Oil outlook to 2020

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Abstract

The latest oil outlook to the year 2020 is presented, using the OPEC World Energy Model (OWEM). In the reference case, the OPEC Reference Basket of seven crudes is assumed to remain within the declared price range of US $22–28 per barrel, in nominal terms, for the rest of this decade, growing with inflation thereafter. World oil demand grows from 76 million barrels a day in 2000 to 89 mb/d by 2010, and to over 106 mb/d by 2020. Two-thirds of the increase in demand over this 20-year period comes from China and the developing countries.

Non-OPEC production is expected to continue to increase throughout the entire forecast period, with the decline in North Sea output more than compensated by increases in the developing countries, Russia and the Caspian region. OPEC's market share in the first decade is accordingly relatively stable, as increases in output are approximately matched by higher non-OPEC supply. In the following ten years, however, it becomes increasingly inevitable that OPEC's market share will increase, as the net rise in non-OPEC output slows.

The net investment requirement will need to cover both additional capacity and the maintenance of the existing production potential. For OPEC alone, the estimate is around

(continued overleaf)

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***Abstract** — continued*

$10 billion a year during this period. Substantially higher or lower oil prices than the assumed values for the reference case are shown not only to generate lower OPEC export revenue, but also to be unsustainable.

THIS ARTICLE CONTAINS the latest oil outlook to the year 2020, developed using OPEC's World Energy Model (OWEM). An econometric model, OWEM has been used for many years to generate insights into important issues of interest to observers of oil and energy markets. Most recently, analyses based upon this model have been used as input to deliberations at the International Energy Forum, in November 2000.

In recent years, an annual paper has been published in the OPEC Review, based on the latest available projections from OWEM. The most recent paper, prior to this one, appeared in the December 2001 issue of the OPEC Review, entitled "Oil outlook to 2020", by Adnan Shihab-Eldin, Rezki Lounnas and Garry Brennand.

In the present paper, the first section develops the reference case. From the demand side, a detailed analysis of sectoral developments in the Organization for Economic Cooperation and Development (OECD) countries, together with an assessment of dynamic elasticities for developing countries, is used to develop reference case oil demand growth over the next two decades. A resource-based approach is used to determine long-term oil production feasibility, while available bottom-up information on investment activity drives the outlook for short-to-medium-term oil output levels. The second section then develops high and low oil price scenarios, based upon this reference case as a benchmark.

1. The reference case

1.1 Assumptions

1.1.1 Oil prices

The assumption is made that the OPEC Reference Basket of seven crudes will remain within the declared price range of US $22–28 per barrel, in nominal terms, for the rest of this decade. By 2010, its real value has fallen to something close to $20/b, in 2001 prices. Thereafter, the oil price grows with inflation, maintaining its real value. The price of $20/b in the medium-to-long-term reflects a number of important perceptions of the emerging market:

1) the confidence that sufficient oil will be made available, both by OPEC and non-OPEC, thereby avoiding strong upward pressure on the oil price;

2) the knowledge that very high prices (in real terms, certainly above $30/b, but perhaps even lower) are neither sustainable nor desirable, with OPEC oil production having to shrink at rates inconsistent with existing and planned capacity. The oil price assumed is, therefore, consistent with stable market development, but not high enough to generate large quantities of additional oil supply, both conventional and unconventional; and

3) the view that very soft prices are also neither desirable nor sustainable, especially if generated by a push for market share, with strong demand growth and weaker non-OPEC output making a capacity-constrained price reaction increasingly likely.

This long-term real oil price vision is unchanged from our previous view. The key change has been to incorporate the short-term effects of a recession-driven weakening of the price, and to assume that the short-term price band effectively shifts downwards slightly.

1.1.2 Gross domestic product growth assumptions

Medium-to-long-term growth in the world economy is expected to be around 3.3–3.5 per cent per annum (pa) over the next two decades (**table 1**), as assumed in last year's reference case. The major difference from last year is the incorporation in the short-term projection of the far weaker global economic growth that emerged over the course of 2001, compared with what had been expected last year. Similarly, expectations for 2002 are now significantly more pessimistic than before. Nevertheless, the assumption is made that, by 2003, most world regions are back on the medium-to-long-term stable economic growth path that had been previously assumed. As a result, average

Table 1
Average annual real GDP growth rates
per cent per annum

	2000–05	**2005–10**	**2010–15**	**2015–20**	**2000–20**
OECD	1.9	2.2	2.0	2.0	2.0
North America	2.0	2.3	2.1	2.0	2.1
Western Europe	2.2	2.3	2.1	2.0	2.1
OECD Pacific	1.2	2.0	1.8	1.8	1.7
OPEC	3.9	4.0	4.0	4.0	4.0
South-East Asia	2.5	4.0	4.0	4.0	3.6
South Asia	5.4	5.3	5.0	5.0	5.2
Africa and Middle East	3.5	3.4	3.4	3.4	3.4
Latin America	3.3	4.0	3.7	3.7	3.7
Oil-exporting DCs	3.3	4.0	4.0	4.0	3.8
Total DCs, excl. OPEC	3.9	4.4	4.3	4.3	4.3
Total DCs, incl. OPEC	3.9	4.4	4.3	4.3	4.2
Former Soviet Union	4.0	3.2	2.8	2.5	3.1
China	6.6	6.1	5.6	5.0	5.8
Other Europe	4.1	3.7	3.3	3.3	3.6
World	**3.2**	**3.5**	**3.3**	**3.3**	**3.3**

annual economic growth over the period 2000–05 is down by 0.5 percentage points for the OECD, and slightly more for developing countries (driven particularly by lower growth in South-East Asia). Future growth rates then return to stable, robust levels. The only other difference from last year's report is the assumption of stronger economic growth for "Other Europe", as optimism grows over the prospects for this region, particularly in the light of increased integration with the European Union.

1.1.3 Other assumptions

1) No major change in energy taxation or regulatory policies is assumed, which could be aimed, for example, at dramatically reducing carbon dioxide emissions. As a neutral assumption, it is posited that the nominal energy taxes, that are already in place, will grow in line with inflation. However, it is assumed that the targets are met in the 1998 voluntary agreement between the European Union and the European automobile industry (under the umbrella of the European Automobile Manufacturers Association (ACEA)), to improve average vehicle efficiency. In this agreement, average CO_2 emissions for new cars must be down to 140 grammes per kilometre by 2008 (equivalent to a fuel efficiency of 5.8 litres of petrol/100 km or 5.25 l diesel/100 km). A recent report[1] suggests that the industry is on track to achieve these efficiency improvements, primarily through the introduction of direct injection diesel engines.

2) Nuclear energy is not expected to play a major role in the future increase in global energy supplies. After 2010, global nuclear power output is assumed to decline somewhat, largely as a result of the policy of no nuclear additional capacity expansion in the United States of America and Germany, and early retirement. The "Bonn Agreement" emerging from the resumed COP6 (the Sixth Conference of the Parties to the United Nations Framework Convention on Climate Change), and the subsequent outcome of COP7 in Marrakech, removed nuclear energy from the Clean Development Mechanism. This may prove a pivotal decision for the future of the nuclear industry. In addition, concern about the security of nuclear power plants, following 11 September, may further limit the scope for growth.

3) Hydro power is assumed to grow rapidly in developing countries and China. In other countries, since all potential sources have been utilised, it will be difficult to further develop hydro power to any significant degree.

4) The share of oil in the transportation sector remains constant over the forecast period.

1.2 Results

1.2.1 OECD sectoral energy demand

Policies regulating efficiency have been shown to have strong potential impacts upon demand in the transportation sector.[2] The effects of the agreement between the EU and ACEA will become increasingly apparent, as the car parc turns over and older cars are increasingly replaced. It has been estimated, for example, that as much as one million barrels a day in demand will have been lost by 2020, as a result of this initiative,[3] representing almost one-third of the growth of a dynamics-as-usual case, based upon average growth rates in the 1990s. The relatively slow growth in demand in the transportation sector in Europe in the reference case, therefore, reflects the growing effects of this policy, with this estimated impact withdrawn from a dynamics-as-usual path. Furthermore, in the longer term, there is evidence that Western Europe will begin to experience the effects of saturation, thereby further slightly lowering the expected growth in demand. However, this saturation effect is only expected to become pronounced in the period after 2020.[4] The resultant reference case path averages growth of close to one per cent pa over the period 2000–20. These growth patterns, when applied to the econometric evidence, imply the effect of the agreement to be an average efficiency improvement of 1.5 per cent pa.

A similar agreement to reduce the average level of CO_2 emissions in new cars sold in the EU has also been reached with the equivalent Japanese and South Korean automobile industries (JAMA) and (KAMA), with a target date of 2009. Although none of the governments in the OECD Pacific region (i.e. Japan, South Korea, Australia and South Korea) have come to similar agreements, it is likely that the region will feel some knock-on effect, as the technological developments, brought about by the EU initiative, filter through to improved efficiencies in cars in use in their own region. It is, therefore, assumed that efficiencies of around half those appearing in the EU case are applicable to the transportation sector in the OECD Pacific. Combining this with the lower economic growth and slightly lower income elasticities for the region generates similar growth of close to one per cent pa over the period 2000–20.

For the North American transportation sector, where the dominant oil consumer is, of course, the USA, there is no assumption made that such efficiencies appear. Indeed, both the long-term equation embedded in the model and a set of rolling regressions point to a stable income elasticity of 0.6 (this value is an average for the three countries — the USA, Canada and Mexico — and its apparent stability could be a reflection of the low and slowly falling elasticities of the USA and Canada — as saturation effects appear — combined with the high and rising elasticities of Mexico[5]). Alternatively, this could be interpreted as an efficiency improvement closer to one per cent pa, representing the “normal” efficiency improvements that are brought about by non-price-induced technological improvements and capital stock turnover. This value is the familiar number taken in many studies for the so-called “autonomous energy efficiency improvement” (AEEI). Thus, in the reference case, the rate of growth in North America is markedly higher than in the other OECD regions, starting at rates of around 1.5 per cent pa in the post-recession years after 2002, and falling gradually to 1.1 per cent pa in the longer term, as economic growth rates settle at a value of 1.8 per cent over the period 2010–20.

The industrial sector of OECD countries is expected to continue to follow a non-linear relationship with economic growth, with intensity movements dependent upon income levels.[6] The reasons for expecting such changes in intensity are well documented:

1) changes in the structure of final demand and production, with increased emphasis placed upon the service sector and high-technology goods production within the manufacturing sector; and

2) changes in the efficiency of energy-use, achieved through technological progress in production processes and improved logistics and use of computers in production processes.

To capture these developments, specifications can allow the income elasticity to change, according to GDP per capita levels. This, however, is rarely done. Examples of recent work that has attempted to do this are Galli[7], Judson, Schmalensee and Stoker[8] and Medlock and Soligo[9]. The innovative approach taken in these studies is to use a quadratic relationship for the income effect upon energy demand. This generates a parabolic relationship. Attempts have been made to estimate such relationships for the sectors of the OECD, but the results were unsatisfactory,[10] possibly because of the lack of non-linearity in the estimated curve over the estimation period. Nevertheless, the estimated econometric equations do point to strong efficiency improvements in this sector, reflecting this restructuring. The rates of improvement represent a combination of the autonomous efficiency change of one per cent pa and the impact of the restructuring of output.

