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EUROSYSTEM

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by Robert Kaufmann[1,2], Pavlos Karadeloglou[3] and Filippo di Mauro[4]

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ABSTRACT

At present, oil markets appear to be behaving in a fashion similar to that in the late 1970s and early 1980s when oil prices rose sharply over an extended period. Furthermore, like at that time, analysts are split on whether such increases will persist or reverse, and if so by how much. The present paper argues that the similarities between the two episodes are not as strong as they might appear at first sight, and that the likelihood of sharp reversals in prices is not particularly great.

There are a number of reasons in support of the view that it is unlikely that the first two decades of this century will mimic the last two decades of the previous century. First, oil demand is likely to grow significantly in line with strong economic growth in non-OECD countries. Second, on the supply side, OPEC is likely to enhance its control over markets over the next two decades, as supply increases in newly opened areas will only partially offset declining rates of production in other geologically mature non-OPEC oil regions. Moreover, while concerns about climate change will spur global efforts to reduce carbon emissions, these efforts are not expected to reduce oil demand. Finally, although there is much talk about alternative fuels, few of these are economically viable at the prices currently envisioned, and given the structural impediments, there is a reduced likelihood that the market will be able to generate sufficient quantities of these alternative fuels over the forecast horizon. The above factors imply that oil prices are likely to continue to exceed the USD 70 to USD 90 range over the long term.

Key words: Oil prices, Oil supply, Oil demand, Alternative fuels, Climate Change Policy

JEL Classification: Q41, Q42, Q43

NON-TECHNICAL SUMMARY

At present, oil markets appear to be behaving in a fashion similar to that in the late 1970s and early 1980s when oil prices rose sharply over an extended period. Furthermore, like at that time, analysts are split on whether such increases will persist or reverse, and if so by how much. The present paper argues that the similarities between the two episodes are not as strong as they might appear at first sight, and that the likelihood of sharp reversals in prices is not particularly great. Two important developments favoured lower prices in the 1980s and 1990s: first, higher non-OPEC oil production, and second, lower demand induced by the higher prices as well by the possibility, which was still high at that time, of replacing oil with coal and natural gas in the industrial and power-generating sectors. Both factors weakened OPEC's control over the marginal supply, which resulted in lower prices. The present outlook is different in many respects. On the one hand, demand remains strong, although it is by no means unprecedented – as some analysts have argued. On the other hand, supply factors are critical in sustaining prices. Specifically, the production of crude oil by non-OPEC countries has not increased since 2004 and the probability of substantial increases in the future is low. OPEC has therefore re-emerged as the main swing supplier and has re-established its control over the marginal barrel by utilising unused capacity and thus driving up utilisation rates.

In the future, economic activity and additions to OPEC capacity will have the greatest effect on oil prices in the long term. The long-run forecast for oil prices depends on OPEC's ability to maintain control over the marginal supply of oil, particularly in view of a possible rise in non-OPEC production and a slowdown in demand: the trigger of the price decline during the 1980s and 1990s.

There are a number of reasons in support of the view that it is unlikely that the first two decades of this century will mimic the last two decades of the previous century. First, oil demand is likely to grow significantly in line with strong economic growth in non-OECD countries, especially Asia, as these countries tend to be highly oil intensive. Second, on the supply side, OPEC is likely to enhance its control over markets over the next two decades due to anticipated changes in the economic, geological, technical, political and institutional environment. Increases in newly opened areas, such as the Caspian Sea region, will only partially offset declining rates of production in other geologically mature non-OPEC oil regions. In this context, regardless of the geological conditions, OPEC future additions to supply are likely to be small as there are few economic incentives to expand existing capacity. This limit is not simulated by most models. There is therefore a considerable risk that the resulting supply forecasts may overstate the amount of oil that can be delivered to the market – a marked distinction with respect to the fundamentals that prevailed in the 1980s, when oil prices dropped. Moreover, while concerns about climate change will spur global efforts to reduce carbon emissions, these efforts are not expected to reduce oil demand. Finally, while there is much talk about alternative fuels, few of these are economically viable at the prices currently envisioned, and given the structural impediments, there is a reduced likelihood that the market will generate significant quantities of these alternatives over the forecast horizon. Technical and economic constraints on production imply that this supply forecast may overstate the amount of alternative fuels that will be delivered. And, even if these amounts were to be realised, a peak in global oil production, as described above, would imply that producing a further 7 million barrels per day (mbd) over 25 years may not be sufficient to fill the gap in demand. Again, both of these factors imply that oil prices are likely to continue to exceed the USD 70 to USD 90 range over the long term.

1 INTRODUCTION

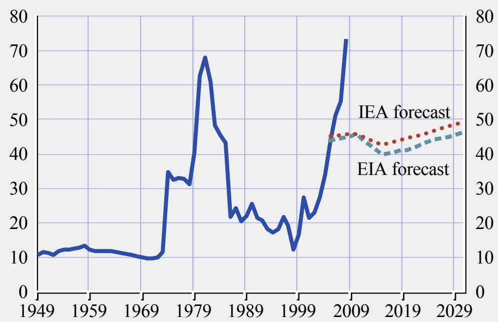
A cursory glance at the world oil market in 2008 reveals similarities to the oil market of the late 1970s and early 1980s. Then, as now, oil prices rose sharply over an extended period and the permanence of this rise was uncertain. In the early 1980s, some analysts forecast that oil prices would continue to rise and reach USD 100 per barrel in 2000. As then, some analysts now forecast that oil prices will remain high. At the same time, other analysts forecast that market forces would reduce oil prices by 2000. Similarly, several academic analyses now suggest that prices in excess of USD 50 per barrel are not sustainable (see, for example, Gately (2007)).

Historically, the forecast that oil prices would decline was correct. Oil prices dropped sharply in the mid-1980s and remained relatively low in real terms through to the late 1990s (see Chart 1).

Nonetheless, there is good reason to doubt that current prices will drop as they did in the 1980s and 1990s. The geological, economic, institutional and technological conditions that allowed oil prices to decline were unique to the last two decades of the twentieth century. Then, oil prices dropped because: (i) geological conditions allowed oil production to increase sharply outside OPEC; (ii) the sectoral composition of oil demand allowed large users to replace oil with coal or natural gas at low cost; (iii) a relatively small fraction of the world's population depended on oil for their economic well-being; and (iv) OPEC was a much weaker institution.

Chart 1 The real price of oil, as measured by the average FOB price for crude oil imported by the United States and deflated by the US GDP price index

(2000 USD per barrel)



Sources: US Energy Information Administration (EIA) and International Energy Agency (IEA).
Note: Latest observation refers to the average value for the first three months of 2008.

Since these conditions no longer exist, oil prices are likely to remain well above the levels that prevailed in the 1990s over the long term, which we define as the next 20 years. This forecast can be substantiated by comparing the conditions that allowed oil prices to decline between 1981 and 2000 with those that prevail in 2008. In short, scenarios[1] in which oil prices would remain in the USD 70 to USD 90 range over the long run must include several assumptions that seem unlikely to be realistic: (i) substantial gains in oil production by non-OPEC countries which could offset ongoing declines; (ii) greater energy efficiency to an extent that it is able to offset the increasing scale of economic activity; (iii) economic contradictions within OPEC that will cause it to fracture; and/or (iv) the intensive development of alternative forms of energy so that they become serious competitors to oil. The main objective of this paper is to put such assumptions to the test.

1 The models run by the US Energy Information Administration (EIA) and the International Energy Agency (IEA) do not simulate prices endogenously. Rather, prices are exogenous, and the models use these prices to simulate energy demand, oil production by non-OPEC countries and oil production by OPEC countries, which is simulated as the difference between the two previous variables. The base-case price scenario reported by the EIA in 2008 is only slightly higher than that reported in 2007.

2 WHY DID OIL PRICES RISE IN THE 1970s AND EARLY 1980s?

During the 1950s and 1960s, an abundance of large oil fields generated considerable excess capacity. To maintain the supply/demand balance, the most important of the state-level organisations, the Texas Railroad Commission, allowed operators in Texas to pump oil from their fields for about nine days per month. This translated into a utilisation rate of about 30 percent (see Chart 2). The remaining 70 percent could be opened quickly if an OPEC Member did not agree to lower prices.

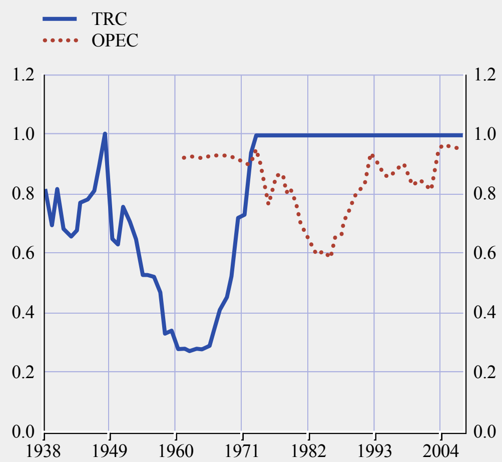
In the mid-1960s, the Texas Railroad Commission started to allow owners to operate at an ever-greater fraction of capacity (see Chart 2). Between 1965 and 1970, the Texas Railroad Commission increased capacity utilisation from less than 30 percent to over 70 percent. By 1973, utilisation rates in Texas were greater than those of OPEC. This meant that spare capacity in the United States and other non-OPEC countries[2] was less than the spare capacity in the OPEC Member Countries.

The loss of spare capacity in the United States gave OPEC control over the marginal supply of oil.[3] In the 1970s and early 1980s, short-run increases in demand could be satisfied only by increasing production from existing OPEC capacity. Similarly, OPEC countries could reduce short-run oil supply by shutting production – without spare capacity, non-OPEC countries could not increase production to offset reductions.

The first example of such market power dates back to 1973 when OPEC stopped oil exports to countries that supported Israel (for example, the United States and the Netherlands) in the Yom Kippur War. The resultant panic and reallocation of supply caused prices to rise more than 250 percent from 1972 to 1974. Recognising this power, OPEC countries nationalised their fields, which meant that the host government (and their national oil companies) now controlled the marginal supply of oil.

Chart 2 The fraction of operable capacity allowed to operate by the Texas Railroad Commission (TRC) and OPEC

(fraction)



Source: Kaufmann (1995).
Note: Latest observation refers to 2007.

The ability to influence oil prices by controlling marginal supply was demonstrated again in 1979, when the return of Ayatollah Khomeini to Iran plunged the country into revolution and much of Iran's oil production, about 5 million barrels per day (mbd), ceased. This reduction in production represented about 10 percent of world oil demand. Rather than increasing production to offset the shortfall, other OPEC countries actually reduced production. This raised prices by about 120 percent between 1978 and 1982. By 1982, the US Energy Information Administration (EIA) forecast that prices would reach USD 100 per barrel in 2000.

2 During this period, no other producer outside the United States shut in significant quantities of crude oil and so the fraction of operable capacity in Texas represented the marginal supply of oil. For a more detailed discussion, see Prindle (1981).

3 The marginal supply of oil refers to the country or group of countries that produces additional oil when oil demand increases and cuts back on production when oil demand declines in order to stabilise prices.

3 WHY OIL PRICES DECLINED BETWEEN 1981 AND 2000?

Contrary to the forecast of USD 100 per barrel, real oil prices declined throughout much of the 1980s and 1990s (see Chart 1). At first glance, this decline can be explained using time-invariant economic principles: higher prices increased non-OPEC oil production and reduced demand, both of which weakened OPEC's control over the marginal supply. However, as described below, these changes were facilitated by a relatively immature resource base and the fact that oil could be easily replaced by alternatives.

