ON POINT

Vol 2, No. 3 March 2007

GORDON ENERGY SOLUTIONS

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

IN THE NEWS

Oil Sands Output will Trigger Major Infrastructure Projects – Altex Energy pipeline could feed oil sands output to Marathon's expanded Garyville refinery in Louisiana. Pipeline startup is planned for 2011. MRO 180 Mb/d expansion targeted for 2010. In addition, Enbridge is considering a 190 Mb/d expansion of the Spearhead pipeline that carries Canadian crude to Cushing.

Taxation

UK Budget Leaves Oil Taxes Unchanged – The 2007 Budget report has just been published and calls for cutting the top Corporation Tax rate from 30% to 28% in 2008. However, the Corporation tax rate on oil & gas will remain 30%. The industry also pays a 20% Supplementary Charge, resulting in a 50% combined rate.

Canadian 2007 Budget – The recently released 2007 Budget plan calls for the elimination of accelerated capital cost recovery provisions for oil sand and in situ projects in Canada

Pemex Reserves Continue Long Slide – Proved reserves fell nearly 6% in 2006. The company's production replacement rate increased from 26% in 2005 to 41% in 2006. Oil output was down slightly in 2006. However, production at the key Cantarell field was down nearly 12%.

Pemex cites inadequate exploration spending in 2006 (down 17% from 2005) and suggests that coming tax changes will alleviate the problem. Whether this will be the case is debatable at best. Pemex's investment needs are multiplying: these are spreading to include a serious shortage in refining capacity (Mexico imported 40% of its gasoline consumption) and transport infrastructure. Moreover, natural gas imports account for 20% of consumption despite the MSC initiatives.

Shell Growth Targets – Shell expects modest growth through 2010, averaging 1 to 2% on an average annual basis. Post 2010, the company believes it has the potential for 2 to 3% growth.

Future Frontier North American Gas Supplies Are Stalling Out

As natural gas futures prices continue to fluctuate at or around $7/mmbtu, a string of events in recent weeks point to a significant weakening in future North American supply prospects from two key sources: the Arctic and from the Pacific Basin.

Key events affecting supply from the Pacific Basin include:

- Chevron dropped its plans to build an LNG re-gasification terminal off Baja, Mexico
- BHP delayed the potential start-up of its Cabrillo Port re-gasification terminal from 2010 to 2012 or 2013. The company still hopes to get final environmental approval by end of year 2007. However, the remaining permitting and approval process is now expected to take five years. The planned facility off California's coast has, not surprisingly, faced significant local opposition.

Average daily gas supply capacity to California and western Mexico from these projects was very considerable: 800 mmcf/d and 1,400 mmcf/d from Cabrillo and Chevron's Baja projects, respectively.

The prospect that new LNG receiving terminals will ultimately all be concentrated in the Gulf of Mexico is very real. It is worth noting that last month Chevron received FERC approval for its 1.3 bcf/d Casotte Landing project. This terminal will be adjacent to the company's Pascagoula refinery in Mississippi. In addition, Chevron holds rights for 1.5 bcf/d capacity at the Sabine Pass facility that is currently under construction, is 55% complete and is expected to be on-line by the second quarter of 2008.

The barriers to future natural gas supply from the Pacific Basin are heavily influenced by the politics of energy in the US.

Serious problems also exist for potential gas supplies from North American Arctic regions, specifically Alaska and the Mackenzie Delta. The critical factors eroding supply prospects from this source are (1) cost inflation and (2) lower natural gas prices and long-term price uncertainty.

Early this month the Mackenzie Gas Project partners announced sharply higher revised real costs of the 1.2 bcf/d development compared to the estimates published in the preliminary application. In addition to the cost inflation, assuming approvals and authorizations are in place by 2009, construction cannot begin before 2010 and first gas is, therefore, delayed until 2014.

