PARKS PATON HOEPFL & BROWN

ENERGY INVESTMENT BANKING, LP

MUSINGS FROM THE OIL PATCH

June 27, 2006

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Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating oilfield service companies. The newsletter currently anticipates a semi-monthly publishing schedule, but periodically the event and news flow may dictate a more frequent schedule. As always, I welcome your comments and observations.* Allen Brooks

Implications of Anadarko Buys

Anadarko Petroleum announced it had reach agreements to purchase Kerr-McGee and Western Gas Resources

On Friday morning, Anadarko Petroleum Corp. (APC-NYSE) announced it had reached agreements to purchase Kerr-McGee Corp. (KMG-NYSE) and Western Gas Resources Inc. (WGR-NYSE) in cash transactions that will cost a total of about $21 billion. Kerr-McGee will be purchased for $70.50 per share, roughly a 40% premium over the closing price the evening before, in what will be a $16 billion deal. The Western Gas transaction is for $4.74 billion in cash and the assumption of $560 million in debt. The purchase price of $61.00 per share represents about a 49% premium over the last trade. Anadarko is funding the purchases with a $24 billion one-year loan from three investment and commercial banks. It plans to permanently fund the transaction via asset sales, cash flow, debt and new equity. So what conclusions should we draw from these deals?

These deals may represent the early phase of a significant consolidation effort within the oil and gas producing sector

While it is highly unusual to see two such large deals announced at the same time, this may represent the early phase of a significant consolidation effort within the oil and gas producing sector. Rumors were that there was supposed to be a major natural resource transaction announced on Monday. No one is sure whether the timing of these deals was driven by the possibility that one or more of the parties were part of this rumored Monday transaction or not. For a number of years, Anadarko was suggested as a possible takeover candidate. That speculation peaked in late 2003 when new management joined the company. The new chairman and CEO, James Hackett, was known as a turnaround master, so the thinking was that he was hired to clean up Anadarko and then sell the company. If Anadarko, or one of the other companies, was a takeover target, then maybe these deals were done from a defensive point of view rather than being strictly an offensive move.

In an investor conference call following the announcement of the deals, Anadarko's Hackett suggested that this was not a defensive move but a statement about growth. Moreover, he suggested it was an attempt to secure technical people to drive the growth of Anadarko, given the growing labor shortage throughout the industry.

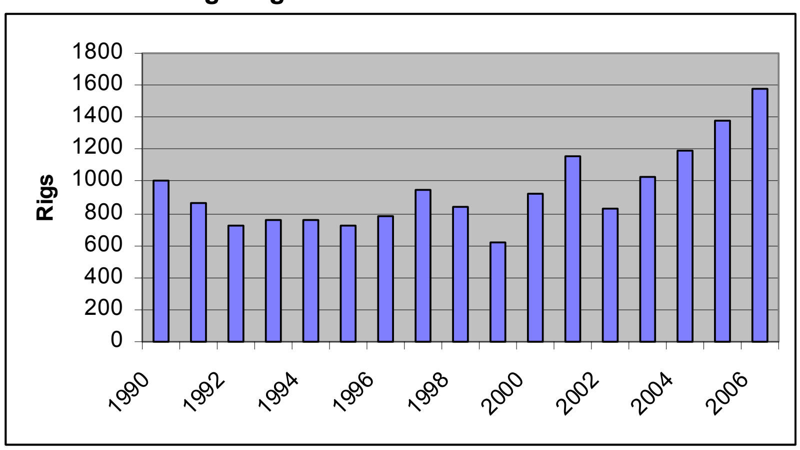
Wall Street analysts are now speculating on which other domestic producers may be bought

Taken with other transactions such as the ConocoPhillips/Burlington Resources (COP-, BR-NYSE) deal announced late last year, the Energy Partners (EPL-NYSE) buy of Stone Energy (SGY-NYSE), the Jana fund battle over control of Houston Exploration (THX-NYSE) and the Apache (APA-NYSE) purchase of significant Gulf of Mexico assets from BP (BP-NYSE), the Anadarko deals signal that the E&P industry consolidation is well underway. Wall Street analysts are now speculating on which other domestic producers may be bought. One analyst interviewed on CNBC suggested that any independent producer with a market capitalization of less than $50 billion is a potential target. He ticked off companies such as Pioneer Natural Resources (PXD-NYSE), Devon Energy (DVN-NYSE) and EOG Resources (EOG-NYSE) as possible targets. Other names that have been offered up include Newfield Exploration (NFX-NYSE) and Southwestern Energy (SWN-NYSE).

Many investors will interpret these purchases as a statement about attractive long-term industry fundamentals for the energy business

If the industry is heading into a consolidation phase, and we've been there before, there are several messages that industry participants and investors should heed. First, many investors will interpret these purchases as a statement about attractive long-term industry fundamentals for the energy business. They will view Anadarko's buys as statements about the attractiveness of the deepwater prospects in the Gulf of Mexico (Kerr-McGee) and the long-term future for unconventional gas in the Rockies (Western Gas).

Exhibit 1. Average Rig Count Continues to Climb



Source: Baker Hughes, PPHB

A second message, however, has possibly negative implications. The uncertainty over job security for the employees of the acquired companies causes them to become more cautious in their actions. That, coupled with the eventual reshuffling of the priorities for E&P

projects in the newly combined company and the length of time required to establish a new priority, usually translates into a drilling and development slowdown. A potential activity slowdown represents a major downside business risk for the oilfield service industry and its investors.

