INTERNATIONAL ENERGY AGENCY

WORLD ENERGY OUTLOOK

2000

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FOREWORD

The *World Energy Outlook* has become the authoritative source for energy projections of the world's energy future. This 2000 edition examines energy demand and supply for 13 world regions to 2020. It draws the implications of these projections for international trade, energy-related CO_2 emissions and investment requirements in power generation.

The study does not try to predict the future, but to identify and analyse key factors in global energy over the next two decades. Its projections are derived from a "Reference Scenario", which incorporates the new policies and measures enacted in OECD countries in order to meet their commitments under the Kyoto Protocol, as well as some other measures which *also* reduce CO_2 emissions. Previous editions of the *Outlook* used a "business-as-usual" approach, which posited a world where no new energy and climate policies were introduced. The IEA's World Energy Model — the tool for generating the projections — has been enhanced to include separate models for Russia, India and Brazil.

We project continuing steady growth in world energy use and in related CO_2 emissions, despite the recent efforts by many OECD countries to mitigate unwanted climate change. Our findings describe the extent of the challenge.

Fossil fuels will continue to dominate the world energy mix. OECD countries' share of world energy demand will continue to decline in favour of non-OECD countries. Consuming regions, including the OECD and the dynamic Asian economies, will become much more dependent on imported oil and gas. As demand grows, massive investment in oil production facilities will be needed, particularly in the Middle East. Large investments in electricity generation, in particular in developing countries, will also be required.

We have developed three "alternative cases" to the Reference Scenario. In one, we measure the extent to which an international market for CO_2 emission reductions could reduce the costs of meeting the Kyoto targets. A second alternative examines the transport sector and points to the need for a package of measures to limit CO_2 emissions in OECD countries. A third case demonstrates the scope that exists for mitigating rising CO_2 emissions in OECD countries by switching to natural gas and renewables, extending the lives of existing nuclear plants, and boosting the role of combined heat and power technologies.

This work is published under my authority as Executive Director of the IEA and does not necessarily reflect the views or policies of the IEA Member countries.

Robert Priddle
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Of course, all errors and omissions are solely the responsibility of the authors.

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EXECUTIVE SUMMARY

Global Energy Market Trends

This edition of the World Energy Outlook provides the IEA's latest world energy projections to 2020. It identifies and discusses the main issues affecting demand and supply over that period. The central projections are derived from a "Reference Scenario". This scenario assumes global economic growth of more than 3% per annum — close to the rate observed since 1990 — but a slowdown in the rate of population growth. Fossil-fuel prices are generally assumed to remain flat throughout the first decade of the projection period, with oil and gas prices increasing after 2010 (2005 for US gas prices) in response to supply-side pressures. The Reference Scenario takes account of a range of major new policies and measures adopted in OECD countries — many of which relate to commitments under the Kyoto Protocol — enacted or announced up to mid-2000. The scenario does *not* include possible, potential or even likely future policy initiatives.

The following major conclusions can be drawn from these projections:

- world energy use and related CO_2 emissions will continue to increase steadily;
- fossil fuels will account for 90% of the world primary energy mix by 2020 — up slightly on 1997;
- the shares of different regions in world-energy demand will shift significantly, with the OECD share declining in favour of developing countries;
- a sharp increase will occur in international trade in energy, especially oil and gas;
- the reliance on imported oil and gas of the main consuming regions, including the OECD and dynamic Asian economies, will increase substantially, particularly in the second half of the projection period;
- despite the policies and measures in OECD countries that are taken into account in the Reference Scenario, energy-related CO_2 emissions in 2010 will still be significantly higher than required to meet commitments under the Kyoto Protocol;
- power generation in developing countries will account for nearly one-third of the increase in global emissions to 2020.

Projected world primary energy demand increases by 57% between 1997 and 2020, or at an average annual rate of 2%. This compares with an annual average growth rate of 2.2% from 1971 to 1997. World-energy intensity — primary energy demand per unit of real GDP — is expected to decline over the projection period by 1.1% a year, equal to the historical rate since 1971.

