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For our summer issue we are looking at what appears to be the same subject from two different angles. The subject is the price of oil and we are looking, on the one hand, at the 'fundamentals' and, on the other, the state of the refining industry.

We have heard much about refining over the past few months. Whose fault is it if there is plenty of heavy crude available but insufficient facilities to refine it? One result, however, is that refining is generally more profitable these days than it has been for years.

Franz Ehrhardt gives us a concise overview of the situation. Globally, the excess refining capacity that we used to enjoy has been used up. Heavy crude is readily available and its price differential to light crude has been huge, but it is only refiners who have the requisite upgrading capacity who can make the large profits that are then available. Tightening product specifications and, particularly in the US, a multiplicity of regional regulations have exacerbated the situation for refiners. Ehrhardt also draws attention to the role of operating costs and efficiencies and affirms that alternative fuels can only help at the margin for at least the next decade or two. The outlook for refiners is healthy.

Douglas Terreson tells much the same story and reckons this to be the Golden Age of Refining. This results from the combination of supply, demand, environmental and logistical elements. Incremental demand for product is likely to exceed incremental supply, margins will be high, and those with heavy crude upgrading capacity will benefit. New environmental standards will give further advantage to those who have the technology to meet them. He sees no immediate end to the pressures building on tight crude demand, nor does it seem probable that upgrading facilities can be provided in sufficient quantity. The Golden Age seems likely to persist.

Marshall Hall is more cautious about the mid-term outlook for refining profitability. He points out that the 2004/5 prices resulted in a simultaneous mismatch at the margin in both crude and products margins, and is less certain than some analysts that refining margins will necessarily continue at the 'golden' level, pointing out the special elements that have conspired to provide the high profitability of the

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past years. He also questions the claim that the refining industry has underinvested, and thinks that the current increase in conversion capacity under construction or planned may well mop up the demand for light products within the next year or two.

If refining capacity, or lack of it, has had its part to play in the formation of oil prices in the recent past, the fundamental imbalance of crude supply to product demand is more usually picked on as the main problem. Even so, it has not been clear whether the sudden jump of price to the $50 and $60 level reflects a new price band or whether it should be seen as another 'shock' of the 1979 variety.

Katherine Spector concentrates her attention on the way in which energy is traded and gives us an analysis of the market and its players. She makes the point that financial futures do not predict future prices, but at the same time asserts that what was a market dominated by energy producers and consumers is now influenced by financial players. She describes who these players are and looks at the role of institutional investors and investor products. She concludes that the increase in buyers of energy products has coincided with a decline in hedging by producers.

David Long provides us with what might be described as a more traditional analysis based on investment in crude supply, potential demand worldwide, and the strategies of OPEC and international energy companies. For the companies, they are faced with decisions on risk, but also with a lack of opportunity, while OPEC, which has not had much incentive to invest in the recent past, is now constrained by field declines and long-term uncertainties. His conclusion is that higher prices are probably here to stay, although, in these days when energy efficiency is high on the agenda, maybe this is no bad thing.

Paul Horsnell is sure that the new higher price level is here to stay, that it is in fact an adjustment towards a sustainable long-term price level. On the supply side he points out that non-OPEC has a greater share that is declining more quickly, on the demand side that growth is now in the hands of non-OECD which wants to catch up. The higher price of oil should not be described in terms of a 'shock'.

Our other article is by Anouk Honoré who gives us an interim look at one aspect of the Institute's Natural Gas Research Programme. She analyses the importance of power generation on the demand for gas in the EU, and her general conclusion is that, despite the new Directives on Emission Trading and Large Combustion Plants, gas demand is unlikely to increase at the rates which have been assumed for it by most forecasters in the last few years.

Personal Commentary has been contributed by Julian West who has taken a look at Research and Development, and wonders whether the industry, which has played an insufficient part in developing new technology over the recent past, may perhaps be investing in it more seriously. He is looking for innovation in this area and is uncertain for the moment whether he should hope it's coming or should fear it isn't.

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Refining and Price

Franz B. Ehrhardt looks at core issues, challenges, and opportunities

Over my career I have written and delivered a number of articles and speeches on refining and other downstream issues. In general, the main theme has been to explain why, despite returns that were mediocre at best, there was still a strategic value in keeping refining as an integrated asset. This is the first time that I have the pleasure of starting from a platform of general earnings levels that I cannot remember having seen before.

While the attractive earnings generation in refining is likely to continue for at least the next 3–5 years, there are a number of strategic issues that need to be addressed and deserve serious consideration.

Global Refining Capacity

By the end of 2004, global refining capacity was at about 82 mb/d with .35 million added that year. Using a practical global average utilisation rate and adding fuel generated from gas liquids and condensates, as well as from coal, natural gas, and agricultural products, the total produced petroleum products matched the range of the indicated existing demand of 81.5–82.5 mb/d. This, however, exhausts the system's capability to meet the further increases in demand projected for this year and in the future, a situation we have not experienced before.

It is clear that the excess capacity which existed until about 1999 has been swallowed by the recent strong expansion in demand and that it will cause a global refinery shortfall from anywhere between 1.5 to 2.5 mb/d (and possibly much more) through at least the next 3–5 years, which is the shortest time-span to bring adequate new capacity on stream. This substantial increase in refining capacity is needed for Asia to supply the emerging consumption mammoths in the region, particularly China and India.

Beyond that, the IEA estimates that the required investment capital for creating longer-term adequate global new refining capacity between now and 2030 can easily be between $350 and $400 billion. This suggests that a significant share of the attractive cash flow presently being enjoyed by refiners needs to be earmarked for these expansions.

It must also be recognised that such expansion will face tremendous challenges and delays in the USA and in Europe stemming from environmental concerns, regulations, and resistance to grass-root refinery construction.

The Matter of Heavier (sour) Crude Oil

While heavy sour crude is in long supply, the energy world is facing a substantial challenge in that the production of relatively easier refinable, light, low sulphur crude oil is in a continuous and irreversible decline quite below the demand level of those refiners that can presently process this high quality crude oil, thus creating idle capacity.

As experienced, this results in a considerable premium for high quality sweet crude oil which significantly widens the price difference to the more abundant heavier sour grades, thus making it much cheaper.

These differences have reached astounding levels. For instance the Maya crude to WTI differential has frequently been around $16 which is far above the level needed for an attractive rate of return on the relevant investment to process heavy sour crude. While these differentials are likely to settle lower than the recent peaks, they will certainly be considerably higher than what has been experienced in the past.

A major challenge, though, is that the plentiful, very heavy and sour crude oils, i.e. Maya, generate around 60 per cent of very low value heavy bottoms, like fuel oil, and medium sour crude still delivers about 50 per cent of heavy residual.

This contrasts with an average residual conversion and upgrading capacity in refining in the USA of about 70 per cent, in Europe 45–50 per cent, and in Asia 25–30 per cent. The combined result is that the world is flooded with fuel oil that in the best case almost never returns the cost of the crude feed and the processing cost – and in the worst case generates significant losses.

Those refiners, however, that have installed heavy sour crude oil processing capability *and* substantial bottoms-upgrading capacity like hydro-crackers and especially delayed cokers are now enjoying, and will continue to do so for some time to come, an amazing bonanza of earnings.

Delayed coking has always produced highly attractive economics as companies like ExxonMobil, ConocoPhillips, which is also a delayed coking licensor, and Shell have experienced over a long time. The latest market conditions, however, have far exceeded even the most optimistic assumptions.

The heavy sour processing and delayed coking pioneer among the independent refiners, Valero of the USA, is quoting, for example, that their recent investment of $350 million in the Texas City coker contributed about $200 million in 2004 alone – suggesting a pay-back period of less than 2 years. Actually, for 2004 Valero delivered an overall return of 98 per cent on shareholder equity.

The coming major challenge for refiners is to process the lowest quality, lowest cost crude oil available into the highest value products in demand. This, unquestionably, strongly suggests considering the inclusion of heavy sour processing and full bottoms-upgrading capabilities. The recent announcement of ConocoPhillips to invest $3 billion in this sector clearly supports this point.

Tightening Product Specifications and Product Shifts

The increasing global demand for cleaner fuels poses substantial challenges for refiners. While the technologies are certainly available to meet those requirements ultimately, significant investments will be required; however, there will be considerable difficulty to recover these from the market place in the foreseeable future.

Let us take a look at some of the most notable changes in Europe and the USA.

Maximum sulphur content in gasoline in the USA will have to drop from 300 ppm in 2003 to 30 ppm in 2006 and in Europe from 160 ppm in 2003 via 50 ppm in 2006 to 10 ppm beyond that.

For diesel fuel, the sulphur content needs to be lowered from the present 500 ppm to 15 ppm in 2006 and beyond with the corresponding number in Europe from 350 ppm to 10 ppm

The previously discussed increase in supply of heavier high sulphur crude oil will certainly add tremendous complexity to this challenge for sulphur removal.

Another major problem is the greatly varying timetable of the introduction of tightened fuel specifications in many parts of the world which substantially complicates the logistics of economically feasible product supply, especially for the merchant refiners.

In the USA, for example, inconsistent regulatory changes are also limiting the most economic regional supply capabilities. For instance, the disconnected push by many individual state governments for state-specific fuel specifications results at present in 18 different gasoline specifications alone. For example, the outcry by Californians that their gasoline prices have reached rip-off levels is the result of the tightest and most advanced specifications that can be met by very few refineries – and they are unable to produce the demand in those boutique products. While there is plenty of gasoline that could be brought into California from other regions of the USA, as well as imports, these tight California specifications just do not permit such a relief.

The ever increasing regulatory demand for cleaner fuels is also contributing to the tighter refining capacity. While technology and processes are certainly available to achieve this objective with substantial investments, one has to realise that the production of such cleaner fuels can easily reduce the resulting finished product slate by 5–6 per cent of the crude oil input.

Environmental Implications

Environmental protection, preservation, and remediation are major challenges for global refiners, and laws, regulations, and enforcement still vary widely throughout the world. The overall thrust, though, is toward achieving global standardisation and full compliance.

This development will require from refiners substantial additional investments for the reduction of all emissions into the air and ground water, as well as for the remediation of previously contaminated soil.

For example, in the USA alone, the industry is likely to have to invest over $20 billion for compliance with Tier II. It will be difficult to recoup these investments in the short term from the market place.

One more point on this issue. As stated earlier, the ever increasing power of environmental laws, regulations, and public sentiments will make it extraordinarily difficult to develop the urgently needed new refining capacity in the USA and in Europe. Therefore, this leaves that development to less regulated countries outside those two regions.