DEMAND

Between the end of the Second World War and the price hikes of the 1970s, real oil prices were low and demand grew rapidly (see Chart 3), increasing by about 25 mbd between 1960 and 1970. During the 1970s, demand growth slowed slightly, rising by about 17 mbd, and during the 1980s, it slowed dramatically. In 1990, demand was about 3 mbd higher than in 1980. Lower levels and rates of demand growth are consistent with the application of time-invariant economic principles – higher prices reduced demand via income and price effects. But the story is not that simple. Oil demand declined in a selected group of countries and most of that decline occurred in a few sectors where oil could be replaced with coal and/or natural gas at relatively low cost.

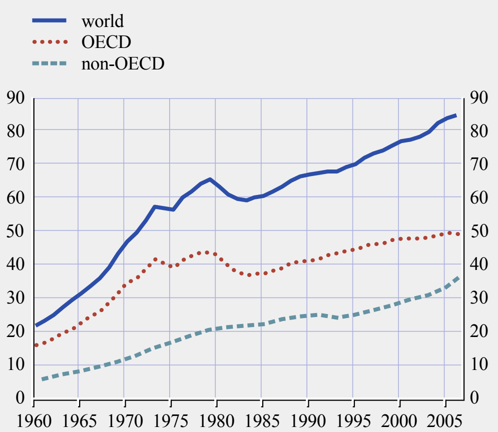
Most notably, much of the slowdown and absolute reduction in demand occurred in OECD countries (see Chart 3). Some of the decline was due to slower economic growth as well greater efficiency in the use of oil. Between 1979 and 1982, OECD oil demand dropped from 44.4 mbd to 37.8 mbd and did not exceed its previous peak until 1995.[4, 5]

4 An extensive literature supports the notion that higher oil prices can cause recessions (for a review, see Jones et al., (2004)).

5 Prior to becoming the current Chairman of the US Federal Reserve System, Ben Bernanke had written extensively on this subject. Bernanke et al., (1997) argues that the recessions of 1973, 1979-1980 and 1990 were caused by poor monetary policy, not by the initial oil price shock. On the euro area, see the article entitled "Oil prices and the euro area economy" in the November 2004 issue of the ECB's Monthly Bulletin and the box entitled "Lessons to be drawn from oil price shocks of the 1970s and early 1980s in the November 2000 issues of the ECB's Monthly Bulletin.

Chart 3 Global consumption of liquid fuels

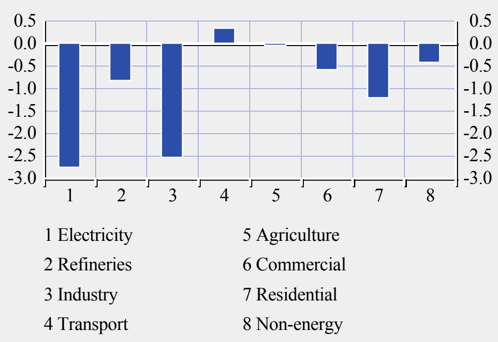
(million barrels per day)



Source: US Energy Information Administration.
Note: Latest observation refers to 2007.

Chart 4 Changes in OECD oil demand by sector between 1985 and 1978

(million barrels per day)



Source: International Energy Agency.

Not only weaker economic growth, but also structural issues were behind the falling oil demand in the OECD countries during the 1980s. Most of this decline occurred in the industrial, petroleum refining[6], residential and electricity-generating sectors (see Chart 4). These sectors were able to curb their use of oil as it could be replaced by coal or natural gas. This substitution was relatively quick and inexpensive because coal and natural gas were readily available, the technology for using these fuels was well established and many boilers could be easily converted so that they could switch between fuels.

SUPPLY

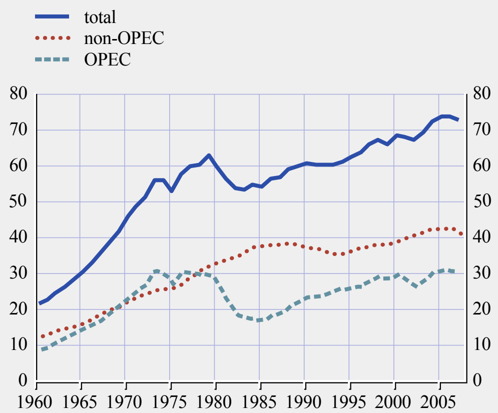
The oil held in fields, which is used for oil production, is termed "proved reserves". Developed countries define their proved oil reserves conservatively. In the United States, the Securities and Exchange Commission defines proved oil reserves as "quantities of oil, known to exist, that can be produced under current economic and technical conditions." This conservative definition is justified by the fact that proved oil reserves are a critical determinant of the stock value of publicly traded oil companies. Given these rules, proved oil reserves of non-OPEC countries constituted a relatively small component of the quantities thought to exist.

Higher prices during the 1970s and 1980s caused proved oil reserves in non-OPEC countries to increase significantly. The main mechanism in this was the discovery of new oil fields. Higher prices increased incentives to drill wells, and the resultant discovery of new oil fields increased proved reserves. This mechanism was highly successful because there were many non-OPEC regions that were relatively unexplored and there was significant potential to eliminate institutional constraints (see, for example, Broadman (1984); Oxley (1988)).

Higher oil prices also raised proved reserves by enhancing the viability of fields previously considered uneconomic. For example, higher oil prices increased the profitability of many

Chart 5 Production of conventional crude oil

(million barrels per day)



Source: US Energy Information Administration.
Note: Latest observation refers to 2007.

Mexican fields and these fields were added to proved reserves in the 1970s. Higher prices also gave rise improvements in the technology used to produce oil. This too allowed operators to boost proved reserves by adding fields that were previously uneconomic. Improvements in deep water drilling added large quantities of oil to proved reserves in the North Sea. The increase in proved reserves led to higher rates of non-OPEC oil production. In total, non-OPEC production of conventional crude oil[7] increased from 25 mbd in 1973 to 38 mbd in the late 1980s (see Chart 5).

Much of this increase was concentrated in the former Soviet Union, Norway, Mexico, China and the United Kingdom. In the former Soviet Union, production increased from about 8 mbd in 1973 to 12 mbd in 1988. During the same period, about 4 mbd were added in the Norwegian and UK sectors. Finally, China and Mexico each increased production by about

6 The use of oil in the refining sector declined by about one mbd. Much of this decline was due to a reduction in refining capacity, which shrank from 49.4 mbd in 1978 to 42.1 mbd in 1985.

7 Conventional crude oil refers to the way in which crude oil is produced. According to the EIA, conventional crude oil is defined as crude oil "that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil to readily flow to the wellbore".

2 mbd. The only significant reduction occurred in the United States, where production declined by about 2 mbd between 1973 and 1990.

Increased production of crude oil was supplemented by increased production of natural gas liquids[8], which grew by about 2 mbd between 1979 and 1990 – split almost equally between OPEC and non-OPEC countries. The increase from non-OPEC countries is consistent with price-taking behaviour – higher prices increased supply. The increase from OPEC countries was generated in part by difficulties that weakened OPEC as an institution (see Box 1). Since natural gas liquids do not come from oil fields, their production was not part of the quota aimed at limiting the production of crude oil. As described below, OPEC countries sought to increase the production of natural gas liquids to offset reductions in the quantity of crude oil that they were allowed to produce.

8 Natural gas liquids are liquids pumped from natural gas fields that can be separated from natural gas and liquefied in a gas processing plant during processing. Natural gas liquids include ethane, propane, butane and lease condensate. These liquids can be added to crude oil and put through a refinery to generate refined petroleum products (for example, motor gasoline). As such, they can increase the supply of liquid fuels.

Box 1

OPEC IN THE 1980S

OPEC was founded in 1960 by five countries[1] in order to halt the ongoing decline in oil prices and gain control of production from fields located within their national territory. At the time, production was controlled by multinational oil companies, which unilaterally cut the price of crude oil throughout much of the 1950s and 1960s. If a host country objected, multinational oil companies would cut production in local fields and increase production in another country, in particular the United States. Although the majority of the world's reserves of crude oil were (and still are) located within the OPEC countries, the OPEC countries did not control the marginal supply of crude oil, as measured by spare capacity (Kaufmann, (1995)).

Instead, the marginal supply of oil resided in the United States, where production was controlled by the Texas Railroad Commission and other state-level organisations. These organisations were charged with stabilising oil prices[2], and they did so very effectively by opening and shutting (prorationing) operable capacity[3], which meant that supply was roughly equal to demand.

At its peak, OPEC's control over the marginal supply of oil enabled it to set an "official" price for oil. OPEC set its first official price for Saudi Light in 1980 at USD 28 per barrel. In 1981, OPEC had sufficient power to raise the official price to USD 32. By 1982-83, the official price of Saudi Light had reached USD 34 per barrel.[4]

As described previously, these higher prices were associated with a recession, interfuel substitution and increases in non-OPEC production. Together, these developments reduced demand for OPEC oil from 30.6 mbd in 1979 to 17.5 mbd in 1983.

1 Namely Iraq, Iran, Kuwait, Saudi Arabia and Venezuela.
2 This power was granted to them under the Connally Hot Oil Act of 1935.
3 Operable capacity is the quantity of oil that can be produced from a field for the next six to 18 months. It is calculated according to the number of wells drilled and the existing capital infrastructure for producing and transporting oil.
4 This is not to argue that OPEC was able to set prices. Analysis by Verleger (1982) and Lowinger and Ram (1984) indicate OPEC's official price was "Granger caused" by spot prices.

In order to defend their official price, OPEC developed a quota system, which was very similar to the prorationing system used by the Texas Railroad Commission. The OPEC countries met on a quarterly basis to coordinate projections for world oil demand and non-OPEC production, and the difference between the two was viewed as the demand for OPEC oil. By limiting production to this difference and dividing this production between its Members, OPEC tried to defend its official price.

These efforts were relatively ineffective, however. By 1983, OPEC had agreed to limit production to 17.5 mbd, which was then reduced further to 16 mbd[5] in 1984. Despite these agreements, many OPEC countries produced oil in excess of their quota. This, as well as ongoing increases in non-OPEC production and continuing reductions in oil demand, meant that prices continued to fall. By 1985, OPEC was forced to cut its official price for Saudi Light to USD 28 per barrel. However, the price reductions did not curb the ongoing increases in non-OPEC production or the decline in world oil demand. As a result, OPEC was forced to shut-in ever increasing quantities of oil (see Chart 6). Most of these reductions were absorbed by Saudi Arabia, which was OPEC's largest producer. Saudi Arabia became the "swing producer", cutting production as demand for OPEC crude oil fell. By August 1985, Saudi Arabia was producing 2.4 mbd, down from 10.4 mbd in August 1981.

The combination of declining output and lower prices reduced OPEC revenues, and thus the efforts to sustain higher prices by shutting in production became financially unsustainable. By December 1985, OPEC had still not reached an agreement on lower levels of output. Continued production in excess of quotas caused prices to decline. In an attempt to halt the price decline, OPEC met in February 1986, but still could not come to an agreement. By mid-1986, the nominal price of crude oil had dropped below USD 10, which, in real terms, was roughly equivalent to the prices that prevailed prior to the first price hike in 1973-74.

Finally, in August 1986, OPEC reached an agreement to reign in excess production. OPEC would again set quotas, but it would no longer set an official price. Instead, OPEC would try to keep oil prices within a range that would allow OPEC producers to maintain a "fair share" of the world oil market.