Using Bank of Canada statistics, the 2004 estimates have been "grossed up" by the inflation in Canada from 2003 to 2006. After this adjustment, the 2004 capital cost estimate is C$8.8 billion in 2006 prices. The total cost of the project in 2006 prices is now estimated to be C$16.2 billion. In short, estimated total development costs are up by almost 85%.

On a unit basis, total costs (before inflation) are almost US$2.30 per mcf of recoverable reserves from the three anchor fields (Taglu, Niglintgak and Parsons Lake).

Figure 1 compares the cost estimates from the 2004 initial application with the revised estimates announced earlier this month. The cost estimates are broken out by segment within the broader project.

Continued on p. 3

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.

Richard Gordon, Ph.D
President & CEO
rgordon@gordonenergysolutions.com

Steve Gordon
Vice President
sgordon@gordonenergysolutions.com

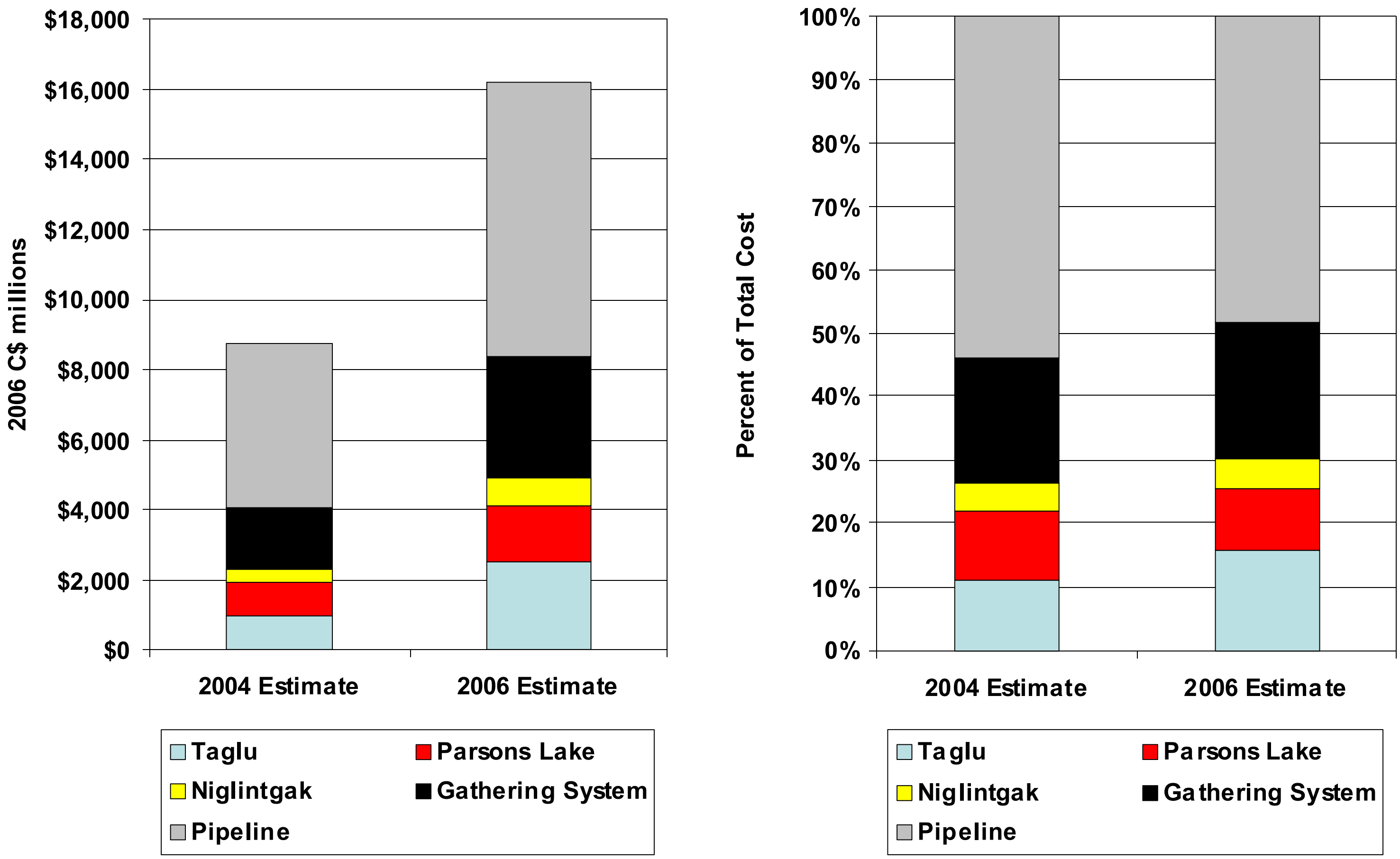
Gordon Energy Solutions
11286 Hadley St
Overland Park, KS 66210
(913) 451-9539