Operational Excellence

Another challenge for refiners is the continuous increase of operating costs. While, for the time being, the prevailing processing margins deliver quite attractive earnings that easily offset such rising costs, for most refiners there are still substantial opportunities to identify and apply efficiency improvements that not only mitigate cost increases but are of a magnitude that can make considerable contributions to the bottom line.

The existing gaps between the operating standards, best practices, and efficiencies employed by the global benchmark refining companies and the rest of the field can reach up to 30–35 per cent. An example of one of our recent analyses for a 130,000 b/d refinery identified a range of between $64 million and $98 million potential annual improvements just from operating efficiencies with no or very minimal capital investments. This translates to about $1.3–2.0 per barrel. The areas of improvement include energy efficiency, yield optimisation, operational and turnaround maintenance, reliability and uptime improvements, capacity creep, working capital management, general operating excellence, and safety, occupational health, and environmental stewardship.

“the excess capacity which existed until about 1999 has been swallowed by the recent strong expansion in demand ”

A mindset of rigorous pursuit of identifying and applying global best practices in every aspect of refinery operation will certainly bring rich financial reward and make a substantial contribution to strengthening the competitive position.

Lowering Consumption?

Since reduced consumption resulting from rising prices is often suggested as a significant potential element of relieving the refining production shortage, it may be useful to consider this subject.

Significant price increases for crude oil and, therefore, for motor fuels have failed in the past to create a sustained reduction in consumption. After a few temporary slow-downs, the demand has picked up again at a normal pace. It is highly unlikely that this will change in the future.

The Europeans have been used for quite a long time to $70–80 a barrel crude oil, thanks to the prevailing taxation on motor fuels. Presently, gasoline is sold within a range of $5.5 to $7.0 per gallon with demand still on an incline, also helped by the economic growth in Eastern Europe.

For the US consumer, complaining loudly at $2.0 to $2.50 per gallon, there is not in fact much choice about making considerable reductions in consumption. Because of the size of the country, the driving distances are quite long, urban and suburban sprawl is not conducive to fuel-effective mass transit systems, and Americans just love their big cars and will forgo many other things before downsizing on a significant scale.

Then there is Asia, especially the population giants China and India which are displaying a seemingly unstoppable economic expansion. While Europe uses 50 BOE of energy demand per person per year and the USA 65, the same number for China is 5.3 and for India 2.5 (and, within that figure, only 1.7 and 0.7 respectively for oil alone). China has added 75 million motorcycles over the last 10 years bringing the total to 90 million, and the car population has grown during the same period from .7 million to about 7 million. China certainly has no incentive to slow down on the way to becoming the preferred global low cost manufacturer for everything imaginable, which also will fuel the desire – and the ability – of the individual Chinese to own motorised transportation. All of this will, of course, further heat up demand for refined products. Because of the population numbers, even relatively small consumption increases can easily draw .5–1.0 mb/d annually of motor fuel, placing more strain on the already challenged global refining capacity.

Emerging Alternative Motor Fuels

A few words are necessary regarding the potential of alternative fuels to provide relief for the tight demand situation. Ethanol, presently providing 0.7 per cent of US fuel requirements, is economically only feasible with substantial government subsidies. Even significant increases at a very high burden to the tax payer, cannot replace volumes of any importance. The same is true for Bio Diesel.

> "Another challenge for refiners is the continuous increase of operating costs"

A number of interesting developments have taken place with hybrid cars and hydrogen fuels. While certainly quite intriguing with appealing future potential, present reliability, feasibility, and economics, as well as public acceptance, they still have a long way to go before a market share can be reached that could provide some relief for fossil fuel-based products. Therefore, one has to accept that for the next 15–20 years the majority of fuels will be still be generated from crude oil.

There is, however, real potential in the conversion from natural gas to petroleum liquids, especially to diesel. The production of gas-based diesel can also be of considerable value in meeting the ever increasing ratio of middle-distillate demand which is more and more difficult for refiners to meet with the existing refinery configurations.

Conclusion

Based on the indicated fundamentals, and barring catastrophic events, one can assume with a certain degree of certainty that very attractive refining earnings, especially from heavy sour crude processing and full bottoms upgrading are likely to be with us for at least the next 3–5 years, perhaps more because of possible capacity constraints in engineering and construction companies, as well as in material availability.

As soon as refiners begin to believe in the sustainable stronger margins and in the need and opportunity to build new refinery capacity, they will face two key challenges. One is the often onerous regulatory and environmental restrictions and rejections; the other is the very limited availability of engineering and construction companies capable of building such new capacity. This capability was lost during the years of minimal new construction and requires quite a long lead-time to rebuild.

And finally, the ever increasing shortage of light sweet crude oil will support a continuing high premium for those grades while the more abundant heavy sour crude oil will be much more price competitive resulting in heavy sour differentials far above historic levels.

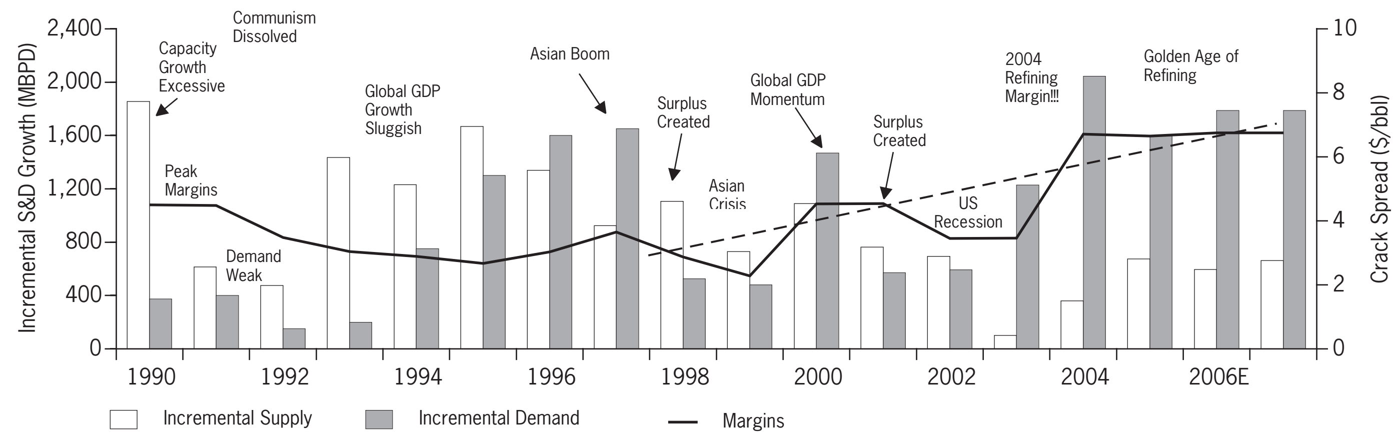
In the meantime, it is certainly rewarding to be in a relatively profitable refining business – at least for a while.

Douglas Terreson looks at the 'golden age of refining'

Positive performance by companies in the Refining and Marketing group has allowed the R&M sector to be the best performing sub-sector in the global energy complex on a year to date basis and during the past 1, 3 and 5-year periods. Nevertheless, profits are expected to be at their highest levels in two decades in 2005, with additional gains likely in 2006.

The drivers of the positive performance that we envision involve expectations that global demand for refined products will remain strong and, with modest growth in refining capacity, utilisation rates and margins are likely to remain unusually high in all major worldwide markets. To give a perspective, we forecast margins

Figure 1: Per Capita Oil Consumption and GDP Per Capita (1990–2007)



in North America of $6.65/bbl and $6.75/bbl in 2005 and 2006, for refiners of light-sweet crude oil compared to the average of $4.95/bbl during the past 5 years (Figure 1).

Another likely positive factor is that most major Integrated Oil and Independent R&M companies process lower-cost heavy-sour crude oils, and with the pricing differential between light and heavy grades of crude oil likely to remain near record levels in 2005 to 2006, margins for such refiners should remain positive as well. We also believe that spreads between light-sweet and heavy-sour crude oils bottomed for 2005 during the past few weeks, with significant gains likely through year-end.

Fundamental Outlook in Global R&M Remains Positive

The basis for our positive viewpoint regarding the global refining business emanates from our proprietary global assessment, which concludes that growth in demand will outpace that of capacity during the next 2 years by at least a 2:1 ratio. Our global assessment, which considers *every* refining project that is planned *or* under construction worldwide, is compared to our projections for growth in global demand, and is truly comprehensive. It includes information from three different global refining surveys that cover 2,800 different refining projects for the period 2005–08.

Supply/Demand, Environmental Policy and Crude Oil Fundamentals Supportive of Favourable Environment

Our conclusion is that growth in demand for refined products (4.7 mb/d) will significantly surpass gains in supply (1.9 mb/d) during the 2005–07 period, with the mismatch between gains in demand and supply similar in each individual year. We believe that utilisation rates and margins are likely to remain high in global markets for refined products, with other positive surprises ahead.

Additionally, a variety of new environmental regulations are set to be implemented in North America, Europe and Asia during 2005–06, which stand to be amongst the most significant in a decade. Apart from projected growth in light products demand, most of the new mandates require reductions in sulphur in gasoline and diesel. In this scenario, demand for light-sweet crude oil which requires less processing to meet tighter product specifications is likely to remain strong.

Combined with our view that incremental supplies of crude oil from both OPEC and non-OPEC producers will probably be heavier and more sour during 2005 to 2007, the differential between light and heavy crude is likely to remain wide. The investment implication is that refiners who are able to process the heavier crude oil grades will post strong financial results.

Importantly, our projections assume that refinery closures that might have resulted from the new, capital-intensive environmental regulations in Europe and North America will be negligible. Assuming that such marginal production will remain in the market over the intermediate term, cash break-even costs will rise for less efficient players. This may have important investment implications for industry margins.

We conclude that 'stay-in-business' investments, and higher operating costs, have increased 'cash break-even' costs for marginal producers in the US market by 20% during the past 5 years. Such a rise in the cost structure is likely to support the trend of 'higher-highs and higher-lows' in refining margins that has been in place since 1999, in that production is likely to be shut-in at higher margin levels than has been the case in years past. The trend of rising capital and operating costs, which has been present in the E&P business for many years, seems likely to apply to R&M through 2006.

New Sulphur Standards Could Materially Impact Supply

The US regulations involve requirements that gasoline contain less than 30 parts per million (ppm) sulphur (January 2006), and that diesel contain less than 15 ppm sulphur (June 2006).

Besides higher downtimes which are likely as US refining systems adjust to the new specification next spring, the environmental standards, which will be the most stringent in the world, will surely restrict imports. Blending of refined products that do not meet the new environmental specifications will prove a challenge, with lower refinery yields and operating rates likely during a period in which maximum production volumes will surely be needed.