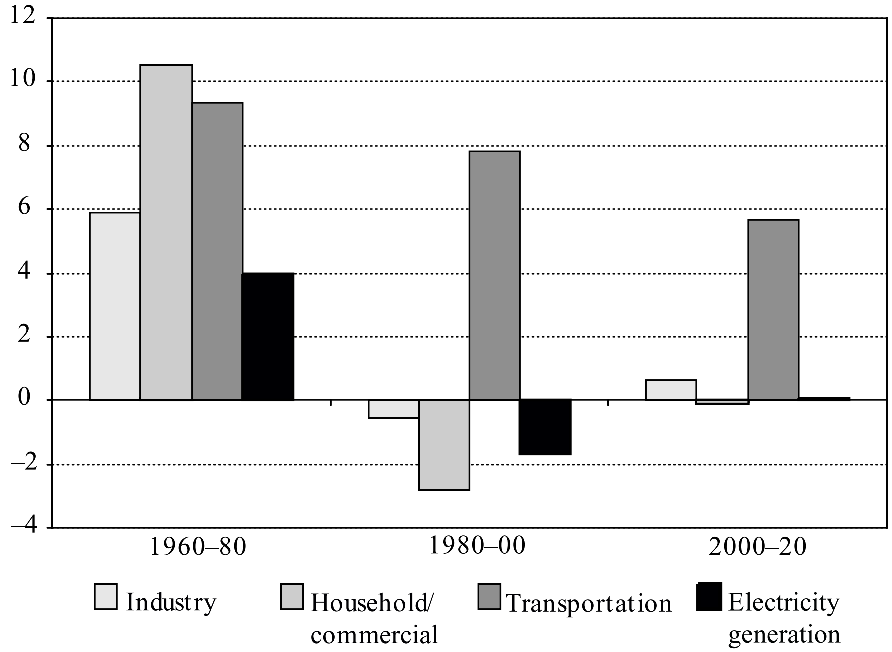
The share of oil in the industrial sector falls gradually over the forecast period in all three OECD regions, as its use becomes increasingly limited to being a feedstock for the petrochemical industry. In this sector, the principal competing fuel is natural gas. The demand for oil in this sector, therefore, increases only slightly over the forecast period, rising by little more than 0.5 mb/d over the entire period to 2020.

The electricity generation sector in the OECD regions is where oil's share of total fuel use is at its lowest, ranging from just six per cent to 11 per cent in 1999. This was not always the case: in the early 1970s, oil accounted for close to 20 per cent of fuel inputs in North America and Western Europe, and over 60 per cent in the OECD Pacific. Following the oil price rises of the 1970s, this share fell precipitously, never to recover, even once oil prices fell in 1986. It is expected that oil's role in this sector will continue to be to provide peak-load electricity, with demand consequently stagnant over the forecast period. In contrast, the share of gas in this sector has risen dramatically over recent years, particularly in Western Europe and North America (the OECD Pacific's gas share in electricity generation had already risen to current levels by the 1980s, as it substituted oil-use). The competitive advantage of combined-cycle plants makes it likely that the share of gas will continue to rise in all regions. The surge in demand in

Western Europe has been partly brought on by deregulation in this sector, and the recent Green Paper of the European Commission[11] confirms the increasing role that this fuel will play in the region. Demand patterns in North America will lead to a large increase in gas imports from Canada, while Japan's imports of liquefied natural gas (LNG), already the largest in the world, are expected to continue to increase. By 2020, the reference case sees the gas share rise substantially in all regions, with North America registering the biggest increase to over 25 per cent (**table A1**).

Although the share of coal-use in electricity generation has also fallen from earlier peaks, it is still an important fuel in this sector in the OECD regions, accounting for one-third of inputs in Western Europe and OECD Pacific, and as much as 50 per cent in North America. The strong growth in the use of gas and increasing environmental concern, both locally and globally, are likely to limit the growth potential of coal in electricity generation. However, the large resource base, particularly in North America, as well as the availability of clean coal technology, should allow the use of coal in this sector to remain relatively robust, with the main growth area expected to be North America, keeping coal as the clear major fuel in this sector for that region. This potential is supported by a lack of net growth in nuclear, hydro and other renewable electricity

Figure 1
Growth in OECD oil demand by sector, 1960–2020
mb/d



capacity. There are also signs that coal-fired electricity is becoming competitive with gas: in the United Kingdom, for example, coal-fired units have been brought out of retirement, while some gas-based units have been made inactive.

With the share of fossil fuels in the electricity generation sector in the projections rising in both North America and Western Europe, and at least staying roughly constant in the OECD Pacific, together with strong electricity growth in the OECD averaging well over one per cent pa, the electricity generation sector is a key source of future increase in CO_2 emissions. Although the prospects for ratifying the Kyoto Protocol appear to have increased, following the Bonn Agreement at COP6 *bis* and the Marrakech Agreement at COP7, the reference case does not include the strong downward pressure on the use of coal that would be inevitably implied by the obligation to reduce greenhouse gases by 2008–12, as stipulated by the protocol.

The household/commercial sector in North America and Western Europe has witnessed a substantial decline historically in fuel-use per unit of GDP, at a rate averaging close to two per cent pa over the past two decades. While much of this can be attributed to the effects of the price increases of the 1970s, the income elasticities are low, at around 0.3, as saturation effects and slowing population growth have limited the increase in demand. To a degree, this negative pressure is countered by the growth of the commercial sector. The reference case reflects the expectation that these pressures will continue to operate. As a result, energy demand growth of below one per cent pa is expected in these two regions. The OECD Pacific, on the other hand, has displayed far more robust energy demand growth in this sector, driven by less downward pressure from the demography, as well as a more aggressive shift towards the service sector. Income elasticities are, therefore, slightly higher for this region, in the range 0.5–0.6. Therefore, in the reference case, energy demand for the OECD Pacific grows at slightly over one per cent pa. With these developments, the intensity of energy-use (as measured by demand per unit of GDP) converges in the long run for the three OECD regions.

Since the early 1970s, the share of oil in the household/commercial sector has fallen almost consistently, as it has failed to keep pace with the increase in demand for other fuels in this sector, particularly gas and electricity. In the reference case, a similar decline is assumed. As a result, there is very little net change in OECD oil demand in this sector over the forecast period.

The net impact of these sectoral developments is that the transportation sector is the only source of increase in oil demand to any significant degree in the OECD, increasing by over five mb/d over the period 2000–20 (**figure 1**). It is, therefore, particularly important, in the context of long-term projections, to continue to monitor closely this sector, in order to improve understanding of the scope and impact of the potential developments of technology and policy. To this end, the transportation sector is to be the subject of more intense investigation by OWEM in the future. Specifically, the acquisition of a transportation model from Petroleum Economics Limited (PEL) will provide further insights into this sector; moreover, data from the International Road Federation[12] has been acquired, and this will be used to enhance our understanding of this sector. Finally, there is a plan to improve the treatment of energy demand in developing countries, which is, at present, at an aggregate level; from next year's OWEM report, an analysis of sectoral data for developing countries will be included, with specific attention paid to the transportation sector.

1.2.2 Oil and energy demand in non-OECD countries

Developing countries

On top of data limitations, there are specific difficulties associated with modelling energy demand patterns in developing countries: for example, consumption may often have been supply-constrained, or affected by import controls and/or rationing. Another major factor, that pervades the question of the future structure of demand in developing countries, is the strong shift in the structure of many of the economies in the developing world, both as observed historically and as conjectured for the future.

Much as has been observed in OECD countries, intensity movements in all sectors are likely to be dependent upon income levels. The reasons for expecting this are, however, even more strongly applicable for developing countries. For example, the changes in the structure of final demand and production can be even more dramatic for poorer countries, with a pre-industrial phase based upon low-intensity agriculture, followed by industrialisation, which leads to the development of infrastructure (roads, railways, urbanisation, etc) requiring higher energy consumption, as well as the more direct effect of increased incomes leading to the higher use of cars and appliances. Furthermore, the scope for increasing motor vehicle ownership from the current low base in many countries is likely to be a strong source of increase in the use of oil products. For example, while already over 500 people per 1,000 own cars in some OECD countries, this contrasts with rates of just four per 1,000 in India, and six per 1,000 in China.[13] To capture these developments, specifications should allow the income elasticity to change according to development levels. This, however, has rarely been done.

Allowing income elasticities to change is, however, increasingly becoming a key aspect of energy demand modelling for developing countries. This is typically either undertaken at an aggregate level, with non-linear specifications, such as a quadratic function, or with non-linear growth patterns estimated for specific sectoral developments, such as the growth of vehicle-ownership. Dargay and Gately,[14] for example, develop an econometric model of saturation for car-ownership, using Gomperz functions (S-shaped curves), similar in behaviour to logistics curves. However, the estimation of the non-linear ownership curve is particularly difficult for poorer countries, as their experience has yet to demonstrate much non-linearity, making a reliable estimation of the curve highly unlikely. On top of this, crucially, the impact of congestion in major cities, as well the increasing demands on the available infrastructure, are usually ignored. Implicitly, the assumption for the investment in road infrastructure is that it effectively mirrors the patterns of exponential increases in car-ownership.

These issues serve to highlight some of the uncertainties involved in making projections for developing countries, particularly for the transportation sector. On top of the uncertainty regarding the non-linearity of the impact of income growth, it is also necessary to make assumptions regarding, for example, the future evolution of vehicle energy intensity, i.e. average fuel use per car, the assumption made being fundamental to any oil demand projection. In some published forecasts, for example, historical efficiency improvements of over five per cent pa are followed in the forecast period by a rate of less than one per cent pa. Another key uncertainty is the impact that increased local pollution will have on transportation policy in these countries, such as clean fuel legislation and public transportation policy.

Tests have been made to generate quadratic oil demand functions, but these have been of limited success. Instead, the specifications, based upon constant elasticities, have been additionally tested as a set of rolling regressions. This is a direct attempt to identify stability in elasticities, or possible trends along a non-linear path, and to compare those potential trends with the evidence in both the dynamic and long-term regressions. The amount by which the elasticities are allowed to change in the projection period is relatively small, and the values are largely consistent with estimated long-run income elasticities. Notable exceptions are OPEC (where the gradual increase in domestic retail product prices is stemming demand growth to a degree that the long-run equation cannot capture) and South-East Asia (where the maturity of the region and the dynamics of the rolling regression suggest lower elasticities to dominate the future than over the past two decades). The aggregate income elasticity for all regions, of 0.8–0.9, is not contrary to the range of elasticities appearing in a survey of Energy Modeling Forum results.[15] Furthermore, the growth in demand in Africa/Middle East and China is higher through this analysis than the pure econometric evidence would suggest. The resulting figures for South Asia are also consistent with the evaluation of a working group, set up by the Indian Prime Minister, that income elasticities can be further reduced below unity.[16]

Russia, Eastern Europe and other transition countries

The final regions to address in the analysis of oil demand do not lend themselves well to analyses based upon historical behaviour: demand in the 1970s and 1980s was driven by large subsidies, while the post-1990 era has seen a dramatic collapse in energy demand. Future developments will be determined by the combined effect of complex forces: domestic prices have not yet reached world prices, inefficiencies still exist and supply constraints may still pose a restriction on growth; on the other hand, with the expectation of strong economic growth over the projection period, and a significant potential for growth in the transportation sector, the upward pressures upon demand are strong. The year 1999 saw, for the first time in that decade, an increase in oil demand in Russia in all consuming sectors, although its use in electricity generation continued to fall. Total demand fell by over 30 per cent in Eastern Europe in the ten years from 1990 to 2000, and by almost 60 per cent in Russia and other transition states formerly in the Soviet Union, but these regions are now seen as having reached the low point in demand, with the turnaround having begun.