This strategy remained in place throughout the 1980s and 1990s. During this period, real oil prices remained at levels well below the 1981 peak. As recently as 2001, OPEC argued that the desired range for crude oil prices was USD 22 to USD 28 per barrel.

5 Actual production was 1.5 mbd higher, 17.44 mbd.

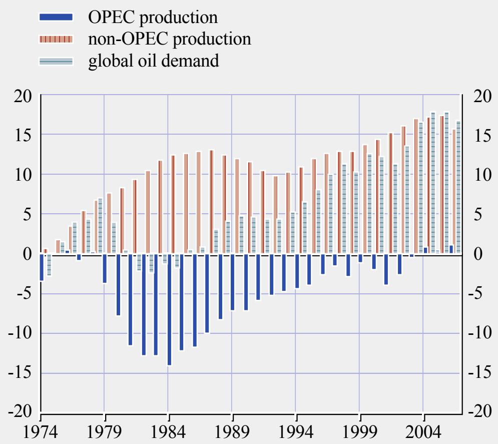
4 WHY HAVE OIL PRICES RISEN OVER THE LAST EIGHT YEARS?

Taking the USD 22 to USD 28 range as a starting point, oil prices have risen steadily over the last ten years, temporarily breaching the USD 140 threshold in the third quarter of 2008. This price is well above the previous high in real US dollar terms.

Several analysts argue that the current price increase is being driven by increasing demand, and they use the role of demand to differentiate between this price increase and the price increases of the 1970s and early 1980s, which they attribute to changes in supply. Global demand for oil increased from 74.0 mbd in 1998 to 85.6 mbd in 2007 (see Chart 6). The 12 mbd increase should be seen against the background of available spare production, transportation and refining capacity. In this context, the 12 mbd increase differs significantly from the increases during the 1950s, 1960s and the years 1988-98 when capacity bottlenecks were more limited. Similarly, world oil demand increased by about 10 mbd between 1988 and 1998, which also was a period of relatively flat oil prices.

Chart 6 Changes relative to 1973

(change relative to 1973; million barrels per day)



Source: US Energy Information Administration.
Note: Latest observation refers to 2007.

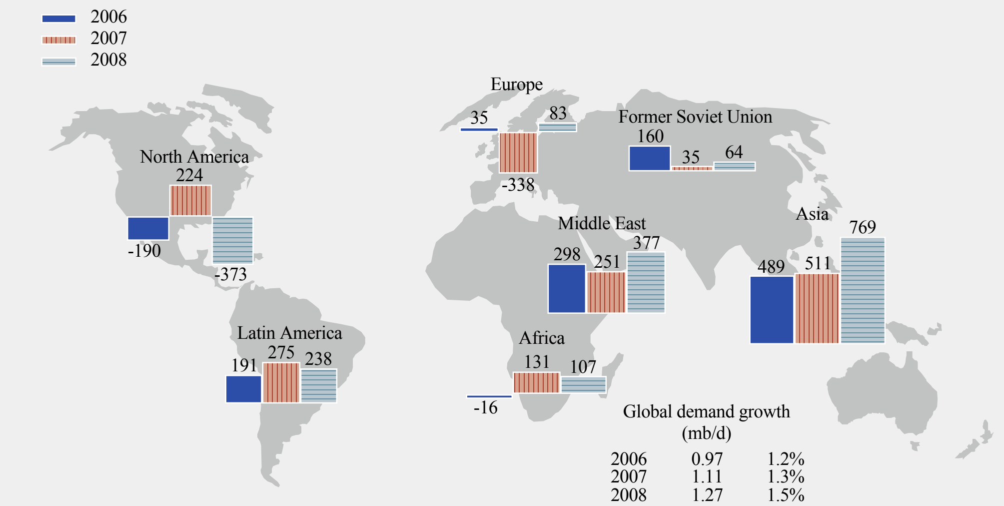
While the role of demand cannot be denied, changes on the supply side appear to have played an even more critical role.

DEMAND

Demand increased at a slightly accelerated pace during the years 2000-07 (see Chart 8).

Chart 7 Global demand growth in 2006, 2007 and 2008

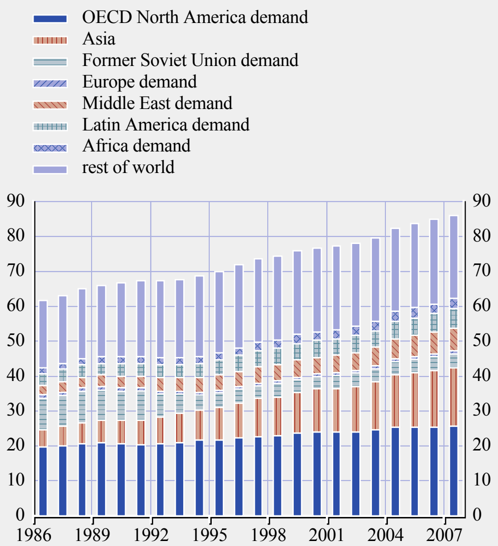
(thousand barrels per day)



Source: International Energy Agency.

Chart 8 World oil demand by region

(million barrels per day)



Source: International Energy Agency.
Note: Latest observation refers to 2007.

The smallest contribution to this increase came from OECD countries – their demand rose from 47.8 mbd in 2000 to 49 mbd in 2007 – while the greatest contribution came from non-OECD countries, whose oil consumption rose from about 29 mbd in 2000 to about 36 mbd during the first half of 2007. The majority of this total was located in China, where demand rose from about 4.8 mbd in 2000 to about 7.8 mbd in 2007.

STOCKS

Over the last 20 years, oil stocks have generally declined. For example, stocks of crude oil in OECD countries (other than the Strategic Petroleum Reserve in the United States) declined from about 95 mbd in the mid-1980s to about 78 mbd in 2004. Most of this decline was associated with stagnant stocks, as the capacity to hold crude oil had steadily fallen behind demand over the last decade. From 2004 onwards, however, there was a recovery back towards about 85 mbd in 2007.

SUPPLY

Over the last five years, there has been a dramatic slowdown in the growth of non-OPEC oil production. During the 1980s, non-OPEC oil production grew from 32 mbd to 38 mbd. Production declined slightly around the mid-1990s due to the collapse of the former Soviet Union, but by 1997, Russian oil production had started to grow again, which powered a steady rise in non-OPEC production through to 2004.

Specifically, the production of crude oil by non-OPEC countries has not increased since 2004 (see Charts 5 and 6). Since 2004, all of the increase in world oil demand – more than 4 mbd – has been supplied by crude oil pumped by OPEC countries and natural gas liquids produced by both OPEC and non-OPEC countries. This has allowed OPEC to re-establish control over the marginal barrel. Furthermore, this marginal barrel has come from existing OPEC capacity, which has driven up utilisation rates (see Chart 9). The lack of further gains in non-OPEC production means that OPEC has supplied much of the oil needed to meet the recent gains in demand.

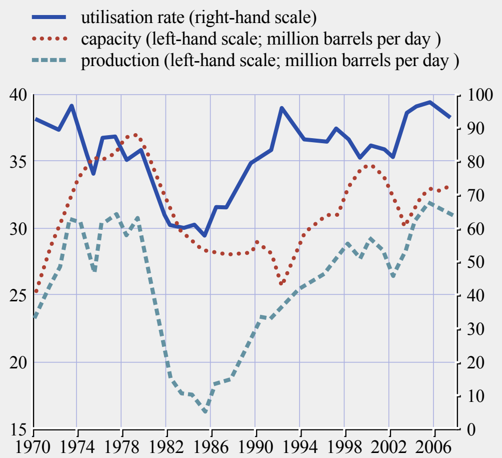
OPEC's increasing control over the marginal supply of oil is reflected in OPEC's high rate of capacity utilisation. OPEC's short-run capacity to produce oil has not changed significantly over the last 30 years (see Chart 9).

Much of this capacity remained unused during the 1980s and 1990s and this excess exerted downward pressure on prices. Most of this excess capacity has now been reopened. As a result, OPEC is now producing oil at rates very close to its short-run capacity. As with any other commodity, high rates of capacity utilisation push up prices.

This upward price pressure has been partially dampened by a change in the types of crude oil produced. Crude oil varies in quality (see Box 2), which is measured by density (light vs heavy) and sulphur content – sour

Chart 9 OPEC capacity utilisation and production

(percentages)



Source: US Department of Energy.
Note: Latest observation refers to 2007.

(high sulphur content) and sweet (low sulphur content). Light sweet crude oils are more valuable than heavy sour crude oils because they generate a larger fraction of valuable products (for example, motor gasoline and jet fuel) and they are less damaging to refineries. Since non-OPEC production has stagnated and OPEC has not increased capacity, recent growth in oil demand has forced OPEC to open fields that produce heavy and sour crude oils. However, adding these crude oils lowered the average quality of crude oil and consequently also lowered – ceteris paribus – the average price of crude oil.

SPECULATION

In May 2008, more than half of the holders of positions in oil on the NYMEX were non-commercial players, i.e. agents not physically involved with oil. Non-commercial players have been increasingly active in futures oil markets, and this has raised questions about their potential impact on prices. First of all, it has to be said that non-commercial players can be divided in two categories: *speculators* (active investors) who trade in the oil market on the basis of their supposedly better information in the hope of making profits by anticipating market movements in commodity prices, and *index funds* (long-term oriented, passive investors) which have emerged only more recently and reflect the desire to add commodities to one's portfolio in view of their risk/return profile. For example, commodities are added to portfolios in order to hedge against adverse risks coming from oil-sensitive assets in the portfolio. Accordingly, these funds are "long-only" players; they buy oil futures and roll them over as expiry dates approach in order to avoid the delivery of the commodity.

There is currently scant evidence of the activity of financial players having an impact on oil prices. A formal assessment is hampered by data and methodological problems, including the difficulty of identifying speculative and hedging-related trades. OPEC countries argue that market fundamentals alone cannot account for the rise in oil prices. In March 2008, the Saudi Arabian Minister for Petroleum and

Box 2

THE QUALITY OF CRUDE OIL

Crude oil varies in density (light vs heavy) and sulphur content, sour (high sulphur content) and sweet (low sulphur content). The density of a crude oil is indicated by its API gravity index, which is an arbitrary scale that expresses the gravity or density of liquid petroleum products relative to water. Larger numbers indicate lighter grades of crude oil, which have a value of 38º or above. A value of 22º or below indicates heavy crude, while values between 22º and 38º indicate medium-grade oil.

Mineral Resources, Ali Al Naimi, argued that "speculation in futures markets is determining prices". However, OPEC argues that investors have allocated a larger portion of their portfolio to crude oil and that the large flow of capital into the oil market has forced prices higher. It therefore appears to be arguing that index funds are generating additional demand. In our opinion, however, there is no sound evidence to corroborate this argument. First of all, index funds do not produce any additional physical demand, since they are not interested in the delivery of oil. As the delivery date of the future contracts approaches, spot and future prices have to converge, and the spot price is indeed determined by the supply and demand curves of producers and consumers.

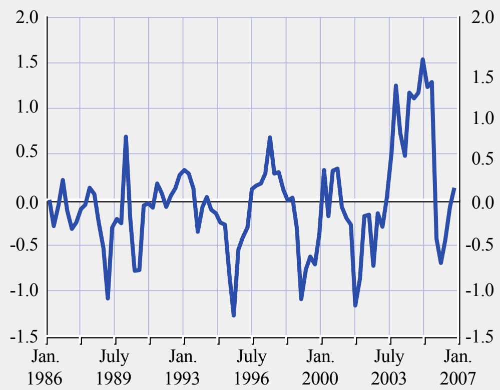
Furthermore, although it is true that the assets managed by commodity index funds have surged since 2001, from USD 10 billion to more than USD 200 billion, the overall size of index funds is still very small relative to the size of the physical market. Compared with the physical oil market, the size of index funds is equivalent to only 80 million barrels, which is less than the world oil demand for one day, and 0.26% of annual demand. It therefore seems very unlikely that index funds have had a sizeable impact on oil prices.

