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A New Era for Oil Prices

by
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CHATHAM HOUSE

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## Summary and comment

Since 2003 the international oil market has been moving away from the previous 20-year equilibrium in which prices fluctuated around $25/bbl (in today's dollars). The single most important reason is that growing demand has eliminated the structural surplus of crude production capacity which had existed since the oil price shock of 1979-83.

So far, the higher oil prices since 2003, and even higher since 2005, have not induced economic recession in oil-importing countries so that oil demand has not fallen as it did in the 1980s after the second oil shock. Unless this occurs, a structural surplus will not be re-created, and prices are likely to remain 'high' – above $50/bbl – until longer-term reactions take effect. If the political situation in the Middle East deteriorates further prices could reach new levels, but the reaction would be quicker and stronger.

Meanwhile, supply and demand are set to expand roughly in balance over the next five years, though there are many uncertainties which will lead to short-term fluctuations. With so little controllable flexibility in supply or demand, prices will remain volatile in the short term.

Five or more years of oil and related energy prices averaging double (or more) their previous long-term average cannot fail to create a new long-term situation both in terms of economic behaviour and government policy. This will bring new competition which will simultaneously reduce the demand for energy, increase the supply of oil, and increase the substitution of other fuels for oil outside the transport sector. As these forces develop, oil prices will be unstable through the long term.

For the transport sector, there is a very large range of possibilities which do not depend on the development of new technology. Examples are a shift in US vehicle demand to vehicles with typical Japanese or European fuel efficiency (which would reduce world transport fuel demand by nearly 10%) and the opening of US and European markets to competition from Brazilian and other developing country ethanol supplies. A period of high oil prices will also lead to investment to increase the production of liquid fuels from oil sands or natural gas. Once these investments are made, they are likely to continue producing as long as their operating costs remain lower than the price of oil.

Outside the transport sector, oil has a higher share of the energy market in many countries than in the US. If other countries substituted other fuels for oil to the same extent as the US has, world oil demand would be about 25% lower. However, other countries do not have the same range of natural resources and competitive energy markets as the US has. The main uncertainty about the long-term outlook is where and how new natural gas markets will develop at the expense of oil. This in turn depends on changing the pricing system for natural gas, which has so far tracked high oil prices outside the US, and on investment to expand gas production and transport infrastructure for international trade. The business model for these projects must adapt to the trend for liberalisation of gas markets in importing countries and specifically to rules which are often better adapted to secure competition within established markets than to the management of infrastructure expansion risks.

Power generation in centralised systems currently absorbs about 5% of world oil demand. This would reduce to 2% if the rest of the world used other fuels for power generation to the same extent as the US. There are some trends in this direction. Over half of the world's oil

use in power generation is in oil exporting countries, many of which are replacing oil with domestic gas in order to free oil for export. A further third is in South East Asia, where oil is being replaced by imported coal because coal prices have not tracked the rise in oil prices, and expansion of coal imports (unlike gas imports) does not depend on massive infrastructure projects. The global oil market and price are only marginally affected by the European use of oil for power generation (less than 1% of world oil consumption) and the promotion (for climate policy reasons) of 'renewable' sources of electricity generation.

The main '<u>energy policy</u>' conclusions of this analysis are:

- <u>Price stability is an unattainable goal.</u> The disappearance of the structural surplus of oil production capacity means than the main mechanism for stabilising oil prices – production control by OPEC and other key oil exporters – will in future only work during periods of deep economic recession when exporters will seek to protect their revenues. Markets can, with some risk-taking, handle day-to-day volatility. The question is how to understand the possible effects of longer-term price uncertainty.

- <u>A new equilibrium will not wait for new technology.</u> This in turn has the strong policy implication that economic incentives, such as prices, can be effective. The current period of 'high' oil prices, if it persists, will generate a wave of competition to replace energy use, particularly in transport, thanks to more efficient demand technologies which already exist and are applied in some countries. This competition will also replace oil outside the transport sector by other fuels. It may be politically difficult to overcome market failures which protect vested interests in existing market structures and distribution systems, but it may be more rewarding than spending money on long-term technological 'fixes' for existing systems.

- <u>Gas matters</u>. Reducing the role of the 'high' priced oil outside transport and power will depend on the expansion of the international gas market. The challenge is to find policies that simultaneously promote competition (as in market liberalisation) *and* investment in massive new infrastructure and production projects for international gas trade.

- <u>The power sector does not matter much to oil</u>. The questions of gas or nuclear, and how far to subsidize or mandate renewable energy sources, are important for other reasons, such as climate policy or energy security. Their economics depend respectively on the price of coal (competing with nuclear for base loads) and gas (competing with renewables).

## 1. In transition

Like most accidents, the price explosion of 2004-5 was the result of an unlikely combination of events. In 2004 world oil demand was about 2 million barrels a day (mbd) above trend, mainly in China but also in the US,[1] while non-OPEC supply was 0.5 mbd below. OPEC through 2003 and early 2004 carefully managed to prevent any excessive build-up of stock in importing countries; then, as prices surged in mid-2004, it became clear that Iraq and Venezuela were producing less than expected. Finally, in 2005, with North Sea production falling, Hurricane Katrina further disabled production (and about 2 mbd of refining capacity in the US) so that non-OPEC oil production did not increase.

**What happened last time**

For most of the 20 years after the 'second' oil price shock, of 1979-80:

- There was a surplus of 5-10% crude oil production capacity, almost entirely within OPEC. This was the result of the fall in demand for oil following the oil price shock of 1979-80 and subsequent economic recession, the substitution of other fuels for oil, and acceleration in the long-term trend to use energy, including oil, more efficiently. By 2005-6 demand had caught up with capacity and the spare was reduced, by mid-2005, to less than 2%;

- While the structural surplus existed, the price of oil (2005 dollars), fluctuated around $25/bbl. When it fell to $20 in 1998 (following the collapse of Asian demand) OPEC and some other exporters (Mexico, Norway) reduced supply under agreed quotas to restore the price;

- The oil share of the world energy market remained at around 33% - 10% below its peak in the 1970s.

Spare capacity – not an exact term – fell to around 2% of supply, but there were no physical shortages of crude oil. In a parallel development, the surpluses of refinery capacity (also created after the second oil shock) had been absorbed by rising demand and finally eliminated by the damage caused by Hurricane Katrina. With tight capacity, it was more difficult for the refinery system to transform the mix of crudes available into the mix of products demanded. As a result, premiums were paid for the 'benchmark' low-sulphur, light crudes such as Brent, which required less processing.

'Normally' one could expect these exceptional and unrelated events to unwind and prices to return in a couple of years, as they always have done after previous surges, to something like a 5-year average. This normality no longer exists. The key change is that the structural surpluses have now gone and, according to the main public forecasts, are unlikely to reappear on the same scale. Only Saudi Arabia deliberately plans to maintain spare crude production capacity (at around 2% of world supply). Therefore, short-term volatility is inevitable. For the longer term, it is difficult to argue that a new stable equilibrium will emerge in which the world will go on as before, but with oil prices at more than double their previous 20-year average. Reactions to a transitional period of high prices will take time to unfold: investments will take time to deliver results, for instance in developing higher-cost oil resources such as Canadian or Venezuelan 'heavy oil'.

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[1] The US Energy Information Agency (EIA) *Short Term Energy Outlook (STEO)* of January 2005 shows 2004 world consumption higher by 3.5 mbd than projected in Jan 2004. The *BP Statistical Review 2006* shows an actual increase of 2.5 mbd in 2005.

Investment will be needed to develop gas supplies and markets to replace oil outside the transport sector. It will take time to develop wider use of fuel-efficient technology (in heating and cooling systems, vehicles, and the use of electricity), to reduce consumption of oil and other fuels whose prices are related to oil. These are the leads and lags of investment cycles typical of many commodities.

A five-year period of 'high' oil prices is therefore likely to be more than 'just another turn of the cycle'. A transition to a different era is likely. Though its shape and stability are now uncertain, several factors can be identified:

- *External competition*:

  At around present prices, oil can be challenged in every country and every sector either by other fuels or by changes in consumption, using known resources and technology. This challenge is wider and deeper than during the previous period of high oil prices in 1978-83. Then, many alternatives had been looked at in response to the first oil shock of 1973. When the second shock of 1978-79 took place, implementation followed rapidly. Now, many alternatives have been prepared in response to climate policies intended to reduce the use of fossil fuels, but their rapid adoption has been lacking economic drive other than those weak and uncertain incentives provided by government subsidies and regulations. A period of high oil prices, so long as they last, reduces the dependence of these changes on uncertain future government policies. How long oil prices remain 'high', and how 'high', is of course uncertain: that depends on decisions taken during the transition period.

- *Perceptions of future resource limits*:

  In the future (say after 2010-15) the extent of depletion and the difficulties of finding new, large, low-cost reserves will restrict the scope for a continuing rise in conventional oil production at prices similar to the 1986-2003 period (which fluctuated around $25 barrel (2004 dollars). The restricted scope for increase does not imply that the production levels cannot be maintained for many years, but oil production will reach a plateau.

- *Geopolitical changes:*

  During the second oil shock, the Soviet oil and gas industries exported to Europe but otherwise did not interact with the international market or investment community. Now, a large part of the Russian oil industry is privatized, foreign companies are developing oil and gas exports from Azerbaijan and Kazakhstan, Russian companies have investments or potential investments in the Middle East, and there is a domestic pricing system in Russia connected to international prices. China, an oil exporter in the early 1980s, now accounts for 15% of the world economy, whose oil imports are growing rapidly. However, unlike the developing country importers in earlier decades, China runs large current and capital account payment surpluses which can sustain these imports. Among the oil exporters, the current period of high prices – while it continues – is generating revenue beyond their capacity to absorb in

**Peaks and plateaux**

The 'peak oil' image supposes that most economically recoverable oil reserves are already known, and that they will be produced up to a technically maximum rate of depletion – around 10% per year, so that after the peak decline will be rapid. In fact, the major holders of the reserves - OPEC governments - follow a more conservative policy of depletion of 3-5% per year, guaranteeing 20-30 years of supplies so that oil will not 'run out' suddenly. 'Plateau' rather than 'peak' is the appropriate image. How much oil can economically recovered also depends on future prices and costs. Reserves at $10 are not the same as reserves at $50.

domestic development. They may prefer to save oil in the ground rather than increase exports to acquire financial assets abroad.

- *Slow shock:*

  The oil price changes since 2003 have developed slowly, compared to those triggered by the loss of supply from Iran after the revolution of 1978-79. Disruptions since 2003 have been smaller, shorter, and unrelated (Venezuela, Iraq, Nigeria, Hurricane Katrina). With no pressure on the panic button, policy responses have been slow and soft.