The cornerstone of our firm is supplying Research Services on Demand, enabling GES to deliver the analysis you want, when it's needed. Our services are uniquely tailored to fit your company's needs and reflects our role as a source of independent research and analysis.

Please feel free to distribute this to your colleagues. If you received this issue as a forward, and wish to receive it directly, please send an e-mail to subscribe@gordonenergysolutions.com. If you no longer wish to receive this newsletter and would like to have your e-mail address removed from our list, please send an e-mail to unsubscribe@gordonenergysolutions.com. Please let us know how we may improve this service.

For additional information concerning our most recent work or to find out more about our company, please visit http://www.gordonenergysolutions.com.

Figure 1: Mackenzie Gas Project Cost Estimates



Sources: Imperial Oil, Shell Canada and ConocoPhillips application to the National Energy Board, 2004; Imperial Oil revisions submitted to the NEB 12 March 2007; Bank of Canada inflation estimates

Upstream costs for the three anchor fields have risen from 26% to 30% of the project total. Taglu (Imperial) and Niglintgak (Shell) are the key drivers, up by 159% and 109%, respectively. Gathering costs have also escalated dramatically, now slightly more than double the original estimates.

The pipeline's share of total costs is now slightly less than 50%. Nevertheless, this represents C$7.8 billion and is the portion most likely to be "averaged" down if other reserves are brought into the project over time.

These results are generally consistent with cost inflation data regularly tracked in On Point. Specifically, drilling costs are up 124% compared to 2004, support services are up 32% and tubular steel is up 74%. Reports on labor cost inflation also are consistent with these revised estimates.

While Imperial Oil would not estimate the rate of return on the project under current cost estimates, it was made clear that the relevant return is in the single digits.

The Mackenzie Gas Project remains highly speculative at this time. The proposed changes in oil sand cost recovery rules in the Canadian budget proposal do not affect this project directly. Indirectly, however, it is reasonable to worry that the Federal government may be unwilling to offer tax concessions to the project.

Meanwhile, Alaska continues to limp along with little or no material progress under the new governor's proposals. The purpose of the Alaska Gasline Inducement Act (AGIA) is "to encourage expedited construction of a natural gas pipeline...". While the legislation contains multiple provisions two are directly relevant to incentives. First, the state offers to match up to $500 million of costs associated with gaining a certificate of public necessity and convenience from FERC or the Regulatory Commission of Alaska. Second, the state offers to protect the project from increases in the production tax for a period of 10 years after pipeline start-up.

We have not yet heard responses from the major North Slope partners. However, it seems unlikely at this time that the AGIA will materially contribute to any progress on this long-delayed pipeline project.

As a result of the events we have discussed here, a ten-year window of opportunity will exist for North American producers in unconventional plays and for international gas export projects to establish themselves as viable sources of future supply to North America. During this window, look for natural gas prices to be much more robust than might seem possible now.

Tax Policy Issues: the UK and Canada

As noted on page 1, central government budgets in the UK and Canada include significant provisions affecting oil and gas.