Turning to the role of speculators, we first remark that it is true that much of the increase in oil prices between 2005 and 2007 was associated with a change in futures markets from backwardation to contango (see Chart 10).

Throughout much of the 1990s and the early part of this decade, futures markets were in backwardation. This backwardation was sustained in part by OPEC's strategy to maintain prices and speculators sensed that the strategy would not work. In order to maintain prices, OPEC quotas were designed to match supply and demand. Adhering to the quotas meant that there was little extra oil to build inventories. Low inventories supported prices in the near term by keeping the market dependent on current production. Furthermore, backwardation

Chart 10 Difference between the four-month and near month contract on the NYMEX

(USD per barrel)



Source: US Energy Information Administration.
Note: Latest observation refers to July 2008.

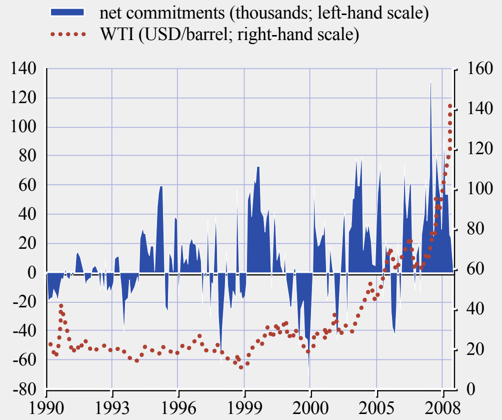
was self-reinforcing because when the market is in backwardation, there is no incentive to build stocks. Far-month contracts remained lower than near-month contracts because speculators expected that increased levels of non-OPEC production and a breakdown in OPEC cohesion would generate excess supplies in the future.

Between late 2004 and mid-2007, prices of near and far-month contracts changed such that the market was in contango. This created market conditions that tend to boost prices but it also created an opportunity for speculators. Once the price difference between a near-month contract and a far-month contract exceeds the physical cost of storage, more expensive future month prices give firms and speculators an incentive to build stocks – it becomes less expensive for firms to buy oil now and pay the storage costs than to contract for deliveries of more expensive oil in the future. Furthermore, this arbitrage opportunity can be "rolled forward" which is what added to the upward pressure on oil prices between 2005 and 2006.

Since March 2007, speculative pressure on prices has been indicated by high levels of fund activity in crude markets, with the data from the Commodity Futures Trading Commission (CFTC) showing that speculators in the NYMEX

Chart 11 Speculative positions and oil price

(net futures commitments of non-commercials)



Source: Bloomberg.
Notes: Net commitment = number of long - short contracts, where each contract represents 1000 barrels. "Non-commercials" denotes entities not engaged in crude oil production or refining. Latest observation refers to June 2008.

crude oil market have been positioned net long, with increasingly high and volatile positions (see Chart 11). Yet, it should be noted that in the past months this position has changed despite surging prices, and recently non-commercial players have assumed a net short position for the first time since 2007.

In any case, an econometrically sound formal assessment is hampered by data and methodological problems, including the difficulty of identifying speculative and hedging-related trades. Despite such problems, however, a number of studies seem to suggest that speculation has not systematically contributed to higher oil prices (see IMF (2006)) as they show that causality runs from prices to changes in speculative positions. In fact, although many transactions are described as speculative, they may reflect a precautionary desire to hedge exposures in the face of uncertainty.[9]

Other studies that use more disaggregated data confirm that speculation does not drive oil prices. NYMEX staff found that hedge funds trading on the NYMEX is a non-disruptive source of liquidity to the market and that the positions and trading volumes of hedge funds have a neutral impact on price levels and a negligible influence on volatility. Using a unique set of data from the CFTC, Haigh, Hranaiova and Overdahl (2005) find that speculators (hedge funds) do not change their positions as frequently as commercial operators (oil companies that use derivatives to hedge), that there is a significant negative correlation between speculative positions and the positions of commercial operators, and that it is speculators who are providing liquidity to commercial operators and not vice versa.

9 For example, concerns about future shortages could lead to a genuine desire among consumers to hold increased inventories, which would push up prices, everything else being equal.

5 THE LONG-RUN FORECAST FOR OIL PRICES – NO RERUN OF THE 1980s

The long-run forecast (15 to 20 years) for oil prices depends heavily on OPEC's ability to maintain control over the marginal supply of oil. As described below, market fundamentals suggest that OPEC will be able to maintain its control over the marginal supply of oil and therefore avoid a rerun of the 1980s and 1990s during which rising non-OPEC production and slowing demand diminished OPEC's control. First, oil demand is likely to grow significantly in line with strong economic growth in non-OECD countries, especially Asia, as these countries tend to be highly oil intensive. Second, on the supply side, OPEC is likely to enhance its control over markets over the next two decades due to anticipated changes in the economic, geological, technical, political and institutional environment. Increases in newly opened areas, such as the Caspian Sea region, will only partially offset declining rates of production in other geologically mature non-OPEC oil regions. In this context, regardless of the geological conditions, OPEC future additions to supply are likely to be small, as there are few economic incentives to expand existing capacity. This limit is not simulated by most models. There is therefore a considerable risk that the resulting supply forecasts may overstate the amount of oil that can be delivered to the market – a marked distinction with respect to the fundamentals that prevailed in the 1980s, when oil prices dropped. Moreover – as for non-OPEC procedures – while concerns about climate change will spur global efforts to reduce carbon emissions, these efforts are not expected to reduce oil demand. Finally, while there is much talk about alternative fuels, few of these are economically viable at the prices currently envisioned, and given the structural impediments, there is a reduced likelihood that the market will generate significant quantities of these alternatives over the forecast horizon.

We illustrate changes in oil demand, non-OPEC oil production, OPEC production and the production of alternative fuels with simulations generated by models run by the EIA and the International Energy Agency (IEA). These are among the few models with a forecast horizon that is consistent with the 20-year horizon used here. Furthermore, these simulations are available to the public and are frequently described in the media. Most of the figures that follow are derived from the EIA simulation because it reports annual values, as opposed to the five-year interval values reported by the IEA. Nonetheless, the general changes simulated by the IEA are also reported to illustrate that the simulations generated by the two models are very similar.

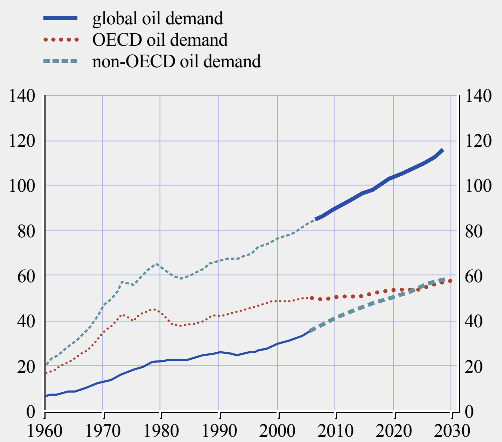
DEMAND

Oil demand is forecast to expand steadily over the next two decades. Growth will be driven by demand increases in non-OECD countries outpacing stagnant levels of demand in OECD countries. These differences are largely the result of income effects relative to price effects. In non-OECD countries, income gains associated with economic development will outstrip the price effects associated with higher oil prices.

Forecasts generated by both the EIA and the IEA currently expect oil demand to grow over

Chart 12 Oil demand forecast

(million barrels per day)



Source: US Energy Information Administration.
Note: Latest historical data refer to 2007. Forecast goes up to 2030.

the next two decades. For example, the EIA forecasts that global demand for liquid fuels will reach 118 mbd by 2030 (see Chart 12).

Similarly, the IEA forecasts that oil demand will reach 116 mbd by 2030. The growth rates needed to reach these levels are relatively low compared with historic levels. To reach 116 mbd in 2030, global demand must grow by about 1.3 percent per year. Although this seems like a slow growth rate (as described below, there is a considerable risk that oil demand will grow faster than projected), sustained growth generates a large absolute increase in oil demand.

Demand continues to grow because, for most non-OECD countries, income effects outweigh efficiency gains associated with improved technology and/or higher prices. It is also continuing to rise despite some early studies suggesting that demand for oil (and other natural resources and environmental quality) can be modelled using an "Environmental Kuznets Curve" (EKC). According to the EKC hypothesis, demand for natural resources and/or the emission of pollutants increases as income rises. These increases slow down as income rises, and beyond a certain "turning point", further income gains reduce demand for natural resources and/or the emission of wastes (Grossman and Krueger (1991); Shafik and Bandyopadhyay (1992)). This generates an inverted u-shaped curve for the relationship between income and oil use. The turning point and subsequent decline prompt some analysts to forecast that economic development will slow growth in oil demand, and perhaps cause it to decline.

The notion of an EKC for energy use in general, and oil use in particular, is supported by some initial empirical studies (for example, Bruyn et al. (1998); Schmalensee et al. (1998); Holtz-Eakin and Selden (1995)). Schmalensee et al. (1998), for example, find that energy intensity declines as GDP per capita grows beyond about USD 10,000 (in 1985 prices). But these results are contradicted by more recent findings that indicate that the decline in intensity is caused by model misspecification. Empirical estimates for the EKC are often generated by fitting observations to a quadratic function. The turning point is often greater than the largest observed value for income. Without observations on the right side of the turning point, it is possible to model the relationship between income and oil use with a semi-log or double-log specification (as opposed to a quadratic specification). Richmond and Kaufmann (2006) use these three specifications to estimate the relationship between energy use and GDP per capita from observations made between 1973 and 1997 for 36 countries. Tests of the predictive accuracy of out-sample forecasts generated by the three models indicate that the semi-log model is the best descriptor of the relationship between energy use and GDP per capita in non-OECD countries. This would imply that there is no turning point. Richmond and Kaufmann (2006) find that a quadratic model is the best descriptor of the relationship between GDP per capita and energy use in OECD countries. But even this support is invalidated by omitted price effects – including energy prices- in models of the relationship between GDP per capita and energy use in OECD countries and hence indicates that a double-log specification generates the best description of the relationship (Richmond and Kaufmann (2007)). Again, this would imply that there is no turning point. Nor will a turning point in the relationship between income and intensity of use automatically generate a reduction in oil use. Even if the turning point found by Schmalensee et al. (1998) is correct, the scale effect associated with increases in GDP (associated with gains in GDP per capita and population) more than offsets the reduction in energy intensity such that total energy use rises. The importance of scale relative to efficiency is demonstrated by an econometric analysis of sectoral oil demand in 133 countries (Kaufmann and Shiers (2008)). The dependent variable is oil demand by sector[10]; independent

10 The ten sectors analysed, as defined by the IEA, include (1) agriculture, (2) commercial, (3) electricity, (4) heat and power, (5) residential, (6) transportation, (7) other transportation, (8) manufacturing, (9) non-energy, and (10) bunkers.