Primary Energy Mix

Oil

Oil remains the dominant fuel in the primary energy mix with a share of 40% in 2020, as a result of 1.9% annual growth over the projection period. This is almost identical to its share today. The volume of world oil demand is projected at close to 115 million barrels per day in 2020, compared to 75 mb/d in 1997. In the OECD countries, the transport sector accounts for all oil-demand growth. In non-OECD regions, transportation accounts for most of the growth in oil use, but the household, industry and power-generation sectors also contribute.

The *Outlook* views the physical world oil-resource base as adequate to meet demand over the projection period. Although oil industries in some countries and regions are maturing, the resource base of the world as a whole is not a constraining factor. One need expect no global "supply crunch". To bring these resources into the market, however, will demand large and sustained capital investment, particularly in Middle East OPEC countries. This is reflected in the assumption that the international crude oil price is flat at $21/barrel in today's money until 2010, but then rises steadily to $28 through 2020. The concentration of oil resources in a small number of producing countries will also mean an increase in the oil-import dependence of the major consuming regions.

Natural Gas

Natural gas is the second fastest growing energy source after non-hydro renewables in the global energy mix. Gas demand rises at 2.7% per annum over the projection period, and its share in world primary energy demand increases from 22% today to 26% in 2020. The bulk of this increase will come at the expense of nuclear and coal. Gas use is expected to surpass coal use after 2010. New power plants will provide the bulk of the incremental gas demand. Technological advances in combined-cycle gas turbines

(CCGTs) have shifted the economics of power generation in favour of gas. Its environmental qualities, notably its much lower content in carbon and other pollutants compared to oil and coal, also contributes to its attractiveness to those concerned about climate change. In many developing regions, the expanded use of gas implies a need for huge infrastructure investments.

World reserves of natural gas are thought to be more than sufficient to meet the projected 86% increase in demand over the outlook period. However, gas resources are not always located conveniently near centres of demand. Cost is both the key to bringing large gas resources to market and the major source of uncertainty regarding the outlook for gas. Pipelines will continue to provide the principal means of transport for gas from North Africa, Russia and the Caspian region to growing gas markets in Europe, for cross-border trade in the Latin American Southern Cone and for exports of Canadian gas to the United States. Liquefied natural gas transportation mainly to East Asia is nonetheless expected to account for a growing share of the increase in international trade. The *Outlook* assumes that it will be possible to supply expanding markets in most regions to 2010 at stable prices (2005 for North America), but only higher prices can elicit higher volumes in the second half of the projection period.

Coal

Projected world coal demand advances by 1.7% a year, slower than total primary energy demand, so that its share declines slightly, from 26% in 1997 to 24% in 2020. In the OECD, virtually all the increase in demand for coal stems from power generation. The switch from coal to gas in industrial applications and in heating households continues. China and India, with ample coal reserves and strong electricity demand-growth prospects, contribute more than two-thirds to the increase in world coal demand over the projection period.

Nuclear

After peaking around 2010, production of nuclear power is projected to decline slightly by the end of the outlook period. Its share in the primary energy mix falls from 7% in 1997 to 5% in 2020. Nuclear power output increases only in a few countries, mostly in Asia. The expected retirement of a number of existing reactors in OECD countries and the transition economies leads to a decline in nuclear power output in these two regions.

Renewables

The world will be using some 50% more hydropower by 2020 than today. More than 80% of the projected increase will arise in developing countries. Nevertheless, hydro's share in the global primary energy mix falls slightly.

Other renewables, including geothermal, solar, wind, tide, wave energy and combustible renewables (commonly known as biomass) and waste, are expected to be the fastest growing primary energy sources, with an annual growth rate averaging 2.8% over the outlook period. Despite this rapid growth, the share of renewables climbs to only 3% by 2020 from the current 2%. Power generation in the OECD countries accounts for most of this increase. Concerns over climate change will encourage the deployment of renewables, although they remain expensive compared to fossil fuels.