UK: The UK budget plan calls for a relatively modest cut in the large company rate of Corporation Tax from 30% to 28%. Oil and gas operations, which are subject to an additional 20% Supplementary Charge (doubled from 10% effective 1 January 2006), are excluded from the rate cut available to other large companies under the budget.

The real significance of the situation in the UK is much deeper than a quarrel over 2 percentage points on the tax rate. At heart, the debate is over the appropriate tax policy in a mature province experiencing very serious cost inflation pressures. In its 2006 Activity Survey the UK Offshore Operators Association noted that:

- Average operating costs have risen from \$5 to \$6 per boe in 2003 to \$9 to \$10 per boe currently and
- Combined per boe opex and capital costs rose by 45% in 2006 to \$22 per boe

The adverse effects of cost inflation are being compounded by the fact that UK natural gas prices have declined from recent peaks back to 2004 levels.

In March 2007 the Treasury issued "The North Sea Fiscal Regime: a discussion paper". The document summarizes the results of discussions held with industry on oil and gas taxation and the government's conclusions.

The key conclusions from the government's perspective are clear both from the discussion paper and from the 2007 budget: changes in the UK oil and gas taxation system are not considered to be necessary. Whether this position is sustained after follow-up discussions this year will have less to do with these "discussions" and much more to do with the industry's decisions concerning exploration and development spending in the UK in 2007 and beyond.

Canada: The budget proposal was released on 19 March 2007 and contains significant adverse changes affecting future oil sands projects. The proposal calls for the repeal of accelerated capital cost allowances (ACCA) for oil sands projects (both mining and in situ projects).

Regular capital cost allowance for these projects is calculated using a 25% declining balance method. The ACCA allows oil sands projects to recover in any year after startup all un-depreciated capital cost up to the project income after regular CCA for the year.

Projects involving assets acquired prior to 19 March 2007 are grandfathered as are costs associated with assets acquired before 2012 that are part of a construction phase that began before 19 March 2007. Assets that fail to meet the grandfather test are limited in their access to to ACCA. The percentage of ACCA otherwise available will be 90% in 2011, 80% in 2012, 60% in 2013, 30% in 2014 and 0% thereafter.

The government's rationale for the change is explicit:

> "This incentive [the ACCA] helped to offset some of the risk associated with early investments in the oil sands and contributed to the development of this strategic resource. Over time, however, technological developments and changing economic conditions have led to major investments that have moved the sector to a point where the majority of Canada's oil production will soon come from oil sands. As a result, this preferential treatment is no longer required."

The impact on oil sand projects currently in the planning phase will be very substantial and is magnified by cost inflation pressures.

Venezuelan Natural Gas – Trinidad and Venezuela have signed agreements on development of cross-border natural gas reserves. There are indications that Venezuela may opt for liquefaction in Trinidad. Given the severe commercial security risks in Venezuela, this option is likely to make a great deal of sense to the upstream stakeholders in Plataforma Deltana. Similarly the economics from Trinidad's perspective are clear. However, negotiations over processing tariffs will likely be contentious at best.

Gulf of Mexico Asset Sales

Two major sales of deepwater Gulf of Mexico fields have recently been reported: BP's sale of its interest in Entrada and Anadarko's sale of part of its interest in K2.

BP's Entrada interest was acquired by its partner, Callon Petroleum, for US\$190 million. Estimated net proved reserves are 13.7 Mmbbls oil and 68.1 Bcf gas and the estimated cost per proved net undeveloped boe is \$7.58. Based on an estimated US\$200 million cost of developing the field, the total cost per net proved boe is \$15.57. Callon estimates probable reserves of 13.7 Mmbbls and 32.9 Bcf.

Also, Anadarko announced that it was selling a 23.2% interest in the K2 producing field to two, unidentified buyers for US\$1.2 billion.