Table 1 Impact of GDP per capita (in constant USD 2000) for the sectoral inflection points for oil demand

(USD)

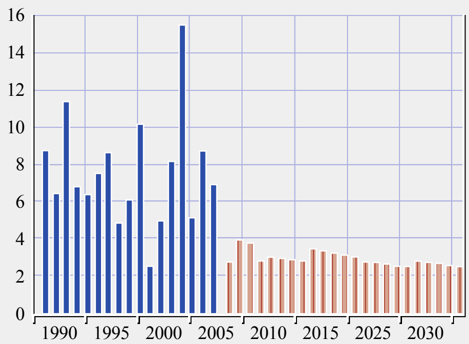
Sector	Turning points	
	First	Second
Agriculture	1,010	2,510
Bunkers [1]	-	-
Commercial	68,000	122,000
Electricity	42,100	120,000
Heat and power	5,420	17,500
Manufacturing	90,600	237,000
Non-energy	4,630	49,800
Other transportation [2]	12,000	-
Residential	8,940	22,400
Transportation	-	-

1) Coefficients associated with income are not statistically different from zero.
2) Coefficient associated with income cubed is not statistically significant.

variables include GDP, population, as well as linear, squared and cubic terms for GDP per capita. In this specification, GDP per capita should be interpreted as non-linear interactive terms for GDP and population. Coefficients associated with GDP per capita show two turning points; sectoral oil use grows with initial gains in income, declines with further gains, but then rises again as income reaches higher levels (see Table 1). The conclusion of such analyses is therefore that, regardless of the income levels and at odds with the EKC hypothesis associated with these turning points, population and GDP effects are predominant. In these circumstances, increases in GDP or population push up oil demand.

Chart 13 Annual changes in Chinese oil consumption

(percentage change)



Source: US Energy Information Administration.
Note: Latest historical data refer to 2007. Forecast goes up to 2030.

Given the importance of scale, much of the income and population-driven increases in global oil demand originate in non-OECD countries. For example, the IEA forecasts that more than 70 percent of the increase in world oil demand will originate in non-OECD countries, so that by 2030 non-OECD countries will eventually consume more oil than OECD countries (see Chart 12). Much of this growth in demand will be concentrated in China and India. Together, these countries are home to about a third of the world's population and their income has been growing rapidly over the last decade. In China, real GDP has increased by about 10 percent each year since 1990.

A closer look at projections for oil demand indicates that demand could grow faster than forecast. For example, the EIA forecasts that Russian oil demand will grow 0.8 percent annually between 2005 and 2030, reaching 3.4 mbd by 2030, which is lower than the 1993 level of consumption of 3.8 mbd. The fact that 25 years of economic growth (powered in part by high oil prices) will not cause Russian oil consumption to exceed the levels of the early 1990s suggests that the forecast for Russian oil demand is very low. The IEA forecasts Russian oil demand to grow slightly faster at 1 percent each year until 2030.

Even more significant is the fact that the EIA forecasts Chinese oil demand to only grow from 6.9 mbd in 2007 to 15.0 mbd by 2030, which corresponds to an average annual growth rate of 3.2 percent: a very substantial reduction in the annual change, which is hard to justify from previous trends (see Chart 13). Similarly, the IEA forecasts Chinese oil demand growth to drop to 3.4 percent a year.

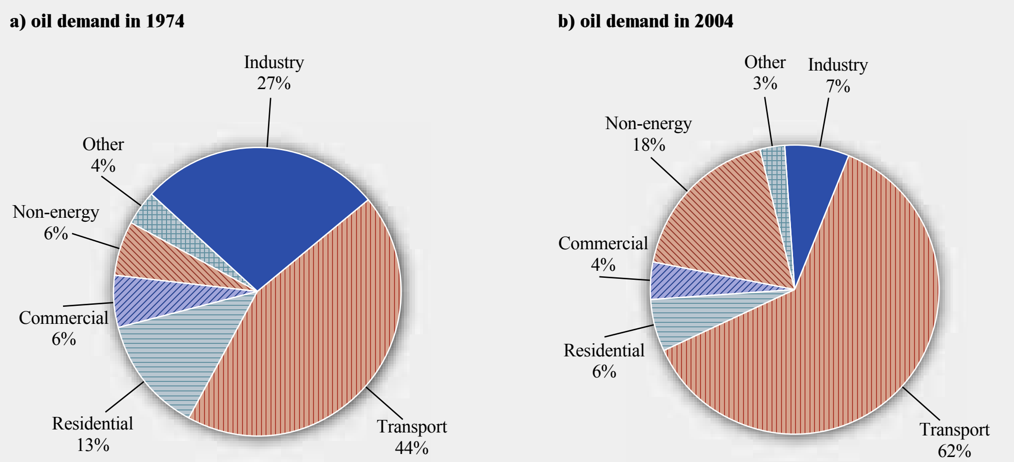
There is reason to doubt that Chinese oil demand growth will drop as dramatically as forecast by the EIA and IEA. An econometric analysis performed by Gately (2007) indicates that the Chinese automobile fleet will increase 20-fold by 2030 (the global fleet is expected to double). Currently, China consumes 1.2 mbd of motor fuel. The 20-fold increase in the automobile fleet implies a 23 mbd increase in motor fuel consumption, even if fuel consumption per car remains constant. This may be a conservative assumption as motor fuel use per car responds strongly to initial income gains (this increase may, however, be offset by gains in energy efficiency). On the production side of the economy, increased output and exports imply similar increases in the demand to transport raw materials and finished goods.

The apparent underestimation of oil demand growth in non-OECD countries is an important factor that could result in a downside bias in global demand growth forecasts. In fact, income and demand elasticities differ between OECD and non-OECD countries, and differential rates of demand growth will support higher prices. Both theory and empirical analyses indicate that income elasticities in non-OECD countries are greater than in OECD countries. Conversely, own-price elasticities are greater in OECD countries. These differences suggest that, as non-OECD countries are responsible for a greater fraction of global oil demand, the average income elasticity will rise and the average price elasticity will fall. These changes will tend to increase oil demand and make it less sensitive to higher prices, both of which support higher oil prices.

The structural change in the composition of OECD oil demand associated with the price increases of the 1970s and 1980s reduced the price sensitivity of OECD oil demand. The fraction of oil demand in sectors sensitive to oil prices decreased significantly between 1974 and 2004 (see Charts 14(a) and (b)).

The manufacturing and residential sectors are currently responsible for a much smaller fraction of final oil demand than before. Most oil is instead consumed by the transportation and non-energy sectors. In both of these sectors, it will be difficult to replace oil with other forms of energy, which will limit the downward pressure on prices that could be generated by lower demand. This general pattern is already is present in developing countries where transportation and non-energy uses accounted for 64 percent of total energy use in 2004, as opposed to 50 percent in 1974 (see Charts 14(a) and 14(b)).

Chart 14 Sectoral composition of OECD



Source: International Energy Agency.

These difficulties are best illustrated by the transportation sector's dependence on oil use. The need for liquid fuels in the transportation sector means that they cannot be replaced by coal or natural gas. Eventually, electricity may be able to be used as a replacement for motor fuel, provided there are significant advances in battery technology. But, given that there has been limited progress in improving battery life over the past two decades, using electricity to power a significant portion of the world's fleet of motor vehicles within the next two decades seems unlikely.

The relatively small impact of higher energy prices and advanced technology on oil demand is consistent with results generated by three price scenarios recently run by the EIA.[11] Prices for 2030 range from USD 100 per barrel (high price scenario) through USD 60 (reference scenario) to USD 36 (low price scenario). The respective rates of world oil consumption are 128 mbd in the low price scenario, 117.4 mbd in the reference scenario and 101 mbd in the high price scenario. These differences imply a small own-price elasticity of demand. Crude oil prices in the high price scenario are about 200 percent higher than in the low price scenario, while oil demand is about 27 percent lower. This would imply an own-price elasticity of about -0.13. Elasticities calculated using the reference scenario are similar, and these values are consistent with those reported in the peer review literature (for example, Narayan and Smyth (2007); Eltony (1999)).

Small price elasticities imply that very large price increases would be needed to offset the effect of rising income on oil demand. Since price elasticities are small, and international changes in the composition of oil demand reduce the global average, rising energy prices are unlikely to generate reductions in oil demand that would be sufficiently large to cut into OPEC demand as they did in the 1980s. This implies that OPEC may be able to sustain higher oil prices without causing a reduction in oil demand that would diminish its control over the marginal supply.

CLIMATE CHANGE POLICY

Forecasts for oil demand depend partly on the possibility of an international agreement to limit carbon emissions. Historically, oil producers such as OPEC have been hostile to such agreements, as they fear they could spark a reduction in oil demand. As described below, coal producers are instead likely to bear the brunt of such agreements, with rather limited effects on oil demand.

At first glance, oil demand could be significantly depressed by efforts to limit emissions of carbon dioxide, which are produced by the combustions of fossil fuels and are at the root of climate change. The reason for this belief is that, globally, oil use accounts for about 37 percent of primary energy use (2005) and is responsible for about 39 percent of carbon emissions.

Different fossil fuels emit different quantities of carbon per heat unit and oil is not the largest "pollutant". In particular, burning one thousand BTUs (BTUs measure the energy content of a fuel) of coal emits 26 grams of carbon dioxide, whereas one thousand BTUs of oil emit 21.4 grams of carbon (and 14.5 grams of carbon using natural gas). These quantities are fixed by the chemical composition of the fuel.

Price-based mechanisms to reduce carbon emissions, such as a carbon tax, will probably have little impact on oil demand. Carbon taxes raise the price of fuels based on the amount of carbon emitted per heat unit burned. Given the relative emission rates, carbon taxes raise the price of coal by the greatest amount, while oil and natural gas prices rise by smaller amounts (see Table 2).

The percentage increase in coal prices is even greater because coal is much less expensive than oil. For example, a USD 1000 carbon tax raises the price of coal delivered to electric utilities by about 150 percent while it raises oil prices only by about 27 percent (see Table 2).

11 Oil prices are exogenous in the model simulated by the EIA.

Table 2 Effects of a USD 1000 per metric ton carbon tax on the price of fossil fuels delivered to US electric utilities

(percentages)

	Emission rate (grams/1000 BTU)	Tax dollars per million BTU	Prices to US utilities	Percentage change
Coal	26.0	USD 2.60	USD 1.69	154
Oil	21.4	USD 2.14	USD 7.85	27
Natural gas	14.5	USD 1.45	USD 6.34	23

Source: US Energy Information Agency.

The increase in energy prices relative to capital and labour will reduce energy use, including oil use. But some of this reduction will be offset by changes in the relative price of energy, which will prompt consumers to replace coal with oil and/or natural gas. As such, a carbon tax may actually increase oil demand. These gains may be offset by substituting oil for natural gas (Kaufmann, 1991(a)). In the light of these directions for interfuel substitution, price-based climate change policies will have relatively little impact on oil demand.

Similarly, oil demand will probably be relatively unaffected by policies aimed at reducing emissions with a cap and trade system. With such a strategy, governments manage permits that entitle permit holders to emit carbon dioxide. Owners can use a permit to emit carbon dioxide or can sell the permit if he/she can reduce emissions at a cost lower than the market price for the permit.

The feasibility of a cap and trade system is determined in part by the number of participants and their technical sophistication. For the system to succeed, emissions must be monitored to ensure that those who emit carbon dioxide have the requisite permits. To ensure efficiency, participants must be able to make economically rational decisions to buy or sell permits and must have access to capital that would support economically rational investments to reduce emissions.

The totality of these requirements implies that a cap and trade system is most likely to include only large energy consumers in the manufacturing and/or electricity–generating sectors for example. These sectors use large quantities of coal relative to oil and natural gas. The quantity of coal (measured in heat units) used by OECD countries in the industrial and electricity-generating sectors is about ten times greater than the amount of oil used. These relative rates support the notion that efforts to reduce carbon emissions will be achieved by reducing coal use – climate policy will therefore have relatively little impact on oil consumption.