Power Generation

World electricity generation increases on average by 2.7% per annum over the period 1997-2020. The power sector's share of primary energy use increases from 36% to 38%. Coal maintains its position as the world's largest single source of electricity generation. While coal's share declines in the OECD area, it increases in developing countries, where electricity production from coal triples by 2020. Natural gas-fired generation grows to more than three-and-a-half times its current level. OECD countries account for nearly half of the increase. Gas is likely to be the preferred fuel for electricity generation so long as its price remains low. The share of oil in power output falls from 9% now to 6% in 2020, while that of nuclear power drops from 17% to 9%. World hydro-electricity grows by 1.8% per year over the projection period, but only by 0.5% per year in the OECD. Electricity generation from other renewables grows rapidly in the OECD area, where their share doubles to 4% in 2020. Most of the projected growth will be dependent upon various forms of financial incentives from governments.

Over the outlook period, nearly 3 000 GW of new generating capacity are projected to be installed around the world. More than half of the new capacity will be in developing countries, much of it in developing Asia. The total cost of these plants is estimated at nearly $3 trillion at today's prices, not including the cost of expanding the transmission and distribution network. The developing countries will need to invest around $1.7 trillion in new generation plant.

Sectoral Trends in Final Energy Demand

World final energy demand increases at 2% a year over the outlook period — the same rate as for primary energy demand. Growth is significantly faster in transportation (2.4%) than in all the other end-use sectors (1.8%). Transport's share increases to 31% in 2020 from 28% in 1997. This results in increased demand for oil, which becomes increasingly concentrated in transportation because of the lack of substitute fuels, and implies a continued shift in oil demand towards lighter oil products, especially aviation kerosene, gasoline and diesel fuel. Demand for oil for transportation uses increases by around 1 200 Mtoe to 2 770 Mtoe in 2020. Most of this growth results from increased incomes and industrialisation in developing countries.

Electricity demand grows more rapidly than for any other end-use fuel. Its projected share in world final energy consumption increases from 17% today to 20% by 2020. The increase is strongest in non-OECD regions where the share of electricity in final energy demand reaches 19% in 2020, equivalent to that of the OECD today. Of the other fuels, coal consumption increases the slowest.

Regional Energy Trends and International Trade

The bulk of the projected increase in world energy demand will come from developing regions. They will account for 68% of the increase between 1997 and 2020. OECD countries will contribute only 23%. Consequently, the current 54% share of the OECD in world primary energy demand declines to 44% by 2020, while that of developing countries rises from 34% to 45%. The share of the transition economies declines slightly.

The main factors behind the strong increase in demand in developing countries include rapid economic growth and industrial expansion, high rates of population increase and urbanisation, and the substitution of commercial for non-commercial fuels. Low energy prices in many developing countries also play a part, although this factor will become less important on the assumption that governments reduce subsidies. Nonetheless, the uneven distribution of per capita energy use between industrialised and developing countries will not change much over the projection period.

In line with general energy market trends, the developing regions are projected to account for 70% of the increase in world demand for oil. Of the 40 mb/d of incremental oil demand expected between 1997 and 2020, 45% comes from China, India and the rest of Asia. Oil demand in China alone surges by 7 mb/d — equivalent to more than current total consumption in the OECD Pacific region (Japan, Australia and New Zealand). Substantial growth in oil use is also expected in OECD North America, where demand increases by about 6 mb/d.

A big increase in international trade is projected to meet the widening gap between consumption and indigenous output in many parts of the world. Regions that depend on imports to meet a major part of their oil needs — notably the three OECD regions and non-OECD Asia — become even more dependent on imports over the projection period, both in absolute terms and as a proportion of their total oil consumption. The OPEC countries are expected to supply much of this increase in import requirements.

The share of gas in the fuel mix increases in all regions. Growth rates are highest in East Asia, China, India and Latin America. The largest increment in absolute terms comes from OECD Europe, which alone accounts for about 19% of the increase in world gas demand over the projection period. The region becomes increasingly dependent on imports of gas as demand outstrips indigenous production. The transition economies and Africa are expected to remain the main sources of gas supply to Europe. Significant increases in demand are also expected in Latin America, OECD North America and the Middle East.