### 1.1 Has there been a failure to invest?

Spare capacity remained at around 5% until 2003. It is controversial to argue that the oil producing countries and companies had 'failed' to invest in capacity development. Broadly speaking, non-OPEC investment by the private sector has been and is governed more by lack of opportunities than by lack of demand.

Investors may have failed to anticipate the combination of events that pushed up the price in 2005-6, but investment has been increasing since the earlier, lesser price 'spike' of 2000. Financial investment in offshore developments (mainly by the private sector) increased between 2001 and 2005 by 40%, to $163 billion, and is scheduled to increase a further 50% (in current dollars) by 2010.[2] In the mainly state-controlled sector in the Middle East and North Africa, where onshore capacity is relatively cheap, forward investment plans have increased by 26% for 2006-10, compared to 2004-09.[3] Part of this increase is due to cost inflation.

In contrast to the 1980s, private-sector companies have been more willing to return money to the shareholders than to invest in opportunities which depend on the continuation of present high prices. OPEC producers, since the price collapse of 1998, have tended to 'wait and see' whether demand growth materializes before risking the creation of additional spare capacity.

The surge of investment is confirmed by the tightness of capacity in the oil field services sector, reflected in higher prices for drilling rigs, specialised equipment, platform supply vessels and even steel. During the relatively stable period of 1986-2003, long-term US rig counts (which accounted for about half of the world rig activity) were more or less stable at around 1000. Canadian rig counts varied between 200 and 400 while counts outside North America fell from over 1000 to around 700. Since 2003, the count of long-term rig contracts has increased by over 500 in the US, 350 in Canada, and 200 in the rest of the world.[4]

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[2] John Westwood, Presentation at Offshore Technology Conference, Houston, 1 May 2006 (*Oil and Gas Journal*, 10 May 2006).

[3] *The Arab World's Energy Investment Outlook*, 2006-10 Review, APICORP research Unit. Paper for 8th Arab Energy conference, 14-17 May 2006.

[4] *WTRG.com/rotaryrigs.html*, 14 April 2006.

## 1.2 Balance of supply and demand to 2010

### *Supply projections*

Because of the time needed to complete projects, a range of potential oil supply to 2010 can be reasonably estimated. An independent survey of 'the status of individual projects'[5] shows gross capacity additions of 17.6 mbd by 2010. 110 large identified projects in some 20 countries, if completed on time, would add 17-18 mbd to world supply by the end of 2010. Against that increase there would be capacity lost from older reservoirs and some projects would slip. After allowances for erosion of existing capacity because of depletion (8.4 mbd) and some slippage of project completion (1.6 mbd), the 'net' addition would be 7 mbd. However, both of these factors are difficult to predict and the net addition to capacity is very uncertain. In some countries, investment and the application of the necessary technology depend on foreign investment, and if the conditions are not right this may not take place in timely fashion. In others, governments (or private-sector companies) may adopt a 'wait and see' policy, which would defer investment until its justification is clear. The earlier period of this expansion is quite widely distributed, mainly outside OPEC (Brazil, Canada, the Caspian region), but OPEC capacity grows more in the later part of the decade.

**Critical countries**

These projections assume for *Saudi Arabia* only that current plans will be carried out, leading to capacity of 12.5 mbd (14 including Natural Gas Liquids-NGLs) by 2010 through to 2015.

It is easy to identify countries where projects may not deliver the expected capacity before 2010 for one or another political reason. In *Iran,* if confrontation over the nuclear issue leads to tighter sanctions against non-US supply of equipment, foreign investment to projects scheduled to add about 800,000 bd of new liquids capacity could be delayed.

In *Nigeria*, disruptions around the 2007 presidential election, and operating conditions in the Delta, could delay new projects for around 500,000 bd of liquids capacity and obstruct extension drilling in producing reservoirs.

In V*enezuela,* the new terms enforced by the Venezuelan government may limit foreign investment and operational support for work on producing fields, so that production does not recover from 2.5 mbd to its earlier level of around 3 mbd.

These projections do not seem to assume any new projects in *Iraq* adding to production before 2010 (though production from existing producing fields is assumed to recover to pre-war levels). There could be a positive surprise if a government is formed quickly, and oil policy agreed on, licences for international companies are awarded, and the security situation is brought to a point where personnel and equipment could safely be committed to new projects.

There are three other public sources for mid-term oil supply projections. None indicates any standstill on investment in expanding oil production capacity. The US Energy Information

[5] Chris Skrebowski, *Megaprojects Petroleum Review*, UK Institute of Energy April 2006.

Agency (EIA)[6], the OPEC Secretariat[7] and the International Energy Agency (IEA)[8] all project a net increase in capacity of between 6 and 7 mbd by 2010 in their reference cases.

There is thus a rough consensus that supply capacity will rise at least in line with the mainline demand projections – an increase of around 7 mbd[9] – for 2010. In this reckoning, an increase in spare capacity from around 1-2 mbd at present to 5-6 mbd by 2010 is possible.[10] However, this is far from certain. The OPEC document emphasized the uncertainty of their alternative scenarios, with a range of 10 mbd in 2020 in the call on OPEC resulting from the combination of demand and non-OPEC supply. Investment to meet the higher end of the call for their supplies, they argue, is very risky.

The scenario of $50+ prices through 2007 implies that finance will be available for development through both the private and public sectors. There is a common problem of competition for drilling rigs, construction equipment, and skilled personnel. This is being reflected in above-inflation price increases, which make it difficult to measure the extent of new physical investment which is taking place.

There are countries with smaller oil potential which depend on direct investment by foreign companies to increase their production capacity. In some of these, major international companies may be reluctant to invest because of difficulties with human rights, transparency of revenues and implications for financing local conflicts. Sudan and Burma are examples. Some Asian state companies are investing in these areas.

### *Demand: no recession yet?*

So far (August 2006) the mainstream view appears to be that post-2003 high oil prices are unlikely to bring about a world recession, and with it the kind of reduction in oil demand that the world experienced in 1979-83 after the second oil shock.[11] The IMF *World Economic Outlook* of April 2006 and the OECD *Economic Outlook* of May 2006 revised the outlook for economic growth in 2006 and 2007 *upward,* notwithstanding the higher oil prices, which they projected to last throughout 2007. However, the upward revisions were mainly in Asia and Russia. Projections for 2007 for the more oil-dependent US and EU economies were down, but energy prices were not generally seen as the main cause.

In particular, until spring 2006, 'core inflation' in the OECD countries had not accelerated (the indicators are more uncertain now). This has been attributed to more competitive labour markets in Europe and the US, to the current high share of profits in the distribution of national income (allowing companies to absorb some increases in cost), and to competition from low-cost manufacturing economies. There was little reason for monetary authorities to combat inflation by raising interest rates to slow down spending, because growth was

6 *Annual Energy Outlook*, March 2006.

7 *Long Term Strategy Document* of March 2006, and associated presentation to the 10th International Energy Forum.

8 *Oil Market Report (OMR),* December 2005.

9 At prices which in the EIA report (and in the IMF *World Economic Outlook of April 2006*) are assumed to decline slightly after 2007 from levels above $60.

10 This is implicit in the EIA projections of capacity in the 2005 *International Energy Outlook*, and explicit in the presentation by acting OPEC Secretary General (Barkindo) to the 11th International Energy Forum of Ministers in April 2006.

11 Though the risk of economic slowdown is receiving more attention than it did earlier in the year.

moderating anyway. These benign features may now (August 2006) be beginning to change, with signs of accelerating core inflation and monetary tightening in major economies.

Energy expenditure is also a smaller proportion of national expenditure in the OECD countries than it was during the 1979-83 oil price shock. Fuel imports in 2003, before the recent price rises, were about 1.5% of GDP in the US and the European Economic Area (EEA).[12] If expenditure on domestic fuel production (whose prices match imports) is taken into account, the EEA and the US spent respectively roughly 4.2% and 3.7% of their income on fuel in 2003.

However, the effects of 'high' oil prices on economic activity may lie ahead. The period of $60+ prices is very recent (starting in August 2005). At the end of 2004 the price of North Sea Brent crude in Europe was $39.90, compared to $30.15 at end-2003 and an average (in 2004 dollars) of $25 from 1986 to 2003. The five-year average to the end of 2005 was $34 (in 2004 dollars).[13]

In OECD countries where prices are not controlled, oil and gas price increases have generally not been passed through into general inflation. Without general inflation, consumers must spend less on other things to maintain their use of transport, heat and power, all of which are inelastic to price in the short term. In the US, consumers paid 25% more for gasoline in January 2006 than a year earlier, and winter heating bills (taking account of the weather) were estimated in March as 17% higher for homes heated by gas and 16% higher for homes heated by oil.[14]

As spending on oil rises, recession begins in the sectors in which consumers in the oil-importing countries reduce their expenditure.[15] There is some offset because oil exporters are spending more (roughly half their extra revenues), but the demand for goods and services from businesses and governments in the oil exporting countries differs from that of businesses and consumers in the OECD. The oil exporters buy different goods and services, from different countries, than oil importers. Manufacturers and service providers to OECD markets will face reduced demand, reduced profits and reduced employment.

Finally, there are a number of rapidly growing countries where oil prices in the domestic market are held down, the shortfall against import costs being carried in the accounts of the national energy companies or in the general government budget. Such countries account for about 25% of world oil consumption. Roughly half of this is in oil-exporting countries, but most of the balance is in oil-importing countries in Asia – notably China and India – which accounted for almost half the increase in oil consumption between 2003 and 2004. Manufactured exports from these countries gain an advantage over exports from countries such as Korea, where oil import prices are passed through into domestic oil prices, and where the cost of fuel imports doubled between June 2003 and June 2006.

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[12] The EEA consists of the EU, Norway, Iceland and Lichtenstein.

[13] End-year data: EIA International Crude Oil Cost tables; average data, derived from *BP Statistical Review*.

[14] USEIA STEO, March 2006.

[15] For a review of the literature, see: Jones et al., *Oil Price Shocks and the Macro-economy: What Has Been Learned Since 1996, The Energy Journal*, Vol. 25 No. 2, 2004. They look at non-monetary results of oil price shocks, estimate and elasticity of 0.05 and 0.06, spread over two years. The oil price increases since June 2005 can be characterized as a 100% increase over the average of the preceding five years. A 2% fall in GDP could be imagined.

It will be difficult for developing countries, especially importers, to maintain subsidies in the face of continued prices of $60 and above. Where domestic prices do not increase, the cost of cheap oil for domestic consumers will fall either directly on government budgets or on the balance sheets of the mainly state-owned refining and distribution companies. In the oil-exporting countries this will add to the distortion of their economies and increase their dependence on oil revenues. Adjustment will be painful and will hurt demand in countries where it has been growing most rapidly.