CONVENTIONAL CRUDE OIL SUPPLY

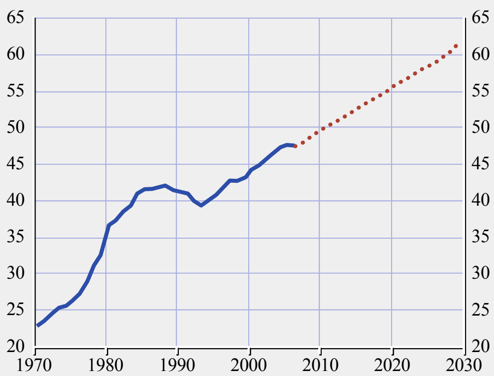
IEA and EIA projections that 30 mbd of additional crude production will be needed by 2030 present a formidable challenge given that many oil-producing areas are now considered "mature" and so production is expected to remain stable or decline. To satisfy growing demand, both non-OPEC and OPEC countries will need to produce additional quantities of conventional crude oil, and these quantities will need to be supplemented by the production of alternative fuels. As described below, it is generally considered unlikely that the resource base will support significant gains in non-OPEC production. Assuming that OPEC does have sufficient supplies, there are no strong economic incentives for it to expand production. Instead, the ability to match supply and demand may depend on the technical improvements and capital investments that are needed to expand the production of alternative fuels (see the next section).

NON-OPEC PRODUCTION

Both the IEA and the EIA forecast non-OPEC production to increase over the period 2005-30. The EIA forecasts production of both crude oil

Chart 15 Projection for non-OPEC oil production

(million barrels per day)



Source: US Energy Information Administration.
Notes: Latest historical data refer to 2007. Forecast goes up to 2030.

and natural gas liquids to increase by 1.0 percent each year. The IEA forecasts an annual gain of about 0.8 percent over the same period. As a result, the EIA forecasts production to increase by about 14 mbd, from 47.3 mbd in 2005 to 61.5 mbd in 2030 (see Chart 15).

Where should this extra production come from? It is certainly unlikely that significant increases in non-OPEC production will originate in areas that are presently not known to contain significant quantities of oil. Most of the world's sedimentary rock formations (the only type of rock that can hold crude oil) have been already explored using seismic techniques. These techniques cannot identify oil *in situ*, but they can identify formations that have the potential to hold significant quantities of oil. Based on seismic information (and the results of drilling wells), both the EIA and IEA forecasts indicate that the largest increases in non-OPEC production will occur in areas around the Caspian Sea. Oil production is forecast to increase in other areas, but the pace of this increase is expected to be slower and oil output is expected to be smaller (see Table 3). For example, the EIA forecasts smaller increases in production in the non-OPEC areas of Africa and South America. Even smaller increases are forecast in the United States.

On the other hand, there are other areas in which resource depletion is expected to reduce production. For example, the EIA and IEA forecast that OECD oil production will decline in Europe, as well as in Canada, Mexico and China.

Geological considerations imply that much of the risk associated with the forecast for a 14 mbd increase in non-OPEC production lies on the downside, i.e. that production is likely to be less than forecast. Unlike the 1980s and 1990s, there are few unexplored sedimentary rock formations. This is likely to reduce discoveries relative to the 1980s and 1990s. This difference is not captured by the EIA or IEA models because they do not explicitly consider the resource base and/or tend to overstate the potential for higher prices to elicit additional production.

This bias is especially apparent in forecasts for production in two of the largest non-OPEC regions, namely the United States and the North Sea. The EIA model forecasts US production to

Table 3 Projections for oil production

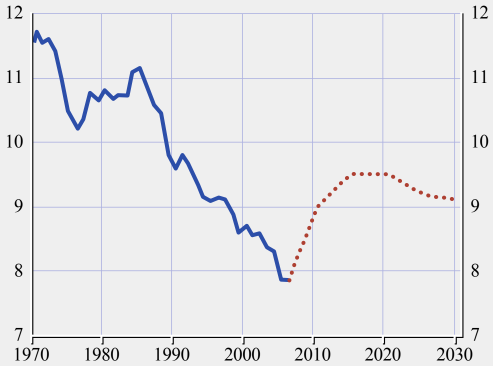
(million barrels per day)

	2005	2030	Difference
Non-OPEC	47.3	61.5	14.2
of which Asia	2.4	3.3	0.9
Caspian Sea	2.1	5.7	3.6
South America	4.1	6.8	2.7
USA	8.6	9.2	0.6
OECD Europe	5.9	2.7	-3.2

Source: US Energy Information administration.

Chart 16 Projection of oil production in the United States

(million barrels per day)



Source: US Energy Information Administration.
Note: Latest historical data refer to 2007. Forecast goes up to 2030.

rise, i.e. a reversal of its long-term downward trend, with US production of crude oil declining from 11 mbd in 1973 to 6.8 mbd in 2004 (see Chart 16). One of the few differences between the two forecasts is that the IEA does not forecast US production to rise.

Just after the rise in real oil prices during the early 1970s, analysts in the US Department of Energy (Federal Energy Administration (1974)) and the National Petroleum Council (1971) forecast that higher prices would reverse the decline and boost production to new all-time highs. Although real oil prices exceeded the threshold forecast to generate a new all-time high, production continued to decline. With the benefit of hindsight, the continued decline in production can be explained by econometric analyses that explicitly account for changes in the resource base (for example, Kaufmann (1991(b)); Kaufmann and Cleveland (2001)). These analyses indicate that the United States has exhausted many of its largest fields and it is not possible to offset the decline in these fields by increasing production in fields that are one or two orders of magnitude smaller.

A similar bias is likely to be responsible for the forecast of greater production over the next 25 years. Production in the United States has been declining because resource depletion is reducing production in the giant onshore fields that generate most of the United States' output – the forecast does not include production from the Arctic National Wildlife Refuge, which is currently off-limits. Even if this area is opened, the US Geological Survey (1998) indicates that a decade would pass before 1-2 mbd could be produced for about a decade. Such an increase would largely offset the ongoing decline in production from Prudhoe Bay, Alaska (United States). Instead, reversing the decline would require very large increases in offshore production. While gains in these fields are possible, it is very unlikely that they will more than offset losses elsewhere.

Similarly, it is unlikely that the forecast for increased production of natural gas liquids (by increasing the production of natural gas) will be realised. Over the last decade, production of both natural gas and natural gas liquids has declined. Again, assuming an increase in US production of natural liquids would imply a complete trend reversal; a long-term decline would need to be replaced by a long-term increase.

The improbability of these reversals is illustrated by the initial failure of the forecast. The EIA forecast US production of crude oil and natural gas liquids to rise from 8 mbd in 2006 to 8.6 mbd in 2007, which was the first year of the forecast. Observations indicate that US production in 2007 increased by 0.04 mbd relative to 2006. And much of this small increase may have been associated with the absence of hurricanes. To sum up, even the short-term forecast of an increase in production has proved to be too optimistic.

Similar downside risk exists in the forecast for the production of liquid fuels from OECD-Europe. The EIA forecast calls for a net reduction of 3 mbd over the next 25 years, while the IEA forecasts a reduction of 3.3 mbd. Such reductions are significant, but recent declines in production indicate that the reduction could be more severe. As mentioned previously, production of crude oil in both Norway and the United Kingdom has already dropped more than 1 mbd relative to its peak. These declines are expected to continue.

Higher prices are also unlikely to generate a significant increase in production. Analyses that account for the resource base indicate relatively small own-price elasticities of supply in non-OPEC countries, with most estimates being between 0.1 and 0.2 (Kaufmann (1991(b)), Ramcharran (2002)).

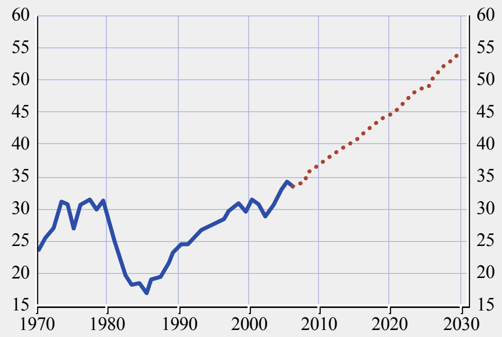
OPEC PRODUCTION

Even if forecasts for increasing rates of non-OPEC production prove to be accurate, this increase will be less than the projected increases in demand. To close the gap, OPEC will have to increase production. For example, the EIA forecasts OPEC production to increase from 33 mbd in 2005 to 54 mbd in 2030 (see Chart 17). The IEA forecasts production to reach 56 mbd.

Although the forecast for continued growth looks like a linear extrapolation of gains since 1985, future gains will have to be of a different nature. Most notably, while gains since 1985 have been supported by the reopening of existing capacity, future gains will require investments in new capacity.

Chart 17 Projection for OPEC production (crude oil, lease condensate, and natural gas liquids)

(million barrels per day)



Source: US Energy Information Administration.
Note: Latest historical data refer to 2007. Forecast goes up to 2030.

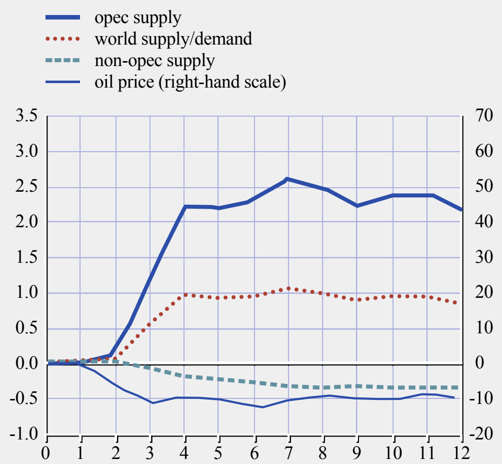
OPEC's willingness to boost production by expanding capacity, however, is far from evident and most importantly is largely ignored by long-run simulations. Most models extrapolate OPEC's role as the marginal supplier. Using this assumption, modellers generate exogenous price scenarios and use these prices to forecast demand and non-OPEC production (non-OPEC producers are assumed to act as price takers). OPEC is assumed to balance the market by producing enough oil to close the gap. However, such behaviour may not be consistent with the long-run economic interests of OPEC. OPEC has not increased its operable capacity over the last 30 years, including the last five years, over which utilisation rates have increased significantly. As explained previously, higher utilisation rates put upward pressure on prices. Now that OPEC is operating near full capacity, a critical issue for long-term price forecasts is whether OPEC will increase capacity at a sufficiently rapid rate. The preliminary answer seems to be negative.

In the short term, OPEC's willingness to expand capacity is determined by the extent to which the negative effects of lower utilisation rates are compensated for by greater oil demand and lower rates of production by non-OPEC countries. To evaluate these effects, Dees et al. (2008) simulate the effects of an increase in OPEC capacity using their world oil market model. A 5 percent increase in OPEC capacity lowers utilisation rates, which in turn reduces oil prices by about 12 percent. The reduction in prices increases the call for OPEC oil by about 2 percent. Most of this increase is associated with higher oil demand, although some is associated with lower production by non-OPEC countries. Higher demand for OPEC oil raises utilisation rates, but not back to the levels that prevailed prior to the increase. Under these conditions, oil prices decline by about 10 percent and revenues fall by about 8 percent (see Chart 18). Such losses reduce the likelihood of OPEC expanding capacity.