The oilfield service industry's customer base is shrinking and the surviving companies are becoming much larger entities

The final message that comes from these deals is that the oilfield service industry's customer base is shrinking and the surviving companies are becoming much larger entities. As a result, the oilfield service industry will come under pressure to increase its critical mass to counter balance its larger customers. We expect increased pressure on service companies to combine; something we have seen during previous E&P industry consolidation periods.

We anticipate that Wall Street will begin to question the impact of these deals on the future pace of drilling and oilfield activity, and ultimately on oilfield service company earnings prospects

It usually takes a while for the investment community to figure out the implications from these industry-reshaping events that were unleashed on Friday. We anticipated Wall Street to initially view the news positively, sending the stocks higher. In reality, the OSX oil service and XOI oil producer indices gained 2.0% and 3.5%, respectively, by the market close on Friday. Then we anticipate that Wall Street will begin to question the impact of these deals on the future pace of drilling and oilfield activity, and ultimately on oilfield service company earnings prospects. Investors may begin to question stock price valuations for oilfield service companies facing the potential for slower growing earnings. Stay tuned.

2006 Capex Spending Projected Higher

The mid-year capital spending survey of oil and gas companies conducted by Lehman Brothers projects a higher growth rate than forecast in the earlier survey. Based on a survey of 308 oil and gas companies, total spending is projected to grow 21.3% this year, up from the prior survey that showed a 14.7% increase. The companies say they are planning to spend $261 billion in 2006.

The spending gains are strongest in the domestic and international markets with Canadian spending barely inching higher from the December 2005 survey. In the U.S. market, the companies are expecting to spend 27.7% versus a 14.9% gain projected in the December survey. Lehman's oilfield analysts believe the spending hike is a reflection of strong industry fundamentals due to high commodity prices and inflation in oilfield service and drilling rig costs. We don't disagree with this analysis as oil and gas companies continue to put rig availability at the top of their requirements list and are willing to pay more for assured availability.

Exhibit 2. Lehman Brothers Mid-year Capex Spending Survey

($ Millions)	2006E	2005A	Year-to-Year % Change	Companies Surveyed	Year-to-Year % Change in 12/05	Companies Surveyed
U.S. Spending	64,358	50,399	27.7%	224	14.9%	247
Canadian Spending	25,821	22,526	14.6%	69	13.3%	71
International Spending	170,716	142,188	20.1%	88	14.9%	85
Worldwide Spending	$260,895	$215,113	21.3%	308	14.7%	325

Source: Lehman Brothers

Internationally, spending is anticipated to increase by 20.1% versus the prior 14.9% projected increase. The higher spending reflects a broad upswing by all types of oil and gas companies active and in virtually every geographic region. It is actually surprising to see such a significant rise in international spending as the nature of exploration and development work generally requires longer lead-times for projects. The international rig count has continued to climb throughout the first part of 2006 and service costs are being ratcheted higher as equipment and people remain in short supply.

The Canadian market has reacted faster to the fall in natural gas prices that has put greater pressure on very shallow drilling and coal bed methane drilling

The Canadian market showed the smallest revised increase. The new survey suggests a 2006 spending increase of 14.6%, up from the prior forecast of a 13.3% increase. Lehman Brothers suggests the small increase reflects limited rig availability, the strong Canadian dollar and project timing. Based on our conversations with Canadian oilfield service companies, we believe that this market has reacted faster to the fall in natural gas prices and that has put greater pressure on very shallow drilling and coal bed methane drilling. In addition, there have been several significant acreage farmouts that often delay spending plans as the new owner needs to perform his analysis of the properties before moving forward with work. The latest industry forecasts suggest that there may be virtually no growth in the number of coal bed methane wells drilled this year compared to 2005 due to low gas prices. The absence of this market growth will limit capital expenditure growth.

67% of the companies are indicating higher E&P spending in 2007

One of the most positive aspects of the survey was the news that 67% of the companies are indicating higher E&P spending in 2007. Almost 72% of those companies are planning double-digit increases. Based on a number of considerations, we would not be surprised to see industry capital spending grow by something in the mid double-digits. Even with this magnitude of spending increase, we expect rig availability to ease and the pressure on oilfield service inflation to moderate, also.

Were PSAC Presenters In Denial About Market?

Producers suggested that the cost of drilling rigs and oilfield services would soon be dropping after years of steady increases due to the activity declines

The week before last, the Canadian oil and gas producer and service industries held their annual investor conferences. While positive about long-term industry fundamentals, a number of producers used their conference presentations to discuss activity cutbacks they were making to counter the fall in natural gas prices. Producers also suggested that the cost of drilling rigs and oilfield services would soon be dropping after years of steady increases due to the activity declines. According to an article in the business section of *The Globe and Mail*, the three leading drillers in Canada were all suggesting that oilfield costs were heading lower due to the collapse in gas prices.

It was clear that the producers were using their conference and the attendant media attention to send a message to their contractors. Executives of EnCana Corp. (ENE-TSX), Canadian Natural

Last fall when drilling budgets were being planned, natural gas prices were around $15 per Mcf

Resources Ltd. (CRL-TSX) and Talisman Energy Inc. (TSL-TSX) all commented on the impact of falling gas prices relative to their budgetary planning that was forcing them to cut their drilling programs. Last fall when drilling budgets were being planned, natural gas prices were around $15 per Mcf. They now have fallen to a low of $6 per Mcf in recent weeks. According to Jim Buckee, CEO of Talisman, "I've heard it said that rigs are becoming more available."