Meeting the new diesel standard, which is set for June 2006, will prove even more challenging for the industry. As with the new gasoline standard, high downtimes are expected as refiners retrofit their systems. There will be significant logistical issues as well as the probability of lower yields, in that product degradation appears possible. Results from a recent test on the Colonial Pipeline system (the refined products pipeline that connects the Gulf Coast and the East Coast of the USA) confirm that supply and distribution problems may well materialise in 2006.

Refiners appear to have two options in order to comply with the new environmental specifications for gasoline and diesel. The first is to apply the sulphur reduction prior to shipment. The Colonial pipeline system has, for instance, recently specified a sulphur content of 8 ppm for its system. While this is below next year's national standard of 15 ppm, it is necessary in order to meet the new standard after shipment. The second option involves reprocessing or blending of contaminated shipments post the transportation phase. In either case, yields and operating rates in refineries are likely to decline in 2006, which in an import dependent market, such as the USA, is likely to give higher refining margins.

Crude Oil Fundamentals are Supportive of Wider Light/Heavy Differentials

In each of the three major refining basins of the world, North America, Europe, and Asia, returns in refining and marketing are likely to rise and to remain strong during the period 2005–07. The gains will be driven by healthy demand for refined products, especially light products, which, combined with a deceleration of growth in new capacity, should allow utilisation rates for conversion capacity to rise. This factor, along with our projection that demand for light-sweet crude oil will rise in relation to that of heavy-sour at a time when the major part of new supply is relatively heavy, suggests that the light-heavy differential will remain at high levels in coming years, supporting positive economics for refiners.

Our projections show that global petroleum demand will rise annually by 2.0 mb/d during 2005 to 2006. This represents the strongest two-year rate of growth since 1977. Moreover, 80% of this increase will be taken up by light products which are manufactured most efficiently by processing light-sweet crude. Demand and prices are likely to remain high.

While it has been questioned whether governments will proceed with the new environmental regulations as costs increase, we believe that they will. In the USA alone, the EPA estimates that industry costs will approximate $5.3 billion, but at the same time the related health and environmental benefits to be derived from the new regulations are estimated to be $25.2 billion.

It is equally important in our view that the supply of heavy-sour crude oil is likely to equate with that of light-sweet crude oil, both in non-OPEC and OPEC areas, during 2005 to 2006.

For non-OPEC, the incremental flows of light-sweet crude oil are expected to be surpassed by heavy-sour barrels in each year from 2003 to 2008. Furthermore, the areas of declining production tend to be those in which light sweet crude has been predominant. This has further exacerbated the light/heavy balance.

An equally important area of assessment for the spread between 'light and heavy' crude oils involves incremental flows from OPEC. The production group increases production of heavier-sour barrels as prices rise as they have the lowest profitability, i.e., higher cash operating costs. With more lower-quality barrels the market price typically widens in relation to lighter, sweeter output, with the opposite dynamic as barrels are removed.

Lastly, there is the question of upgrading capacity. In theory, if a sufficient increase in upgrading capacity were to be installed the demand, and therefore price, of heavier crude should similarly increase and the light-heavy differential decrease. However, investment in upgrading capacity at such a level seems improbable and our analysis is that the high light-heavy differential will continue.

Conclusion

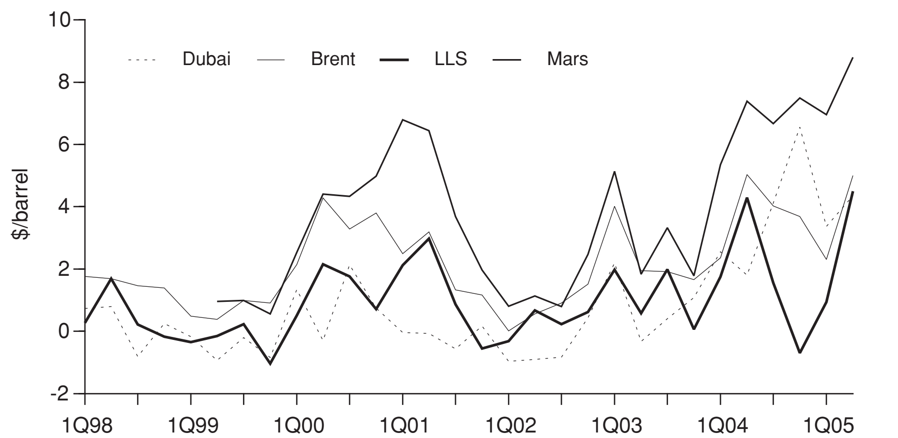
In summary, the 'Golden Age of Refining' appears to be with us, as supply, demand, environmental and logistical issues all provide positive signals for the downstream industry. With current capital spending plans emphasising clean-fuels specifications rather than increased capacity, the market is likely to stay volatile as supply shocks cause margins to stay above mid-cycle levels. With the futures market discounting margins of $8.00/bbl in 2006 and equity valuations discounting $5.75/bbl, there is significant upside potential for the downstream business model.

Marshall Hall looks at refining margins and investment

$50/bbl Crude Oil and Refining Capacity Constraints

After years of quiet neglect by most oil market commentators and policy makers, the refining industry burst back into the headlines in 2004. Suddenly, it found itself the

Figure 1: Quarterly Indicative Refining Margins 1998–2005



subject of investigations, speeches by central bankers and press releases from energy ministers. Investment in refining even forced its way into discussions at G8 meetings. Disagreement also emerged between producer and consumer governments over whether crude production capacity constraints were more important than refining constraints and over who was ultimately responsible for $50/bbl oil. As short-term capacity constraints revealed themselves throughout the oil supply chain, everyone discovered the importance of refining in oil price formation and energy security. What happened to provoke this sudden interest?

The short answer is that oil prices rose to record nominal levels at a pace which had not been expected and could not be explained by conventional analysis based on the observed relationship between prices and inventories. Moreover, OPEC appeared for a while to lose its influence over international crude prices. The origin of the run-up in the price of light sweet crudes above $50/bbl lies in a complex mix of structural, cyclical and one-off factors, which include financial market influences, notably the depreciation of the US dollar and the influx of new financial investors into energy derivatives. The over-riding 'fundamental' factor was the unexpected surge in worldwide demand for oil products, which revealed short-term capacity constraints at almost all stages of the supply chain. At the same time, the dramatic and unprecedented widening of light/heavy and sweet-sour price differentials in crude and product markets pointed to 'new' capacity constraints in refining and attracted the renewed interest of policy-makers, especially in the US.

The acceleration in demand growth in 2003–04, led by China, was heavily concentrated in light products and, notably, jet fuel and diesel. This coincided, by chance, with the first major tightening of US gasoline sulphur under the Tier 2 regulations, a further reduction in EU diesel sulphur at the end of 2004 and a very small net annual increase in worldwide conversion capacity. Since all existing conversion capacity was generally fully loaded, any incremental light product had to be produced from simple operations (normally straight run or hydroskimming), thereby increasing the output of residual fuel oil. This depressed residual fuel oil prices and widened the light/heavy spreads further.

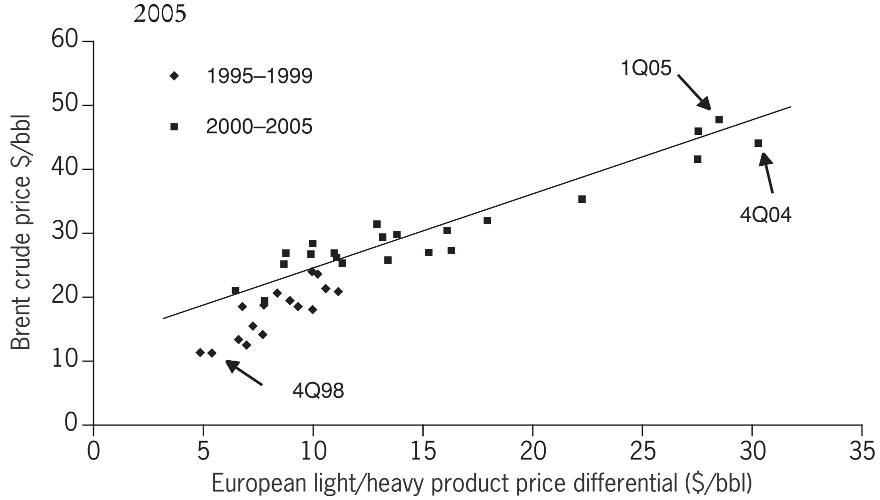
On the crude supply side, the only significant spare production capacity was of medium-gravity (27–34° API), high-sulphur grades from the Gulf, normally available only to term customers at monthly contract prices. This simultaneous mismatch *at the margin* in both crude and products margins drove both light/heavy and sweet/sour differentials (so often wrongly conflated) to record levels in 2004. Record crude and clean product freight rates provided the final impetus for unimagined price differentials, which have since begun to narrow in 2005. In other words, both upstream and refining constraints were instrumental in driving oil markets in 2004.

Sulphur emerged in 2003–04 as a major independent factor in crude and product price determination and will continue to be influential in the years to come, especially if lower bunker fuel sulphur limits are extended beyond northern Europe. Any reliable analysis of oil markets now has to incorporate crude and product quality considerations, not only volumetric tracking of flows and stocks. In the past, the focus of crude quality issues has been largely on the supply side, the conventional view being that world crude supply is destined to get progressively more sour and heavier. The experience of 2004 shows that it is changes in the sulphur content on the *demand side* of the crude market which are just as influential because the step-changes in light product sulphur limits cannot be matched exactly and immediately by increases in hydrodesulphurisation (HDS) capacity. This shift in refiners' sulphur tolerance is illustrated by the trend in the quality of US crude imports. Between 2002 and 2004, the volume of imports increased from 9.1 mb/d to 10 mb/d but the average sulphur content fell from 1.64% wt to an estimated 1.53% wt. This may appear only a modest change but it is one which marks an important shift *at the margin* in the demand for imported crude and helps to explain why Saudi Arabia's share of US crude imports fell to a 17-year low (15%) in 2004.

Structural Change in Profitability?

World average refining margins have risen from $2.50–3/bbl in the period 1995–9 to $4–5/bbl in 2000–05. Has there been a 'structural' upward shift in dollar refining margins and profitability? The tentative answer is perhaps 'yes, but only if there has been an accompanying structural shift in crude oil prices'. We tend to underestimate the influence of the *level* of crude prices on refining margins. As Figure 2 shows, light/heavy product price differential (a proxy for the conversion margin) has been closely correlated with the level of crude prices. As crude price rises, the

Figure 2: Brent Crude and Light/Heavy Product Price Differentials 1998–2005



low price elasticities of light products and need for fuel oil to compete in inland markets tends to ensure that light/heavy spreads widen and crude refining margins increase. If this is correct, then refiners owe much of their improved returns to OPEC's successful pursuit of a price target of $25/bbl since 2000.