Uncertainties about the short-term economic outlook are not all generated by uncertainty about the effects of high oil prices. A long period of low interest rates, and a competitive rate for the dollar, and the matching propensity of the Chinese to save and the Americans to spend has created imbalances in the world economy which will eventually need to be corrected by a fall in the dollar (relative to the renminbi), higher interest rates in the US, and higher domestic expenditure in China. How and when these adjustments will take place affects investor and consumer confidence. High oil prices add to the imbalances meanwhile.

***What next for prices?***

Well-informed people, with similar information, can reach very different conclusions about the present outlook for oil prices. At a meeting of over 30 experts organized by Chatham House at the end of January 2006, the participants were asked to assign probabilities to various numbers for the oil price at the end of 2007.

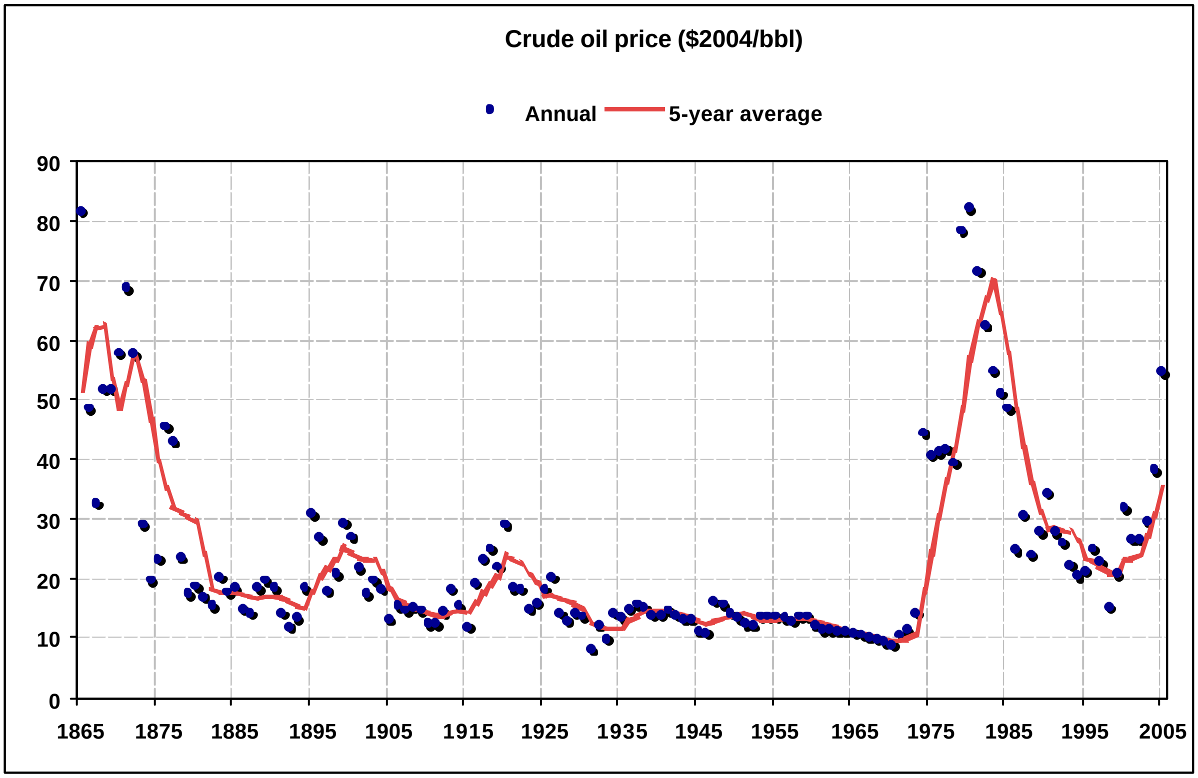
Only one person gave a probability of over 50% to the end-2007 oil price being below $40; a third of the participants gave a 50% or greater probability to prices over $50. What was most striking was the range in each category - for prices above $50 the probabilities ranged from 15% to 100%.

Similar uncertainties are reflected in the volumes projected in the scenarios in OPEC’s Long Term Strategy Document. Published in March 2006, it gives a range of 4 mbd (about 5% of today’s demand) in its scenarios for oil demand to 2010; taken with uncertainties about non-OPEC supply, this is translated in their analysis to a range of around 7 mbd (nearly 20% of their current capacity) in the demand for OPEC oil.

One reason for the uncertainty is that the disappearance of surplus capacity removes the buffers which enable OPEC to absorb some of the uncertainties of supply and demand. The feasibility of any ‘price target’ is doubtful. Prices in the future are likely to be more uncertain than in the past. Some of the conditions of 2004-5 will turn around. It is possible that prices will fall: there is no enduring rationale for $60 or $70 per barrel.

***Instability is certain***

***Chart 1: History of crude oil prices***




Source: *BP Statistical Review 2006.*

Chart 1 shows the annual price of Brent crude oil[16] in 2004 dollars from 1865 to 2005, compared to a five-year moving average. Usually, the price has returned close to a five-year moving average within 2-3 years. From 1986 to 2003 the annual average price appeared to fluctuate around $25 (2004 dollars). Since July 2005 the daily spot price of Brent crude has averaged over $60 per barrel, reflecting a combination of developments over 2004-5.

The US Energy Information Agency projected in January 2006 that the price of WTI would remain above $60 through 2006-7. On 7 July Futures Contracts[17] on the New York Mercantile Exchange showed open quotes for light sweet crude rising from $75.45 for August 2006 to $77.75 for December 2007 - roughly constant in real terms - before a slow decline (in real terms) to $71.90 by the end of 2010.[18]

[16] As defined in the *BP Statistical Review*. 2005 data are interpolated from the IEA *Oil Market Report*.

[17] Source: GFX Group SA, *quotes.ino.com/exchanges/?r=NYMEX_CL*.

[18] Futures prices are not necessarily good predictors of current prices: there is a complicated relationship between the cost of storage and the 'convenience' premium of being certain of delivery at a future date. Also, in recent years financial investors appear to have been bidding up oil and other commodity futures because of the low yields on corporate and government bonds. A study by the Federal Reserve Bank of San Francisco in December 2005 (*Economic Newsletter 2005-38*) found that the relationship between spot and futures prices produced better forecasts than futures prices alone, but that the accuracy of such forecasts was low (their model forecast with 90% probability a March 2006 price between $55 and $74).

The IMF April 2006 Economic Outlook projects, on the basis of futures prices, a WTI price of $64.40 through to the end of 2008. It is difficult to imagine 'surprises' of higher supply than projected, though the delays and depletion assumed in the projections may not come about. It is easy to imagine local difficulties delaying projects and affecting operations in some key countries.

On the demand side, there is uncertainty: it is difficult to imagine higher demand than that already projected to 2010. There is instead a risk of lower prices if economic growth turns out to be lower than expected. If the risks combine - lower supply and demand - prices may not change very much. Lower supply combined with higher demand may create a further price spike but, given the imbalances in the world economy, that may in turn provoke a recession-led fall in demand.

The most likely outcome is continuing fluctuation in price as the market's perception of each of these uncertainties waxes and wanes.

Fluctuations are normal in oil prices – stability has been the exception. The period of stability in 1935-1970 depended on the interconnections between major private-sector oil companies. In the period 1986-2002 some stability was achieved by OPEC's management of the structural surplus capacity (see box).

| **1935 -1970** | **1986 – 2002** |
|---|---|
| • Almost all international oil trade was between or within seven international integrated companies. | • More than half international crude oil exports was supplied by NOCs. |
| • The seven companies integrated refining and upstream. There were no spot or commodity markets. Companies set prices and negotiated taxes with exporting governments. | • Only 5-10% of NOC trade was integrated. Commodity markets in New York and London set day-to day prices which were reflected in NOC price formulae. |
| • Companies, in different consortium, controlled crude oil export production and investment in exporting countries to match their downstream demand. | • OPEC countries tried to regulate crude production (of about 40% of world supply) to support prices on a quarterly and annual basis. |
| • This situation was unsustainable because of competition from new countries and companies and nationalization by governments of exporting countries. | • This situation depended on a structural surplus of up to 25% of OPEC capacity, following the fall in demand for OPEC oil in 1981-83. Surplus in late 2005 fell to less than 5%. |

## 2. The long term

If prices remain around or above $60 through 2006 and 2007 (as projected by the EIA, the IMF and the OECD), the five-year average will have reached almost $50, two thirds of the previous high five years 1979-83 covering the second oil shock and double that of the period 1986-2003. It is difficult to imagine that this will have no effect on the longer-term outlook. Nevertheless, the outlooks of the IEA (*World Energy Outlook*, 2005) and the (EIA *International Energy Outlook*, 2006) for 2010 through to 2030 have reference cases for the longer term, which look very like previous projections, except that prices are higher and demand for oil is lower than in the previous projections.

The EIA *International Energy Outlook* of June 2006 has raised its price projection by around $10 bbl (falling to just $45 by 2010, rising after 2020). The projection of oil demand in 2025 is 8 mbd lower than a year ago. The comparable IEA *World Energy Outlook* is due to be published in November 2006.

Such projections assume continuing world economic growth, continuing expansion of oil supply, similar policies including an anti-carbon bias in some countries, and the share of gas in the world energy mix rising more slowly than previously projected. Both agencies present long-term variants. ExxonMobil has published a similar outlook, without price projections.[19]

These agencies' reference cases are essentially based on 'unchanged policies'. Their alternative projections are more interesting, since it is difficult to believe that the policies will not change in respect to current high prices (and to future prices nearly double those which prevailed when present policies were developed). There are three broad possibilities:

- Delays in investment – possible for a variety of reasons – some economic, some political (the 'Deferred investment' case in the IEA 2005 WEO).
- Stronger policies in importing countries to change energy demand and encourage substitution for oil. (An 'Alternative Policy' case is expected in the 2006 IEA WEO).
- Stronger policies to reduce carbon emissions (the 'Kyoto Protocol' case in the US EIA *International Energy Outlook* 2006).

Otherwise, the reference projections treat the present prices as an aberration after which previous trends will continue. However, the 'long term' may be path-dependent: what is invested in the period after three years of oil prices above $60 will shape the competition between fuels and technologies for the longer term, given a market structure which is more cyclical and less manageable than before. Policies put in place in reaction to a period of high prices will not be quickly dismantled. The possibilities and implications are discussed below.

[19] See, *Tomorrow's Energy*, Feb. 2006, ExxonMobil.

## 2.1 Demand destruction

High oil prices during the period 2005-2010 will affect the longer-term future through three mechanisms, which are combined in the phrase ‘demand destruction’:

- Short-term changes in economic activity, which will affect the demand for oil and energy; however, as economic activity recovers so will energy demand, and previous trends will be resumed after a two- or three-year ‘destruction’ of demand (discussed above under the heading: ‘Demand: no recession yet?’ page 10)
- Changes in the energy share of economic activity (demand for energy per unit of GDP), as a result of investment in more efficient energy-using capital equipment and control mechanisms. While this investment is utilized energy demand will be less;
- Changes in the oil share of energy demand, as oil products are substituted by other fuels, the prices of which do not reflect the higher oil price. Such substitution also requires investment, except in the case where existing enterprises have dual firing capacity, either in individual plants or in an electricity-generating network.