The OECD countries' share of world coal use continues to decline. The biggest contributors to growth in demand for coal are developing Asian countries, led by China and India. Power generation in developing countries is the main source of new demand. Other factors such as the relocation of energy-intensive industries like iron and steel from the OECD area to developing regions also contribute.

Implications for CO_2 Emissions

The Reference Scenario's energy-use projections imply a steady increase in global CO_2 emissions, averaging 2.1% per annum to 2020. This amounts to 13.7 billion tonnes, equivalent to a 60% increase between 1997 and 2020. From 1990 to 2010 — the mid-point in the 2008-2012 emissions-limitation target period established under the 1997 Kyoto Protocol — the projected rise is 8.7 billion tonnes, or 42%.

Fast-growing developing countries contribute heavily to the increase in CO_2 emissions, as they do to global energy demand. OECD countries were responsible for 51% of global CO_2 emissions in 1997, developing countries for 38% and transition economies for 11%. By 2020, the developing countries will account for 50%, the OECD countries for 40% and the transition economies for 10%. East Asia and South Asia contribute heavily to the increase in developing-country emissions. China's projected CO_2 emissions alone climb by 3.3 billion tonnes, while the whole OECD area generates an additional 2.8 billion tonnes.

Global CO_2 emissions increase faster than energy demand over the projection period and at a higher rate than in the past. While the share of fossil fuels in the primary energy mix has declined since 1971, it increases slightly over the projection period. The expected increase in use of non-hydro renewables is not enough to make up for the decline in the shares of nuclear and hydro.

The choice of technology for power-generation equipment in developing countries is of paramount importance for successful action to contain global greenhouse-gas emissions. Power-generation emissions in developing countries, which grow by 4.1% a year between 1997 and 2020, contribute almost one-third of the total increase in *global* CO_2 emissions over the projection period, and an even higher share (35%) in 1990-2010. The transport sector also contributes heavily to CO_2 emissions — especially in OECD countries. From 1997 to 2020, it accounts for 26% of the increase in total emissions.

The CO_2 emission projections of the *Outlook* have particular relevance to the efforts of Annex B countries (the OECD and transition economies) to achieve their commitments to reduce or limit their greenhouse gas (GHG) emissions under the Kyoto Protocol. The difference between target emissions and projected emissions for Annex B countries as a percentage of the target emissions amounts to almost 16%. The gaps are large for all three OECD regions, particularly North America and the Pacific. The situation differs in Russia and Eastern Europe (including Ukraine), whose projected emissions are considerably less than their commitments. The modalities of achieving the Kyoto Protocol that are currently under discussion may allow different countries and regions to mutually offset their emission commitments while remaining within the collective obligation.

Major Uncertainties and Alternative Cases

As with any attempt to project future energy developments, uncertainties surround the projections presented in the Reference Scenario. The main sources of uncertainty are macroeconomic conditions, fossil-fuel supplies and costs, energy and environmental policies (including liberalisation and climate change policies), the role of nuclear power and developments in energy technology. Economic growth is by far the most important factor in energy demand trends and is thus a key source of uncertainty. The close relationship between energy demand and economic activity means that deviations from assumed economic growth paths have a fairly predictable impact on energy demand. Another important source of uncertainty is government policy initiatives, in particular those related to environmental objectives such as the limitation of CO_2 emissions

In this *Outlook*, three alternatives to the Reference Scenario have been developed to analyse the effects of different assumptions concerning specific policy variables. The first focuses on the impact of CO_2-emission trading in Annex B countries; the second on transportation in the OECD; and the third on the power sector in the OECD.

Emission-Trading Case for Annex B Countries

Fulfilling their commitments to limit CO_2 emissions without unduly affecting economic growth is clearly a major policy aim for OECD and other Annex B countries. The Kyoto Protocol provides for the use of emission trading, involving the creation of an international market for CO_2 emission reductions, to reduce the cost of meeting those commitments compared with an exclusive reliance on domestic policies and measures.