As an indication of the potential for growth, the vehicle density for Russia (passenger cars, buses, coaches, lorries and vans) was 171 per 1,000 inhabitants in 1999, compared with figures of well over 500 in European countries, such as France, Germany and Italy.[17] However, this difference is in part due to the higher incomes per capita in those countries. For example, average GDP per capita in the region of countries, that were contained in the former Soviet Union (FSU), is down to close to $5,000, whereas the average for Western Europe at present is close to $15,000. FSU GDP per capita is estimated to rise to close to $9,000 by 2020, a level similar to those seen in Western Europe in the early 1970s. The corresponding vehicle intensity at that time was typically around 250 per 1,000 inhabitants, so there is still clear potential for strong growth from the current levels of 171. On this basis, vehicle-ownership would be expected to grow at robust rates close to two per cent pa. Demand growing at this pace would place the implicit income elasticity at 0.6–0.7, between those of the OECD and developing countries. This is consistent with available econometric evidence for aggregate demand.[18] Therefore, the rates of oil demand growth are based upon an assumed elasticity of 0.65.

1.2.3 World oil demand

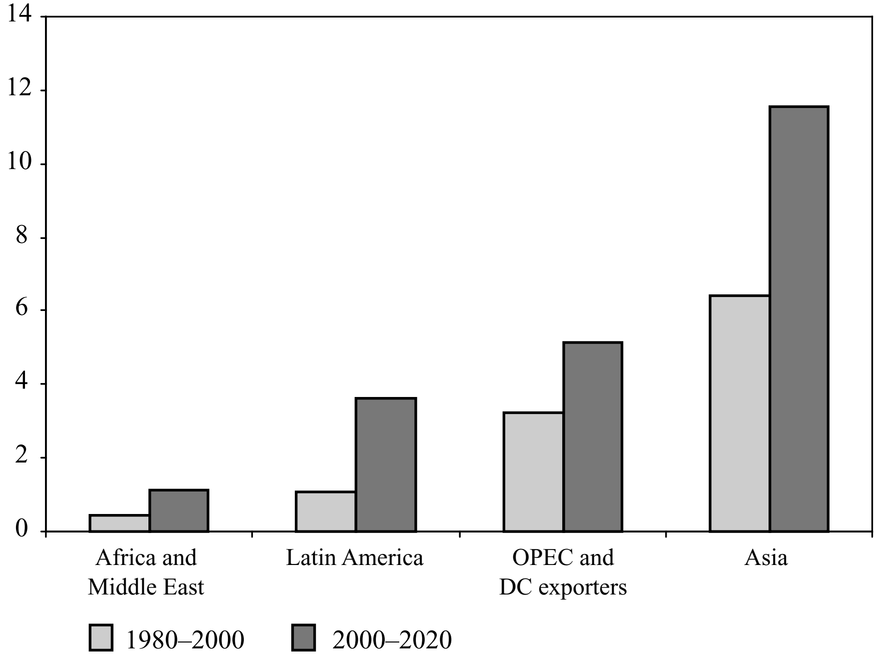
As a result of this assessment, a global demand balance has been derived, which appears in **table 2** (the demand for gas and coal in the reference case appears in **tables A2**

Table 2
World oil demand outlook in the reference case
mb/d

	2000	**2005**	**2010**	**2015**	**2020**
North America	24.1	25.0	26.1	27.2	28.2
Western Europe	15.1	15.6	16.3	16.8	17.1
OECD Pacific	8.7	8.9	9.2	9.4	9.6
Total OECD	47.9	49.4	51.6	53.4	55.0
South-East Asia	3.0	3.4	4.1	4.9	5.8
South Asia	2.6	3.2	4.1	5.1	6.3
Africa and Middle East	1.5	1.7	2.0	2.3	2.6
Latin America	3.2	3.8	4.7	5.7	6.9
Total oil-importing DCs	10.4	12.1	15.0	18.0	21.6
OPEC	5.6	6.2	7.1	8.1	9.1
Other oil-exporting DCs	2.6	2.9	3.4	3.8	4.3
OPEC and other DC oil-exporters	8.3	9.2	10.5	11.9	13.4
DCs excl. OPEC	13.0	15.1	18.3	21.8	26.0
DCs incl. OPEC	18.7	21.3	25.5	29.9	35.0
Former Soviet Union	3.8	4.2	4.7	5.1	5.6
China	4.7	5.5	6.7	8.2	9.8
Other Europe	0.8	0.8	1.0	1.0	1.2
World	**75.7**	**81.3**	**89.4**	**97.6**	**106.5**

and **A3**). World oil demand grows from 75.7 mb/d in 2000 to 89.4 mb/d by 2010 and to 106.5 mb/d by 2020. Two-thirds of the increase in demand over that 20-year period comes from China plus developing countries (the grouping known as “G77 and China”). The fastest growth rates are in South Asia (primarily India and Pakistan). Within G77 and China, Asian countries account for over half the increase in demand, which was also the case in the previous two decades (**figure 2**). OECD demand, though growing the slowest, at average rates of 0.6–0.8 per cent pa, nevertheless contributes 25 per cent of the total increase, due, of course, to its large starting base. Russia and other transition economies add another two mb/d of demand, but do not reach their pre-1990 levels over the time-horizon considered.

Figure 2
G77 and China oil demand growth, by region
mb/d



1.2.4 Oil production

The resource base has become an important element in the treatment of non-OPEC supply in the projections made by OWEM. In particular, data released by the United States Geological Survey (USGS) is used to generate logistics curves of cumulative discoveries against cumulative drilling, rising to the asymptote of ultimately recoverable resources (URR).[19] A recent technical review at the OPEC Secretariat[20] of the treatment of non-OPEC oil supply has further developed this approach, together with several new methodologies and classifications. These improvements have now also been incorporated into the source code of the model, so that the analysis of non-OPEC production in this report benefits from that technical review. Specifically, the key changes that have been introduced are:

1) a new regional classification:

   i) separating developing countries into three regions, namely Latin America, Africa and Middle East and Asia; and

   ii) separating North America into the USA and Canada from Mexico; and separating the FSU into Russia and the Caspian;[21]

2) the implementation of a set of logistics curves for discovery rates based upon these regions; one essential element of the analysis is the assumption that the reference case oil price, close to $20/b at 2001 prices, is consistent with the mean assessment of the resource base by the USGS — higher prices, on the other hand, would lead to a higher URR value, something which is dealt with in the price scenario analysis;

Table 3
Latest USGS estimates of oil resources*
billion barrels

	Known and undiscovered oil	With potential reserve growth
USA and Canada	313.6	400.2
Mexico	67.8	87.6
Western Europe	93.3	119.1
OECD Pacific	18.6	22.1
Developing countries	283.9	331.3
Latin America	126.1	143.9
Africa and Middle East	118.8	137.4
Asia	38.9	50.0
FSU	447.2	572.0
Russia	350.3	454.5
Caspian	96.9	117.5
China	65.3	86.9
East Europe	60.3	63.7
Non-OPEC	**1,302.6**	**1,682.1**
OPEC	**1,265.4**	**1,662.1**
World	**2,568.0**	**3,345.0**

* *including NGLs.*

3) a new specification for drilling, based upon an expected net future profit algorithm, together with allowance for asymmetric responses to price movements; and

4) the use of cointegration techniques to develop flexible dynamics for the responsiveness of both drilling and production to oil price movements.

The model thereby generates profiles for drilling, production, and remaining resources and reserves used to develop internally consistent long-term output figures, as well as providing the basis for analyses of alternative scenarios. For the short-to-medium term, however, available information on planned development and production is used to establish the most likely immediate path for non-OPEC production.

The USGS has now included potential reserve growth in its estimate of URR, reflecting, *inter alia*, improved recovery rates. However, the estimate of the impact of this factor is only undertaken by the USGS at a global level. In calculating the individual values for the regions, it has, therefore, been assumed that this growth is distributed as a constant percentage of known oil (i.e. cumulative production plus proven reserves) across all regions (with the exception of the USA, where figures are available). Furthermore, natural gas liquid (NGL) figures are also included. The resulting regional estimates of URR appear in **table 3**. These assumptions are used to drive the discovery rates of the reference case, thus assuring developments that are consistent with the resource base. The discovery rates implicit in the logistic function also feed into the profitability algorithm. Long-term resource-to-production profiles have then been analyzed to assess the feasibility of various long-term paths.

The regional prospects for oil production are outlined below in the light of both this resource information and more detailed “bottom-up” insights. Furthermore, for the first time, supply includes an assessment of the potential for gas-to-liquids.

USA and Canada

The use of the resource base to assess potential developments in discoveries, and ultimately the scope for future production, is particularly well-suited for mature producing regions, where financial and logistical constraints are not so likely to restrict output. Having said this, the future exploitation of the available resources in the USA, in particular, are likely to be in increasingly geologically complex reservoirs (deep-water offshore) and harsh and remote areas (Alaska). Although improved technology continues to bring down costs, the extent to which additional production potential can continue to keep up with natural rates of decline is unclear. Economic risks exist, and new transport infrastructure will be needed, for example, to bring distant offshore oil to the US coastline. There is also concern that there will be bottlenecks in the supply of new offshore rigs, together with a likely growing problem of an insufficient experienced workforce. Furthermore, the outer continental shelf in the Gulf of

Mexico, containing substantial resources, is currently not available for development, largely through concern over oil spills. It is also still far from clear whether the Arctic National Wildlife Refuge will be opened for production (estimated to have a long-term potential for 1.0 – 1.3 mb/d in output), although a report in May 2001 of the US National Energy Policy Development Group was unequivocal in recommending the authorization of exploration and development in this area.

While US oil production has fallen steadily over the past 30 years, that of Canada has enjoyed strong growth. Average growth throughout the 1990s was over three per cent pa, and, by 2000, Canadian production was up to 35 per cent of that of the USA, compared with just 22 per cent a decade earlier. Much of this increase has come from oil sands, which can be converted to synthetic crude. As operating costs continue to fall,[22] and investment in necessary infrastructure is made, output is expected to increase from the current levels of 0.6 mb/d to 1.1–1.8 by 2010–15, according to the development of crude oil prices.[23]

The USA has the second-highest level of non-OPEC reserves in the world, as well as the second-highest level of estimated remaining resources, including those yet to be discovered. Canada also has substantial amounts of oil, so that the resource base for this regional grouping can comfortably support production at levels similar to current ones for the forecast period, although significant growth is not thought feasible. The key to the production path followed by this region is, therefore, likely to be the extent to which the other mentioned constraining factors will limit output development. As a region, the reference case sees the total production levels increasing slightly, as the declines in the USA are compensated by new production potential, particularly offshore, and growth in Canadian conventional and non-conventional oil output.