Gately (1995; 2007) explores the long-term effects of increases in OPEC capacity on the

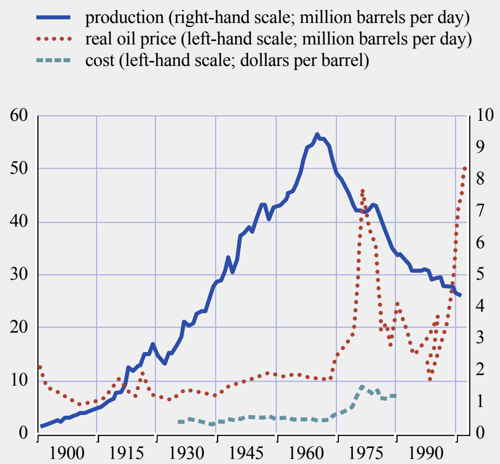
Chart 18 The effect of a 5 percent increase in OPEC capacity

(percentages)



Source: Dees et al. (2007).

Chart 19 Oil production, the real price of oil and cost of producing a barrel of crude oil in the lower 48 states of the United States



Sources: Kaufmann and Cleveland (2001).
Note: Latest observation refers to 2005 for oil production and the real price of oil and to 1991 for cost.

present value of OPEC revenues. Results indicate that OPEC's long-run interests are not maximised by simply increasing capacity to accommodate low prices and growing demand. By analysing a series of market-adaptive strategies (as indicated by the period 1979-86, it is very difficult to target an official price), Gately (2007) finds that expanding production to accommodate global demand does not maximise long-term revenues. A better strategy would be for OPEC to target a constant share of non-OPEC oil demand and to allow oil prices to rise.

HOW MUCH OIL REMAINS?

Regardless of OPEC's economic willingness to expand capacity, its physical ability to do so depends on the geological resource base. In short, can the levels of oil demand described above be met by the quantity of oil that remains to be produced? This quantity often is used to determine when the world will "run out" of oil. This date, however, is largely irrelevant because the world will not run out of oil overnight. Engineering and economic aspects of oil production dictate that production will decline over an extended period.

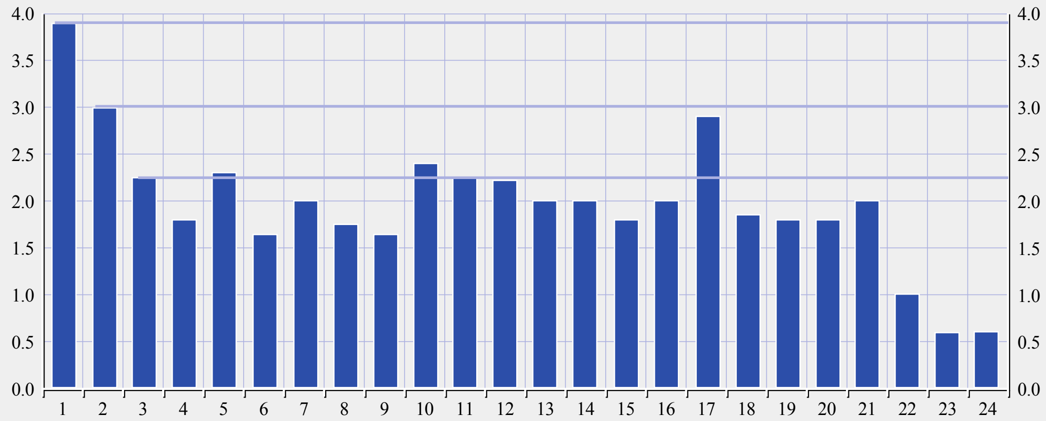
Given this "ending", the date on which production peaks is critical. Prior to the peak, production can be expanded to accommodate growing demand at relatively low cost. Beyond the peak, production declines irrespective of price increases or improvements in technology. The importance of this peak is illustrated by the history of crude oil production in the lower 48 states of the United States and the North Sea. In the United States, production increased nearly 10-fold between 1900 and 1970, even though real oil prices remained largely constant (see Chart 19).

After 1970, oil production declined even though prices rose significantly and technology became ever more efficient. A similar, albeit shorter, downward trend is currently ongoing in the North Sea, despite the significant increase in prices since 2000.

There is considerable uncertainty about the date on which the global production of conventional crude oil will peak. Using techniques that fit logistic curves to cumulative production (the so-called Hubbert curve), some analysts argue that global production has already peaked or that

Chart 20 Global estimates for the recoverable supply of conventional crude oil

(trillions of barrels)



Source: USGS and Colin Campbell.

it will peak shortly (see, for example, Deffeyes (2005); Campbell (1998)). Consistent with this hypothesis, the production of conventional crude oil fell from 73.5 mbd in 2006 to 73.2 mbd in 2007. Other analysts argue that this decline was caused by OPEC's reluctance to increase capacity, and that OPEC could expand global production for decades to come if they chose to do so. In line with this argument, production during the first three months of 2008 was about 1 mbd greater than during the same period in 2006 and 2007.

There is considerable uncertainty about the amount of oil that will ultimately be recovered from the ground. Estimates vary from less than 1 trillion barrels to nearly four trillion barrels (see Chart 20).

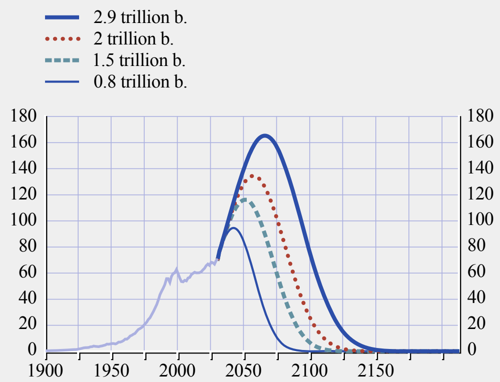
As of 1 January 2005, about 1 trillion barrels of oil have been pumped. This implies that if pessimistic estimates are correct, the world will produce another 0.8 trillion barrels. Another 2.9 trillion barrels will be produced if the most optimistic estimate proves to be correct.

Surprisingly, this 4-fold difference implies only a relatively small difference in the date that global oil production is likely to peak. This effect is described using a relatively simple algorithm that generates production paths which are based on assumptions regarding: (1) the amount of oil that remains; (2) the growth rate of demand; and (3) the rate at which production declines. In 53 of the 64 scenarios analysed by Kaufmann and Shiers (2008), the date of the peak is estimated to be between 2009 and 2031 depending on the amount of oil remaining. For example, the peak year is delayed from 2013 to 2032 if the amount of oil remaining is raised from 0.8 trillion to 2.9 trillion barrels (see Chart 21).

If the quantity of oil that remains is held constant at 2 trillion barrels, and the growth and decline rates are varied, the peak year is at some point between 2017 and 2036. The peak in global oil production can be pushed beyond 2040 only if demand grows very slowly and production declines very rapidly. These scenarios seem unlikely given the rapid rates of demand growth

Chart 21 The peak in global oil production according to the amount of remaining reserves

(million barrels per day)



Sources: Chart from Kaufmann and Shiers (in press).
Note: Latest historical data refer to 2004. Forecast goes up to 2150.

associated with developing countries that are described above.

To sum up, global production of conventional crude oil may peak within the next 20 years. This limit is not simulated in either of the EIA or IEA models. There is therefore a considerable risk that resulting supply forecasts may overstate the amount of oil that can be delivered to the market – a marked distinction with respect to the fundamentals that prevailed in the 1980s, when oil prices dropped.

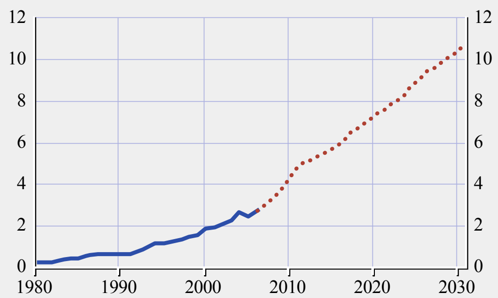
6 ALTERNATIVE FUELS

Despite much discussion about alternative fuels, few currently appear to be fully economically viable. Against this background, and in the light of the prices currently envisioned and the structural impediments to their development, the likelihood is rather low that alternative fuels will meet a significant proportion of energy requirements any time soon. Model forecasts vary widely in this respect. Somewhere towards the middle of this range, the EIA forecasts that over the period 2005-30 global production of replacements for conventional crude oil will increase from 2.8 mbd to 10.9 mbd (see Chart 22). The IEA forecast is slightly less optimistic in that it states that non-conventional sources of oil will contribute 9 mbd in 2030. The replacements include oil shale, sand-based extra-heavy oil and derivatives, such as synthetic crude products and liquids derived from coal and natural gas.

Although this represents a rather significant increase, technical and economic constraints on production imply that these forecasts may overstate the amount of alternative fuels that will actually be delivered. And even if these amounts are realised, a peak in global oil production, as described above, would imply that producing a further 7 mbd over 25 years may not be sufficient to fill the gap in demand. Again, both of these factors imply that oil prices are likely to continue to exceed the USD 70 to USD 90 range over the long term.

Chart 22 Forecast for the production of unconventional liquid fuels

(million barrels per day)



Source: US Energy Information Administration.
Note: Latest historical data refer to 2007. Forecast goes up to 2030.

WHAT ARE THE OPTIONS?

Under the current technical and economic conditions, a wide array of energy sources can be considered alternative fuels. These include hydrogen,[12] tar sands, oil shale, ethanol, electricity generated from nuclear fission, windmills and photovoltaic cells. For this discussion – the impact of alternative fuels on oil prices – we focus on alternative fuels that could replace crude oil in the transportation sector. Existing technologies, such as the jet and internal combustion engines, as well as the mobile nature of the activity, necessitate liquid fuels. This restricts viable alternatives to (i) ethanol from biomass; (ii) unconventional fossil fuels, such as oil shale and tar sands; and (iii) technologies that convert natural gas or coal into liquids.

12 Hydrogen is not really a source of energy – it is an energy carrier, i.e. a form in which primary energy inputs to the economy can be stored.

Box 3

ALTERNATIVE FUELS

Like conventional crude oil, alternative fuels are derived from solar energy that has been converted into chemical energy by biological organisms. Ethanol is produced from plants, both agricultural crops, such as corn or sugar cane, and natural vegetation, such as switchgrass and trees. Fossil fuels are generated from the partially decomposed remains of biological organisms that lived millions of years ago. These sources differ according to the amount of effort required to generate liquid fuels. Over millions of years, geological energies convert the remnants of biological organisms into conventional crude oil. When these geological processes are truncated due to insufficient temperature or pressure, the product is kerogen, which is the form of energy in tar sands or oil shale. Technologies to harness these fuels supplement geological energies by recovering and converting the kerogen into a liquid that can be refined like conventional crude oil. Living biomass can be converted into ethanol through human efforts alone, without the involvement of geological energy.

These fuels are available over various timescales and in various quantities. Fuels produced from current plant growth can be generated on a sustainable basis. However, because solar energy is diffuse and photosynthesis is inefficient (about 0.3 percent of the solar energy that reaches a plant is converted to biomass), annual production of ethanol is limited. For example, converting the entire 2005 US corn crop to ethanol would have satisfied only about 12 percent of the US demand for motor gasoline in 2005. Conversely, the geological resource base for oil shale and tar sands is considerable. For example, the US Geological Survey estimates that global oil shale resources constitute the equivalent of at least 2.8 trillion barrels of oil (Dyni (2005)).

Large estimates for the reserves of alternative fuels overstate the potential of alternative fuels to replace conventional crude. Although the world currently produces 2-3 mbd of liquid alternatives, which represents about 4 percent of global demand, their production generally is not technically or economically viable. In the United States, ethanol production is highly subsidised, as is the production of tar sands in Canada (see Chart 23).