A few caveats are in order before we herald the continuation of a new 'golden age' for refiners worldwide. The first thing to observe about the remarkable financial performance of refiners in 2003–04 is that it was more highly differentiated than in the past. High-conversion refiners capable of processing sour crude reaped a record harvest in 2004; many simpler refineries restricted to running light, sweet crude did not. Second, it seems that the cyclical and 'one-off' factors at play in 2003–04 may have been widely under-estimated. As the economic cycle matures and investment in new conversion and HDS capacity is completed, margins and returns can be expected to moderate again. Last year was also marked by a series of 'one-off' events which raised margins by creating uncertainty about light product supply, namely tighter sulphur and MTBE phase-out in US gasoline, the reduction in EU diesel sulphur and Hurricane Ivan. Third, refining margins have become more volatile since 2000, increasing corporate earnings volatility but rewarding those who seek to actively manage margin risk.

Has the Refining Industry Under-invested?

The explosion of oil prices and refining margins in 2004 led to accusations that the refining industry had been guilty of 'under-investment', that is, of spending less than was either appropriate or necessary to meet product demand. Reliable consistent data on financial expenditure in refining are hard to come by but it is true that the overall trend in capex and the rate of capacity addition was down between 1999 and 2003. Furthermore, both private and public companies had become more cautious about committing new capital to refining, not least because of the steady requirement for compliance expenditure. However, such accusations of 'underinvestment' seem wide of the mark since they fail to take full account of the *unexpected* nature of the demand growth in 2003–04, the significant lead times in the refinery investment process and the obstacles and disincentives to new capacity investment.

Over the last 25 years, financial returns in the refining industry operating in liberalised markets have been very volatile but have, on average, generally not matched the cost of capital. Markets have seldom remunerated large-scale discretionary investment and every few years refiners have been required to invest to meet tightening fuel quality and emission standards if they wish to stay in business. As in comedy, timing in refining investment is everything. Even when refiners have correctly anticipated long-term demand-side trends correctly and executed expansion projects successfully, they have sometimes brought new capacity on stream when margins are poor because of external events, such as the terrorist attacks of September 2001. Refining investment is a risky business and many integrated companies have concluded from painful experience that better opportunities lie in the upstream. The rational response of refiners to market signals was to comply at least cost with new environmental standards but not to deploy excessive capital through significant discretionary expenditure.

The widening of light/heavy and sulphur spreads to re-investment levels in 2004 and strong cash flow has transformed the investment outlook, as the spate of announcements since mid-2004 illustrate. Refiners are already committing capital to new conversion and HDS capability in order to run more heavy sour crude. Some of the integrated majors are even proudly announcing increases in refining capex. The rate of new worldwide conversion capacity additions picked up in 2004, will increase again in 2005 and 2006 and may exceed that needed to meet incremental light product demand in both 2006 and 2007. Governments too have responded. They have recognised the need to remove any unnecessary obstacles to new refinery capacity and the way in which cleaner fuel regulations have restricted the ability of refiners to raise light product output. The Chinese government authorised in 2004 the construction of two new refineries, ending a decade-long moratorium, and US authorities have sought to ensure that permitting issues and site-specific regulations do not delay unduly capacity expansion. The Indian government has also agreed to postpone the introduction of new diesel sulphur specs. Market participants and governments are responding and new capacity is on its way but the deep-seated caution shown towards new refining investment will take a long time to dispel.

Impact of the Power Generation Sector on Future European Gas Demand

Anouk Honoré

Gas demand forecasts commonly show optimistic trends increasing gently or steeply, especially for the power sector which is seen to be the main driver for gas consumption in the next 20 years. However, high gas prices and the predominance of oil-linked prices in Continental Europe have already started to delay gas demand growth. This article surveys demand in Europe and examines possible future developments in the power generation sector.

The European Union (EU) is the world's second-largest energy consumer behind the United States. Gas demand in the 25 countries of the current EU has increased by about 68% over the last two decades from 291 billion cubic metres (bcm) in 1985 to 488 bcm in 2003.

However, there are large disparities between countries. Gas demand is mainly concentrated in North-West Europe, where gas markets developed 40 years ago, plus Italy and Spain. Nine of the 25 members represented 89% of European gas demand in 2003: Belgium, France, Germany, Hungary, Italy, the Netherlands, Poland, Spain and the United Kingdom. The UK is the biggest natural gas market, followed by Germany and Italy; these three countries accounted for more than half of EU25 demand in 2003.

The residential sector was still in 2002 the largest consumer in EU25, followed by the industry sector. The power sector represented the third largest sector with 124 bcm, but is the fastest growing sector with a 6.3% increase per year from 1985 to 2002, and 7.8% per year between 1990 and 2002.

Power generated from gas-fired plants has increased by roughly 230% since the beginning of the 1990s driven by the relative advantage of CCGT plants in comparison with coal-fired plants. The Netherlands, UK, Italy and to a lesser extent Hungary rely heavily on natural gas for production of electricity. Spain is the fastest growing market for gas-fired power generation.

All the main energy forecasts predict natural gas demand for power generation to be the main driver for this development in Europe. Does the general assumption that CCGT power plants will be the most economic choice for newly built power plants lead to overestimating gas demand? The key questions regarding future gas to power are: *how much, how quickly and in which countries?*

In comparison to supply, natural gas demand is a very under-researched subject. It is also a poorly understood issue, with assumptions used to forecast the demand generally not known nor explained. Following this observation, we decided to undertake research on gas demand in Europe. We have used a bottom-up approach, which appears to us to be the most easily understandable and verifiable methodology (as opposed to complicated models which do not always reflect market reality). What follows are the first results of our study.

The non-power sectors (residential, commercial and industrial) will not increase dramatically over the coming years. They are well-developed markets in most countries – especially in the major markets of North-West Europe – and are approaching saturation. Their growth should remain relatively modest at around 1% of increase per year, largely depending on historical trends and GDP forecasts. There is a slightly different story in individual countries in South Europe (Spain, Portugal, Greece and even Italy) in which these sectors may grow faster, but it will have a relatively small impact on total European gas demand.

The power sector represents two-thirds to three-quarters of the projected increases in gas demand. However, our analysis shows that different time-frames provide different stories. Investors making decisions on the basis of possible demand two decades hence need to know how much of that demand will arrive in 10, 15 or 25 years time. Gas demand is influenced by so many factors that we believe it is impossible to get a clear vision more than ten years ahead. It is difficult to compare scenarios published by different organisations because of differences in definitions, regional groupings, time-frame, conversion factors, and efficiency assumptions; however, our preliminary conclusions seem to be less optimistic than other projections of gas demand.

Because of the 4 to 5 years lead time needed to develop a gas-fired power plant project that will run at maximum capacity, capacity additions for 2010 are known.

Firstly, it is apparent that the increase in demand is highly sensitive to the development of gas-fired generation in three countries: Spain, Italy and to a lesser extent, the UK.

Secondly, it is clear that a high-gas demand scenario by 2010 is not supported by the actual construction of gas-fired power plants. If, as some anticipate, the UK starts to be oversupplied by 2008, two possibilities suggest themselves:

1. The UK exports gas via the Interconnector to continental Europe by pipeline; these additional supplies could create gas-to-gas competition with lower gas prices which in turn would increase gas demand for power generation. The merit-order in generation would be changed, opening the possibility of running the existing gas-fired capacity on base-load and, provided that investors were confident in low gas prices in the long term, this could trigger substantial investment in gas-fired power generation (with an impact on gas demand at least 5 years later).
2. Suppliers redirect their LNG cargos to the USA where gas prices are higher than in Europe; gas supplies remain balanced in Europe, with high oil-linked prices, and there is little incentive to develop new CCGTs.

The key question for the period 2010–2015 is: when might we see large numbers of gas-fired power stations being built? The choice for a specific generation technology and a particular fuel is preceded by the decision to make any investment in generation capacity. In a situation of high-gas prices and oversupply capacity (except for Spain and Italy), why would a generator build new (gas-fired) power plants while old coal-fired or nuclear plants, fully amortised, remain much more lucrative? This may explain current, and possible future, delays in the construction of large-scale new gas-fired plants in some countries (e.g. UK and Germany). The key judgement is the likelihood of a scenario where the construction of large numbers of gas-fired power plants can be confidently predicted.

What are the main drivers of construction? We are looking at three principal sets of issues:

– Environmental policy impacts, in particular the EU Emissions Trading Scheme (ETS) and Large Combustion Plant Directive (LCPD)
– Commercial and political incentives (government policies and measures to promote the use of renewables, clean coal technologies, nuclear phase-out)
– Economic drivers: gas/electricity prices (high oil-linked gas prices, coal prices with CO_2 costs and their effect on plant dispatch, and the economics of new plant construction).

Natural gas has inherent environmental advantages over other fossil fuels, including lower carbon content and fewer emissions of noxious gases. The ETS has created a price for emission permits that should have a significant impact on the use of fossil fuels in power generation, and could support the use of natural gas, both for new and existing power plants. But the allocation of emission permits for the first allocation round (2005–07) was rather generous, and will not have a positive impact on investment in CCGTs. The next round of allocations (2008–12) could be less generous, but this would delay decisions to invest to 2008 at the earliest, and additional capacity would not appear before 2013. However, 5-year rounds give high uncertainty for 20-year investment decisions in new capacity. Moreover, high gas prices may counterbalance the impact of the ETS on gas relative to coal.

Gas would need to be positively promoted for the ETS to have an impact on gas demand, both present and future. If only a small number of coal-fired stations are closed, this can be compensated by renewables, which are generally actively promoted by governments. The requirements for conventional back-up generation capacity for renewables are believed to favour gas. However, in Germany, this back-up capacity could be covered by existing gas-fired plants.

The LCPD will come into force in 2008. All thermal power generators, with at least 50 MW of capacity, will have to reduce their nitrogen oxides (NOx) and sulphur dioxide (SO_2) emissions or face closure. This Directive is believed to favour natural gas, which makes the meeting of emissions standards much easier and thus cheaper than coal. But most coal-fired plants in Continental Europe have already installed the required controls, and this measure will pose a problem only for UK stations. This potential decrease in coal-fired generation could be compensated by gas, but also partly by renewables and nuclear power.

