUTIONS

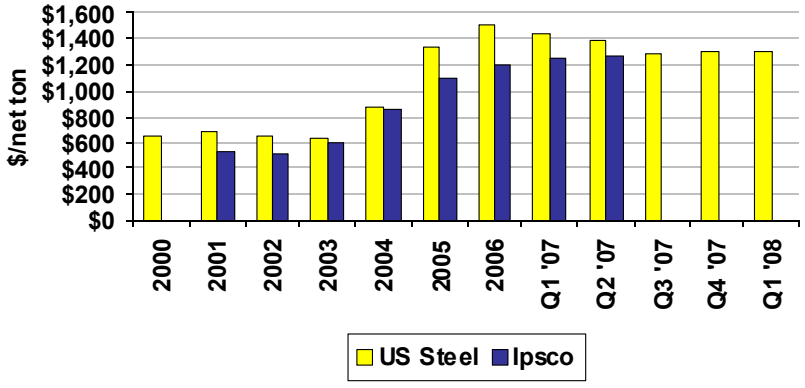
Monthly Year over Year Inflation of Selected Industry Costs



The recent stabilization of drilling costs combined with strong machinery cost inflation suggest two things.

- First, composite onshore drilling and completion costs are likely to be on the upswing again but at more moderate rates than before.
- Second, based on the mixed behavior of drilling costs thus far in 2008, expect that composite well costs will show significant but probably moderate inflation.

Tubular Steel Products Price



IIpsco was acquired by SSAB and its Tubular Division was sold to Evraz