Mexico

Mexico's reserves, at 28 billion barrels, are the third-highest of all non-OPEC countries, behind only Russia and the USA. Estimates of reserve growth and undiscovered oil suggest that more than double this figure forms the resource base. Similarly, Mexican oil production is the third-highest within non-OPEC. However, the prospects for future expansion from the current production levels of 3.5 mb/d are strongly contingent upon the necessary investment taking place. For example, the General Director of the Mexican state oil company, Pemex, has recently made an appeal for investment of $33 bn over the next five years to reverse a decline in its reserves and to maintain production levels. With sufficient funding, the expectation is that output can even be increased slightly, largely through improved output from existing fields. The analysis of the resource-constrained maximum output levels confirms the limits to expected increases in Mexican output, with production levels not likely to be sustainable past four mb/d. Although the questionable availability of investment funding is directly due to the nationalized structure of the Mexican oil industry, it is possible, for the same reason, that Mexican oil production will not respond strongly to future oil price movements. Indeed, the recent cooperation with OPEC suggests a future link to extreme price movements that could be in the opposite direction to that experienced in other non-OPEC countries.

Western Europe

Norway and the UK account for over 90 per cent of Western European production, with Denmark, the Netherlands and Germany also producing small amounts from the North Sea. According to recent estimates from the Norwegian Petroleum Directorate, Norwegian production is expected to reach a plateau in the period 2002–05, then begin a decline of three per cent pa[24] in the period to 2020. These figures are based upon operators' reports on fields in production and under development, as well as for anticipated projects over the next ten years. For the years to 2010, projections are based primarily upon fields currently in production, the greatest uncertainties relating to recovery factors and how the decline rate can be reduced,[25] as well as uncertainty over when production will start in development projects. The vision towards 2020 is subject to far greater uncertainty, as it will increasingly involve currently undiscovered resources.

The UK Department of Trade and Industry (DTI) releases an annual report[26] on the UK oil industry (known as "the Brown Book"), and this contains projections for production over the short-to-medium term to 2006. A survey undertaken by the DTI has revealed a likely continuation in the decline of drilling activity, as well as a gradual expected decline in investment in oil and gas production on the UK continental shelf. The resulting projections suggest that production will remain around current levels until 2003, followed by annual declines close to ten per cent pa.

Putting these two projections together suggests that North Sea output will reach a peak in 2002–03, and then move into a decline of around 3–4 per cent pa. This amounts to a more rapid decline than was projected in the last OWEM Scenarios Report. Nevertheless, the longer-term vision remains very similar and is consistent with the limited remaining resources for this region.

Latin America

Current production in non-OPEC Latin America is dominated by Brazil, Argentina, Colombia and Ecuador, which, between them, account for almost 90 per cent of the region's output. The resource base is large enough to sustain substantial growth in output over the next two decades: according to a mean estimate of the URR, over 120 bn b of resources remain. Over half these remaining resources are in one country, Brazil. Indeed, maximum sustainable growth patterns suggest that Brazil would account for more than 80 per cent of the potential increase in production.

Brazilian oil production is rising fast, and, although it is still a net importer of oil, the expectation is that the country will eventually reach self-sufficiency. The strong growth in output has been spurred by the opening-up of the Brazilian petroleum industry in 1998. Since then, three licensing rounds have been held, mostly for deep-water offshore areas that are relatively unexplored. The plan to continue to hold annual licensing rounds points to strong likely growth in exploration and production, consistent with the large estimated resource base. In the short term, production activity will be dominated by Petrobas operations, but this will progressively change. The Petrobas plans for production capacity expansion up to 2005 are, therefore, the best indication of probable short-term growth. This foresees production rising from 1.3 mb/d in 2000 to

1.85 mb/d by 2005,[27] an average rate of increase of over seven per cent pa. Indeed, some think that total Brazilian production will rise even more swiftly over this period, possibly to reach 2.3 mb/d by this date.[28] What seems certain, however, is that exploratory drilling by other operators will escalate rapidly, so that the prospects for longer-term growth in production for Brazil and, largely as a result of this, for the region as a whole, are very bright.

Argentina accounts for the second-largest output in non-OPEC Latin America, having increased rapidly in the 1990s, on the back of deregulation. However, the resource base is not large enough to sustain this growth. It is probable that exploitation of reserves will be able to maintain production levels, but a decline in output will become increasingly likely over the forecast period. Of the other major producers, the resource base should be sufficient to enable steady expansion in Colombia, Trinidad and Tobago, Ecuador, Peru and Bolivia. Reference case production for the Latin American region grows from under four mb/d in 2000 to over five mb/d and six mb/d in 2010 and 2020 respectively.

Asia

The largest producers of oil in non-OPEC Asia are India and Malaysia, both with current output levels of around 0.8 mb/d. Most of the rest of the oil produced in this region comes from Brunei, Thailand and Vietnam. The resource data suggests that sustained growth in output is most feasible in India and Brunei. In a bid to reduce the level of oil import dependence, the Report of the Group of India, “Hydrocarbons Vision — 2025”, emphasized the need to encourage exploration and production in the country, to “develop the hydrocarbon sector as a globally competitive industry”, by providing competitive fiscal terms, moving to deep-sea offshore areas in the search for new discoveries, and further deregulation. Nevertheless, the resource base suggests little scope for net increases in the output from this region, unless the high estimates from the USGS are assumed. In the reference case, production rises only slightly from the current level of 2.2 mb/d to just under three mb/d by 2020.

Africa and Middle East

Current production levels are similar in non-OPEC Africa and non-OPEC Middle East, with both producing close to two mb/d. However, the prospects for future development, according to the resource base, are markedly different. Production can only rise very gradually, or will probably even have to fall in the major Middle East producing countries of Oman, Syria and Yemen. Egypt is also unlikely to be able to achieve sustained growth. On the other hand, West African countries, particularly Angola, Congo and Gabon, have the resource potential to expand considerably. It is primarily these countries, therefore, that hold the key to the group of Middle East and Africa being able to increase production over the forecast period. Angola’s government, for example, has stated that it hopes to sustain peak production of 1.3 mb/d from 2005,[29] which appears feasible, given the USGS estimates of reserves and undiscovered resources. The reference case sees output from this region growing from the current five mb/d to just over six mb/d in 2010 and almost seven mb/d by 2020.

Russia

As the world's third-largest oil producer (after Saudi Arabia and the USA) and owner of the highest oil reserves outside of OPEC, the Russian Federation is clearly of great relevance to current and future global oil and gas balances. The extent to which this obvious resource potential is realized will be fundamentally driven by the ability to attract sufficient capital for the necessary development, production and transportation of the oil and gas.

Short-term increases in output can be achieved by increasing well-productivity from current low levels. However, the scope for such increases in production is likely to be limited by bottlenecks in the transportation network. In line with these matters of concern, efforts are currently being made to develop new pipeline projects. For example, these include a project to deliver oil to northern China (capacity eventually rising to 0.6 mb/d by 2010), and the Baltic Pipeline System, which will eventually be able to handle 0.8 mb/d, although construction is not expected to be completed until around 2010.

However, the potential for increases in Russian production, although substantial, because of the resource base and scope for efficiency improvements, will most probably be constrained in the future by the rate at which pipeline capacity is expanded. Reference case production rises from 6.5 mb/d in 2000 to over eight mb/d by 2010 and almost nine mb/d by 2020.

Caspian

Current estimates of proven oil reserves for the littoral states of the Caspian Sea stand at 22–32 bn b.[30] This makes the region comparable in size with estimates for Mexico or the USA and higher than the UK and Norway combined. Such a reserve level can clearly support increases in production from this region: for example, even with no new additions, these reserves could clearly allow a substantial increase in output from the current levels of 1.3 mb/d over the next decade. However, it is the as-yet undiscovered oil which has the real potential to make this region an important source of oil. The latest estimates by the USGS for undiscovered oil resources in this region, including NGLs, foresees an additional 62 bn b to be part of the resource base, more than double the current proven reserves. Moreover, the probability approach taken by the USGS also suggests another 61 bn b of speculative resources, at the five per cent level. Such a potential resource base provides the key to the enthusiasm with which the Caspian region is seen as a major future source of oil output.

A key focus of attention for this region is the development of a transportation network capable of bringing additional oil to markets. Much attention is currently focused upon the proposed pipeline from Baku in Azerbaijan through to the Mediterranean port of Ceyhan in Turkey (BTC). So far, only the civil engineering phase has been completed, to determine a 500-metre wide corridor for the pipeline (following an existing gas pipeline). The total length, as currently planned, is 1,743 km. Full operation of the pipeline is scheduled for mid-2005, at an estimated total cost of $2.4–2.7 bn. This construction phase, however, will involve the majority of the financial outlay, and it is still unclear whether the legal frameworks and engineering phases will be enough to bring the project into commercial reality. In particular, there is some scepticism that the estimated total costs are comparable with that of the Caspian Pipeline Consortium (CPC), yet requiring approximately double the amount of new pipeline. The vast difference in unit costs is explained largely in terms of higher engineering costs for the CPC, but it seems that the potential for increases in the estimated cost for the Baku-Ceyhan pipeline is substantial. Should the project materialize, however, the expected throughput would increase to one mb/d by 2010.

As of March 2001, oil began to flow in the pipeline developed by the CPC, connecting Tengiz in Kazakhstan with the Black Sea port of Novorossjnsk in Russia. Although the overall distance is comparable with the proposed Baku-Ceyhan pipeline, approximately half its length consists of an existing pipeline (752 km) which was refurbished, with an additional 738 km newly constructed. Total project costs are estimated at $2.6 bn. Throughput capacity is expected to begin at 0.6 mb/d in 2001, rising to 1.3 mb/d by 2014.

The increased potential for oil exports from the BTC and CPC pipelines will be accompanied by some increase in Bosphorus traffic, although the upper limit allowed by the government of Turkey is likely to be in the range of 1.2–1.6 mb/d, up from the current traffic of 0.9 mb/d. Additional routes that could add to the export potential are a proposed Constana (Black Sea) to Trieste route (0.8 mb/d capacity) and the Odessa to Gdansk Bosphorus bypass (0.6 mb/d), already under construction. Although there remains considerable disagreement over the aggregate potential of the Caspian area to deliver oil and gas, as well as the likelihood of individual projects being implemented, it is clear that the Caspian area has the potential to substantially affect the oil supply/demand balance over the coming two decades, although the timing and extent of this eventual impact is highly uncertain. The reference case values for Caspian production reflect a balance between the obvious potential of the region and the considerable challenges involved in getting that oil to the market. This is consistent with the risk profile generated by Wood Mackenzie.[31] The key increases in Caspian production are expected to come from the Tengiz, Kashagan and ACG fields. As a result, Caspian oil production doubles from 1.4 mb/d in 2000 to almost three mb/d by 2010 and nearly four mb/d by 2020.

Gas-to-liquids

The fall in the costs of production for gas-to-liquids (GTL) technologies over the past 20 years increasingly makes this an additional potentially important source of liquid fuel in the future. Current GTL production amounts to just 0.2 mb/d, the only significant current commercial use of GTL technology being in South Africa (primarily using coal), but announcements over the past three or four years have generated fresh interest. Declarations are often heard that GTL technology is now economically viable, with a number of pilot research and development projects already underway. Studies by Arthur D. Little[32] and the Centre for Global Energy Studies[33] suggest that the potential for global production could be 1–2 mb/d by 2015 (although Arthur D. Little posits that technical and project risks will limit potential production to the lower end of this range, i.e. around 1 mb/d by 2015). The really large potential for GTL, however, is expected to evolve in the longer term, beyond 2020, with Arthur D. Little estimating an eventual potential of 11 mb/d.