Political agreements to phase out nuclear power have been concluded in Germany, Belgium, the Netherlands and Sweden. However, the timing of closure remains subject to discussion. The UK is also discussing the future of its nuclear generation. Carbon dioxide reduction and security of supply concerns are important considerations, and some countries are seriously considering increasing the life-time of their nuclear plants. This would have a big impact on gas demand in the short to medium term. In Germany for instance, if part of the nuclear phase-out is delayed – which is almost certain now – then the small decrease in power generation will be covered by wind generation (renewables) and gas will be delayed until after 2015. As a result, serious pressure on gas demand from nuclear phase-out would not be seen before 2015–20 at the earliest.

Political opposition to more gas-fired generation using imported gas on ‘security’ grounds is also a potential obstacle. The main concern is not lack of availability, but the price of available gas. A major uncertainty about the projected rate of growth for gas consumption in the power sector relates to the development of gas prices. The assertion that ‘demand will be there whatever the price of gas’ cannot be taken seriously. Gas does not have a protected market and is relatively easily substitutable. Since the late 1990s, gas-fired power growth has been slowed by a combination of high oil-linked gas prices and lower electricity prices due to liberalisation. In recent years, rising oil and in consequence rising natural gas prices in Europe have worsened the competitive position of newly built CCGTs for base load relative to coal-fired power plants, even renewables. This is partly offset by strongly increased coal prices. However, high gas prices may delay new CCGTs and/or prevent them from running on base load. A difference of load factor has a huge impact on gas demand. Gas-to-gas competition (and therefore the expectation of lower prices) in the late 2000s could provide a boost to gas demand with new investment in gas-fired power plants, but not until after 2012–13 because of lead times.

Conclusions

Our main conclusion is that, *yes*, the use of natural gas for power generation will increase substantially in Europe, *but* not as much and not as fast as is generally believed. By 2015, large numbers of new CCGTs will not be in operation, although construction may have commenced, despite ETS, LCPD or the possibility of nuclear phase-out. Only lower gas prices up to 2015 will lead to a huge increase in gas demand. Moreover, if any significant numbers of currently anticipated CCGTs in Spain, Italy and the UK are not built, increases in demand will be correspondingly reduced.

Interestingly, it is worth noting that the IEA and the US EIA, which publish gas demand forecasts every year, have reviewed their past predictions on demand and have progressively lowered them over the years. Something is clearly happening to future European gas demand, which has been universally projected to increase in a steep straight line for the next 25 years. It is not clear whether anybody really understands what is happening and how far companies really want to understand it given that steep demand growth is excellent news for the industry. Lower gas demand than has been expected in Europe – at least up to 2015 – should cause all market players to adjust their future plans and recheck the viability of their investment programmes.

The final report on *Gas Demand in Europe: the importance of the power sector* will be published in autumn 2005 on the OIES web site: *www.oxfordenergy.org.*

Oil Prices and Fundamentals

Katherine Spector analyses the market and its players

The most surprising thing about \$50+ per barrel oil prices isn't, arguably, the lofty nominal price per se, but the fact that this two-year rally has coincided with a remarkably flat futures curve or, in other words, remarkably high deferred futures prices (Figure 1). The idea of mean reversion to a \$20–24 per barrel level is effectively debunked.

In recent months, what had been a relatively flat backwardation turned into a steep upward slope, or contango, in the prompt six months of the crude curve. (In energy markets, a downward sloping futures curve – where prompt prices trade above deferred futures – is termed backwardation. Contango refers to an upward sloping futures curve, where deferred futures trade at a premium to spot prices.)

A survey of analysts two years back probably would have generated some scenarios in which outright prices broke old records, but few, if any, rationales for such a severe departure from the old paradigm that contango only occurs when prices are very low (Figure 2).

Expensive Forever?

So what changed? For starters, we have in recent months seen a divergence between short- and longer-term fundamentals. Contango suggests wide availability of prompt supply, and recent inventory levels – particularly crude inventories, and particularly in the USA – tell us more or less the same thing. In fact, the slope near the front of the oil futures curve today is in line with what history would suggest at this inventory level (Figure 3).

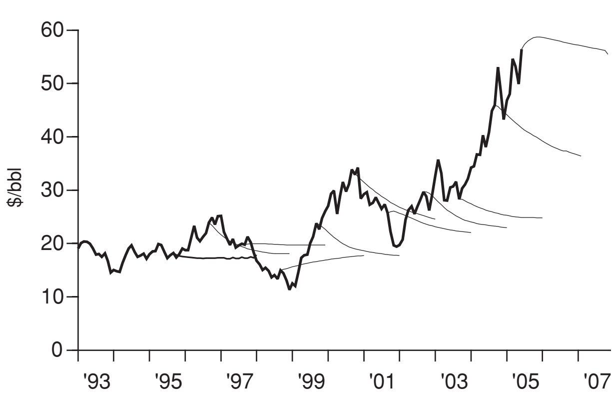
Medium- to long-term fundamentals, meanwhile, do support the notion that oil prices will revert to a higher mean level going forward than they have in the past:

- Underinvestment in refining and distribution infrastructure has introduced bottlenecks to the supply chain that cannot be resolved overnight.
- The industry holds structurally less inventory than it did 10, or certainly 20 years ago, which means that temporary disruptions can have a more acute market impact than they used to.
- The marginal barrel of oil is becoming more expensive to find and produce.
- Oil demand – which grows incrementally even in periods of weak economic growth – is bolstered further now by the emergence of new economic powers that are in a more energy-intensive stage of development than the mature economies of the USA and Western Europe.

But the argument that long-dated futures are high because oil will be expensive forever is a dicey assumption in a historically boom-bust market characterised by periods of over- and under-investment. Financial futures are not a predictor of future price, but rather the price at which a buyer of tomorrow's crude can find a seller of tomorrow's crude in the market today. And more than anything it is the balance of buyers and sellers of financially traded energy that has changed.

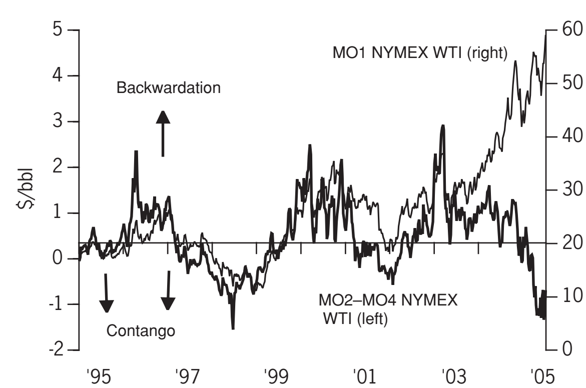
Relative to more mature financial markets – such as interest rate derivatives, bonds, or equities – financial energy markets are young and dynamic. What used to be a market dominated primarily by energy producers and consumers is now increasingly influenced by pure financial players. Physical supply/demand fundamentals still determine price in the long run, but the changing balance of market participation increasingly influences the price path. While new entrants add

Figure 1: Front-Month NYMEX West Texas Intermediate with 'Snapshot in Time' Futures Strips



Source: JP Morgan Energy Strategy

Figure 2: WTI Flat Price versus Forward Spread



Source: JP Morgan Energy Strategy, EIA

liquidity to what are still relatively shallow markets, price distortions and exaggerations feature prominently in this rapidly developing playing field. What could be called the 'paper supply/demand balance' – or, in other words, supply of and demand for deferred energy price – is increasingly relevant in this new market.

Who Trades Energy Today and Why

Traditional participants in the financial energy trade – consumers, producers, and market-making financial institutions such as banks – are of course still present in the market, but have evolved since the inception of the energy futures trade. For starters, hedging has, in most circles, shaken off the 'gambling' stigma for the risk management label. In the corporate landscape hedging is now not only understood by shareholders but in many cases insisted upon. Derivatives strategies have become more sophisticated, and tenors longer as liquidity in deferred periods improves. A crude oil trade that might have met with decent liquidity 5 years out on the curve 3 to 5 years ago, for example, could expect to find fair liquidity as much as 15 years out on the curve today.

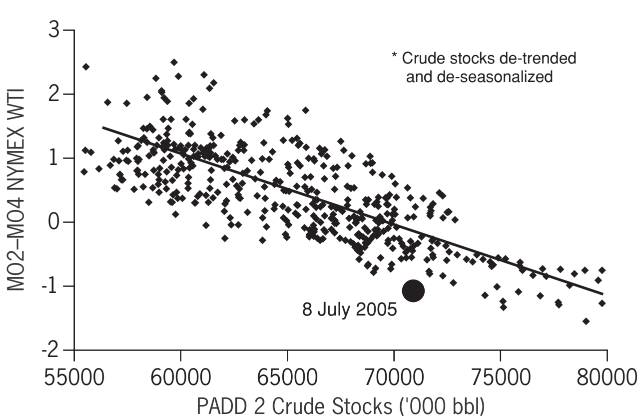
The hedging behaviour of energy producers and consumers is important because it determines, on both a macro and regional basis, the number of 'natural' longs or shorts in markets. Typically (as counter-intuitive as it may seem) we see producers hedge most actively in a weak price environment, and consumers move to lock in forward price in a strong market. Pressure from investors tends to mirror this tendency. In a bullish energy market, investors want reassurance that consumers have some protection from rising costs, but invest in energy producers for proxy exposure to upside energy price risk. Locking in future price eliminates that exposure. We are beginning to see a shift in the producer paradigm, as some investors demand the monetisation of future production at these high price levels, but by and large most of the producer business seen over the past couple of years has been associated with merger or acquisition activity, as opposed to pure strategic hedging. As a result, the natural population of sellers of deferred oil and gas price is automatically reduced.

Outside of producer and consumer risk management, there is a temptation to group all 'speculative' energy market participants together. In reality, these players are a varied bunch that we would roughly define as financial institutions, commodity trading advisors (CTAs) or 'black box' traders, macro hedge funds, and institutional investors.

Banks as a group are not new to the energy space. They have historically been the market makers in the energy trade, and may also warehouse risk in short- or long-term proprietary trading positions. In either of these roles, banks may be long or short the market depending on client flow and house views. CTAs, too, have been active in the energy trade for some time, and may also be long or short at any given time. CTAs can, however, move in and out of positions very quickly and tend to trade purely technically, or mathematically, as opposed to fundamentally.