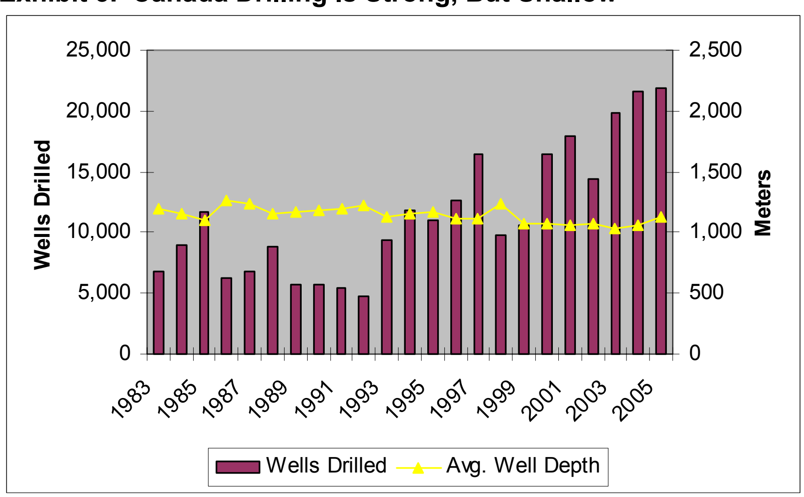
Confirming, or hoping to accelerate the softening, EnCana CEO Randy Eresman said, "We're starting to see it." As the largest driller of wells in Canada, one would think it alone could impact oilfield activity. Earlier this year, the company announced it was cutting its budget by $150 million. However, when examined, the expenditures it reduced had limited impact on Canadian activity since EnCana farmed out most of the targeted acreage.

When asked how far rig and service costs could fall, Mr. Eresman said, "I don't know how far it can go. I can tell you it rose 15 percent year over year, and 15 percent the previous year, so you would expect the rollbacks could be as significant." John Langille, vice-chairman of Canadian Natural said, "I wouldn't be surprised if a lot of other companies don't start doing similar things too. When you get that happening, obviously the service companies aren't as busy and obviously their costs will start coming down."

Mr. Murray Cobbe, CEO of Trican Well Service, responded that he was more worried about the weather than possible spending cuts

Based on these comments, analysts began questioning the first panel of presenters at the Petroleum Service Association of Canada (PSAC) meeting about the impact of producer drilling cutbacks on future activity and profitability. Mr. Murray Cobbe, CEO of Trican Well Service Ltd. (TCW-TSX), responded that he was more worried about the weather (it was raining quite hard that morning) than possible spending cuts. Other presenters pointed to new long-term contracts for equipment and services that they felt would carry their company through any activity slowdown.

Exhibit 3. Canada Drilling Is Strong, But Shallow



Source: CAODC; PPHB

The average well depth in Canada has averaged just short of 1,100 meters, or about 3,600 feet, over the past ten years

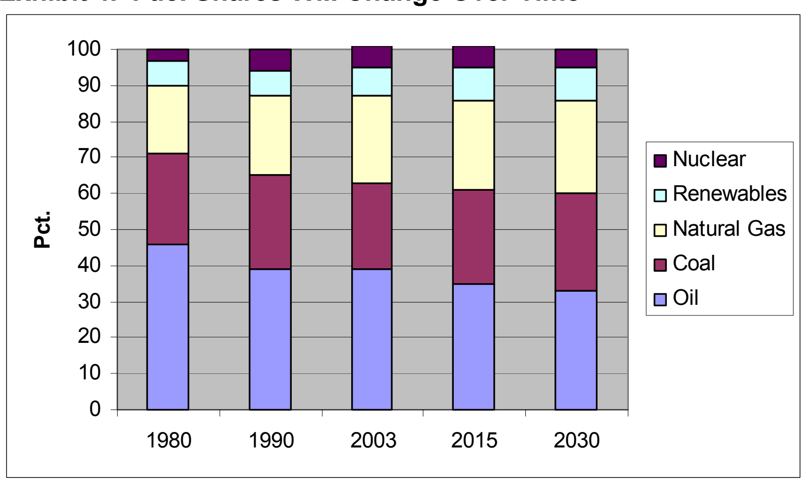
When pressed about what he was hearing from his customers about potentially reduced activity in shallow drilling, Ken Mullen, CEO of Savanna Energy Services Corp. (SVY-TSX) made two of the best, and most astute statements, we've heard in a long time, all based on his experience in the industry. First, in response to what his customers were saying, he said, "Let's face it, we're the last know anyway." We would observe that that comment is not totally correct. The last people to know are the equipment providers to the drilling companies. But on the issue of cutbacks in shallow and coal bed methane drilling, Mullen commented, "The last time I looked, all of Canada was shallow." He is correct as drilling data shows that the average well depth in Canada has averaged just short of 1,100 meters, or about 3,600 feet, over the past ten years. That's shallow in anyone's book.

Reality Sets in At the EIA

The EIA acknowledged that high crude oil prices are having, and will continue to have, an impact on oil demand, and more important, on the relative growth rates for demand for other fuels – most particularly coal

The Energy Information Administration (EIA) issued its *International Energy Outlook 2006* forecast to 2030 on June 20. The forecast for world energy demand growth remains bullish, although this forecast appears to have a larger dose of reality built in to its projections than recent forecasts. The reality reflects the EIA's acknowledging that high crude oil prices are having, and will continue to have, an impact on oil demand, and more important, on the relative growth rates for demand for other fuels – most particularly coal. Under the EIA's forecast, oil's share of world energy use falls from 39% to 33%. Nuclear joins oil in losing market share under this forecast while coal, natural gas and renewables gain.