While technological development will continue to bring these costs down somewhat,[34] the economics of GTL production are strongly related to oil prices and the costs of the gas input. Arthur D. Little, for example, suggests that, for GTL to be economic, expectations for oil prices (Brent) over the coming years need to be above \$20/b, and low-cost gas of the order of \$0.50/mBtu needs to be available.[35] The US Department of Energy (DOE), for example, suggests that the sort of projections quoted above are only likely to materialize in a high-price environment, with real prices in the upper \$20s (their "high-price" scenario) giving rise to GTL production of almost two mb/d by 2020. Although the target price band of \$22–28/b might be consistent with a degree of optimism regarding the economic viability of GTL projects, the prospects of a slump in prices should give rise to a more cautious appraisal of commercial viability. With regard to gas prices, average US wellhead gas prices are almost five times higher than the low-cost threshold, and, in Europe, prices are perhaps six-to-eight times higher than the required \$0.50/b. The areas that are likely to be important sources for GTL are primarily those that are remote or stranded, or associated gas that is currently flared, vented or reinjected as a result of the absence of available infrastructure. In particular, such low-cost gas is likely to be available in the Middle East, Venezuela and West Africa.[36] Russia, with its huge gas reserves, is another key candidate, but transportation costs to an ice-free port will limit the availability of low-cost stranded gas reserves. It would thus appear that OPEC countries have, at least, the potential to become key suppliers of GTL fuel. Interestingly, the analysis in Greene[37] suggests that it would not be in OPEC's economic interests to develop GTL export capacity. This is because the substitutability for crude oil-based products would lead to downward pressure on the oil price, which would reduce revenue, and/or a displacement of conventional crude oil production, which would increase average costs. This does not, of course, preclude the attraction of GTL for any individual country, as long as GTL development does not compromise other investment in the petroleum sector. In particular, GTL is likely to often offer a more attractive gas export development option than either LNG or pipelines.

Actual proposals for new GTL plants amount to just over 0.3 mb/d in capacity, while the addition of those currently being studied for their feasibility brings the total close to 1 mb/d, consistent with the Arthur D. Little estimate. Of the proposed projects, almost 60 per cent are in OPEC countries. Of the non-OPEC proposals and feasibility projects, those of the USA (Alaska) and Australia are the largest.[38]

Notwithstanding the distinction between proposals and feasibility studies, however, the projects listed are subject to varying degrees of uncertainty. At one extreme, some projects are practically underway: the projects in Nigeria and Qatar, for example, are already at the "front-end engineering and design" stage, with commissioning planned for 2005. Shell is also expected to commit itself to the construction of plants in, at least, four of its feasible destinations by 2010. The Australian government, on the other hand, has formed a "GTL taskforce" to assess GTL potential, and this group has concluded that GTL projects will not go ahead without government support, at least in the short term.[39] This support could come from fiscal conditions, infrastructure provision or low-cost gas. The Malaysian government, for example, has committed itself to provide required facilities, such as industrial land, water supply, waste-water treatment, gas supply, port facilities, roads and power, while, for Qatar, such infrastructure is largely already in place. For Australia, without such support, the delay in GTL investment is likely to be considerable.

1.2.5 World oil supply

The reference case production paths for the world regions are shown in **table 4**. Non-OPEC production continues to increase throughout the entire forecast period, with the expected decline in North Sea output more than compensated by increases in the developing countries, Russia and the Caspian region. OPEC's market share in the first decade is relatively stable, as increases in output are approximately matched by higher non-OPEC supply. In the following ten years, however, it becomes increasingly

Table 4
World oil production outlook in the reference case
mb/d

	2000	**2005**	**2010**	**2015**	**2020**
OECD	21.9	22.3	21.6	21.0	20.4
USA and Canada	10.8	11.3	11.4	11.5	11.4
Mexico	3.5	3.7	3.8	3.9	3.9
Western Europe	6.7	6.4	5.4	4.5	3.9
OECD Pacific	0.8	0.9	1.1	1.1	1.2
DCS excl. OPEC	11.0	12.7	13.9	14.5	15.1
Latin America	3.7	4.6	5.4	6.0	6.4
Africa and Middle East	5.0	5.8	6.1	6.3	6.6
Asia	2.2	2.4	2.4	2.2	2.1
Russia	6.5	7.6	8.2	8.7	8.7
Caspian*	1.4	2.0	2.7	3.4	3.8
China	3.2	3.4	3.4	3.4	3.4
Other Europe	0.2	0.2	0.2	0.2	0.1
Processing gains	1.7	1.8	2.0	2.2	2.4
OPEC (incl. NGLs)	**29.9**	**31.2**	**37.3**	**44.3**	**52.6**
Non-OPEC	**45.8**	**50.1**	**52.1**	**53.3**	**53.9**
World	**75.7**	**81.3**	**89.4**	**97.6**	**106.5**
OPEC market share %	***39.5***	***38.4***	***41.7***	***45.4***	***49.4***

** All FSU states, except Russia.*

inevitable that OPEC's market share will increase, as non-OPEC approaches peak levels. By 2020, OPEC will thereby be called upon to supply 53 mb/d, an increase of 76 per cent over the production levels of the year 2000. Non-OPEC supply, on the other hand, increases by just 18 per cent over this period.

The implications for the investment requirement, however, are strongly influenced by both the lower costs for expanding capacity in OPEC and the differences in the decline rates, since the net investment requirement will need to cover not only additional capacity, but also the maintenance of existing production potential. The assumption was made, in a recent International Energy Agency (IEA) analysis of fuel supply,[40] that the investment requirement in OPEC amounts to $5 bn per 1 mb/d, and is four times higher for non-OPEC. Decline rates can be approximated by the inverse of the reserves-to-production ratio. Given the assumption of a five per cent natural decline for OPEC and an average seven per cent decline for non-OPEC, **table 5** documents the estimated cumulative investment required to produce the oil in the reference case projection.

Table 5
Oil production capacity investment requirement
$ billion (2001)

	Cumulative investment		Annualised investment		Total annualised costs	
	2000–10	**2000–20**	**2000–10**	**2000–20**	**2000–10**	**2000–20**
OPEC	97.0	209.4	9.7	10.5	36.9	48.9
Non-OPEC	598.7	863.4	59.9	43.2	154.9	141.5
World	**695.7**	**1,072.8**	**69.6**	**53.6**	**191.9**	**190.4**
OECD	261.4	341.6	26.1	17.1	65.6	54.3

Over the period to 2020, investment of over $1 trillion will be necessary to create the capacity necessary to supply the estimated demand of 106.5 mb/d by that year. However, the investment requirement in non-OPEC is far greater than for OPEC, even though non-OPEC output is only expected to increase by eight mb/d in 2000–20, compared with 23 mb/d in OPEC. The higher cost of investment, together with the higher decline rates, leads to this outcome. Indeed, OECD countries, with even higher decline rates (nine per cent is assumed in the above table) and *falling* production, would account for over one-third of investment in global production capacity. Making assumptions of extraction costs of $3/b and $5/b for OPEC and non-OPEC respectively,[41] total world expenditure on capacity investment and extraction would average over $190 bn annually, over the forecast period.

2. High and low oil price scenarios

Recent developments with OWEM have included the emphasis of the oil resource base on not only developing feasible reference case paths, but also analysing potential sensitivity to oil price movements. In particular, the incorporation of an endogenous assumption for ultimately recoverable resources, responding to very high prices, led to the development of so-called “boom-bust” scenarios: at these high prices (in last year’s report, a value of $32/b, at 2000 prices, was assumed), although demand fell, it was the strong response of non-OPEC supply that dominated the impact upon the call on OPEC oil, leading to an unsustainable decline in OPEC production. This scenario formed the basis of an OPEC Secretariat working paper submitted to the Seventh International Energy Forum in Riyadh in November 2000.[42]

Over the past year, further methodological advances in the treatment of the supply of oil in the model have been developed and subsequently implemented into the model code. With this new specification, the sensitivity of oil production to changes in the oil price has been affected by two basic mechanisms:

a) the implementation of an expected profitability algorithm, together with improved dynamics, the incorporation of asymmetric responses and the introduction of a new regional disaggregation, affects the way that drilling responds to oil prices; and

b) the link between reserve additions, including those stemming from endogenous URR responses, and oil production is affected by the incorporation of a more formal econometric treatment of dynamics through an error-correction mechanism.

With these changes in mind, it is instructive to revisit the boom-bust scenarios to reassess the potential reaction of the market to high oil prices.

2.1 High-price scenarios

As a point of departure, we choose a price path similar to that assumed in last year’s high-price scenario, namely that the Reference Basket of OPEC crudes rises to $32/b in 2002, and stays there in real terms. The only other assumption involves stronger growth of close to 1 mb/d for non-conventional oil over the forecast period, consistent with the upper range of expectations of GTL production[43] and price sensitivity analysis undertaken for the Canadian National Energy Board for oil sand potential.[44] This is, however, an area of great uncertainty, with regard to the longer-term potential. For the period to 2010, however, the response is likely to be modest. For the initial scenario development, no endogenous URR response is assumed. However, the resource base nevertheless plays an important role in determining drilling, because of the link through expected profitability. Finally, it is also assumed that the high price leads to no response in the countries of the FSU, an assumption that is later relaxed.

The implicit elasticities of drilling, with respect to oil prices, appear in **table 6**. Several aspects of these reactions are worth noting. First, the most responsive region is the USA and Canada, with a medium- and long-term elasticity of over unity. Other OECD regions are considerably less responsive, especially in the longer term, when the resource constraint brings drilling activity back towards reference case levels. The developing countries exhibit rather differing responses, with Africa and Middle East

Table 6
Elasticity of drilling, with respect to the oil price

	2005	2010	2015	2020
USA and Canada	1.1	1.3	1.4	1.4
Mexico	0.2	0.1	0.1	0.1
Western Europe	0.4	0.4	0.3	0.2
OECD Pacific	0.5	0.3	0.2	0.2
Latin America	0.6	0.6	0.5	0.3
Africa and Middle East	0.6	0.7	0.8	0.8
Asia	0.4	0.2	0.1	0.1
OECD	**0.9**	**1.2**	**1.2**	**1.2**
DCs (excl. OPEC)	**0.5**	**0.6**	**0.5**	**0.4**
OECD and DCs	**0.8**	**1.0**	**1.0**	**1.0**

and Latin America exhibiting a strong, sustained increase in drilling, while Asia, with its more modest resource base, returns gradually to reference case levels.

These higher drilling rates lead to higher levels of discovery, applying the rates derived from a logistic discovery function climbing to the URR asymptote. The key difference between this first scenario, ***no URR response***, and the next, ***with URR response,*** is the rate at which the higher drilling activity translates into discoveries and, ultimately, production. Before exploring the results of the ***no URR response*** scenario, we therefore turn our attention to the alternative possible assumption that the URR asymptote responds to the higher oil price.