The second two types of change may ‘destroy’ oil demand through the lifetime of the new investment in alternatives to oil consumption, even if oil prices fall to their previous levels.[20]

It is difficult to disentangle these effects precisely from the statistical record: there are other factors at work. If economic activity grows faster in less energy-intense sectors such as services, energy use per unit of activity will fall anyway. It will also fall if countries with low household energy consumption per unit of GDP (such as China) continue to grow faster than countries such as the US. The key message is that when oil prices appear to change permanently, relative to everything else, all of oil’s various markets are at risk. It is necessary to re-evaluate the competitive position of oil in all sectors and countries.

## 2.2 Economic activity and energy demand

Energy use per unit of GDP is a simple indicator combining different sectors – some energy-intensive, some less so – with different energy mixes, which may reflect availability and competition as well as technical factors. Energy prices of different energy forms are not necessarily closely linked to the oil price. In some countries domestic prices are not closely linked to international oil prices. What links there are change over time.

There appear to be very striking simple changes in the use of energy per unit of GDP which correspond roughly to big changes in international oil prices. These are illustrated in the graph below. This compares energy use (in barrels of oil equivalent) per $10,000 (2004 dollars) in the United States with movements in the international oil price. The lines show simple trends of barrels of oil equivalent (boe) to $10,000 of GDP for the periods between each major change.

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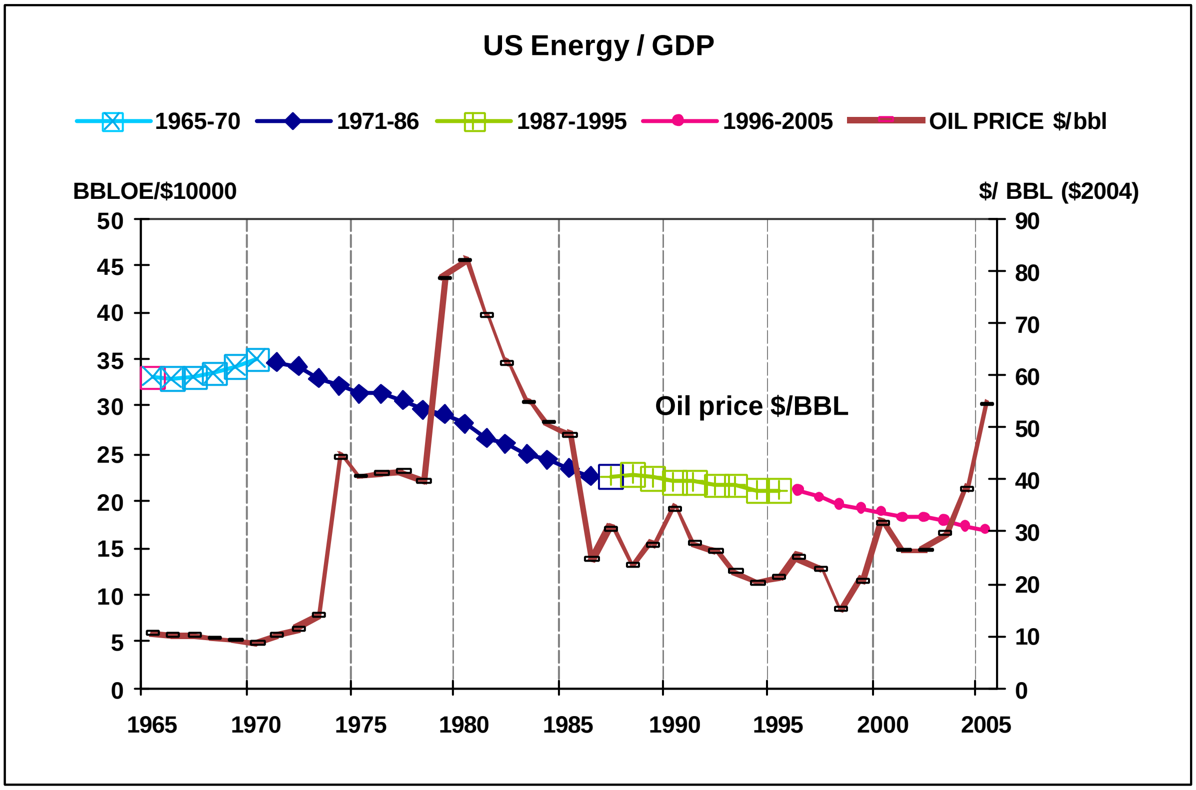
[20] This “asymmetric” effect arises because the investment costs or alternatives to oil consumption will be sunk. The demand for oil will not be re-created as long as the variable costs of alternatives to oil consumption remain below those of returning to oil.

***Chart 2: US Energy use per unit of GDP***




Sources: Energy consumption: *BP Statistical Review 2006.* US GDP: US Bureau of Commerce, Bureau of Economic Analysis, National Economic Accounts at 25.6.06, adjusted to 2004 dollars by US GDP deflator.

Without the benefit of econometric analysis, chart 2 suggests two strong conclusions:

1) The oil price environment has influenced the use of total energy per unit of GDP. There appear to be four periods:

- 1965-1970, when oil prices were falling slightly in real terms, energy use per unit of GDP was rising rapidly;
- 1971-86, when oil prices rose erratically, to a peak (in 1983) seven times their previous stable level. During this period the rising trend in US energy use fell by a third;
- 1987-1995, when oil prices continued to fall, slowly, and energy use per unit of GDP fell about 7%;
- 1996-2004, when oil prices tended to move up more than down, and the use of energy per unit of GDP fell by 18%.

2) The response was quick. This implies that the reductions in energy use were achieved by the wider application of existing technologies which were more energy-efficient. This would be consistent with the observation that within any sector there is a wide range of energy efficiencies for similar activities. This in turn has the strong policy implication that economic incentives, such as prices, can be effective. This is likely to be the case especially where energy users are competing in final markets (or energy is competing with other consumer goods and services in household budgets). New technologies, and government policies to

subsidize or create protected markets may have a longer-term effect but are not necessary for short and medium-term responses – in fact they may even be counter-productive if they are linked with maintaining barriers to competition or the transmission of energy prices through the value chain.

### *The transport sector*

The transport sector, where oil faces few effective substitutes at present, indicates how energy efficiency may be improved in the short to medium term by the application of existing technologies, and in the medium to longer term by the development and application of technical changes which are identified but not yet widely applied.

The most obvious demonstration of the existing technical potential for greater fuel efficiency in transport is the fact that miles-per-gallon (MPG) averages differ widely between countries (and in some large countries such as the US, between states). Comparisons are complex because of different test systems and definitions, but a careful study by the Pew Center shows the following situation in 2002 for the average fleet economy of new vehicles.

| | **Minimum miles per US gallon** | | |
|---|---|---|---|
| | 2002 | Future | Notes |
| USA | 24.1 | 24.9 (2007) | Predates recent raising of light truck CAFÉ standards and assumes 50% light trucks. |
| EU | 37.2 | 44.2 (2008) | EC Agreement with motor manufacturers. |
| Japan | 46.3 | 48 (2010) | Government standard |
| China | 29.3 | 34.4 (2005) | State Council standard, Oct 2004. |

Source: excerpted from table 13, *Comparison of Passenger Vehicle Fuel Economy And Greenhouse Gas Emission Standards Around The World,* Fen An & Amanda Sauer: Report prepared for the Pew Center, Dec 2004.

Because of the complex assumptions, the relationships should be treated as broad indications. The point is that in 2004, new passenger vehicles sold in Japan were nearly twice as efficient as those sold in the US. If (ignoring all other reasons for difference) the average actual US fleet had achieved the efficiency of the new Japanese fleet, US gasoline consumption would be 4.8 mbd lower, reducing US net imports by roughly a third. No new technology is needed to achieve such a change.

There are various reasons why US efficiencies are lower: US drivers buy larger and heavier cars, but prices and regulation are also a large part of the explanation. Japanese prices for gasoline are typically almost double those in the US, as a result of higher taxes on gasoline in Japan.

In the US, governments have relied on regulation through the CAFÉ standards (see box), rather than using fuel taxes to promote fuel efficiency.[21] CAFÉ standards have not significantly changed since 1985 – the point at which oil prices fell to the 1986-2003 average

[21] But the Energy Policy Act of 2005 creates tax credits for hybrid cars.

of $25 (2004 dollars). Authority to change car standards rests with Congress. Various bills in Congress have unsuccessfully proposed to increase the standard for cars.

In the US Energy Policy Act of 2005 There were small changes in the structure of the CAFÉ standards for light trucks. President Bush in April 2006 asked Congress to authorize the Department of Transport to reform CAFÉ for cars on the same lines as it has been authorized to do for light trucks. The president's proposals do not indicate a new MPG standard. Representative Boehlert has launched a bipartisan bill (HR3762) to raise the MPG standard to 33 MPG (US gallons) for cars and light trucks by 2016, but a similar effort in the Senate in 2005 failed to gain support. There is some talk in Congress, led by Senator Obama, of a deal which would link higher CAFÉ standards with some assistance to US automakers. A study has suggested that higher CAFÉ standards would create higher employment in the US auto industry to produce fewer but more technically advanced vehicles.[22]

**Corporate Average Fuel Economy (CAFÉ)**

The US Congress enacted CAFÉ standards in 1975. The standards apply to the average of the fuel efficiency of a manufacturer's (or importer's) new vehicles sold in the US. Different standards apply to cars and to light trucks (which include SUVs). The efficiency of new cars in 1985 (27.5 miles per US gallon) was roughly double that of 1975, and has improved little since.

The Energy Policy Act of 2005 authorized the National Highway Traffic Safety Authority (NHTSA) to amend the structure (but not the level) of standards for light trucks, and change the labelling system for cars. The NHTSA propose to apply specific standards to each weight class (ending the present averaging of light with heavy), and to allow trading of credits.

Vehicles over 8,500 lb gross weight (including SUVs) have been exempt from CAFÉ. These accounted for about 9% of total truck fuel use in 1999 (NHTSA Overview FAQ). The new NHTSA proposals will apply to SUVs from 2011 when the light truck average will reach 24 MPUSG.

The proposal is expected to reduce US gasoline demand by around 260 million barrels 'over the lifetime' of the vehicles sold (Robert Bamberger, Congressional Research Service: *Issue Brief for Congress IB90122* Jan 2006).