Diverse Players in Indonesia

Declining oil production and multiplying problems in the gas sector have eroded Indonesia's position dramatically. In the midst of these problems a number of interesting companies have taken significant license positions in Indonesia:

- Pertamina's looks to re-position itself through its effort to acquire a 10% stake in the Mahakam block assets as part of the early contract extension negotiations with Total and Inpex
- Japex, with PT Medco acquired a position in North Sumatra Block A and just this month Japex and Mitsubishi each picked up a 25% share in the Kangean Block,
- Pearl Energy (a wholly owned subsidiary of Abu-Dhabi based Aabar Petroleum Investments, acquired interests in Sibaru and Karana blocks in 2007
- Statoil has acquired interests in the Kuma and Karama blocks off the west coast of Sulawesi
- Talisman was awarded a 100% interest in the Sageri block located in the South Makassar Basin
- Indonesian companies, PT Medco and Energi Mega Persada, have expanded their domestic roles

The government has recently announced plans to offer coalbed methane acreage in South Sumatra and East Kalimantan. PT Medco and Arrow signed a Letter of Understanding for South Sumatran coalbed methane.

OUR PERSPECTIVE

GORDON ENERGY SOLUTIONS

Some Thoughts on National Oil Companies

GES, along with Thomas Stenvoll from Hetco, participated in a two-year Japan Petroleum Energy Center and Baker Institute Energy Forum study of national oil companies (NOC) and their changing role in the international business. The case study results are available at www.rice.edu/energy/publications/nocs.html. Additionally, we presented our results at conferences in Houston and Dubai.

The opinions and views expressed here are solely those of Gordon Energy Solutions. These comments present, in capsule form, some observations on the broader issues facing the national oil companies, the international oil companies (IOC), how they interact and compete, and a description of the future oil and gas company.

We are witnessing the need for the emergence of a new species in the oil industry; a hybrid organization. This type of company combines the unique strengths of the NOC and the IOC and, as a result, will be a superior competitor in the modern oil and gas industry environment.

For a number of reasons, including some discussed here, this emergent process will be difficult. There are a number of barriers to the process and not all companies will make the transition. However, the environmental forces driving this institutional evolution are extraordinarily powerful. What makes the evolution even more likely to occur is that these forces are uniquely symmetrical in their impacts on the NOC and the IOC.

There are multiple catalysts accelerating and intensifying the coming changes in the role and character of the NOCs and IOCs:

- The maturation of the oil industry in multiple major producing countries is posing new and extreme challenges to the NOC and its government, challenges that many are ill-prepared to handle.
- The aging of IOCs asset positions, the intense competition for new investment opportunities internationally, and the recent rapid cost inflation
- The rapid rise of crude oil prices since 2003 and their control over host country resources offers NOCs an extraordinary competitive opportunity that they can ill afford to waste
- The growing international trade in natural gas and the associated liquids has and will continue to shift the balance of power among countries in the oil and gas industry

As illustrated in our case study for the JPEC/Baker Institute project,

> "By their nature and reflecting policy maker goals, a National Oil Company (NOC) is typically a microcosm of the host country's oil and gas sector. As a result, the evolution of the NOC as an organization, the role it plays within its host country and the factors driving its strategies will tend to reflect and parallel the maturation of the host country oil and gas sector. … [As a result] an NOC's ability to grow and to create wealth will be substantially constrained as the national hydrocarbon sector matures." Source: Statoil: A Study in Political Entrepreneurship, The James A. Baker III Institute for Public Policy, Rice University, March 2007

A large number of NOCs, both as institutions for public policy within their home countries and as commercial players in global oil and gas markets, are at a critical point in their evolution. Inevitably, as the host country hydrocarbon sector matures the NOC and its host government must make a fundamental strategic choice:

- Stand by and watch the NOC's role deteriorate to one of managing a gradually stagnating industry or, at worst, a declining industry or
- Seeing the NOC as a tool that has been created for wealth management and creation, allow the NOC to become more international in its scope of operations, more diverse in its commercial functions, and more limited in its non-commercial functions

The necessity of this strategic choice is now becoming apparent to a significant cross-section of very different NOCs and their host governments.