Exhibit 4. Fuel Shares Will Change Over Time



Source: EIA, PPHB

According to the forecast, world marketed energy consumption will grow at an average rate of 2.0% per year from 2003 to 2030 due to robust global economic growth. This growth comes despite the

The EIA forecast that world oil prices will remain between $47 and $59 per barrel in real 2004 dollars

EIA's forecast that world oil prices will remain between $47 and $59 per barrel in real 2004 dollars. The economic growth is projected to come primarily from non-OECD countries. Combined, the non-OECD countries are projected to have economic growth, measured by gross domestic product in purchasing power parity terms, of 5.0% per year on average. This rapid growth is in contrast to the EIA's projected average annual economic growth rate of 2.6% for the OECD countries.

Due to the high rate of economic growth, total non-OECD energy demand is projected to grow over the period by an annual average of 3.0% compared to OECD growth of only 1.0%. The low rate of OECD energy demand growth reflects the more mature nature of their economies, the well-established infrastructures and the shifting focus of economic activity away from energy-intensive industries in favor of more service businesses. Within the non-OECD market, Asia, including China and India, should grow by an average of 3.7% per year, 2.8% per year for Central and South America, 2.6% for Africa, 2.4% for the Middle East and 1.8% for non-OECD Europe and Eurasia.

Worldwide, energy demand in the industrial sector should show the most growth averaging 2.4% per year

The EIA's new energy reality is reflected in its forecast of energy demand growth by end-use sector. Worldwide, energy demand in the industrial sector should show the most growth averaging 2.4% per year. Residential demand is projected to grow at only 1.7% per year while commercial demand should experience an annual average increase of 1.8%. The slowest growing sector will be transportation that is projected to increase at 1.4% per year. The EIA attributes this slow growth directly to high oil prices, since, as they point out, oil dominates this sector and there is no current widely available fuel substitute.

Oil consumption in 2025, the last year of the prior forecast, will be 8 million b/d lower in the new forecast, totally attributable to the impact on demand from high oil prices

The impact of high oil prices is shown by the EIA's projection for world oil use. According to the EIA, world oil consumption in 2003 was 80 million barrels per day (b/d), which should grow to 98 million b/d in 2015 and 118 million b/d in 2030. In this new forecast, oil consumption in 2025, the last year of the prior forecast, will be 8 million b/d lower in the new forecast, totally attributable to the impact on demand from high oil prices. However, even with lower demand in 2025, the EIA's new oil price forecast calls for a price per barrel 35% greater than projected in last year's forecast. The EIA is calling for the price of low-sulfur, light crude oil imported to U.S. refiners that averaged $31 per barrel (in 2004 dollars) in 2003 to rise to $57 per barrel in 2030.

The EIA's demand forecast translates into an average annual increase of 1.4 million b/d, but more significant is the amount of new oil that needs to be added merely to offset depletion

An interesting component of the EIA's forecast is its view of oil supply. Between 2003 and 2030, the world will need an additional 38 million b/d of oil production to meet the EIA's demand forecast. In simple mathematical terms, that translates into an average annual increase of 1.4 million b/d. But more significant is the amount of new oil that needs to be added merely to offset depletion. The global oil depletion rate used to be estimated at about 2%, but recently the rate has been increased to the 4%-6% range. In certain

At the new, higher depletion rates, we are looking at having to replace between 3.2 million b/d and 4.8 million b/d each year

circumstances the rate may be as high as 8%. Based on the old 2% depletion rate, the incremental oil needed to merely hold global oil production at the 80 million b/d level would be 1.6 million b/d. At the new, higher depletion rates, we are looking at having to replace between 3.2 million b/d and 4.8 million b/d each year. Put in other terms, to grow, we are looking at adding annually a new Kazakhstan, but merely to stay put, we need between a new Libya to a new North Sea every year. These volumes are not easily produced and will challenge the industry's capabilities.

62%, or 23.7 million b/d, will come from non-OPEC sources over the forecast period

The EIA believes that the world will get its new oil supplies predominantly from non-OPEC sources. Under its projections, 62%, or 23.7 million b/d, will come from non-OPEC sources over the forecast period. OPEC is expected to provide roughly 14.6 million b/d of new oil resources. One trend that will help meet our future oil supply needs is significant growth in unconventional resources, including biofuels, coal-to-liquids and gas-to-liquids. This category accounted for about 1.8 million b/d of supply in 2003 and is projected to supply almost 10% of the world's oil needs in 2030, or 11.5 million b/d.

The rise in fossil fuel prices, growing concern about energy security and new plant technology are driving a revival of the nuclear power business