There are various existing technologies which could be applied in the US (and Europe) to improve vehicles' use of energy to meet existing demands for transport more efficiently. Many of these also reduce emissions of carbon dioxide ($CO^2$) and other pollutants. In the power train, variable valve timing, stratified diesel combustion (and the use of diesel rather than gasoline) all improve MPG, as do reduction of vehicle weight, and reduction of friction losses in the body design

In the longer term, hybrid vehicles could reduce fuel demand for urban driving. The use of ethanol or bio-diesel requires matching engine modification and the development of parallel fuel supply distribution. These fuels would reduce $CO^2$ emission and to some extent alter the supply pattern of fuels in some countries without, however, reducing the mainline global dependence on oil for transport. It is unlikely that agriculture-based fuels (such as biomass) would be used to generate electricity to produce hydrogen for fuel cells for vehicles powered by electric motors (a double energy conversion). Rather, ethanol or bio diesel may be produced for direct use as a transport fuel in combustion engines served by the existing fuel distribution infrastructure.

[22] J. Andrew Hoerner, Center for a Sustainable Economy: testimony to US Senate Committee on Commerce, Science and Transportation, 24 Jan, 2002.

In the longer term, vehicles may be powered by fuel cells supplied by hydrogen. This could be produced on board the vehicle from a liquid hydrocarbon, or supplied through a new infrastructure and manufactured by electrolysis from electricity produced from additional nuclear, hydro, wind or wave power.

### 2.3 Liquid fuels in the future

#### *'Unconventional' oil*

Since 2000, there has been an increase in the number and variety of projects for producing liquid hydrocarbon fuels from sources other than 'conventional' crude oil. Together they supply about 9 mbd of oil-like liquid fuels (about 10% of current oil consumption).[23] Their great advantage is that the resulting products can be processed, distributed, marketed and used more or less like conventional oil products. As such, they are direct competitors with conventional oil, and are included in the main agencies' oil projections.[24]

*Heavy oil, shale oil and tar sands*

'Unconventional' oils in Canada and Venezuela are produced by injecting heat into underground reservoirs of 'heavy' oil or bitumen (which is too viscous to flow under natural conditions underground), or by mining oil shales. Other countries, such as Russia, also have large potential reserves of heavy oils and there are also large resources of oil shales in the US, Australia, Brazil, Canada and China. These 'unconventional' oils need heat treatment (underground in the case of heavy oils, in surface facilities in the case of oil shales), processing, and the addition of hydrogen from natural gas, to produce something comparable to a conventional crude oil. These processes are energy-intensive and result in high emissions of greenhouse gases. The largest scope for near-term increase is in western Canada. The Canadian Association of Petroleum Producers projects 'unconventional' production to increase from 1.1 mbd in 2005 to 3.5 mbd by 2015 and 4 mbd by 2020,[25] when that would represent about 4% of conventionally projected world oil demand. The speed of development is constrained by the availability of infrastructure, construction teams, and diluents for blending. These constraints may also put a ceiling on the development of heavy oil or oil sands in individual regions, though the size of the reserve means that, unlike in conventional oil reservoirs, production at the ceiling could be maintained for a long period – there would be no 'peak'.

*Gas or coal-to-liquids (GTL or CTL)*

The Fischer-Tropsch reaction process was initially developed in Germany in the 1930s. The reactor technology was significantly extended by SASOL in South Africa in the 1970s and 1980s. Major petroleum companies have developed variations of the process and reactor design. The process converts 'synthesis gas' to diesel for transport and naphtha for petrochemicals. The diesel can be used in conventional diesel engines and has some environmental characteristics which are superior to conventional diesel. Synthesis gas is produced from coal in South Africa but can also be produced from natural gas, and cheap

[23] Robert Skinner, *World Energy Trends: Recent Developments and their implications for Arab Countries*, SP 10, OIES, May 2006.

[24] Though the US Securities and Exchange Commission excludes shale oil from its definition of oil reserves.

[25] CAPP May 2006: *Oil Production forecasts*, The Canadian National Energy Board Energy Market assessment of June 2006 projects 3 mbd by 2015.

natural gas is the basis of existing plants in Malaysia, a plant under construction in Qatar, and other projects under study in Qatar, Iran, Indonesia, Australia, Nigeria, Trinidad and Egypt. The composition of the natural gas (the proportion of liquids already in the gas) has an important effect on the economics.

Uncertainty about the growth and ultimate size of GTL or CTL supplies depends essentially on economics. The input cost of the gas reflects its alternative markets and the profitability of these schemes depends on the relationship between these costs and the price of the oil products, such as diesel, which the synthetic product replaces. In a scenario of oil prices continuing above $50, the availability of natural gas at relatively lower prices could bring about investment to yield about 1 mbd from projects currently under study.

*Ethanol in Brazil and the US*[26]

The key point of the Brazilian ethanol story is that with existing technology a major consuming country has replaced oil for 40% of its transport fuel requirements, even after dismantling extensive government fiscal and price support for the replacement programme.

In 1975, Brazil set a target for ethanol to replace (by blending) 20% of gasoline used in transport. This target has remained in force consistently since 1975 but has recently been exceeded. Ethanol currently supplies about 200,000 bd (40% of Brazil's spark ignition cars). The ethanol programme was supported by subsidies and taxes, as well as mandates on gasoline distributors to distribute ethanol. In the1980s, under government incentives, cars designed to run on 100% ethanol were produced in Brazil, and nearly half of Brazil's liquid fuels were supplied by ethanol. Adverse economics led to a reduction of subsidies and incentives during the 1980s.

Recently, the Brazilian auto industry, with US and German partners has developed 'flex-fuel' vehicles which can switch between ethanol and gasoline: these receive a reduction of 2% in sales tax, and accounted for over half of new vehicle sales in 2005. The ethanol in Brazil is produced from sugar, and its price and availability depend on the alternative of selling sugar into the food market. The sugar mills and refineries are partly powered by burning the cane by-product, bagasse, depending on availability and relative prices.

In the US, the Energy Policy Act of 2005 created federal tax credits for small producers of ethanol and bio-diesel, and for distributors installing facilities for refuelling with ethanol or ethanol blends. Ethanol produced from corn grain replaces gasoline and makes available more energy than is used to produce it.[27] Some states offer similar credits against state taxes. The Act requires fuel distributors to supply almost 0.5 mbd of ethanol annually by 2012 (about 5% of US gasoline demand). There are parallel mandates on motor manufacturers to produce flex-fuel vehicles similar to those used in Brazil. The maximum production of corn-ethanol achievable without prejudicing domestic supply of corn for food is around 0.6-0.7 mbd (compared to a US gasoline consumption of 9 mbd in 2005). US production of ethanol is protected against Brazilian imports by a subsidy of 54 cents per gallon, which President Bush has asked Congress to reduce or suspend.

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[26] Source: Note by David Sandalow, *Brookings Environment and Energy Project*.

[27] The net gain is estimated at 20%, by the National Commission on Energy Policy, a bipartisan group, and by an Argonne Laboratory study at 35%. *NCEP Testimony to Senate Committee on Foreign Relations*, 16 May 2006.

*Biomass*

Ethanol is not produced from cellulosic biomass (such as wood, corn stalks, grass etc.) on a large-scale commercial basis anywhere in the world, but its potential is the object of much government policy measures. The US Energy Act of 2005 contains a wide range of grants, loans, volume commitments and tax breaks totalling about $4 billion over ten years and further incentives are given for ethanol production (known in Europe as 'biomass') from corn stalks and other cellulosic product. Given present technologies, to supply half the current US vehicle fleet's fuel requirements from biomass would require dedicating 40% of the cultivated land in the US to growing biomass for transport fuels.[28]

*The EU bio-fuels policy*

The EU has adopted a Directive (2003) to promote bio-energy (bio-diesel from rapeseed oil, ethanol from grain, and ethanol from biomass) for various uses. Production in 2004 was just over 40,000 bd of bio-diesel and 5000 bd of bio-ethanol. Rapid growth is projected but still falling short by almost half of the Commission's target of 18m tons (about 370,000 bd by 2010). A variety of tax and quantitative incentives are in place in EU member states and these have not been reduced since the increase in oil prices. The Commission has estimated that EU-produced bio-diesel and bio-ethanol break even with oil prices of $76 and $115 respectively.[29] In the face of this negative situation for bio-fuels, the Commission is proposing a review and revision of the 2003 strategy, with:

- An emphasis on R&D for 'second generation' (cellulosic) bio-fuels;
- Provision for imports (with 'certification' of sustainable production methods) from developing countries;
- Better alignment of bio-fuels obligation with $CO^2$ reduction signals;
- Review of fuel quality standards which restrict the use of bio-fuels;
- Allowance for biomass production for fuel on land which has been set-aside from agricultural production under the Common Agricultural Policy (CAP);
- Simplification of current customs treatment of various bio-fuels, many of which enter free of duty under various free trade agreements and under the EU/ACP tariff preference scheme.

It will take some years to develop an operational bio-fuels policy, have it approved through the various EU decision-making processes, and integrate the complex and difficult agricultural policies. It is unlikely that there will be much medium-term effect on liquid fuel supplies, beyond some rationalization of government interventions. In the longer term, the effect will depend on the extent to which (as in the US) 'second generation' cellulosic conversion technology is improved, and how the lower-cost developing country suppliers associated with the EU respond to the markets which should be opened for them under any rational EU policy.

*Hydrogen and fuel cells*

Several governments and companies are carrying out or sponsoring R&D into the use of hydrogen, either as a transport fuel for direct combustion or as an input into fuel cells which could be used in transport or in homes to generate electricity. There are a variety of competing technologies. Unless large-scale supplies of nuclear-generated electricity become

[28] Ibid.

[29] EU Commission COM(2006) 34 Final, 8.2.006: An EU Strategy for bio-fuels. Para 2.1.