Table 7 shows the latest USGS assessment for URR that is used for the reference, together with the values assumed in the ***with URR response*** scenario. These higher values are taken, as in previous analyses, from the five per cent fractile USGS figures. The aggregate numbers are the same as those appearing in last year's assessment, but the values have now been recalculated for the new regional disaggregation. The smallest addition, in percentage terms, comes from USA and Canada, due to the geological maturity of the USA, in particular. The single largest response, both in volume and percentage, is for Latin America (dominated by an increase in the offshore resource assessment for Brazil).

In addition to the impact of these higher URR values, this scenario also incorporates higher production levels in the Caspian region. The nature of the responsiveness of this region to oil prices is of some debate, and deserves closer attention in its own right. The assumption made in this scenario follows the analysis made in a separate OPEC Secretariat report from 2001, that, *inter alia*, considered maximum potential output levels for this region.[45] Caspian production is thereby assumed to reach 3.5 mb/d by 2010, compared with 2.7 mb/d in the reference case, with the difference from the reference case increasing to two mb/d by 2020.

Table 8 documents the results for the supply and demand of oil for these two scenarios. The impact of the high price upon demand is, of course, essentially the same in both cases, dropping by four mb/d by 2010, compared with the reference case, and by over six mb/d by 2020. These modest responses to the oil price movement are in part due to the large tax buffer that is in place in some world regions, but they are also a reflection of the known low elasticities in key consuming sectors, particularly transportation. The estimated reaction of demand to high prices, however, clearly does not capture the possible major developments in either policy or technology that could be triggered by such a high price environment. Although modelled within an asymmetric framework, which is an attempt to capture how these non-linear reactions have occurred in the past, the response to prices from the demand side could certainly be eventually greater than this 4–6 mb/d. For example, it has been estimated that the response of US transportation demand to the 1970s price increases was due at least as much to increases in CAFE standards as to a direct response to high prices.[46] Should higher prices engender a climate where such policy developments become desirable and/or acceptable, then it is likely that a higher demand response would be observed.

Table 7
Ultimate recoverable resources by region
billion barrels

	Reference case	High price (with URR)	Difference	
			Level	Percentage
OECD	629	750	121	*19.2*
North America	488	549	61	*12.6*
USA and Canada	400	431	31	*7.7*
Mexico	88	118	30	*34.5*
Western Europe	119	169	50	*41.7*
OECD Pacific	22	32	10	*44.3*
DCs	331	507	176	*53.0*
Latin America	144	234	90	*62.8*
Africa and Middle East	137	205	67	*49.0*
Asia	50	68	18	*35.8*
Memorandum items				
FSU	572	779	207	*36.1*
Russia	454	609	154	*33.9*
Caspian	118	170	53	*44.7*
China	87	120	33	*37.8*
Other Europe	64	121	58	*90.7*
Non-OPEC	**1,683**	**2,276**	**593**	***35.3***
OPEC	**1,662**	**2,167**	**505**	***30.4***
World	**3,345**	**4,443**	**1,098**	***32.8***

Source: UAGS World Petroleum Assessment, 2000.

The oil supply reaction to the higher price is of a greater order of magnitude than that of demand, even in the ***no URR response*** scenario, with non-OPEC supply increasing by six mb/d by 2010, compared with the reference case, and by 11 mb/d by 2020. Again, however, the relative size of the demand and supply effects may not be so uneven, if policy and/or technology developments respond to reduce demand further. The net impact of these movements is to reduce the amount of oil required from OPEC by over ten mb/d by 2010 and by over 17 mb/d by 2020. This implies OPEC production staying approximately flat for at least the rest of the current decade.

The results for the ***with URR response*** scenario demonstrate, of course, an even stronger non-OPEC response to the high price, with output levels already up by 11 mb/d by 2010, compared with the reference case. In the even longer term, the response through the higher resource base becomes even stronger. These longer-term results, however, are highly unlikely to be regarded as feasible outcomes; the required investment in non-OPEC to reach corresponding capacity levels could be seen as being prohibitively high, given the far higher costs involved, compared with OPEC countries. A more direct limit to feasibility, however, lies in the implications for the development in OPEC output: while the ***no URR response*** scenario already projected an unlikely path of flat production for at least the rest of this decade, the ***with URR response*** variant involves a constant decline in OPEC production, with market share falling in the longer term to below 20 per cent, which is clearly inconsistent with planned capacity expansion.

The responsiveness of non-OPEC production is, therefore, a strong limiting factor in sustaining any given oil price. The fact that the ***no URR response*** scenario already projects a questionable OPEC output path clearly suggests that even lower real prices than the $32/b assumed are also not sustainable. How the resource base responds to oil price rises is a key element in assessing sustainability; it is, indeed, probable that the threshold for such non-linear supply responses lies well below $32/b. Finally, with demand responses to price movements increasingly likely to be in a non-linear fashion at higher levels, it becomes clear that there is considerable downside risk regarding the sustainability of oil prices. The level at which this sustainability is ensured is not addressed within this specific modelling context. Further research is clearly of paramount importance to address the individual components of the potential price reactions throughout the market.

2.2 Low-price scenarios

To complement the high-price scenarios, it is now assumed that a drive for market share pushes prices down to $12/b, in real terms. The reaction from supply and demand is determined by the model, but additionally an assumption is made that non-conventional oil contributes one mb/d less to supply by 2010, and is almost two mb/d lower than the reference case by 2020. This is broadly consistent with the estimates of price sensitivity of oil sand development and GTL. The results of this scenario appear in **table 9**. Demand is estimated to increase by 4.5 mb/d by 2010, and by over six mb/d by 2020. Meanwhile, non-OPEC supply is decreased, compared with the reference case, by five mb/d by 2010 and by seven mb/d by 2020. The net result is for OPEC

Table 8
Results of high-price scenarios, with and without URR responses

	Reference case				**High price and no URR response**				**High price, URR response and Caspian**			
	2005	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Real Basket price *$(2001)/b*	**20.6**	**19.7**	**19.7**	**19.7**	**31.3**	**31.3**	**31.3**	**31.3**	**31.3**	**31.3**	**31.3**	**31.3**
Annual OPEC export revenue *$(2001) bn*	**159.2**	**152.5**	**147.2**	**142.5**	**214.7**	**189.9**	**171.5**	**159.9**	**211.2**	**176.8**	**147.0**	**124.5**
Oil requirements *mb/d*												
OECD	49.4	51.6	53.4	55.0	47.5	48.5	49.6	50.6	47.5	48.7	49.8	51.0
DCs, incl. OPEC	21.3	25.5	29.9	35.0	20.7	24.4	28.5	33.2	20.7	24.3	28.2	32.8
Former CPEs	10.6	12.4	14.4	16.5	10.6	12.4	14.3	16.4	10.6	12.4	14.3	16.4
World	**81.3**	**89.4**	**97.6**	**106.5**	**78.8**	**85.3**	**92.3**	**100.2**	**78.8**	**85.3**	**92.4**	**100.2**
Oil production *mb/d*												
OECD	22.3	21.6	21.0	20.4	23.9	25.2	26.4	26.7	24.1	26.9	30.5	33.6
DCs, excl. OPEC	12.7	13.9	14.5	15.1	13.6	16.8	18.9	20.2	13.9	18.6	23.3	28.4
Former CPEs	13.2	14.5	15.7	16.0	13.2	14.5	15.7	16.0	13.5	15.4	17.1	18.0
OPEC	**31.2**	**37.3**	**44.3**	**52.6**	**26.4**	**26.8**	**29.2**	**35.0**	**25.6**	**22.4**	**19.3**	**17.9**
Non-OPEC	**50.1**	**52.1**	**53.3**	**53.9**	**52.4**	**58.5**	**63.1**	**65.3**	**53.2**	**62.9**	**73.1**	**82.4**
OPEC market share *per cent*	***38.4***	***41.7***	***45.4***	***49.4***	***33.5***	***31.4***	***31.7***	***34.9***	***32.4***	***26.3***	***20.9***	***17.8***

Differences from the reference case

	High price, no URR response				High price, URR response and Caspian			
	2005	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Real Basket price *$(2001)/b*	**10.6**	**11.6**	**11.6**	**11.6**	**10.6**	**11.6**	**11.6**	**11.6**
Annual OPEC export revenue *$(2001) bn*	**55.5**	**37.4**	**24.3**	**17.4**	**52.0**	**24.3**	**–0.2**	**–18.0**
Oil requirements *mb/d*								
OECD	–1.9	–3.0	–3.8	–4.4	–1.9	–2.9	–3.5	–4.0
DCs, incl. OPEC	–0.6	–1.1	–1.5	–1.8	–0.6	–1.2	–1.7	–2.2
Former CPEs	0.0	0.0	0.0	–0.1	0.0	0.0	0.0	–0.1
World	**–2.5**	**–4.1**	**–5.3**	**–6.3**	**–2.5**	**–4.1**	**–5.3**	**–6.3**
Oil production *mb/d*								
OECD	1.6	3.6	5.4	6.3	1.8	5.3	9.5	13.2
DCs, excl. OPEC	0.8	2.9	4.5	5.1	1.1	4.7	8.8	13.3
Former CPEs	0.0	0.0	0.0	0.0	0.3	0.8	1.5	2.1
OPEC	**–4.9**	**–10.5**	**–15.1**	**–17.6**	**–5.7**	**–14.9**	**–25.0**	**–34.7**
Non-OPEC	**2.4**	**6.4**	**9.8**	**11.3**	**3.2**	**10.8**	**19.7**	**28.4**
OPEC market share *per cent*	***–4.9***	***–10.3***	***–13.7***	***–14.5***	***–6.0***	***–15.4***	***–24.5***	***–31.5***