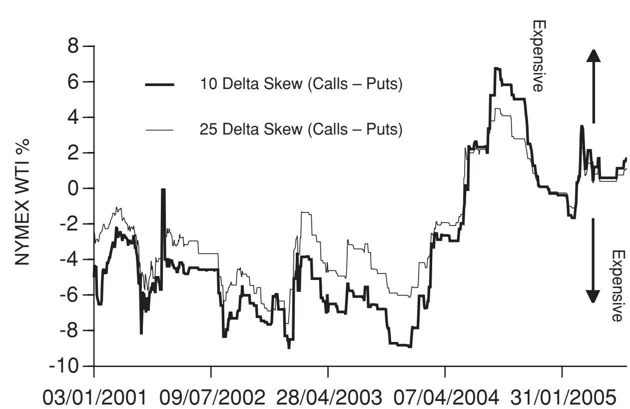
Macro hedge funds are not new to the energy space per se, though their presence has certainly increased and with it the hype surrounding their role in the market. Hedge funds are not only allocating more money to energy now, but as a group have also become significantly more sophisticated in terms of the type of trading they do. By hiring career energy traders in many cases, hedge funds increasingly trade a fundamental view in lieu of or in addition to a technical model. Increasingly sophisticated relative value trading supplements directional strategies, and positions are taken further and further out on the futures curve. While hedge funds may be either long or short depending on their view of opportunities in the market, they have probably been more long than short over the past two years in line with a compelling market trend and broadly supportive fundamental energy story. Virtually all the acute, event-driven shocks that one can imagine waking up to one morning with no advance warning would increase energy prices not lower them, and this has not been lost on the speculative community.

Figure 3: Adjusted* Midwest Crude Stocks versus NYMEX Forward Crude Spread



Source: JP Morgan Energy Strategy

Figure 4: Rolling 12-Month Implied Volatility Skew



Source: JP Morgan Energy Group

Institutional investors – a group distinct from other, more active financial participants – are the newest entrants to the energy space, and possibly the most poorly understood. During a period of low interest rates and relatively few opportunities in traditional investment arenas, the notion of commodities as an asset class and vehicle for portfolio diversification has caught on, aided by a supportive fundamental bull story that has become prominent even in the mainstream media. This group includes pension funds, mutual funds, and even retail investors who may have a broad, macro view of the sector but little expertise in the intricacies of these markets.

Investor products, such as commodity indices and commodity-linked notes give the non-expert an opportunity to add commodity exposure to a diversified portfolio. The indices, such as the Goldman Sachs Commodities Index® and the Dow Jones AIG Index℠, are long-only baskets of commodities and have been the most popular product for passive participation in the commodities space. The ratio of commodities in the basket is set for branded index products – the DJ-AIG Index, for example, includes roughly equal weightings for energy, metals, and agricultural products, whereas the GSCI weights the energy component more heavily. An investor may express a view on one or more commodity groups by customising a similar structured index-style product that favours or excludes certain commodities.

In any case, length in branded index products is held in the second or third month futures contracts, and rolled every month or every second month as those contracts approach maturity. In this way, an index position could, under the proper circumstances, make money in two ways: a 'spot return' is earned when the outright prices of the underlying commodities go up, and a 'roll return' is earned when the futures curves of the underlying commodities are downward sloping. In other words, if the second or third month future price – the entry level – is lower than the prompt price – which is effectively sold during roll periods – then an index position earns a positive yield as length literally rolls up the curve. For this reason, the total return on an index position could be positive even if one of the components of that return – the spot return or the roll return – is flat or negative.

Over the past couple of years, commodity indices have been tremendous performers as spot prices of most major commodities rallied while, until recently at least, several major index components were in steep backwardation.

Institutional investors participate in the energy trade exclusively from the long side, and exclusively over-the-counter, making their influence hard to quantify. Most estimates see as much as $45–55 billion in passive commodity investment products today, relative to less than $10 billion 2 to 3 years ago – not a lot of money for deeper and more mature financial markets, but a sizable and sudden influx for energy markets.

It is tough to put a dollar value on the outright contribution of 'speculation' to oil or other commodity prices. But certain market distortions do highlight concrete ways in which the change in the balance of energy market participation – in the investor community as well as the traditional consumer/producer community – has influenced the trade.

The volatility skew for West Texas Intermediate – which effectively shows the relative cost of puts and calls struck at equal deltas – also illustrates how the market has changed recently (Figure 4). Typically, crude volatility is skewed towards the put side – i.e. puts are relatively more expensive than calls – reflecting the traditional dominance of producer hedging. In the past 2 years or so, the skew has shifted more often to the call side, reflecting the marked increase in the number of market participants willing to pay a premium to reserve the right to buy oil at a certain price, relative to the number of participants looking to reserve the right to sell. While the skew has on occasion shifted back to the put side during large producer deals, such as M&A related hedging programmes, by and large the buyers have been the dominant presence in this market.

The front of the oil curve, in particular, has become saturated with index-style investment dollars. With index length held in the second or third month futures contracts, and rolled every month or every other month during a designated and well flagged roll period, we have seen for over a year – even when most of the oil curve was still in consistent backwardation – pressure on the very front of the curve during these periods.

Now that the oil curve is in a more consistent contango – partly attributable to weak short-term fundamentals – the roll yield that had for some time contributed to positive index returns has disappeared. While spot returns, and thus total returns, have still been relatively good on these investor products, the shape of the curve today suggests that passive investors will have to adjust their expectations or find new ways to gain exposure to commodities going forward.

Pointing Fingers

What often follows (or even precedes), any analysis of speculative interest in energy is a value judgment. The negative connotation of 'speculation' – often implied to have no grounding in a fundamental view of the market – makes financial participants in the trade easy scapegoats for uncomfortably high prices. But energy speculators are attracted to this market by a perceived opportunity in response to a compelling fundamental story. The story came to the fore in early 2003, when military action in Iraq came hot on the heels of crippling strikes in Nigeria and Venezuela, and has gained significant mainstream traction as refinery capacity constraints, robust Chinese demand growth, and debates over Saudi reserves draw media attention. The proliferation of investor products offered by banks and other financial institutions offers vehicles for passive participation in this story.

'There were more buyers than sellers out there today,' traders offer as a tongue-in-cheek explanation for a price rally. Though clearly it is the availability of a seller that makes a buyer a buyer, the cliché in a sense does help explain the persistent support for deferred futures prices. The increase in the number of would-be buyers of energy over the past few years – including energy consumers, fundamentally-inspired speculators, and passive investors – coincided, as prices rose, with a marked decline in hedging by producers, the market's natural sellers. The result is a sharp increase in the competition for forward price that has changed the way the market responds to supportive energy fundamentals.

David Long sees this as the end of an era

Are high oil prices here to stay? The answer is probably yes. Demand growth remains strong despite a doubling of the oil price over the past 18 months. And supply is constrained by capacity bottlenecks upstream and downstream. After 25 years in which the industry has struggled with the problem of surplus capacity, the oil market is now being driven by the over-riding need for more investment rather than cost minimisation.

The change is profound. Oil is a capital-intensive business with high fixed costs and low variable costs. When there is spare capacity available, supply adjusts quickly and cheaply to changes in demand making it difficult to defend prices or sustain margins. But when capacity is tight, supply becomes much more rigid and prices rise sharply in order to signal the need for new investment and to discourage demand for the scarce commodity.

None of this is surprising. The basic economic principles are well understood by all in the industry. What is surprising is the scale and persistence of the price changes that are taking place and the slow response of investment to the new price environment. At $60/bbl, crude oil prices are far above the fully built-up cost of finding and developing even the most expensive source of oil liquids supply. Yet companies remain reluctant to boost upstream expenditure in response to higher oil prices and OPEC seems unwilling to compensate for the shortfall.

The major oil companies still use a hurdle price of around $20/bbl to test the viability of new upstream investments and are only prepared to relax this rigid constraint (a little) for projects with a quick payback. After being accused by their shareholders of destroying capital when oil prices plummeted to $10/bbl at the end of the 1990s, directors are unwilling to risk investing in long-term projects that require a higher hurdle price. As a result, there seems little prospect of a strong supply-side response to higher oil prices from the international oil industry.

But the problem is not just a question of attitudes to risk. It also reflects a lack of opportunity. The distribution of global oil reserves is very unequal. Most of the world's oil reserves are contained in a very small number of very large oil fields. Around 94 per cent of the known oil reserves are concentrated in 3 per cent of the known oil fields and most of these very big oil fields are in the Middle East. Even though there are more than 35,000 fields in production, half the world's oil supply comes from around 120 very big oil fields.

If these very large oil fields were allowed to produce to the technical limit of their geological potential the price of oil would only be a few dollars a barrel – which is why the industry and OPEC have always sought to control their development so that the rest of the world's oil industry could remain in business. The history of oil is a succession of agreements to restrict the output of ultra-low cost oil from very large oil fields in order to protect higher-cost investments in smaller fields. Until now this has worked to the benefit of all producers (although consumers have paid a much higher price as a result). After OPEC member governments nationalised the upstream assets of the major oil companies – sparking the oil price crises of the 1970s – they took on the role of swing producer, allowing their production to fall as demand collapsed in order to slow the decline in oil prices in the 1980s. But this also enabled non-OPEC producers to develop their higher cost oil reserves secure in the knowledge that OPEC was not going to let prices fall too far.

During the 1990s, the cost of developing new non-OPEC oil supplies effectively set a limit on how high oil prices could go as there were plenty of opportunities for companies to boost investment and expand production if oil prices rose. But the scope for additional investment became much more restricted with the start of the new century. Production began to decline in more of the mature non-OPEC provinces as new discoveries failed to replace reserves. Although new fields were still being discovered, the average size was getting smaller and there were only a limited number of new areas where large new fields might be found. Outside the former Soviet Union, non-OPEC conventional oil production has levelled off – leading some to predict a peak in total non-OPEC oil supply by the end of this decade.

Now it is doubtful whether non-OPEC producers can respond in the same way to higher oil prices. Although companies are still investing heavily upstream and there is a long list of new projects set to come on stream during the rest of this decade, it is becoming very difficult to find additional projects or to speed up the pace of development. Most of the big new developments are technically-complex deepwater offshore projects and construction yards and drilling rigs are close to full utilisation already. At the same time output has either passed or is close to a peak in many established provinces, creating a growing capacity deficit that has to be filled by new fields before non-OPEC production can rise. More investment may slow the decline and extend the life of an individual oil field, but it cannot restore capacity to its former peak.

Looking forward, the balance of power in the oil market appears to have shifted permanently in favour of Middle East producers – as long as global oil demand continues to expand faster than non-OPEC supply. Nearly two-thirds of world known oil reserves are concentrated in the Middle East – primarily Saudi Arabia, Iran and Iraq – in countries that remain largely closed to foreign investment by the international oil industry. In the past, competition between these three countries for market share periodically threatened to undermine oil prices but this threat is greatly diminished because of the continuing unrest in Iraq and the absence of spare capacity in Iran.