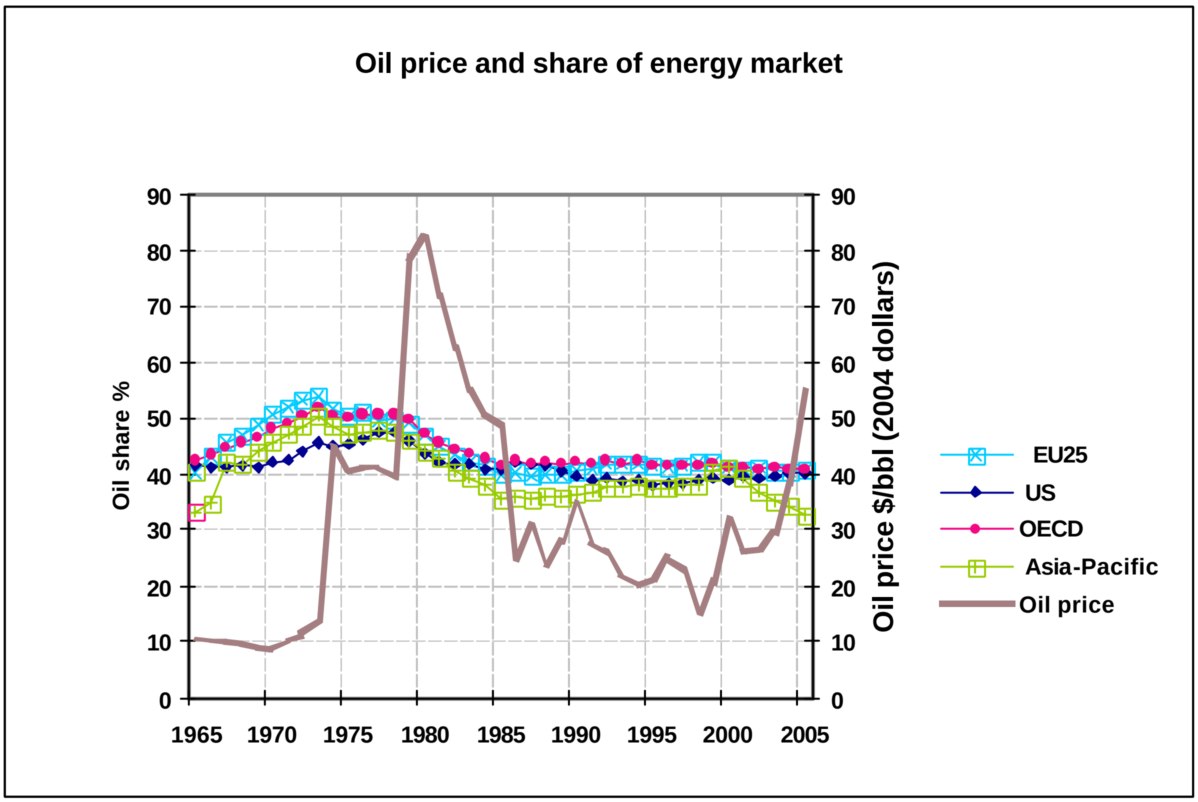
available, hydrogen production requires fossil fuel hydrocarbon inputs. The main advantages of using hydrogen and fuel cells rather than the fossil fuels themselves are:

- The $CO^2$ emissions can be concentrated and managed centrally, leaving 'clean' fuels for use in vehicles and homes;
- The coal and natural gas can be used in hydrogen manufacture for final consumption in uses currently dependent on oil products.

### 2.4 Substitutes for liquid fuels

The last great heave in oil prices had a great effect on oil demand. Between 1979 and 1986, oil's share of world energy demand fell by about 10 percentage points. At the prices of $20-$25 (2004 dollars) from 1986 to 2003, the oil share remained more or less stable in the world as a whole, with some increase in the Asia-Pacific region (which seems to have reversed since 2003). This is shown in Chart 3. There were many complex factors at work, but it is difficult to avoid the idea that price was important. A new 'high oil price' scenario will enlarge the arena within which oil producers must compete, beyond the narrow world of conventional oil. How far would five years of $50+ prices further shrink the share of oil?

***Chart 3: Oil price and market share***




Source: *BP Statistical Review 2006.*

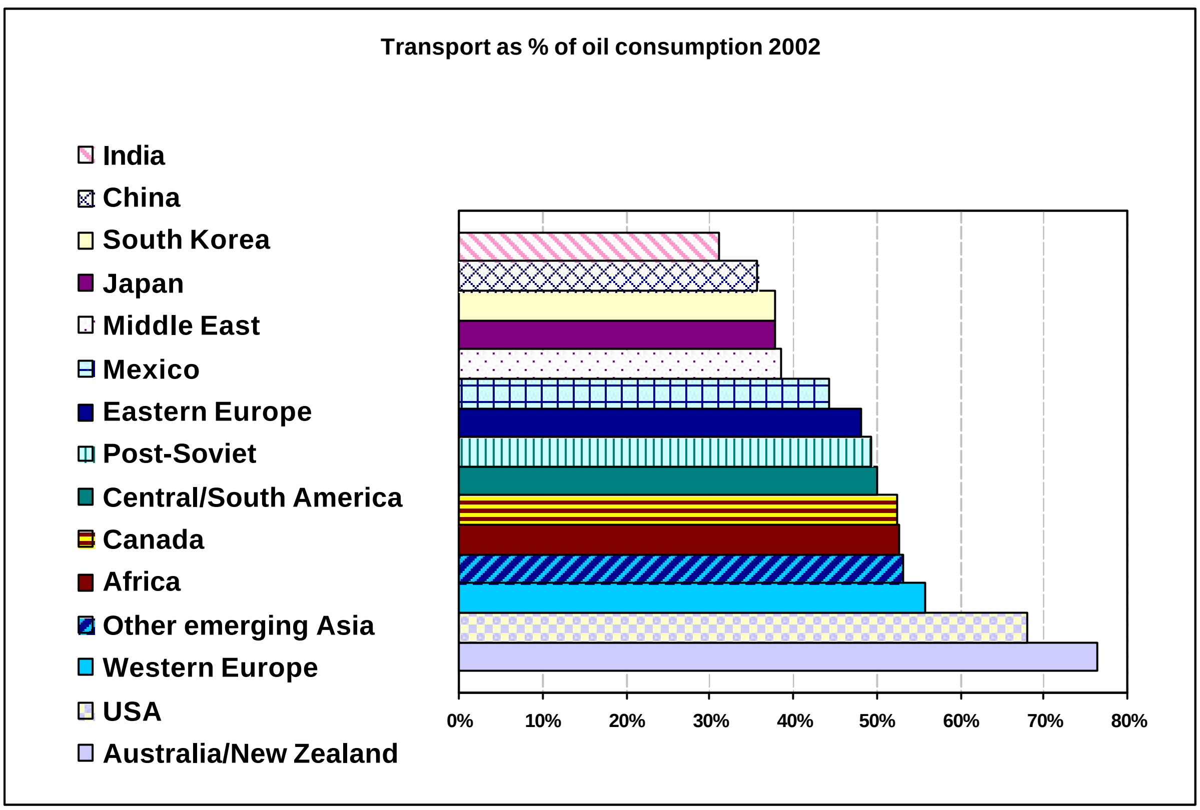
The scope for substitution for oil is much greater outside the transport sector than within it. Such substitution has two effects:

- It reduces the demand for oil absolutely;
- It increases the availability of oil for transport uses.

In 2002 (the latest year for which comparable data are available), 46% of oil in world energy consumption was for non-transport uses, so that substitution outside of that sector of demand could at the limit almost double the availability of oil for transport. In reality, there are many non-transport energy uses where oil has advantages for which consumers would pay prices similar to those paid in the transport sector, rather than use substitutes.[30] It is difficult to estimate how big this 'core' non-transport demand for oil might be. However, the US may serve as a model. In the US only just over 30% of oil in energy was used outside the transport sector in 2002.

Chart 4 compares the proportion of oil used in transport in major countries. Most countries used more oil outside the transport sector than the US, where competing fuels have been available for a long period of time for non-transport uses, energy markets have been liberalized for roughly twenty years, and there is a diverse, flexible economy.

***Chart 4: Oil for transport***




Source: US EIA, *International Energy Outlook 2005.*

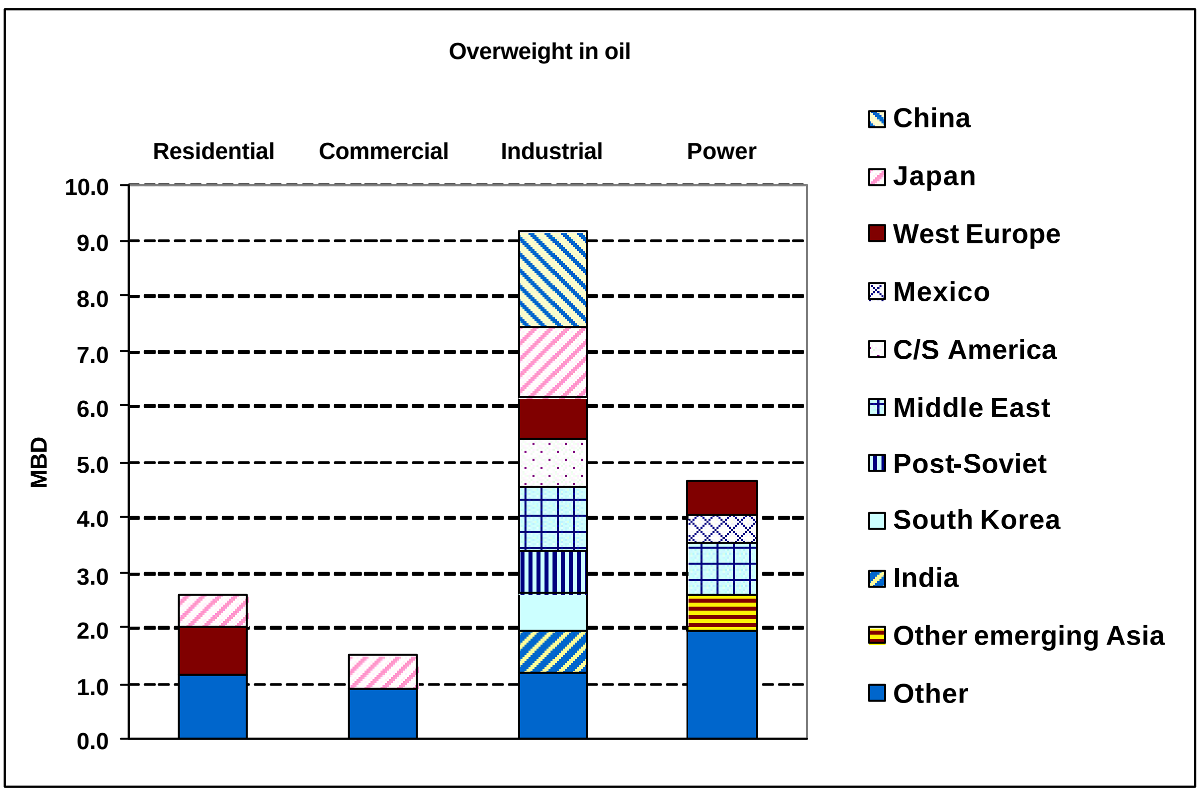
[30] For example fuels for stationary use in remote locations and in standby generators.

As a 'thought experiment' we can ask what would happen if the world displaced oil out of the non-transport sector to the same degree as in the US. Bringing the rest of the world's oil consumption into the same proportions, with just over 30% of oil consumed outside the transport sector, would reduce oil's share of the world energy market by 9% (similar to the loss of share after the second oil shock) or about 18 mbd. For oil this would mean a 'destruction' of over 20% of demand and for other fuels an increase in market size of around 15%. These are, of course, theoretical numbers: the high share of oil in non-transport sectors in some countries may be due to price, lack of availability of alternative fuels, the structure of the economy and the level of household income.