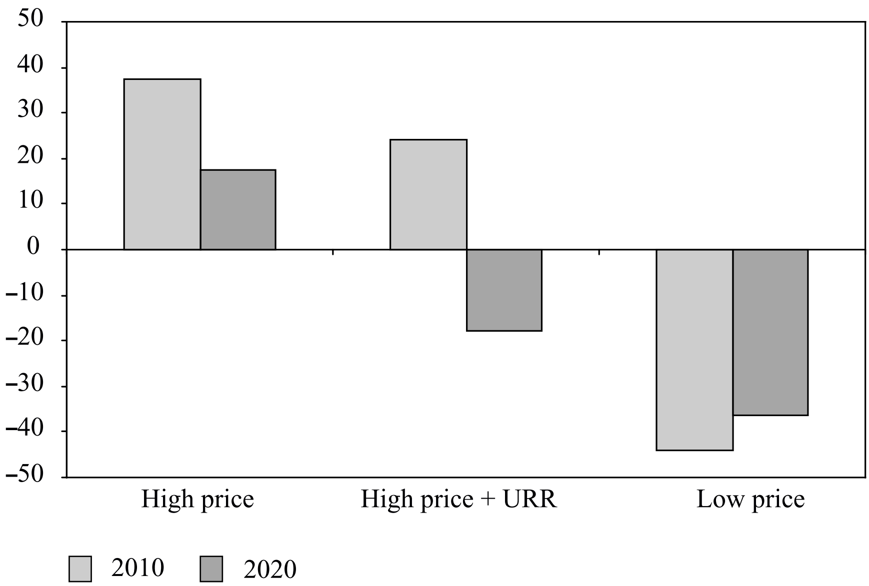
Table 9
Results of low-price scenarios

	Reference case				**Low price**				**Differences from the reference case**			
	2005	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**	**2005**	**2010**	**2015**	**2020**
Real Basket price *$(2001)/b*	**20.6**	**19.7**	**19.7**	**19.7**	**11.8**	**11.8**	**11.8**	**11.8**	**–8.8**	**–7.9**	**–7.9**	**–7.9**
Annual OPEC export revenue *$(2001) bn*	**159.2**	**152.5**	**147.2**	**142.5**	**105.9**	**108.6**	**108.2**	**106.1**	**–53.3**	**–43.9**	**–39.1**	**–36.4**
Oil requirements *mb/d*												
OECD	49.4	51.6	53.4	55.0	51.8	54.7	57.0	59.0	2.4	3.1	3.6	4.0
DCs, incl. OPEC	21.3	25.5	29.9	35.0	22.2	26.8	31.7	37.3	0.9	1.3	1.8	2.2
Former CPEs	10.6	12.4	14.4	16.5	10.6	12.4	14.4	16.6	0.0	0.0	0.1	0.1
World	**81.3**	**89.4**	**97.6**	**106.5**	**84.6**	**93.9**	**103.1**	**112.8**	**3.3**	**4.5**	**5.5**	**6.3**
Oil production *mb/d*												
OECD	22.3	21.6	21.0	20.4	20.6	18.9	17.4	16.5	–1.7	–2.8	–3.5	–4.0
DCs, excl. OPEC	12.7	13.9	14.5	15.1	12.1	11.8	11.7	11.9	–0.7	–2.1	–2.8	–3.2
Former CPEs	13.2	14.5	15.7	16.0	13.1	14.4	15.5	15.8	–0.1	–0.1	–0.2	–0.2
OPEC	**31.2**	**37.3**	**44.3**	**52.6**	**36.9**	**46.7**	**56.1**	**66.2**	**5.7**	**9.4**	**11.8**	**13.6**
Non-OPEC	**50.1**	**52.1**	**53.3**	**53.9**	**47.7**	**47.2**	**47.0**	**46.7**	**–2.4**	**–5.0**	**–6.4**	**–7.3**
OPEC market share *per cent*	***38.4***	***41.7***	***45.4***	***49.4***	***43.6***	***49.8***	***54.4***	***58.6***	***5.2***	***8.0***	***9.1***	***9.3***

market share to increase to 50 per cent by 2010, a level reached in the reference case only by 2020. OPEC production by that year reaches 66 mb/d, a level that might not be considered feasible.

What do these different price assumptions signify for OPEC export revenue? A recent IEA report,[47] for example, suggested that OPEC revenue is lower with *either* substantially higher *or* lower prices than reference case values, both for 2010 and for 2020. The implications of the above scenarios for OPEC export revenue are summarized in **figure 3**. Indeed, the low-price scenario generates lower revenue both for 2010 and 2020. Additionally, the higher price, when it includes the URR response, also generates lower export revenue in the very long term, although by 2010 this result does not hold. This confirms the broad result that OPEC export revenue is not maximized by sustaining extremely high or low prices. However, the key interpretation of these results is that the prices depicted in these scenarios are simply not sustainable.

Figure 3
OPEC export revenue in 2010 and 2020 with high and low oil prices: difference to reference case
$ billion (2001)



Footnotes

1. *Monitoring of ACEA's Commitment on CO_2 Emission Reduction from Passenger Cars, joint report of the European Automobile Manufacturers Association and the Commission Services, June 2001. Available at http://www.acea.be/acea/CO2-2000.pdf.*

2. *See, for example, "CAFE or PRICE? An analysis of the effects of federal fuel economy regulations and gasoline price on new car mpg, 1978–89", Greene, D., Energy Journal, vol. 11, no. 3, 1990.*

3. *Scenarios Related to the Security of Supply of the European Union, Capros, P., et al, National Technical University of Athens.*

4. *Ibid.*

5. *See "Vehicle ownership to 2015: implications for energy use and emissions", Dargay, J., and Gately, D., Energy Policy, vol. 25, 1997.*

6. *See, for example, "The relationship between energy intensity and income levels: forecasting long-term energy demand in Asian emerging countries", Galli, Rossana, The Energy Journal, Vol. 19, No. 4, 1998.*

7. *Ibid.*

8. *"Economic development and the structure of the demand for commercial energy", Judson, Ruth A., Schmalensee, Richard, and Stoker, Thomas M., The Energy Journal, Vol. 20, No. 2, 1999.*

9. *"Economic development and end-use energy demand", Medlock III, Kenneth B., and Soligo, Ronald, The Energy Journal, Vol. 22, No. 2, 2001.*

10. *A planned project for a sectoral analysis of developing countries will aim to adopt this approach.*

11. *Towards a European Strategy for the Security of Energy Supply, 2001, available at: http://europa.eu.int/comm/energy_transport/doc-principal/pubfinal_en.pdf.*

12. *World Road Statistics 2001, International Road Federation, 2001.*

13. *See Rapid Motorisation in the Largest Countries in Asia: Implication for Oil, Carbon Dioxide and Transportation, Schipper, L., Marie-Lilliu, C., and Lewis-Davis, G., IEA, 1998, available at: http://www.iea.org/pubs/free/articles/schipper/rapmot.htm*

14. *See Dargay and Gately, op cit.*

15. *See Huntington, "Inferred demand and supply elasticities from a comparison of world oil models", in International Energy Economics, ed. T. Sterner, 1992.*

16. *Report of the Group on India Hydrocarbons Vision — 2025, New Delhi, 2000, available at http://pmindia.nic.in/pminitiatives/ihc-vl2.pdf.*

17. *Source: World Road Statistics 2001, International Road Federation, 2001.*

18. *Furthermore, the current intensity of 50 vehicles per km of roads in Russia suggests that these values would rise to similar levels to those currently seen in many European countries, even without an extension of the road network: development of infrastructure is, therefore, unlikely to hamper this growth.*

19. *See "Oil outlook to 2020", Shihab-Eldin, Adnan, Lounnas, Rezki, and Brennand, Garry, OPEC Review, December 2001.*

20. *A Framework for Modelling Petroleum Supply: Theoretical and Practical Considerations, OPEC Secretariat, June 2001.*

21. *Although, strictly speaking, this group consists of all FSU countries, except Russia.*

22. *Reportedly already down to $8/b (see US Department of Energy's Energy Information Administration (DOE/EIA), Country Analysis Briefs).*

23. *National Energy Board, Canada's Oil Sands: a Supply and Market Outlook to 2015, October 2000.*

24. *The Norwegian Petroleum Directorate, The Petroleum Resources on the Norwegian Continental Shelf 2001, August 2001, available at http://www.npd.no.*

25. *A recovery rate of 50% is being aimed for.*

26. *Development of UK Oil and Gas Resources 2001, UK Department of Trade and Industry, July 2001, partly accessible at http://www.ecdti.co.uk.*

27. *Source: Market Opportunities, Oil and Gas Equipment and Services Sector, Expetro, November 2000.*

28. *See "Greater competition, more investment", John Weston, Gaffney Cline Associates, in Fundamentals of the Global Offshore Industry, Petroleum Economist, September 2001.*

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34. *Although there is little scope for further cost reduction without significant changes in technology. See GTL Technology Update, Godley, N., and Thijssen, J., Arthur D. Little, 2000.*

35. *Other factors also inevitably play a role, such as capital and operating costs, fiscal conditions and sharing facilities with other projects, such as NGLs.*

36. *See GTL Technology Update, Godley, N., and Thijssen, J., Arthur D. Little, 2000.*

37. *An Assessment of Energy and Environmental Issues Related to the Use of Gas-to-Liquid Fuels in Transportation, Greene, David L., Oak Ridge National Laboratory, November 1999.*

38. *Gaffney, Cline and Associates, Report for Department of Industry, Science and Resources, Australia, May 2001.*

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40. *World Energy Outlook, Assessing Today's Supplies to Fuel Tomorrow's Growth, International Energy Agency (IEA), 2001.*

41. *See Gately, D., "How plausible is the consensus projection of oil below $25 and Persian Gulf oil capacity and output doubling by 2020?" The Energy Journal, Vol. 22, No. 4, 2001.*

42. *See http://www.energyforum.gov.sa/html/papers.html.*

43. *The DOE has assumed a threshold price of $27/b, before GTL projects attract substantial investment. See International Outlook 2000, DOE/EIA, p.60.*

44. *See Canada's Oil Sands: a Supply and Market Outlook to 2015, National Energy Board, October 2000, available at: http://www.neb-one.gc.ca/energy/emaoils_e.pdf.*

45. *Oil Downstream Sector Outlook to 2010: Impacts of Caspian Oil Developments, OPEC Secretariat, June 2001.*

46. *See Greene, D., op cit.*

47. *World Energy Outlook: Assessing Today's Supplies to Fuel Tomorrow's Growth, IEA, 2001.*

Annex

Table A1a
Fuel consumption and its share by sector — North America

Fuel consumption by sector
mtoe

	1970	1980	1990	2000	2010	2020
Industry						
Oil	151.2	216.9	177.6	194.9	201.2	204.9
Gas	169.3	182.4	157.4	153.3	169.1	184.6
Solids	85.3	54.1	50.5	28.8	23.0	17.3
Electricity	53.4	78.4	93.6	119.6	134.5	149.9
Energy	459.2	531.8	479.0	496.6	527.8	556.6
Household/commercial						
Oil	161.1	113.6	84.0	83.7	78.5	72.6
Gas	179.0	187.7	184.8	205.4	213.0	217.6
Solids	10.4	8.0	8.9	2.5	2.0	2.0
Electricity	77.7	126.3	176.8	220.9	250.6	280.2
Energy	428.2	435.6	454.5	512.6	544.1	572.5
Electricity generation						
Oil	50.5	73.5	46.9	60.6	60.4	62.7
Gas	93.1	90.2	95.1	155.4	217.5	296.0
Solids	187.4	307.1	408.9	521.0	538.3	549.4
Hydro/nuclear	43.3	132.2	249.0	301.8	296.1	267.8
Energy	374.2	603.0	799.9	1,038.9	1,112.4	1,175.9

Fuel share by sector
per cent

	1970	1980	1990	2000	2010	2020
Industry						
Oil	32.9	40.8	37.1	39.2	38.1	36.8
Gas	36.9	34.3	32.8	30.9	32.0	33.2
Solids	18.6	10.2	10.6	5.8	4.4	3.1
Electricity	11.6	14.7	19.5	24.1	25.5	26.9
Household/commercial						
Oil	37.6	26.1	18.5	16.3	14.4	12.7
Gas	41.8	43.1	40.7	40.1	39.1	38.0
Solids	2.4	1.8	1.9	0.5	0.4	0.4
Electricity	18.2	29.0	38.9	43.1	46.1	48.9
Electricity generation						
Oil	13.5	12.2	5.9	5.8	5.4	5.3
Gas	24.9	15.0	11.9	15.0	19.6	25.2
Solids	50.1	50.9	51.1	50.1	48.4	46.7
Hydro/nuclear	11.6	21.9	31.1	29.1	26.6	22.8