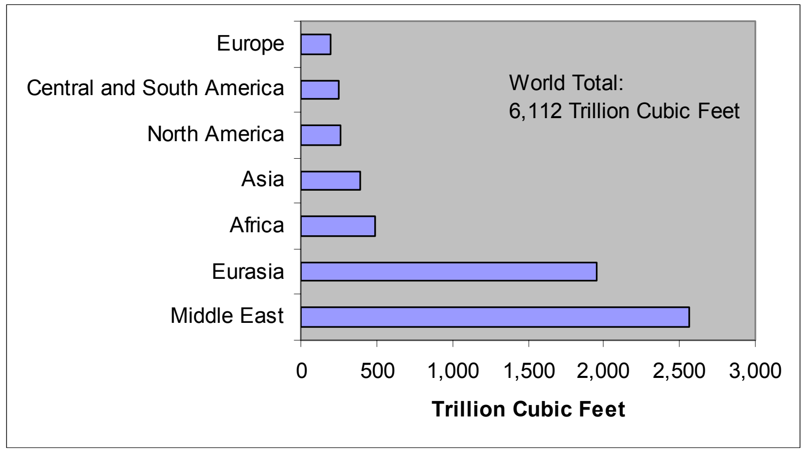
The growth of nuclear power is dependent upon electricity growth, which the EIA expects will more than double from 14,781 billion kilowatt-hours (kWh) in 2003 to 30,116 kWh in 2030. The amount of electricity generated from nuclear power worldwide increases from 2,523 billion kWh in 2003 to 3,299 billion kWh in 2030. The rise in fossil fuel prices, growing concern about energy security and new plant technology are driving a revival of the nuclear power business. The EIA projects that the world's nuclear capacity will increase from 361 gigawatts in 2003 to 438 gigawatts in 2030. Only Europe will likely experience a meaningful drop in nuclear generating capacity as several countries either have mandates to phase out existing nuclear power plants, or their old reactors are expected to be retired and not replaced. Leading countries anticipated to add nuclear generating capacity are led by China (33 gigawatts), Russia (22 gigawatts) and India (12 gigawatts).

Natural gas consumption will nearly double over the EIA's forecast period

Natural gas consumption will nearly double over the EIA's forecast period. The increase is driven by the growing importance of natural gas as a clean fuel source in the electric power and industrial sectors. Even though natural gas is highly valued for its attractive environmental qualities, worldwide consumption is projected to only grow at 2.4% per year annually, just slightly slower than the growth rate for coal. But gas does expand its share of the total world energy consumption, growing from 24% in 2003 to 26% in 2030.

Worldwide, natural gas growth enables it to overtake oil as the dominant fuel in the industrial sector by 2030. However, in the electric power sector, despite rapid growth, natural gas still remains a distant second to coal in terms of share of total energy use. These sectors help drive natural gas demand growth in the non-OECD countries. Gas demand is projected to grow at 3.3% per year annually in the non-OECD countries while growing by only 1.5% per year in the OECD countries. With this disparate growth rate, gas in the non-OECD countries accounts for 73% of the total world increment in gas consumption. Gas use in the non-OECD countries, excluding non-OECD Europe and Eurasia, increases from less than one-quarter of the world total in 2003 to 38% in 2030.

Exhibit 5. World Gas Reserves Support Production Growth



Source: EIA, PPHB

Natural gas supply has become a much more global business over recent years and is destined to become even more so in the future

Natural gas supply has become a much more global business over recent years and is destined to become even more so in the future. According to the forecast, natural gas supply from the OECD countries increases at only 0.5% per year on average while demand in these countries grows at a 1.5% per year rate. As a result, in 2003 when the OECD countries accounted for 52% of the world's total natural gas consumption, they produced 41% of the total natural gas production. In 2030, the OECD countries are projected to account for only 25% of the total world's natural gas production and 40% of its consumption. Obviously, increased supplies of natural gas will have to be imported by OECD countries, either through pipelines or as liquefied natural gas (LNG). In 2004, there were only 12 LNG-exporting countries, but that list is growing. In 2005, Egypt joined the LNG exporting club along with Russia, but not with LNG it produced, but rather with LNG it swapped for pipeline gas. Russia will not enter the LNG exporting market until 2008 when the Sakhalin liquefaction project starts up. Norway and Equatorial Guinea have LNG terminals under construction and Peru is starting to build an export facility, also.

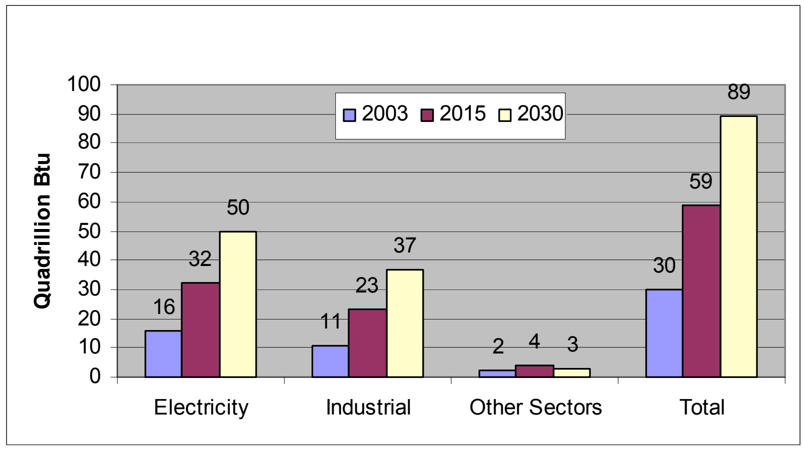
On the LNG importing side, the United Kingdom, which was a gas importer some 30 years ago, has returned to the LNG importer ranks. China, Canada and Mexico all have their first LNG import terminals under construction. Germany, Poland, Croatia, Singapore and Chile are among other countries considering their first degasification terminals.

The most dramatic market change in this new forecast is for coal. The dynamics of the crude oil and natural gas markets have

In 2003, coal accounted for 24% of total world energy consumption. That market share grows to 27% in 2030

positively impacted the economics for coal and new technologies are making coal less of an environmental issue. World coal consumption is projected to increase from 5,440 million short tons in 2003 to 10,561 million short tons in 2030. However, the growth in coal consumption is much faster (3.0% per year on average) for the first part of the forecast period (2003-2015), slowing to about two-thirds of that rate in the second half (2.0% per year). In 2003, coal accounted for 24% of total world energy consumption. That market share grows to 27% in 2030. About 81% of the increase in coal volume is accounted for by demand growth in non-OECD countries.