The *Outlook* has modelled emission trading between Annex B countries in order to calculate the price of a carbon permit that would ensure that the Kyoto targets are met. It has computed the resulting costs and benefits for participating countries. The analysis yields a permit price of \$32/tonne of CO_2 (\$118/tonne of carbon) in today's money. Annex B emission trading would reduce the costs of meeting the targets for the OECD regions by between 29% and 63%, depending on the size of their commitments and the cost of domestic abatement. In addition, permit trading would constitute a major source of revenue for many of the transition economies, which would be the main suppliers of such permits.

OECD Transport-Sector Case

The transport-sector case analyses the impact of possible additional policy measures that might be put in place by OECD countries to mitigate rising CO_2 emissions. The analysis focuses on efforts to improve vehicle-fuel efficiency and to increase the use of alternative fuels; strategies to induce a modal shift in transport demand; and pricing measures, such as fuel taxes based on carbon value (derived from the CO_2 emission-trading case).

The results of this analysis suggest that the combined set of policy measures considered here could stabilise OECD transportation oil demand and CO_2 emissions *after* 2010 — but that emissions still increase significantly until that time. Measures to improve passenger-vehicle fuel efficiency are the most effective, as they can compensate for the growth in passenger-vehicle transportation. Fuel-tax increases have a lesser but nonetheless sizeable impact. Advanced alternative fuels have some effect, but only in the second half of the projection period. Their effectiveness depends critically on their receiving strong government support. Growth in demand for aviation fuel is only slightly affected by the measures analysed and it remains a major source of GHG emissions.

OECD Power-Generation Case

Changes in OECD energy policies, technological developments and relative fuel prices over the next two decades could have a major impact on power-sector energy demand and CO_2 emissions. The power-generation case examines four factors in the future evolution of the power sector in OECD countries. They are intended to represent plausible alternatives to the Reference Scenario and point to opportunities for CO_2-emission reductions:

- a fossil-fuel option involving higher natural gas use reduces OECD power-generation emissions by 10% in 2020;
- keeping existing nuclear plants open results in power-generation emissions 7% below the Reference Scenario in 2020;
- increased use of renewables leads to a 6% emission reduction in 2020;
- more combined heat and power generation (CHP) reduces total CO_2 emissions by 2% in 2020.

Each option has implications for regional electricity balances. The fossil-fuel and CHP options result in higher natural gas use than the Reference Scenario projects. The nuclear and renewables options require less new gas and coal, thus contributing to greater diversification of electricity supply.

There are major challenges to the realisation of each of these options: nuclear has to overcome public resistance. Renewables are costly and may be subject to physical constraints. CHP may also be costly in many instances. In addition, the fossil-fuel option raises concerns over the adequacy of gas reserves and distribution systems. Nevertheless, they do constitute the most plausible options to reduce CO_2 emissions in the power sector and are thus of great policy relevance.

PART A

GLOBAL TRENDS TO 2020

Part A presents and discusses the major global results and key energy trends of the *World Energy Outlook* to 2020. The first chapter introduces the underlying assumptions for the main determinants of energy use — macroeconomic prospects, world energy prices and population. It describes the Reference Scenario and discusses the uncertainties surrounding the *Outlook* projections. Chapter 2 presents main world energy trends, including total primary and final energy demand and environmental implications. Chapter 3 outlines the prospects for each major energy source and for power generation, including estimates of investment requirements. All the Reference-Scenario projections are based on the IEA's World Energy Model (WEM). Appendix 1 describes the structure and main characteristics of the WEM.

CHAPTER 1
THE CONTEXT

Key Assumptions

Macroeconomic Prospects

Economic growth is by far the most important driver of energy trends. The link between energy demand and economic output remains close, despite some signs of its loosening. Figure 1.1 shows this relationship for the last three decades. Only three events significantly disturbed the close association between total primary energy supply (TPES) and economic activity over this long period — the two oil-price shocks in 1973 and 1979-1980 and very warm weather in 1990. This close tie makes macroeconomic conditions critical to the projections in this *Outlook*.