Estimates for the cost of producing alternative fuels, such as those shown in Chart 23, indicate that the production costs for many alternatives are well below the current price of crude oil, and the cost of producing oil shale, which is the most costly, is roughly equivalent to the current price of crude oil. Such values would seem to imply that oil prices should not rise and that they may decline back towards the cost of replacements for crude oil.

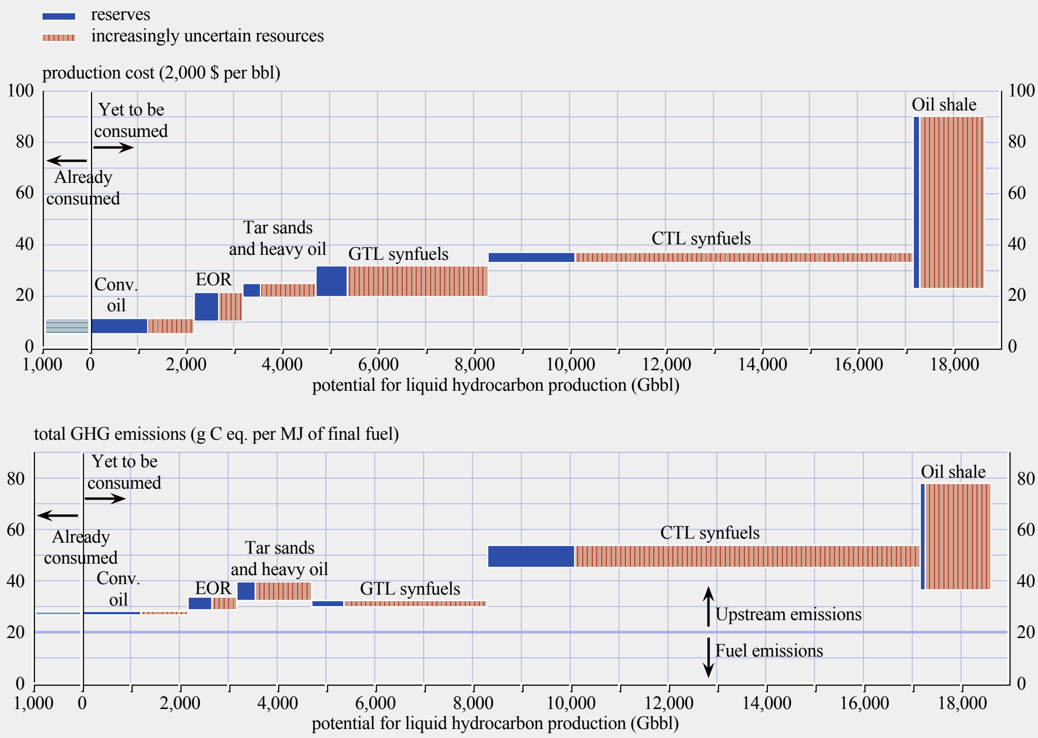
This is unlikely to occur because the dollar estimates for production costs are biased in a way that the true costs are understated.

It takes considerable amounts of energy to recover alternative fuels from the environment and convert into a usable form. This cost can be measured by a physical index, i.e. the energy return on investment, which represents the amount of energy obtained divided by the amount of energy used to obtain it. All alternatives to conventional crude oil have an energy return on investment that is considerably smaller than that of conventional crude oil. For example, estimates indicate that the energy return on investment of oil shale is about 5:1 compared with about 15:1 for conventional crude oil produced in the United States. Even less favourable, the energy in ethanol produced from corn is approximately equal to the amount of energy used to grow and process the corn.

The fact that the energy return on investment for alternative fuels is less than that for conventional crude oil means that production costs are biased in such a way that they understate the price at which alternative fuels can compete economically with conventional crude oil. Since the production of alternative fuels is more energy-intensive than the production of conventional crude oil, their cost will go up with the price of conventional energy sources. Consequently, as the price of crude oil rises, so do the costs of producing alternatives, and these increases mean that the cost of producing alternative fuels continues to just exceed the price of conventional fuels. This effect is demonstrated by changes in the production costs for oil shale. After crude oil prices dropped in the 1980s, the production costs were estimated to be about USD 40 per barrel. As oil prices now exceed that level, newer calculations indicate that the production costs are close to USD 100 per barrel.

Chart 23 Production costs and carbon emissions for liquid fuels, both conventional and unconventional

(EOR enhanced oil recovery, GTL gas to liquids, CTL coal to liquids, grams of carbon equivalent per million joules of fuel)



Source: Farrell and Brandt (2006).

Once the trigger price is exceeded, the capital intensity of alternative fuels creates lead times of 10-15 years (Hirsch et al. (2005)). In order for such fuels to be available in a timely fashion, considerable foresight is needed.

Box 4

HOTELLING'S MODEL: DEFINITIONS AND LIMITS

The foresight needed to overcome these long lead times is based on information generated by Hotelling's model of non-renewable resource extraction (Hotelling, 1931). This model implies that firms use information about the quantity of recoverable oil, its cost of extraction, the demand curve for oil, etc. to maximise the net present value of rents (the price of oil minus its marginal extraction cost).

$$W = B(q(0)) + B(q(1))\left(\frac{1}{(1+r)}\right) + B(q(2))\left(\frac{1}{(1+r)}\right)^2 + ... + B(q(T))\left(\frac{1}{(1+r)}\right)^T$$

$$q(0) + q(1)\_+ q(2) + ...q(T) \leq \text{S}$$

in which $B(q(t))$ is the sum of consumer and producer surplus in period t generated by the extraction of quantity $q(t)$, r is the discount rate, and S is the total quantity of oil to be extracted.

If we make some assumptions about the costs of extraction (for example, they are constant over time), and take into account the size of the oil resource base, maximising total social welfare generates a very simple two-period case:

$$p(t) - c = [p(t+1) - c](\frac{1}{1+r})$$

in which p is the price of oil and c is the cost of extraction. Solving for r generates the following:

$$\frac{[p(t+1-c)-(p(t)-c)]}{[p(t)-c)]} = r$$

This is Hotelling's rule, i.e. that rents earned from the production of a non-renewable resource, such as crude oil, should rise with the rate of interest, which can be used to generate optimal price and production paths. Anticipating changes indicated by these paths allows firms to schedule investment that is required to produce alternative fuels in a timely fashion. Although intellectually attractive, there is little empirical evidence that firms can determine optimal paths. To rectify these inconsistencies, analysts have added real-world complexities, such as the difficulties of the exploration process, constraints on investment and capacity, ore quality and a host of market imperfections. These modifications improve the ability of Hotelling's model to account for the historical record of the oil industry, but the resulting complexity makes the optimal production and price paths specific to the assumptions (Krautkraemer (1998)). As a result, there is considerable literature that indicates that Hotelling's model cannot be used to project an accurate production path for conventional crude oil (Krautkraemer (1998)).

THE ROLE OF PEAK PRODUCTION FOR INVESTMENT IN ALTERNATIVE FUELS

Arranging timely investment in alternative fuels, however, is complicated by several impediments, such as determining the date on which global oil production is likely to peak. If this could be pinpointed, firms would invest in an energy-producing infrastructure that would supply alternatives as of the peak. This optimal investment path would generate alternative sources of energy that would maximise profits for firms as well as total social welfare.

Uncertainty about the peak of oil production creates asymmetric outcomes for firms and society. Society prefers an investment schedule that generates alternative fuels prior to the expected date of the peak, while energy-producing firms prefer an investment schedule that generates alternative fuels after the expected date of the peak (Kaufmann and Shiers (2008)).

This asymmetry complements the effect of the long adjustment period for energy investments. Econometric analyses indicate slow rates of error correction – 0.07 for oil production in the lower 48 states (Kaufmann and Cleveland (2001)) and 0.17 for US refining capacity (Kaufmann, in review) – towards their long-run equilibrium.[13] For example, the 0.07 rate of error correction would eliminate about 50 percent of the gap between the equilibrium and observed

13 An error correction value of 0.07 implies that 7 percent of the difference between the equilibrium level of oil production indicated by oil prices and the observed level of oil prices is eliminated each year.

rate of oil production one decade after a one-time increase in the price of crude oil.[14] The longer lead times and technical immaturity of alternative fuel technologies may imply even slower rates of adjustment.

Compounding this effect, the skewed distribution of oil among fields is likely to delay a pre-peak increase in oil prices that would signal the need for alternatives. Most oil is found in a few very large fields. Consequently, extraction costs may not increase significantly until these fields are depleted and replaced with smaller fields further from the surface in more remote areas. The discontinuous change in extraction costs is illustrated by the production history in the lower 48 states of the United States, where the real cost of producing oil remained steady or declined between 1936 and the late 1970s even as production tripled, but then real costs increased more than 4-fold within a decade as production declined after the peak (see Chart 16).

Such impediments to the production of alternative fuels become highly problematic as global production peaks. If global production of crude oil peaks and declines as shown in Chart 18, demand for alternative fuels will rise more rapidly than forecast by most models. This can be approximated by the difference between the production of conventional crude oil at the time of the peak and subsequent rates of production. The implied demand for alternative fuels reaches nearly 10 mbd, which is the current rate of crude oil production by Saudi Arabia five to ten years after the peak, regardless of the amount of oil thought to remain, the growth rate of oil demand or the rate at which production declines.[15]

14 To illustrate this point, 93 percent of the difference between the equilibrium level of oil production indicated by oil prices and the observed level of oil prices remains after one year of adjustment. That gap is narrowed to about 86 percent (0.93^2) after two years of adjustment. After ten years (0.93^{10}), about 48 percent of the gap remains.

15 Finally, regarding the long-term outlook, the role of technological progress may however also be underestimated. Incentives (price and legislative) are in place for technological progress that could increase energy efficiency, improve field management (increase recovery rates), as well as increase the energy return on investment of alternative sources of energy, such as tar sands and oil shale.

7 CONCLUSION

Although there are similarities between current oil market developments and those during the 1970s and 1980s, prices are not likely to decline significantly and stabilise as they did from the mid-1980s through to 2000. Currently, structural changes in oil demand make it unlikely that high prices will reduce oil demand as they did during the 20-year period between 1978 and 1998 through the substitution of coal and natural gas in the industrial and power-generating sectors. These sectors now account for a relatively small share of oil demand. Instead, there is greater oil demand in the transportation and non-energy sectors where substituting conventional forms of energy is considerably more difficult and demand is more sensitive to income growth. Moreover, rapid economic development, particularly in emerging economies, implies that oil demand will grow more rapidly than forecasted by many models. Nor will oil demand be slowed significantly by climate change policy, as these effects are likely to have the greatest impact on coal use.

The depletion of oil resources reduces the ability of higher oil prices to increase oil supply. Oil prices declined between the 1970s and the 1990s due to concurrent increases in non-OPEC oil production. Since 2000 their production growth has slowed and since 2004 output has declined. Slow growth (or absolute reductions) is (are) likely to continue because resource depletion causes production to decline in mature regions, such as the United States and the North Sea, and these reductions offset gains in newly opened regions, such as the Caspian Sea. Slow or no growth in non-OPEC production will probably be compounded by slow growth in OPEC capacity. Simulations indicate that significant increases in OPEC capacity reduce OPEC revenues by lowering prices by more than the gain in sales due to lower prices. This effect has been ignored by many forecasts that simply assume that OPEC will continue its role as swing producer, i.e. that OPEC will produce enough oil to make up the difference between global oil demand and non-OPEC production. Besides geological capacity, there are few economic incentives for OPEC to increase its capacity; a factor which is likely to have a structural impact on oil prices forwarding the future.

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