Exhibit 6. China Will Use More Coal For Industrial Uses



Source: EIA, PPHB

Coal's share of world energy consumption by sector shows a stable portion of the electric power market at 41% in both 2003 and 2030. The fuel's market share growth occurs in the industrial sector as coal goes from 19% in 2003 to 23% in 2030. This market share expansion is driven primarily by Chinese demand. In 2003, nearly 45% of China's coal use was in the non-electricity sectors, primarily in the industrial sector because the country has only limited reserves of oil and natural gas. Based on the forecast, Chinese demand for coal in non-electricity sectors is expected to nearly triple, growing by 26.1 quadrillion Btu. Despite this dramatic growth, the non-electricity share of total coal demand remains close to the 2003 level.

China is actively promoting the use of new coal technologies to exploit its indigenous resources, as the country will be relying increasingly on imports to meet its growing oil and gas needs

China is actively promoting the use of new coal technologies to exploit its indigenous resources, as the country will be relying increasingly on imports to meet its growing oil and gas needs. The first Chinese coal-to-liquids plant is scheduled to come on stream in mid-2007. The 60,000 b/d plant is being constructed in the Inner Mongolia Autonomous Region. Another group is examining the feasibility of building two 80,000 b/d plants.

What struck us about the new EIA forecast is the admission that current high crude oil prices, and recently high natural gas prices, are having an impact on demand for these fuels. The result is a forecast for less demand and higher sustainable commodity prices.

The greatest weakness in the EIA's forecast may be its oil supply forecast

These trends make the interaction among the various global fuels – oil, gas, coal, nuclear and renewables – more dynamic. While increasing the forecasting difficulty by some multiple, attempting to capture the interactions, logistical challenges and institutional impediments for these various fuels to easily satisfy multiple market needs gives the forecast more substance. The greatest weakness in the EIA's forecast may be its oil supply forecast, but then that's what the debate about Peak Oil and depletion rates is all about.

Wonder Where the Money Went?

With global oil prices hovering around $70 per barrel, many people are wondering why ExxonMobil, and many of its compatriots, is so miserly with its reinvestment cash

Exxon Mobil Corp. (XOM-NYSE) is sitting with roughly $28.6 billion of cash on its balance sheet – substantially more cash than it has long-term debt ($8.0 billion). In the first quarter of this year the company generated over $9 billion of free cash flow and spent $4.8 billion on capital expenditures. According to the latest Lehman Brothers oil and gas industry mid-year capital spending survey, ExxonMobil has stepped up its 2006 internationally-focused capital spending plans by $750 million to $11.85 billion. However, even with the revised budget, the company only plans an overall hike of 6.2% in spending to $14.6 billion. With global oil prices hovering around $70 per barrel, many people are wondering why ExxonMobil, and many of its compatriots, is so miserly with its reinvestment cash.

Lord Browne would make the most famous forecasting obfuscator, Alan Greenspan, proud

Maybe the answer to the reinvestment question is emerging. One possibility is that ExxonMobil executives don't expect current high oil and gas prices to last. That certainly seems to be the view of BP's chairman, Lord Browne, who recently told an investment group that he sees oil prices in the $40s in the intermediate term and long-term in the $25 per barrel range. However, he said that he doesn't see anything to drive prices lower in the near-term. Lord Browne would make the most famous forecasting obfuscator, Alan Greenspan, proud. Browne never defined near-, medium- or long-term for his audience, causing BP's PR department to have to rush out a statement that the company didn't see lower oil prices before 2010.

According to a recent story in *Business Week*, ExxonMobil has a huge employee pension fund shortfall – the largest of major U.S. corporations at $11.2 billion at December 31, 2005

Another explanation for the lack of a significant investment increase is the dearth of opportunities of the magnitude that could impact ExxonMobil's oil and gas production volumes and its earnings. Then again, maybe it's ExxonMobil's pension plan funding. According to a recent story in *Business Week*, ExxonMobil has a huge employee pension fund shortfall – the largest of major U.S. corporations at $11.2 billion at December 31, 2005. The shortfall is determined using generally accepted accounting principles (GAAP) that are more onerous than government accounting rules in measuring the gap between obligations and assets. An ExxonMobil spokesman said that the company is in compliance with all government rules and regulations and that it has the wherewithal to meet its funding obligations, but chooses not to put more money into its pension plan despite the company being flush with cash. Management and the employees are relying on the strength of ExxonMobil and the probability of continued high oil and gas prices, i.e., earnings and cash flow, to meet its future pension obligations. Is that a risk?

The employees are probably safe betting on ExxonMobil, given its AAA credit rating and long history of financial strength and performance