For the past 25 years, OPEC countries have had little incentive to invest in expanding upstream capacity. With strong competition from rising non-OPEC supply, OPEC's priority was to agree how to share out the remaining market between its members in order to prevent competition from eroding prices. But stronger demand growth and a slowdown in non-OPEC supply this decade have unexpectedly eliminated most of OPEC's long-standing capacity surplus – forcing members to consider spending more of their oil revenues on expanding upstream capacity. So far the response is muted. Saudi Arabia – which has the greatest potential by virtue of its huge oil reserves – only plans a net increase of 1.5 mb/d by 2009.

Without effective supply-side competition from non-OPEC producers to limit oil prices on the upside, it is no longer clear where oil prices will settle. Although OPEC claims to be concerned about the effect of high oil prices on demand, the Organisation appears to be quite content to earn \$50/bbl rather than \$25/bbl as long as this does not provoke a global economic recession or a collapse in demand. If OPEC expands upstream capacity too fast, it risks undermining these windfall gains if its members start to compete amongst themselves for market share once a margin of spare capacity opens up again. It makes perfect sense therefore to spend the minimum necessary on upstream investment to expand capacity just enough to prevent a damaging price spike and to let oil prices rise to the highest level that the global economy can stand.

> "there seems little prospect of a strong supply-side response to higher oil prices from the international oil industry"

That price could be very high indeed. Oil remains the most important source of primary energy and still has no effective substitutes as a transport fuel. Unlike the 1980s – when oil demand collapsed as a result of global economic recession and widespread switching away from oil in power generation and household heating – demand (so far) seems much more resilient to rising prices. Although crude oil prices are at record levels in nominal terms, they are still well below the \$80/bbl peak reached in real terms during the 1979 crisis after the Iranian revolution. In addition, the general increase in wealth in the developed world since the 1980s means that cost of oil now represents a much smaller share of both personal and national budgets so it may require a higher price to have the same impact on demand.

Oil also plays a unique role in global economic development. Unlike other fuels it provides a compact and highly portable source of energy that is particularly well suited to a developing economy that lacks the necessary supply infrastructure to distribute natural gas or electricity. Last year, oil demand grew more strongly than it has done for 25 years fuelled by a booming global economy and the accelerating development of the world's most populous countries, China and India. At present, their oil consumption per capita is very low, but – like the United States in the 1920s and Western Europe and Japan in the 1960s – this is rising as China and India become wealthier and more industrialised. Over the past 5 years, oil demand has grown at an annual average rate of 8 per cent in China and nearly 4 per cent in India.

Taken together, the constraints on upstream investment – for both OPEC and non-OPEC – and the renewed potential for strong demand growth as economic development in Asia takes off, paint a very bullish picture for oil prices over the rest of this decade. This does not mean that oil prices will necessarily remain high as there is a huge gap between the price that is required to limit demand growth – possibly as much as \$100/bbl – and the price that is required to justify new upstream investment – probably as little as \$15/bbl. If oil demand slows too rapidly or if a major new source of supply – such as Iraq – suddenly emerges it could be difficult to stop prices falling back towards the bottom end of the range. But there is a rational case that can be made for an extended period of sustained high oil prices if OPEC does not get too greedy and no easy substitute becomes available for oil as a transportation fuel.

Paradoxically this strong medicine may be just what is required. Despite fears to the contrary, the world is not about to run out of oil. But there is a limit to how much oil production capacity can be sustained and there is certainly not enough oil for everybody in the world to use it as intensively as the industrialised world does today. If Chinese consumers were to match US consumption per capita, global oil consumption would almost double from today's levels. Huge gains in energy efficiency will be necessary if the oil industry is to accommodate the needs and aspirations of both the industrialised and the developing world – and high oil prices provide a strong incentive to make those improvements.

Interestingly, consumer governments now appear to accept the inevitability of higher oil prices. Although there are complaints about rising prices and worries about the impact on economic growth, OPEC has so far escaped strong political pressure to bring prices back down to the consensus levels of the past decade. With growing concerns about global warming and the need to take action to limit carbon emissions, energy efficiency is back on the agenda. And environmental concerns are being reinforced by strategic considerations. Even the United States is worried about its dependence on Middle East oil and seems willing to pay a higher price for oil if this will help to limit imports from what is now seen as a politically unstable region.

The era of cheap oil may well be over. A structural change is underway that will shape the behaviour of oil prices for at least the next decade. The economic development of Asia requires increasing amounts of energy that the oil industry will be hard pressed to supply. Competition between the industrialised world – especially the United States – and the developing world – especially China – for oil supply is already a key factor in driving up and supporting high oil prices. Only the Middle East has the reserves to satisfy both. But if the owners of these reserves choose not to develop them to their full geological potential because they can earn more by restraining development, then oil prices can only remain high.

Paul Horsnell thinks we are moving to a sustainable long-term price level

It used to be so much easier. There was an almost universal belief in a particular theory of the way things fitted together, and that theory seemed to fit reality well enough. Any deviation from the theory had then to be either, the product of faulty observation, a temporary aberration, or the work of dark forces. On the one hand, a close look would have revealed that the theory used its result as an assumption, and the logic behind it might look a little stretched. However, on the other hand, all the time that the theory remained dominant, questioning the ruling orthodoxy was likely to be somewhat of a career limiting choice.

We are of course talking about the flat earth theory. It fitted reality well enough to survive for a few centuries, and having the Spanish Inquisition behind it certainly helped to improve its degree of persuasiveness. The Flat Earth Society continues to the present day, although perhaps only to demonstrate that you can still, albeit perhaps somewhat quixotically, continue a debate as much as 500 years after the available empirical evidence rather crushed your side of the argument.

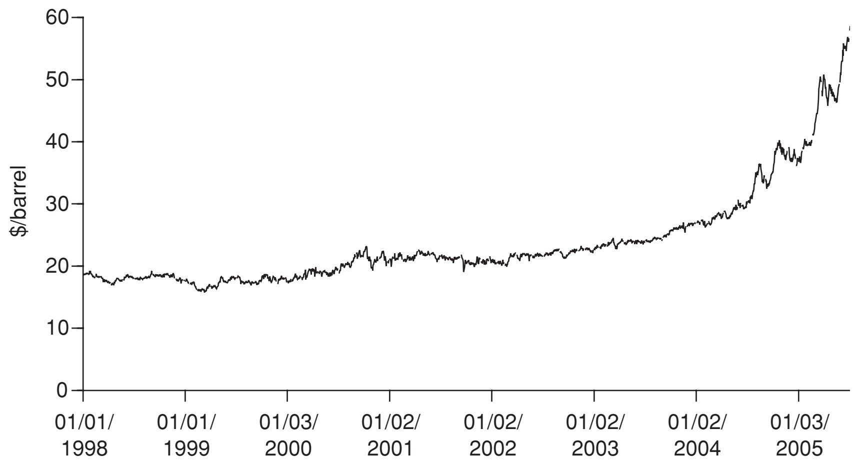
The idea that oil prices had to stay low in nominal terms, and erode even further in real terms, is a little too recent to have had the support of the Spanish Inquisition, and it does not rely on the idea that there is a giant turtle holding everything up. It was, however, taken to be a truth throughout the 1990s, and then well into the current decade, by Wall Street and the capital markets, by energy companies, by most but not all academic observers, and by politicians and planners in consuming countries. The view was very precise, in that the long-term oil price was generally put as being between $18 and $21 per barrel. Indeed, the market's perception of where to place the back end of the crude oil futures curve very rarely strayed outside that $18 to $21 interval over the whole period from 1986 to 2002.

The $18 to $21 range became the touchstone for views of what represented normality, and any hypothesis that suggested prices could be higher than that range was considered heretically abnormal. Governments thought in terms of that range, as did financial markets. Oil companies had to be even more conservative to keep the equity analysts on side. In the 1990s equity analysts were perhaps the closest we came to having a Spanish Inquisition in the setting of market orthodoxy. After all, it is not that long since a former head of BP found his position being significantly eroded for daring to suggest that $21 might be a reasonable assumption for an oil company to make in its planning. The dominance of the low price orthodoxy led to the development of an *ex post* rationale for it. This was based mainly along the lines that prices must be set by the marginal cost of non-OPEC supplies, a line of thought that was sometimes referred to as the 'Goldman Sachs consensus'. In short, the theory was that if longer-term prices moved too far above $20, two things would happen. First, there would be overinvestment in non-OPEC capacity sufficient to lead to a strong supply-side response. Secondly, there would be a sharp truncation of demand growth and then an outright fall in demand. The combination of strongly rising supply and sharply falling demand would mean that prices would have to fall back towards $20.

Very few would argue today that $20 is the correct long-term price for oil. However, it should be noted how that change came about. The rejection of the orthodoxy was not the result of any debate or examination that concluded that supply and demand side responses were not as strong as had been assumed. Instead, the rejection came about simply because oil prices rose, and then kept on going. With a few bumps in the road along the way, the front of the oil price curve has now been rising for just over 6 years. More importantly, the back end of the curve started its march up. The 5-year forward price of WTI (as shown in Figure 1) has passed by a series of milestones. It reached $25 in September 2003, $30 in June 2004, $40 in October 2004, $50 in April 2005 and having reached $58 in July 2005 it is now threatening $60.

It has taken a few years, but the forces behind Figure 1 have proved to be strong enough for most not to want to be too dogmatic about a long-term low price for oil. It is significant that

Figure 1: Five-year Forward Price of WTI, $/b



it was oil price behaviour rather than consensus about assumptions that has produced the change in analyst expectations. It has meant that elements of the 1990s consensus have been recycled and are still in play. There are analysts who would still argue that long-term oil prices are set by the marginal cost of non-OPEC supplies, and hence that prices have gone up because those costs have gone up. For the marginal cost of non-OPEC oil to have followed the path of Figure 1 would be something of a stretch in our view, but that concept is still in the wild. Likewise, political discussion of the oil price still follows some very well worn grooves. Throughout the current year, various politicians have argued that higher prices are either the fault of observation, i.e. if the market had a better understanding and better data it would produce lower prices, or that the rise is temporary, or that it is simply the result of speculators or other dark forces. Even now, among many analysts and consultants there is a belief in a sharp increase in non-OPEC supply growth that will create a sustainable price collapse, i.e. they would say that old theory was perfectly correct but it is just a tad slower to operate than was first believed.

In all, market behaviour this decade has been enough to make it clear what the correct level of oil prices is not, and in particular it has shown that there was nothing magical about the environs of $20. However, that does not in itself help us to tell what the sustainable average level might prove to be. Our view is the sustainable level of long-term prices is that which creates enough investment along the entire supply chain to maintain a reasonable degree of spare capacity, while also ensuring that producing countries are able to maintain some growth in employment and in per capita incomes. That would argue for a long-term price of at least $50, with higher prices needed into the medium term to allow for some catch-up, particularly in the downstream, from the last decade of the 1990s. Prices can of course move to lower levels and indeed in some circumstances to much lower levels. However, they would not be sustainable at those levels into the medium term. Indeed, the real bull case for oil prices would be that we have a period of lower prices and compound the longer-term tightness in the fundamentals of the market.