Nevertheless, the 'experiment' points to where and in what sectors oil demand is likely to be vulnerable. Almost half the vulnerability is in the industrial sector, spread over a number of countries. Industrial consumers may be expected to react rapidly to the economic incentive of price.

Chart 5 shows countries and sectors outside transport where oil supplies a significantly higher proportion of the sector's energy consumption than in the US. The largest sectors which are 'overweight' in oil are: the residential sectors in Europe, South Korea, Mexico, Eastern Europe and Africa; the commercial sector in Japan, Canada, China, India and South Korea; the industrial sector in China, India and Western Europe, and electricity generation in Mexico, India, and South-east Asia. Not surprisingly, oil is the main fuel for industry and power generation in the Middle East.[31]

***Chart 5: Sectors with a higher use of oil than in the US***



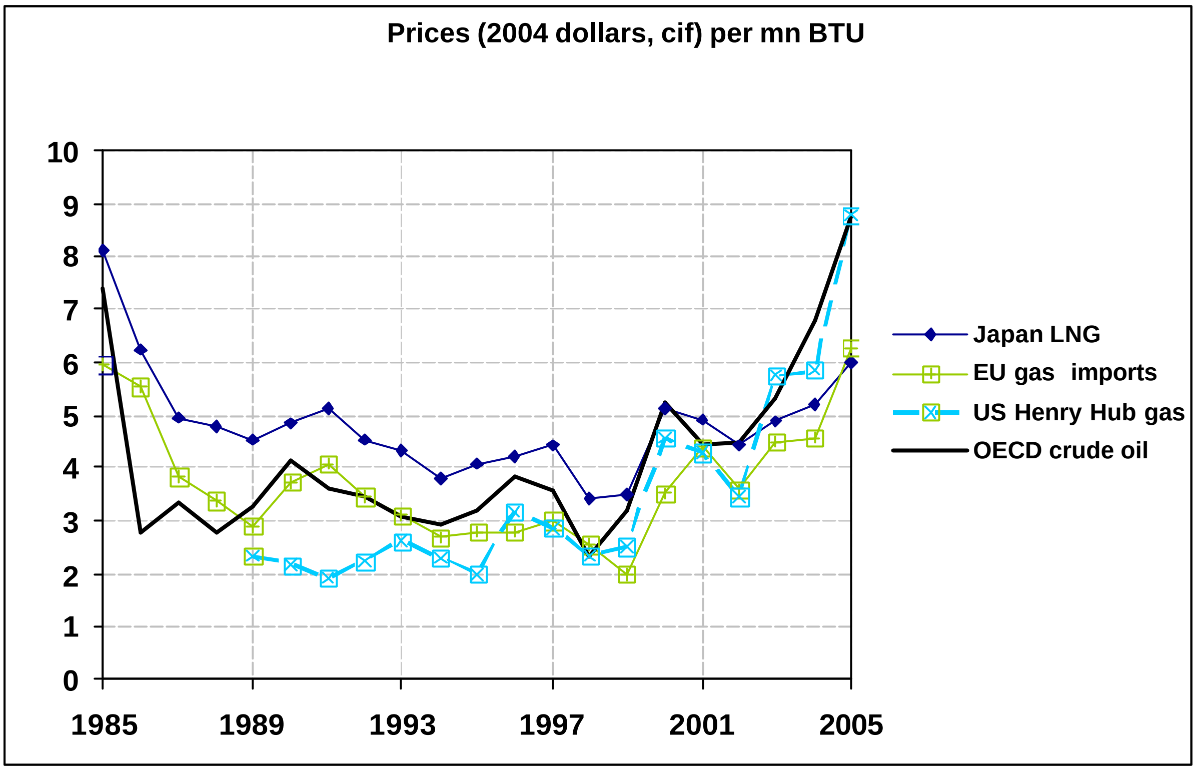

Source: Author's calculations, based on USEIA, *International Energy Outlook 2005.*

[31] Analysis of IEO 2005 data.

### *Gas: the challenge to oil has not materialized*

Gas has been widely seen as a competitor for oil in most of the sectors mentioned. It can be used as a direct source of heat, as chemical feedstock, and for electricity generation through turbine generators. However, its availability in many countries depends on investments to be made to import gas, the establishment of a distribution system which encourages competition, and its price relative to fuel oil. Up to now, even regional competition between gas supplies has not generally prevented a close linkage from oil to gas prices. In some gas-importing countries – notably in Continental Europe and Japan this linkage has been formalized in gas price contracts between importers and exporters. Chart 6 illustrates what appears to be a convergence of regional gas prices and their correlation with OECD oil import prices. Gas prices have followed crude prices, though in 2006 US gas prices have fallen while oil prices have risen. In effect, a price system has not been found which will expand markets outside the US for gas at the expense of oil. Previous projections (before the recent price increase), which assumed an increasing share of gas in the world market, are likely to be disappointed. The period of $50+ oil prices seems unlikely to change that.

***Chart 6: Gas versus oil prices***




Source: *BP Statistical Review 2006.*

<u>*Trends towards more competitive gas markets*</u>

The challenge is for gas to find a place in the changing world energy market of high priced oil. Globalization of markets is coming. Gas markets are in transition from regional markets with different supply, demand and competitive structures to a more connected system in which there are sufficient trade flows between regions for prices to be at least loosely linked. These connections are driven by the growth of international trade as gas production in consuming regions (such as the US, Europe and East Asia) levels or declines, while demand continues to grow. An increasing part of the trade is Liquefied Natural Gas (LNG), shipments of which amounted to 26% of all international gas trade in 2005.[32]

Commoditization will increase competition. The greater part of LNG trade still takes place under long-term contracts, but the proportion traded short-term against spot prices is increasing. (Short-term volumes in 2003 were just over 11% of international LNG trade).[33] In the Barents Sea, it is likely that Norway's Snohvit project short-term contracts and Russia's Shtockman project will reserve part of their production for short-term contracts which will enable them to switch sales between Europe and the US depending on which market offers the most attractive short term price.

Spot gas contracts are already traded in London, New York and Chicago, and a Gazprom subsidiary proposes to set one up in Russia, supported by the Shtockman project. They open the way for competition between new and existing suppliers, provided that new suppliers can access the pipelines of transmission and distribution system.

Liberalization also promotes competition. Transition to liberalized gas markets is more or less complete in the US and the UK. In the EU, the Gas Market Directive 55 of 2003 requires the completion of the single European (liberalized) market by 2007. However, in many European countries 'unbundling' is limited to legal and accounting matters; many national markets are dominated by a small number of suppliers, cross-border transmission is complex and costly, price protection is given to long-standing supply contracts, and retail customers do not have access to competing suppliers. In 2006, following a European Summit, the European Commission started legal actions against 17 governments for failing to implement aspects of the 2003 Directive.

Vertical integration (between pipeline networks and procurement, marketing and retailing of gas) exists in many countries. Liberalization policies are generally designed to limit its potential for restricting competition. In 2006, the European Competition Commissioner launched a sector inquiry on gas and electricity (which is bound to a similar liberalization pattern, but where more progress has been made than in gas).

**Liberalization of gas markets**

Liberalization of gas markets refers to a worldwide trend to move from regulated local or national monopolies which bought gas from producers, transmitted it long distances (usually at high pressure), then distributed it to industrial and retail consumers.

In the ideal deregulated model, consumers are supposed to be protected by competition rather than regulation, and competition is supposed to reduce costs. "Natural monopolies" such as pipeline systems remain regulated but are separated ('unbundled') from gas procurement, supply and retailing.

The Transmission System Operator (TSO) or Distribution System Operator (DSO) are obliged to treat all suppliers equally as regards tariffs and access to the transmission system, so that any supplier can reach any customer.

[32] *BP Statistical Review 2006*.

[33] James T. Jensen, Natural *Gas-a global fuel for the twenty-first century*, Presentation, Pio Manzu, Rimini, 29 Oct 2005.

*Project-led expansion of gas markets*

While liberalization opens the commercial door to competition which may expand the use of gas – long foreseen in international energy projections – investment in cross-border pipelines or LNG projects is also necessary. New commercial models for such investments are evolving which will be consistent with the more competitive markets driven by liberalization policies.

The problem has been that pipeline or LNG infrastructure projects for imports in Europe and Asia have traditionally been financed by long-term contracts in which the competitive position of gas has been secured - in fact usually frozen - relative to oil by linking its price to a bundle of prices for crude oil and oil products. In effect, such contracts protected the position of the importing gas distributor against potential competition from (cheap) oil, and secured market volumes for the exporter. These linkages are now coming under challenge as the liberalization of gas markets in importing regions removes the ability of the importer to maintain formula prices in the face of spot market competition. The industry's response has been to seek more vertical integration between exporter and importer, accepting the need to invest in necessary infrastructure even when liberalization policy requires it to be open to competitors.

Russia, the world's largest gas exporter and holder of gas reserves, is responding aggressively. The Russian government has a controlling interest in Gazprom (which has a monopoly over the export of Russian gas and over the transport of Turkmen gas through Russia to Europe) and a common interest with the company in investing in downstream gas distribution in a variety of markets, controlling Turkmen competition, and reducing Russian dependence on transit countries for exports, European importers' responses are still evolving. The Russian Government Energy Strategy document of 2005 envisaged the expansion of Russian gas exports by 45 BCM from 2000 to 2020, compared to the EU Commission's projection for 180 BCM of additional gas imports during the same period.[34]

Reserves in Qatar, Trinidad and Iran are being brought to market mainly through the traditional joint ventures of producer companies (state and private sector) who contract with gas importing companies. Additionally, there are proposals for LNG import terminals in the US, Europe, China, India and Korea, with corresponding export terminals in Iran, Qatar, Oman, Trinidad, Algeria and Russia.

In South America, expansion of the gas share of energy markets depends mainly on the development of the Bolivian gas resources for supply to Brazil and Argentina.[35] Though the current level of supplies may be maintained, the abrupt nationalization of the foreign companies producing gas in Bolivia has put plans for future expansion in question.

*Key uncertainties in gas*

A period of five years of oil prices above $50 might lead gas investors to finalize market-expanding projects, and generate sufficient contest in the industrial and power markets to open up a gap between oil product prices related to $50 oil and a price sufficient to induce and sustain the potential investment needed for an expansion of gas markets. Whether, where, or when this happens depends on certain key local issues being resolved.

[34] Speech *Geopolitics of Energy Securit*y,Christian Cleutinx, Director EU-Russia Energy Dialogue, Brussels, 10 May 2006, European Enterprise Institute.

[35] There is currently also a proposal, sponsored by President Chávez, for a gas pipeline from Venezuela to Brazil.