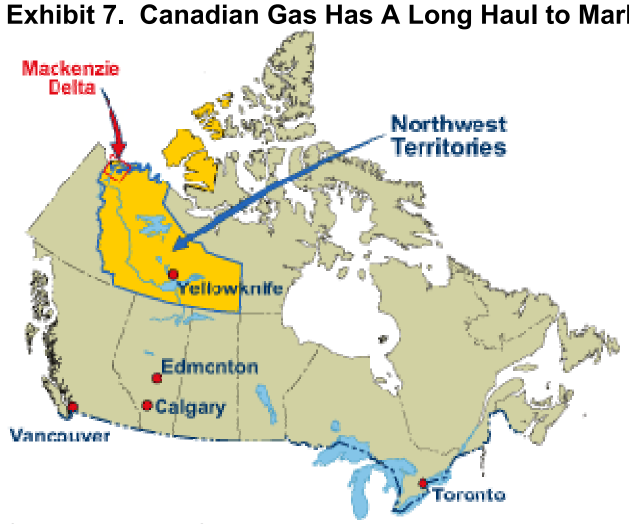
The employees are probably safe betting on ExxonMobil, given its AAA credit rating and long history of financial strength and performance, but one only has to remember that the energy business is cyclical. What's up one day may be down another. While the outlook today for the energy business appears bright for as far as one can see, we need only remind you that Enron once was the 7th largest U.S. company; that WorldCom had the most impressive array of telecom assets; and that Montgomery Ward was profitable for 100 years before it filed for bankruptcy. Maybe the employees are the reason ExxonMobil isn't spending its cash horde.

Mackenzie Pipeline Project Pauses

The cost to build the Mackenzie line has already jumped 50% from the original estimate to C$7.5 billion

Negotiations between the oil companies and the Canadian government over building the Mackenzie Valley natural gas pipeline have paused. Imperial Oil Ltd. (IMO-TSX), the leader of the consortium of five oil companies planning to build the 1,220-kilometer long pipeline from the Beaufort Sea to northern Alberta, has called a halt to the negotiations with the government because they are concerned about the escalating cost to build the line. Until they have developed a revised cost estimate, the pipeline owners believe it is not appropriate to negotiate the fiscal terms under which the line will be constructed and operated. According to the latest information, the cost to build the Mackenzie line has already jumped 50% from the original estimate to C$7.5 billion. Further cost escalation of materials due to the global inflation in steel and labor costs as a result of the substantial oil sands construction is what is creating the problem.

Exhibit 7. Canadian Gas Has A Long Haul to Market



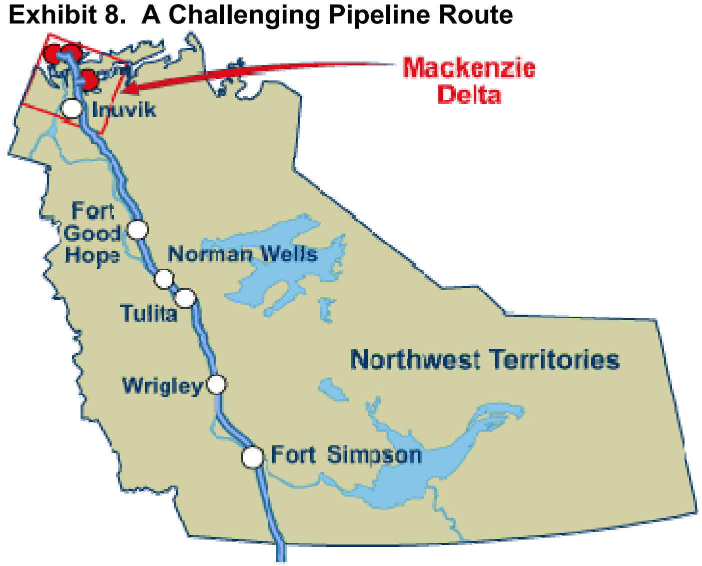
Source: Mackenzie Gas Project

Imperial Oil representatives say that it will take up to six months to develop better cost estimates. Mr. Randy Broiles, senior vicepresident of Imperial's resources division said, "We've paused discussion with the government right now, to let us do the homework we need to do on the cost side." The issue will be how much more financial help the pipeline consortium will want from the federal government. According to Mr. Broiles, "Mackenzie has been a thin project from the beginning, and with more cost pressure, that's bad news." Imperial hopes to have the updated cost estimates by December when the National Energy Board holds the last in a series of hearings on the pipeline in Inuvik in the Northwest Territories.

Imperial has already looked at ways to rein in the cost of the pipeline project

Imperial has already looked at ways to rein in the cost of the pipeline project. They are examining a strategy of building components for various production facilities located near Inuvik elsewhere, such as Korea or Japan, and shipping them by sea rather than transporting them piecemeal down the Mackenzie Valley. This would reduce the amount of fabrication work required to be performed in Canada. Another cost-cutting possibility Imperial is looking at is stretching out the construction effort over three summers rather than two. That would ease the labor situation, but it would delay the startup of the line with a cost that will need to be factored into the equation.

Exhibit 8. A Challenging Pipeline Route



Source: Mackenzie Gas Project

If the long-term outlook for natural gas prices has changed, then the wellhead price for Mackenzie Valley gas will be lower than previously anticipated

With current low natural gas prices in North America impacting some shallow drilling and coal bed methane drilling, pipeline economics have to be re-examined along with the costs. If the long-term outlook for natural gas prices has changed, then the wellhead price for Mackenzie Valley gas will be lower than previously anticipated. If that is the case, and the pipeline owners have to seriously examine that potential, then they will be counting on increased financial aid from the Canadian government. The debate about gas prices this fall will certainly play a role in the pipeline owners' thinking. It is not surprising that Imperial Oil is suggesting it will not be ready before the end of the year to discuss the economic issues of the pipeline.

Publicity You'd Rather Not Have: Nabors Industries

Nabors Industries is seeking a change in legislation granting the company a permanent exemption from a provision of the Jones Act regulating ownership of supply vessel companies operating in U.S. waters

A story on the front page of the Business Section of Friday's *New York Times* was titled "Drilling Firm Seeks Favor As Expatriate." The story detailed efforts by Nabors Industries (NBR-NYSE), officially headquartered in Barbados with a tax status in Bermuda, seeking a change in legislation granting the company a permanent exemption from a provision of what is known as the Jones Act that regulates ownership of supply vessel companies operating in U.S. waters. Nabors has hired a top-notch tax lobbyist in Washington, D.C. to make the company's case for extending a temporary exemption into a permanent one, which is included in legislation about to be voted on by Congress.