Future retrospective studies of the NOC will conclude that the current period is every bit as decisive in its long-term impact as was the formative phase of the late 1960's and 1970's when many NOCs were created or gained serious positions.

Control over access to resources in the host country is a critically important competitive advantage established in the earlier, formative phase of NOC development. If it is used effectively now and in the coming years, this advantage can be an essential tool in forging commercially meaningful and value-creating alliances with the IOCs.

Current high oil prices can be either an enabling or a destructive force.

Prices are an enabling force in that they (1) enhance the short-term value of the NOC's control over domestic resource access and (2) create cash flow surpluses that can fund the international initiatives that will better position the country for the future.

However, high oil prices are proving to also be a destructive force in a number of key countries. In these cases the cash flow surplus is seen as (1) a means to fund more conventional, non-commercial purposes and (2) evidence that the IOCs do not serve a needed role in country and that the NOC's role need not be changed.

Unfortunately, high oil prices are a cyclical phenomenon and, therefore, are transitory. Moreover, cost inflation pressures are a lagging response to prices and the resulting levels of industry investment. Finally, public policy including taxation and decisions affecting access to investment opportunities are also lagging responses. The resulting room for misjudging the situation is considerable.

While the advantages of the NOCs receive a great deal of attention, the competitive strengths of the IOCs are often missed. It is extraordinarily difficult to build a successful international program. Costs and risks are very high. Lead times are long. Despite the publicity surrounding government to government arrangements and understandings, NOCs have very limited strengths in international competition. This area of need is an essential driver of the rationale for NOC/IOC alliances. IOCs possess critically important assets that the NOC needs if it is to succeed internationally. Beyond financial resources that are, temporarily not needed, these assets include (1) current IOC positions in international operations, (2) their experience in the application of high technology, (3) experienced human resources, and (4) access to important midstream and downstream assets and markets.

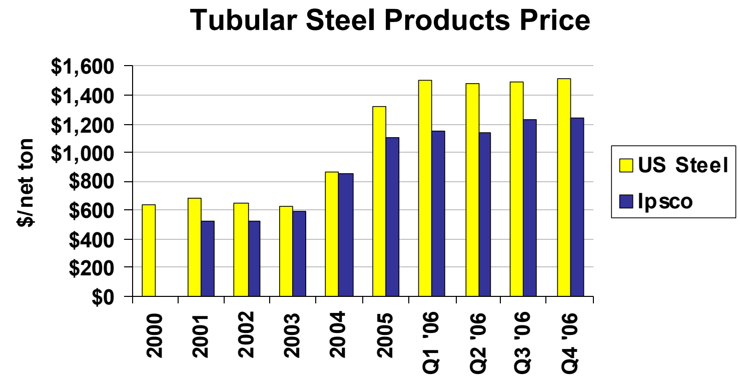
Many key questions remain:

- How will these hybrid organizations be formed? Alliances, either formally or on a de facto basis, are the most likely near to medium-term vehicle.
- What are the most likely component elements of alliances?
- Which companies are likely to be leaders in this process, why and where?
- Will NOC/IOC mergers occur or is the Unocal experience an indication of the long-term barriers to this approach?

COST WATCH

Fourth quarter data on tubular steel prices is now available.