The view of the sustainable price is of course largely a function of supply and demand responses. Compared to the 1970s, it appears to us that the price elasticities of both supply and demand are significantly lower, that the income elasticity of demand is significantly higher. In addition, the increase in the rate of decline of mature non-OPEC production has become a major force in blunting supply response. Compared to 20 years ago, there is twice as much non-OPEC output and its rate of natural decline is also twice as much. That means that there is now four times as much that needs replacing each year as before, and that is why non-OPEC production outside of Russia has been flat-lining this decade despite considerable expenditure and the development of a considerable volume of production in new projects. With Russian supply growth now also slowing sharply, it appears to us that non-OPEC production may not increase in the second half of this decade even by as much as it did in the first half of the decade.

On the demand side, the concentration of OECD demand in transportation rather than power generation or industry has limited the downwards pressure on the demand. However, the major change in the demand is that non-OECD consumers are now very much at the margin of the market, and they have far higher income elasticities of demand than OECD consumers. It is a far more general phenomenon than just China and India, but it is certainly salutary to note that those two countries combined represent 2.5 billion people consuming just 40 gallons of oil per capita per year. The average American consumes over 1000 gallons per year, and the average Briton 400 gallons per year. Should the joint Chinese and Indian average to reach just 100 gallons per capita per year, that would be 22.5 mb/d of oil demand. Two-thirds of demand growth in 2004 came from non-OECD countries, and on Barclays Capital projections that proportion should exceed 80 per cent in both 2005 and 2006.

The move up in prices is not a shock, it is an adjustment towards a sustainable long-term price level. It has been in progress for too long, and has been too gradual to be a shock, and indeed that has been the major reason why the macroeconomic impact has been relatively benign. Had prices gone from $20 to $60 very quickly there would have been a strong impact effect. As it is, a sustained move up with relatively gentle year-on-year changes has allowed demand growth to continue fairly robustly.

Personal Commentary

Julian West

I find it quite hard these days to keep my balance. Some say it's my age and others blame the claret. But my tottering is philosophical, not physical. Can I resist the claims for any change that it is an irreversible, mould breaking paradigm shift, without holding instead that everything has happened before, and nothing works?

I do find it striking how much analysis of current affairs is based on one or other of these points of view. Granted, it's quite a challenge to support them both at once. I think television is the main cause of the over excitability. Maybe, the extreme pessimism is just its counterpoint.

From this perspective, as from many others, energy questions are a special case. For example, the oil market has risen to the challenge of being both revolutionary and old hat at the same time. This is a a real delight that allows me to work on the latest developments, without the need to learn new tricks. We are running out of oil, governments should insist on conservation and nuclear power, the majors are past their prime, national oil companies will have all the opportunities but will overpay. Again.

As the old joke says, if you can remember the 1960s, you weren't there. Well, I do admit to remembering what has happened since, and there are some important differences. In particular, there's less risk this time of global recession. So, there's just a chance we won't see huge excess capacity, nor experience the joys of $15 a barrel before 2010. My money's on the horse called 'History Repeats Itself,' but 'Brave New World' is strongly fancied.

I confess that the second of these two nags has some decent form. We can suppose that oil demand will not collapse during the next few years. People also expect growing limitations, over time, in non-OPEC supplies. 'Where's the new North Sea, or the next Atlantic deep water?' Good questions, if they themselves won't do, which they won't, without some major innovations.

New technology played a major role in the rise and rise of non-OPEC during the 1980s and 1990s. It now looks like the main hope for keeping non-OPEC growing beyond 2010 or so. (There is also a horse in the race called 'Russia Opens All the Taps' but it's at long odds.) And that could be a problem. There are questions, especially from the service sector, about the majors' willingness to support innovation.

The pattern of upstream R&D spending has changed a lot during the past decade – the majors have cut back hard and the service sector has filled the gap. But, as ever, the source and use of capital are related. The result appears to be that majors are doing the research, leaving development to the service sector. A division of labour to gladden an economist's heart, but a big fall in funding for basic and applied research.

Then look at how little the industry spends, proportionately, on R&D, and at its very long lead times for adopting new technologies. True, E&P assets can last for decades and companies compete hardest in acquiring licences. After, they are working in partnership on a given asset. This may discourage technological risk taking. So, too, may the ubiquitous Asset Teams, who nowadays make so many funding decisions in the majors. Their focus and incentives are almost always short term and operational.

Suppose we define 'new' products as those that have been on the market for three years or less. In 2004, the top ten adopters of such products from one of the largest oilfield service firms were national oil companies and independents. The first of the super majors to appear ranked no higher than fortieth. There is also, apparently, an inverse correlation between these rankings and procurement proficiency. Doubtless, the industry is much the better for efficient, centralised and transparent procurement. The unintended consequence may be to discourage the boys and girls from looking for and playing with new toys. On second thought, perhaps the consequence is not so unintended.

So, that's the evidence for the majors being reluctant to pay for or adopt new technology. Quite good enough, these days, for indefinite house arrest without the inconvenience of testing it at trial! The oil companies reply that they have got better at identifying and delivering their requirements. I've been asked 'What is it that we need and do not have?' The answer may be easier to recognise than to define. It is true that industry consolidation has combined some previously duplicated research efforts. It is also fair to question R&D comparisons between different industries. For example, drug discovery in pharmaceutical companies is a close analogy for exploration in the oil business. Much of the former is included in R&D, but none of the latter.

Since we're discussing oil, we must have a conspiracy theory. Some say the majors won't buy a new technology until it's available from more than one provider – to bid down prices. More plausibly, there are few point solutions for a big company. They are so large and complex that they depend on integrated systems and business processes. Innovation can be very disruptive, so big benefits are needed to justify the costs (in time and temper, as much as in money) of bringing it on board.

At this point, we can all shout, 'Market failure!' It's no surprise that there's a growing cry for more government action to promote, encourage, facilitate and of course pay for accelerated innovation in E&P. Few problems are so serious that governments can't make them worse, and I'm not sure this is an exception. It's reassuring to note a renewed interest by the majors in boosting their technological credentials with host governments and national oil companies. They've always claimed such capabilities but are starting to see new benefits in reinforcing these claims. Perhaps, as often happens, the market is working better than we might suppose.

Better in respect of innovation – or also as regards this latest 'end of oil'? I do think there's a connection and that developments on the first front will have a bearing on the outlook for the second. It's not yet clear that there's a real problem about innovation in E&P, but there's enough genuine unhappiness to suggest there might be. For someone like me, looking for signs of progress in the same old cycles, it's one to watch.

Asinus Muses

Rocket Science

It's a great relief to Asinus that the Committee on Radioactive Waste Management has concluded that nuclear waste should not be fired into space.

Patrol Cars

With the price of gasoline rising fast in the United States it's obvious that you need to drive a vehicle that is itself so costly that the price of gas becomes irrelevant. What better than the new 30-foot stretch-Hummer which comfortably seats 16 people, is equipped with six flat screen TVs, two fish tanks and a bar? And it can do 7 miles to the gallon on a good stretch of road. It just shows how useful war can be for spin-off selling opportunities.

Sitting it out

Asinus doesn't know what to make of the news that a seat on NYMEX was sold recently for nearly $2.5 million, but what is absolutely certain is that he has been priced out of that market and must look elsewhere for a resting place.

Greenmarket

Is 'green energy' the new dot.com world for investment analysts and the herd of hopeful get–rich enthusiasts. Quite possibly, it seems to Asinus, who discovers that there is now a Global Energy Innovation Index (GEIX) that deals specifically in renewable energy companies. Where there's an index there's going to be derivatives and hedging and, for sure, a lot of activity that will create plenty of profit, lots of loss and, who knows, some more green energy.

Battery Farms

Asinus finds himself unable to visualise what a factory of rechargeable batteries would look like if it were constructed. He understands, more or less, that it could in theory be a mechanism for the storage of intermittent renewable energies, but where would you have to put how many of these factories if you could develop the batteries to put in them?

Shock Tactics

The IMF claimed the other day that the world faces a permanent oil shock – '…the shock we see is a permanent shock that is going to continue…' This is a startling new concept for Asinus, and he is temporarily at a loss to know how he is going to recognise the ordinary kind of oil shock to which he has become accustomed.

People Power

Chevron, now slimmed down from Chevron Texaco, advertises itself as 'Human Energy'. Meanwhile Royal Dutch Shell plc (as we now know it) is to create two Academies and appoint ten Chief Scientists. Let's hope that all this concentration on people will create lots of successful projects.

Per Soldier Consumption

Asinus learns that, on average, every US soldier in Iraq uses 9 gallons of fuel per day, excluding that consumed by aircraft and ships, but including that which is used to truck it all in from Kuwait, Turkey and Jordan – but on reflection he has little idea whether this is more or less than might be expected.

Weather Forecasts

The great thing about statistics is that they can always prove whatever you need them for. So, the report 'Wind Power in the UK' says that (a) wind power will be cheaper than fossil fuel power within 15 years (b) that there is no need for dedicated fossil fuel power stations for when the wind fails to blow (c) that there is no limit to how much wind power can be added to the grid. Asinus, still enjoying residual breezes in his garden, awaits with confidence a report that proves the opposite.

High Rise Vegetables

Surely we must all applaud the efforts of Steven Peck, the executive director of Green Roofs for Healthy Cities. The idea is that if you can top out all the high rise buildings with gardens it will cool down the city and thus reduce energy consumption. It will also absorb storm water and mitigate the drainage problems of excess rainfall. You will need, however, a lot of flat roofs.

'…by way of Beachy Head'

Twelve US States have joined environmentalist groups in bringing a lawsuit against the Federal Government which aims to define carbon dioxide as a pollutant under the Clean Air Act, and thus force the Government, if not to sign up to Kyoto, at least to act on CO_2 emissions as it now does under that Act on, for instance, sulphur oxides and nitrogen oxides. If successful, it would be a novel, and peculiarly US, route to Kyoto.

Back to Canada

Years ago in Montreal CFCs were phased out from fridges and so on in the interests of the ozone layer. They were replaced by HFCs which, while harmless to the ozone layer, are now, it seems, adding more to greenhouse gases than are in theory going to be removed under the Kyoto Agreement. Maybe it would be easier for everyone if, when they return to Montreal in November, they could sign up to Montreal 2 instead of struggling with Kyoto 1

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