The Jones Act, enacted in 1920, was designed to protect the health of the U.S. maritime industry under the banner of national security. The act requires that all ships moving people and cargo between domestic ports be American-owned, American-built and manned by Americans. The act restricts foreign, i.e., non-American, ownership of these type assets to less than 25%. Publicly-owned companies constantly monitor their stock ownership to prevent more than 25% of the shares being held by foreign shareholders.

In 2001, Nabors re-incorporated in Barbados to reduce its tax burden enabling it to compete more effectively in international drilling markets

In 2001, Nabors re-incorporated in Barbados to reduce its tax burden, enabling it to compete more effectively in international drilling markets. Abroad, Nabors' foreign-based competitors are not taxed on their worldwide profits as American companies are, putting then America-based Nabors at a disadvantage in bidding for drilling work. After extended negotiations with its domestic marine vessel competitors, Nabors secured a two-year exemption from the Jones Act for its supply vessel division. That exemption expires in 2007. The attempt to change a clause of the law to make the temporary exemption permanent is part of the Coast Guard spending authorization legislation about to be voted on by Congress. (This same bill also contains language impacting the approval of the Cape Wind wind farm project in Nantucket Sound.)

The purpose of the Jones Act is to support our domestic shipbuilding industry and our merchant marine people

The purpose of the Jones Act is to support our domestic shipbuilding industry and our merchant marine people. U.S. ships and shipping labor tend to be more expensive than foreign alternatives. Without the Jones Act, the belief is, the U.S. would eventually lose its shipbuilding capacity and its maritime labor force. Foreign governments refer to the Jones Act as protectionist legislation, which they find hypocritical in light of U.S. efforts to open closed markets around the world to foreign (U.S.) trade.

The most recent flap over possible efforts to circumvent the Jones Act was a few years ago when Rigdon Marine used financing from a French offshore support vessel company, Bourbon, to build a fleet of new, state-of-the-art supply vessels for the Gulf of Mexico market. This battle has been diffused recently as Rigdon Marine secured domestic financing and Bourbon became a less-than 25% owner of the company that is in compliance with the Jones Act.

We remember an interesting situation back in the 1980s when the oil industry wanted to drill an offshore well in the Beaufort Sea off Alaska. The oil company needed ice-breaker supply vessels and there were no American-built ones in existence at that time. To get around the Jones Act restrictions on using foreign-owned, -built and -manned vessels, the oil company hired a supply ship to store all its well supplies. The storage vessel, referred to as the "mother ship," would sail around in the Beaufort Sea while the well was being drilled. The ice-breaking supply vessels would pull along-side the mother ship and the two would sail in tandem. The mother ship would load up the supply vessel with drilling materials and supplies, which the smaller vessel then delivered to the drilling rig. Under U.S. law, the drilling is considered a domestic port while it is on location. The mother ship, because it was in constant motion, was not considered a port. Therefore, the supply vessels hauling the supplies were going between a foreign port and a domestic port, eliminating the need for U.S. supply vessels.

If times weren't so good in the offshore oilfield service industry today, we suspect that Nabors would sell the business and move on

If times weren't so good in the offshore oilfield service industry today, we suspect that Nabors would sell the business and move on. Probably no one wants to pay Nabors what it thinks its marine vessel business is worth. The next industry downturn will probably cure the roadblock to a deal.

Energy Bits

Norway Offshore Oil Industry Goes On Strike

Oilfield workers who are members of the Norwegian Oil and Petrochemical Workers Union went on strike last Wednesday after deadlocking in their contract negotiations with the Norwegian Oil Industry Association. Statements from the negotiators suggest the strike could last weeks, or even months. At the moment, offshore production from the third-largest crude oil exporter has not been impacted, but it will be if the strike goes on for a while. What is being impacted is offshore drilling and well completion activity. Since time is a serious constraint for drilling in Norway due to its location and weather conditions, delays will take a toll on the industry. In the past, the government has stepped in to settle the strike when it became evident the oil industry and the local economy could be hurt by its continuation. We'll wait and see when Norway acts.

China Moves Forward on Coal-to-Liquids Projects

Agreements have been signed between South Africa's Sasol (SSL-NYSE) and two local Chinese coal companies to move forward with second-stage feasibility studies to assess the viability of an 80,000-b/d potential coal-to-liquids plant about 650 kilometers west of Beijing and another similarly sized plant about 1,000 kilometers west of the city. The pre-feasibility studies showed that all the necessary drivers to make the projects viable were present. Each plant would cost $5 billion and if they go forward will not be in service until about 2012.

European Wine Supply Problems

The European Union is considering making changes in its program to regulate the local wine making industry due to falling demand and tough competition from New World brands. The thrust of the plan changes is to pay wine growers to stop growing grapes used in low-quality wines. Other efforts will involve altering marketing restrictions to allow European wineries to extol information on the bottle about the grapes used in the wine.

For a number of years, Europe has turned surplus wine into bioethanol for use in cars and factories. We wonder why they don't just expand that program as a solution to their overproduction challenge. Maybe the Europeans have concluded that turning unwanted wine into transportation fuel is not feasible or economic. Could this have implications about the viability of ethanol as the savior for our gasoline crisis?

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