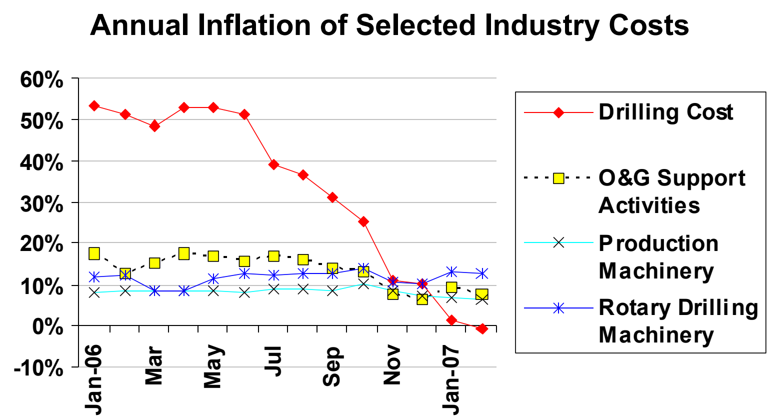
Tubular steel prices have held steady throughout 2006 at more than double the levels paid throughout the period from 2000 through 2003. On the positive side, there is not much evidence that tubular price pressures have been growing in 2006.

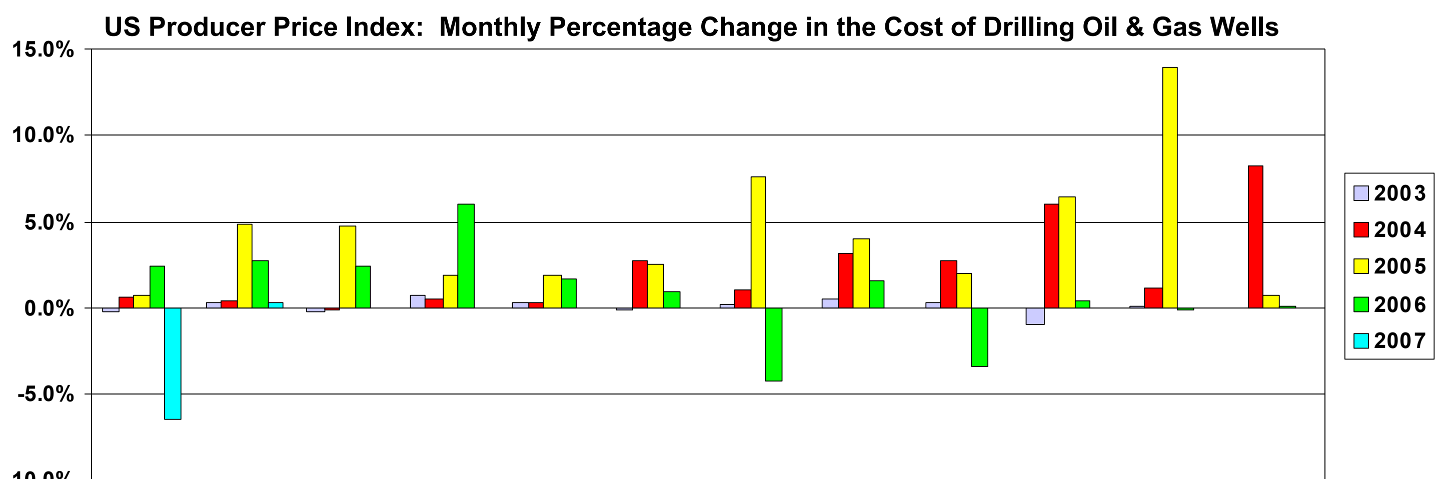


February Producer Price Indices

After falling slightly more than 5% in January compared with December 2006, the producer price index for drilling oil and gas wells has held steady in February.

Oil field equipment and oil and gas support services costs continue to inflate at roughly the same rate as they have throughout much of 2006..





	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	-0.20%	0.30%	-0.20%	0.80%	0.30%	-0.10%	0.20%	0.60%	0.30%	-1.00%	0.10%	0.00%
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%	-0.10%	0.10%
2007	-6.40%	0.30%										

Year over Year Percentage Change

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2005	27.2%	31.7%	36.5%	37.8%	39.4%	39.2%	45.8%	46.6%	45.9%	46.3%	59.1%	51.7%	43.2%
2006	53.3%	51.1%	48.7%	53.0%	52.7%	51.3%	39.2%	36.7%	31.3%	25.2%	11.1%	10.4%	37.4%
2007	1.6%	-0.8%											