Will governments create the conditions, and perhaps fund or part-fund the cost of the infrastructure built to link Asia-Pacific markets with gas exporters (more LNG trains, pipelines, and above all, distribution systems), at prices which are high enough to support the investments but low enough to expand the market at the expense of oil?

- Will European and Russian government policies succeed in reducing the dominant position of Russia as a supplier to the European market and the dependence of Russia on that market? Will what appears to be a mutual desire for diversification inevitably lead to new competitive pressures, which may in turn expand gas consumption?
- Will the US develop a major system of terminals for importing LNG?
- In South America, will Bolivian political events prevent or long delay the penetration of gas in Mercosur markets?

### *The power generation sector*

About 10% of the world's central electricity generating capacity is oil-fired and in 2003 it contributed about 6% of central electricity generated. Central electricity generation consumed 3.7 mbd (about 5%) of world oil supplies. Oil was also used for electricity generation for standby and emergency generators and in remote locations.

By 2020 the EIA projects[36] the oil share of electricity generated to fall to about 5% worldwide. Projections such as the EIA's foresee worldwide stable shares for coal at around 41% and renewables (mainly hydro) at around 19% in the mix of fuels for central electricity generation – while there will be a switch of 3-4% from nuclear to natural gas.

In this projection, oil demand for electricity generation will grow by about 1.8 mbd, instead of 3.2 mbd, which would have been the increase if oil had retained its 2003 share of the generating markets. Almost half the 'lost' oil demand is in the Middle East, as oil-exporting countries increase the use of domestic gas in order to release oil for export. Mexico, the Middle East, and non-OECD Asia remain the principal users of oil for electricity generation.

Further erosion of the projected demand for oil for electricity generation could result from more aggressive pricing and supply of new sources of gas, from an expansion of the coal share of electricity (which may be dependent on managing the increased greenhouse gas emissions), from a renewal of nuclear power plant construction in Europe and the US, and from a higher share of renewable energy. These are discussed below.

The switch will be higher in the OECD where nuclear plants built in the 1980s will be approaching the end of their useful life over the next decades, and conventional forecasts have assumed that their share will be compensated by natural gas combined cycle turbine generators (CCTG). Concerns about security and pricing of future gas supplies have led to a re-examination of the policies which restrict the building of new nuclear plants (see below).

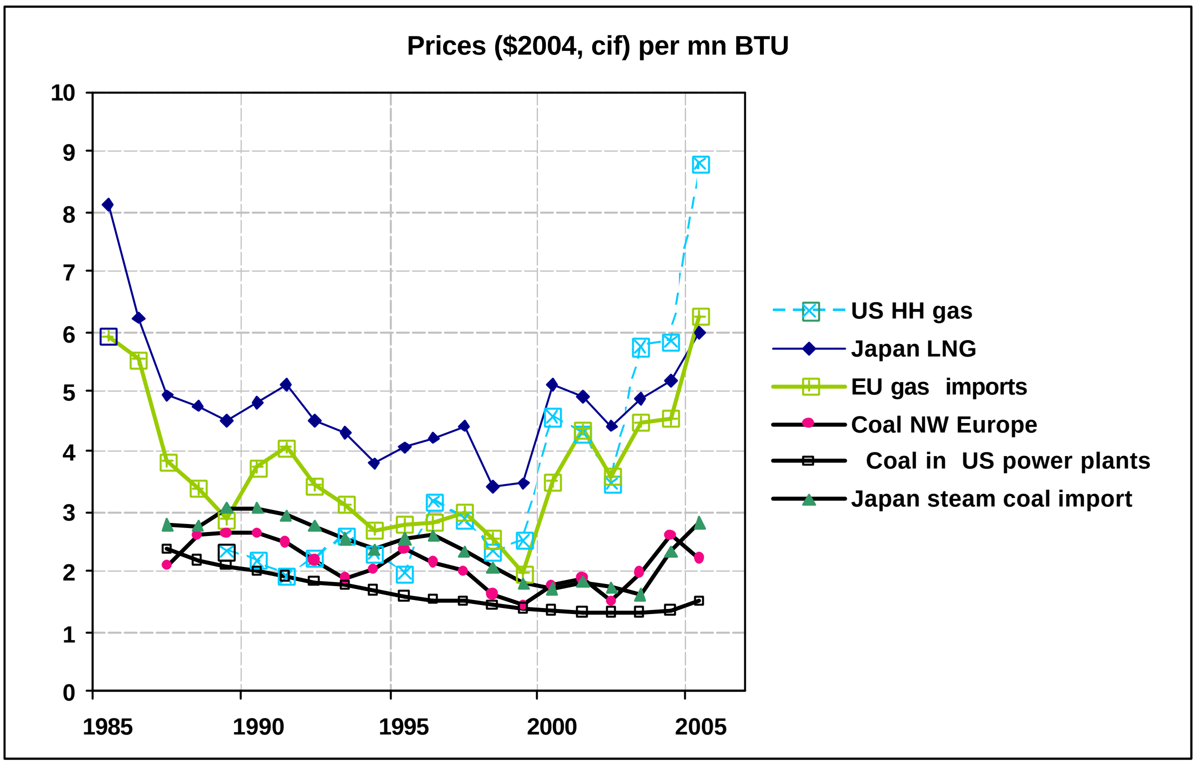
#### *Coal*

Coal supplies about 40% of world electricity generation, though the share varies according to local coal availability (the US, Russia, China and India are major coal producers). The EIA 2006 forecast maintains but does not increase this share in its reference case, despite a

[36] EIA STOE, 2006.

growing gap between coal prices and oil and gas prices. Coal prices followed the general downward trend of energy prices until 1999. There has been some upward movement (high in percentage terms) in 2003-4, which reversed in 2005-6. If oil prices, and gas prices with them, remain at $50+ it seems that a gap will appear which will be wide enough to cover a considerable cost for either buying carbon emission permits (in Europe) or installing carbon sequestration elsewhere.

***Chart 7: Coal versus gas prices***




Source: *BP Statistical Review 2006.*

What chart 7 clearly shows is the gap opening in favour of coal. The gap is wide enough to cover large increases in cost which may be incurred in order to 'clean coal' in countries such as China and India where a range of emission standards is tightening, and in the longer term to develop technologies which will enable carbon emissions to be captured at the generating station.

Coal is available in excess of present and possible future expanded demand in major producing countries: the US, Russia, Canada, China, Australia, Colombia, Venezuela and India. Coal use is also expanding in coal-importing countries. International trade in steam coal has increased by about a third in both the Atlantic and the Pacific markets since 2000 in line with higher world consumption.

With permanently higher oil and therefore gas prices (unless gas-on-gas competition develops) the question for coal is how to find an acceptable technical, regulatory and economic model to increase its share of power market fuel demand. New coal generators using supercritical steam achieve higher conversion efficiencies than traditional designs, but the development of economic carbon sequestration technology is probably the key for any new growth to coal-fired power in Europe and Japan. It may also benefit the oil industry directly by enabling carbon to be sequestered from oil production and refining operations: the emission trading system allows the technology to be diffused by trade as well as by physical reality.

*Nuclear electricity*

Worldwide, trends in nuclear generation are contradictory: in most OECD countries nuclear stations are nearing (within the next 15-20 years) the end of their life (which has already been prolonged in many cases after technical reviews). In China, India and Korea new stations are being constructed (in Japan not at the rate originally envisaged, owing to local opposition to sites for new developments). The US Energy Act of 2005 creates a simpler process for permitting and licensing new nuclear plants (generic approval for designs, single-step approval for planning and construction at a particular site), which should reduce the lead time (and therefore improve the economics) of nuclear construction in the US.

Current forecasts are for the nuclear share of electricity generation to fall slightly, from 21% to 19% by 2015, and by 3-4% by 2020.[37] In Europe there is no EU policy on nuclear power. Some countries (Germany, Sweden) have decided to phase out nuclear generation completely, ahead of the technical life of the plants. A new station is under construction in Finland, France remains committed to nuclear power, and the UK government seems likely to take steps to simplify and shorten the planning procedures for new nuclear stations in order to meet climate policy objectives and reduce the need for gas imports in the future. No change in policy towards nuclear power seems likely in the life of current governments in Germany or Italy.

Five years of 'high' oil prices, combined with concerns about gas availability and the difficulty of meeting climate policy objectives to lead governments to reduce impediments to a larger nuclear share of electricity generation in the future. The need for new building for base-load generation creates opportunities for new choices. Once built, nuclear capacity with low input costs and high sunk costs will supply base-load electricity capacity. It does not necessarily directly compete with natural gas, whose low capital costs in generation and high fuel cost fit the demand pattern of peak daily and seasonal loads, or with 'renewables' (which are now given protected markets in many countries' electricity systems) as their natural variation places them in the mid-load rather than the base-load or peak-load market.

The foregoing suggests that five years of high oil and gas prices will stimulate increased investment in the nuclear industry, but that the effects on the oil and gas markets will be longer-term and depend on the local matching of fuel mix to load requirements. If nuclear energy were to retain its share of the electricity market (rather than decline, as currently projected) demand for other fuels would be approximately 2 mbd lower by 2025 (equivalent to roughly 110 BCM or 8% of OECD natural gas consumption). In the long term, higher figures would be possible: in France, nuclear energy accounts for almost 80% of electricity generation and 38% of total primary energy input, compared with world averages of 16% and 6% respectively.

*Renewables*

For reasons of climate change policy, many governments are offering incentives, or mandating the use of an increasing proportion of 'renewable' energies such as wind power.

[37] US EIA, *Annual Energy Outlook*, 2006, Table 8.

The countries which are major users of oil for electricity generation do not have targets or government incentives for renewable electricity.

In the EU, renewable energies in 2003 supplied 14% of electricity generated in 2003, of which almost three-quarters was hydropower. The EU has set an objective of achieving 21% by 2010, almost entirely be expansion of non-hydro sources, of which wind is the most rapidly growing and the least dependent on direct financial support. There are a variety of incentives for achieving this result.[38] However, oil is used for generating only about 4% of EU electricity (an input of about 650,000 bd).

At present the business model for the development of these sources of electricity generation in the EU is essentially dependent on government support in one form or another. The benefit of using them will be cleaner, rather than cheaper electricity. They will replace variable, mid-load gas for generation in grid networks.

Because of the natural variability of supply, such renewables will not substitute for oil currently used to generate electricity off grid for emergency standby and remote locations, where reliable instant access is critical. Nor will the use of renewables reduce the cost of electricity such that it can replace oil products in direct consumption in the way that coal has done and may do again.

Government policies may promote the use of combined heat and power generation in situations where power and heat demand are concentrated: this could affect electricity demand, but not the mix of fuels.

[38] See EU Commission, *The Support of Energy from Renewable Sources*, COM(2005) 627 7.12.2005.