Table A1b
Fuel consumption and its share by sector — Western Europe

Fuel consumption by sector
mtoe

	1970	1980	1990	2000	2010	2020
Industry						
Oil	197.6	185.3	135.5	142.9	148.3	147.1
Gas	34.1	79.6	89.8	106.8	122.5	134.3
Solids	86.5	78.9	73.3	43.6	37.2	32.6
Electricity	51.4	72.6	85.2	93.2	107.8	121.8
Energy	369.7	416.3	383.8	386.6	415.8	435.8
Household/commercial						
Oil	152.4	158.6	116.4	116.4	116.7	118.1
Gas	28.0	85.0	109.8	153.8	177.1	206.1
Solids	81.4	66.4	48.3	14.1	6.7	4.8
Electricity	37.0	68.7	98.0	123.7	138.0	155.8
Energy	298.8	378.8	372.6	408.1	438.4	484.8
Electricity generation						
Oil	63.1	83.7	46.3	44.0	48.5	51.4
Gas	13.9	31.2	36.7	95.5	121.9	148.5
Solids	166.7	241.4	257.7	210.2	207.8	215.1
Hydro/nuclear	41.8	96.9	242.3	294.4	308.8	315.3
Energy	285.5	453.2	583.1	644.0	687.0	730.3

Fuel share by sector
per cent

	1970	1980	1990	2000	2010	2020
Industry						
Oil	53.5	44.5	35.3	37.0	35.7	33.8
Gas	9.2	19.1	23.4	27.6	29.5	30.8
Solids	23.4	18.9	19.1	11.3	8.9	7.5
Electricity	13.9	17.4	22.2	24.1	25.9	27.9
Household/commercial						
Oil	51.0	41.9	31.2	28.5	26.6	24.4
Gas	9.4	22.5	29.5	37.7	40.4	42.5
Solids	27.2	17.5	13.0	3.5	1.5	1.0
Electricity	12.4	18.1	26.3	30.3	31.5	32.1
Electricity generation						
Oil	22.1	18.5	7.9	6.8	7.1	7.0
Gas	4.9	6.9	6.3	14.8	17.7	20.3
Solids	58.4	53.3	44.2	32.6	30.3	29.5
Hydro/nuclear	14.6	21.4	41.6	45.7	44.9	43.2

Table A1c
Fuel consumption and its share by sector — OECD Pacific

Fuel consumption by sector
mtoe

	1970	1980	1990	2000	2010	2020
Industry						
Oil	81.9	84.7	96.6	122.8	124.6	125.9
Gas	2.7	6.8	11.9	20.0	22.0	24.0
Solids	22.9	27.5	32.1	30.7	33.1	31.0
Electricity	22.3	33.6	43.5	55.5	63.5	72.3
Energy	129.7	152.7	184.1	229.0	243.1	253.3
Household/commercial						
Oil	29.0	43.7	56.9	67.0	69.7	72.2
Gas	3.9	8.6	13.5	25.0	28.1	31.6
Solids	3.5	10.0	10.5	1.3	0.7	0.7
Electricity	8.2	20.4	41.3	63.4	78.7	94.3
Energy	44.7	82.6	122.2	156.7	177.2	198.7
Electricity generation						
Oil	44.8	67.9	53.5	36.1	36.2	33.9
Gas	1.5	17.4	38.6	54.3	69.1	83.1
Solids	29.7	31.6	58.6	111.4	125.0	143.1
Hydro/nuclear	10.6	34.7	81.8	130.0	158.1	185.7
Energy	86.7	151.7	232.6	331.7	388.4	445.7

Fuel share by sector
per cent

	1970	1980	1990	2000	2010	2020
Industry						
Oil	63.1	55.5	52.5	53.6	51.2	49.7
Gas	2.1	4.5	6.5	8.7	9.0	9.5
Solids	17.6	18.0	17.4	13.4	13.6	12.3
Electricity	17.2	22.0	23.6	24.2	26.1	28.5
Household/commercial						
Oil	65.0	52.8	46.6	42.8	39.3	36.3
Gas	8.8	10.4	11.1	15.9	15.9	15.9
Solids	7.7	12.1	8.6	0.8	0.4	0.3
Electricity	18.5	24.7	33. 8	40.5	44.4	47.5
Electricity generation						
Oil	51.7	44.8	23.0	10.9	9.3	7.6
Gas	1.8	11.5	16.6	16.4	17.8	18.6
Solids	34.3	20.8	25.2	33.6	32.2	32.1
Hydro/nuclear	12.3	22.9	35.2	39.2	40.7	41.7

Table A1d
Fuel consumption and its share by sector — OECD

Fuel consumption by sector
mtoe

	1970	1980	1990	2000	2010	2020
Industry						
Oil	430.7	486.9	409.7	460.6	474.1	477.9
Gas	206.0	268.8	259.1	280.0	313.5	342.9
Solids	194.7	160.4	155.9	103.1	93.3	80.9
Electricity	127.1	184.6	222.2	268.3	305.8	344.0
Energy	958.5	1,100.8	1,046.9	1,112.1	1,186.8	1,245.6
Household/commercial						
Oil	342.5	315.9	257.3	267.1	264.9	262.8
Gas	211.0	281.3	308.1	384.2	418.2	455.3
Solids	95.3	84.4	67.7	18.0	9.4	7.5
Electricity	123.0	215.4	316.1	408.1	467.3	530.4
Energy	771.8	896.9	949.2	1,077.4	1,159.7	1,256.0
Electricity generation						
Oil	158.4	225.1	146.7	140.7	145.1	147.9
Gas	108.5	138.8	170.4	305.2	408.5	527.6
Solids	383.8	580.0	725.3	842.5	871.2	907.6
Hydro/nuclear	95.6	263.9	573.2	726.1	763.0	768.8
Energy	746.4	1,207.8	1,615.5	2,014.5	2,187.7	2,351.9

Fuel share by sector
per cent

	1970	1980	1990	2000	2010	2020
Industry						
Oil	44.9	44.2	39.1	41.4	39.9	38.4
Gas	21.5	24.4	24.8	25.2	26.4	27.5
Solids	20.3	14.6	14.9	9.3	7.9	6.5
Electricity	13.3	16.8	21.2	24.1	25.8	27.6
Household/commercial						
Oil	44.4	35.2	27.1	24.8	22.8	20.9
Gas	27.3	31.4	32.5	35.7	36.1	36.3
Solids	12.4	9.4	7.1	1.7	0.8	0.6
Electricity	15.9	24.0	33.3	37.9	40.3	42.2
Electricity generation						
Oil	21.2	18.6	9.1	7.0	6.6	6.3
Gas	14.5	11.5	10.5	15.1	18.7	22.4
Solids	51.4	48.0	44.9	41.8	39.8	38.6
Hydro/nuclear	12.8	21.9	35.5	36.1	34.9	32.7

Table A2
World gas demand outlook
mtoe

	2000	2010	2020	Average annual growth rates *per cent per annum* 2000–10	2010–20
OECD	1,105.5	1,298.0	1,508.0	1.6	1.5
North America	624.0	726.4	844.5	1.5	1.5
Western Europe	381.2	451.1	523.2	1.7	1.5
Pacific	100.4	120.5	140.3	1.8	1.5
OPEC	236.9	397.5	649.9	5.3	5.0
Other DCs	185.9	349.8	657.6	6.5	6.5
FSU	496.1	671.8	839.5	3.1	2.3
China	27.5	41.6	59.0	4.3	3.5
Other Europe	27.5	32.2	36.8	1.6	1.4
World	**2,079.3**	**2,791.0**	**3,750.8**	**3.0**	**3.0**

Table A3
World coal demand outlook
mtoe

	2000	2010	2020	Average annual growth rates *per cent per annum* 2000–10	2010–20
OECD	1,048.8	1,061.4	1,087.9	0.1	0.2
North America	569.1	580.5	586.0	0.2	0.1
Western Europe	299.6	281.5	282.3	–0.6	0.0
OECD Pacific	180.0	199.5	219.5	1.0	1.0
OPEC	13.93	18.6	24.9	2.9	3.0
Other DCs	385.2	525.2	661.9	3.1	2.3
FSU	189.5	223.6	252.4	1.7	1.2
China	652.6	931.2	1,253.3	3.6	3.0
Other Europe	29.9	34.2	38.4	1.4	1.2
World	**2,320.0**	**2,794.2**	**3,318.8**	**1.9**	**1.7**

Table A4
Energy demand in the reference case

World energy demand by fuel type
mtoe

	2000	2010	2020
Oil	3,581.5	4,236.6	5,056.7
Solids	2,320.0	2,794.2	3,318.8
Gas	2,079.3	2,791.0	3,750.8
Hydro/nuclear	943.7	1,068.3	1,146.5
Total	**8,924.5**	**10,890.1**	**13,272.7**

OECD energy demand by fuel type
mtoe

	2000	2010	2020
Oil	2,248.9	2,423.8	2,581.5
Solids	1,048.8	1,061.4	1,087.9
Gas	1,105.5	1,298.0	1,508.0
Hydro/nuclear	726.2	763.0	768.8
Total	**5,129.4**	**5,546.3**	**5,946.2**

World energy fuel share
per cent

	2000	2010	2020
Oil	40.1	38.9	38.1
Solids	26.0	25.7	25.0
Gas	23.3	25.6	28.3
Hydro/nuclear	10.6	9.8	8.6
Total	**100.0**	**100.0**	**100.0**

OECD energy fuel share
per cent

	2000	2010	2020
Oil	43.8	43.7	43.4
Solids	20.4	19.1	18.3
Gas	21.6	23.4	25.4
Hydro/nuclear	14.2	13.8	12.9
Total	**100.0**	**100.0**	**100.0**

Table A4 *(continued)*
Energy demand in the reference case

DC energy demand by fuel type
mtoe

	2000	2010	2020
Oil	890.8	1,217.2	1,678.4
Solids	399.1	543.7	686.8
Gas	422.8	747.3	1,307.5
Hydro/nuclear	106.2	149.8	187.0
Total	**1,818.9**	**2,658.1**	**3,859.6**

FSU/China/Other Europe energy demand by fuel type
mtoe

	2000	2010	2020
Oil	441.8	595.5	796.8
Solids	872.0	1,189.0	1,544.1
Gas	551.0	745.6	935.3
Hydro/nuclear	111.3	155.5	190.7
Total	**1,976.2**	**2,685.7**	**3,466.9**

DC energy fuel share
per cent

	2000	2010	2020
Oil	49.0	45.8	43.5
Solids	21.9	20.5	17.8
Gas	23.2	28.1	33.9
Hydro/nuclear	5.8	5.6	4.8
Total	**100.0**	**100.0**	**100.0**

FSU/China/Other Europe energy fuel share
per cent

	2000	2010	2020
Oil	22.4	22.2	23.0
Solids	44.1	44.3	44.5
Gas	27.9	27.8	27.0
Hydro/nuclear	5.6	5.8	5.5
Total	**100.0**	**100.0**	**100.0**

Table A5a
OECD energy fuel share
per cent

	2000	2010	2020
Oil	43.8	43.7	43.4
Solids	20.4	19.1	18.3
Gas	21.6	23.4	25.4
Hydro/nuclear	14.2	13.8	12.9
Total	**100.0**	**100.0**	**100.0**

Table A5b
Non-OECD energy fuel share
per cent

	2000	2010	2020
Oil	35.1	33.9	33.8
Solids	33.5	32.4	30.4
Gas	25.7	27.9	30.6
Hydro/nuclear	5.7	5.7	5.2
Total	**100.0**	**100.0**	**100.0**

Note: The data for solids excludes biomass.