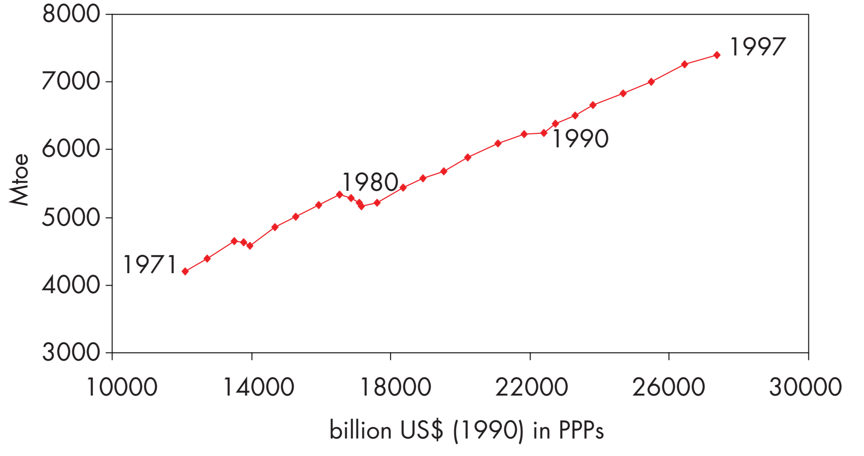
The *Outlook*'s economic-growth assumptions are based on OECD forecasts[1] and studies by the World Bank, IMF and regional development banks, such as the Asian Development Bank, the Inter-American Development Bank and the African Development Bank. The tables in Part D provide details on economic growth rates. All GDP figures are expressed in purchasing-power parities (PPPs) rather than market exchange rates. This provides better indicators for international comparisons of such matters as energy intensities.[2]

The global economy has recovered strongly since the 1997-98 crisis in emerging market economies. OECD North America and developing Asian economies, including China, have driven this stronger growth, but several other regions have also contributed. Almost all OECD economies have performed better than at any time in more than a decade. Japan, an exception to this trend, now shows signs of recovery. After a significant weakening, growth in Russia and other transition economies improved in 1999 and is expected to accelerate in 2000. The Indian economy, after slowing slightly in 1997-98, appears to be regaining momentum, as does the recovery in South America that started in late 1999. The economic

1. OECD, 1997.
2. See Chapter 1 in IEA (1998) for a discussion of the reasons for using purchasing power parities.

performance of most countries in the Middle East, and of several large countries in Africa, has improved significantly over the past year, due mostly to higher world oil prices.

Figure 1.1: **World TPES vs. GDP, 1971-1997**



Note: Transition economies are excluded.

This *Outlook* expects the world economy to grow by 3.1% a year on average to 2020. World economic output more than doubles from 1997 to 2020. Aggregate OECD output rises by an assumed 2% per year, lower than the annual average of close to 3% in the last three decades, continuing as the well-established, long-run slowing of growth in the most mature economies. Expected GDP growth in OECD North America averages 2.1% a year. Annual economic growth in OECD Europe is also assumed to average 2.1% between 1997 and 2020, along with an expected convergence of the European Union (EU) economies. In OECD Pacific, GDP grows by an assumed 1.7% per annum, although the timing of a sustained and consolidated Japanese recovery remains an uncertainty. Growth aside, the *Outlook* also assumes continuous restructuring of the OECD economies — a shift away from energy-intensive sectors towards services, as well as a move toward the use of lighter materials in industry.

Russian growth should average close to 3% a year through 2020, on assumptions that the pace of reform accelerates. The economy expands faster in the second half of the *Outlook* period, as the economy stabilises and market institutions are firmly established. The other transition economies register a similar expansion; expected GDP growth in the group, including Russia, is slightly over 3% per annum.

The developing economies have significantly better growth prospects. The non-OECD share of world GDP rises from 46% to 58% (Figure 1.2). Most of that increase reflects growth in Asia. China will probably remain the fastest-growing economy in the world, with GDP increasing at an average annual rate of 5.2% over the projection period. China becomes by far the largest economy in the world by 2020, with a GDP adjusted for purchasing-power parity equivalent to around half that of OECD countries combined. This high growth is nonetheless significantly lower than the average of 8.3% over the last three decades. The Indian economy is also assumed to expand rapidly to 2020, by almost 5% per year. Achieving this will depend largely on the broadening and deepening of India's economic restructuring programme.

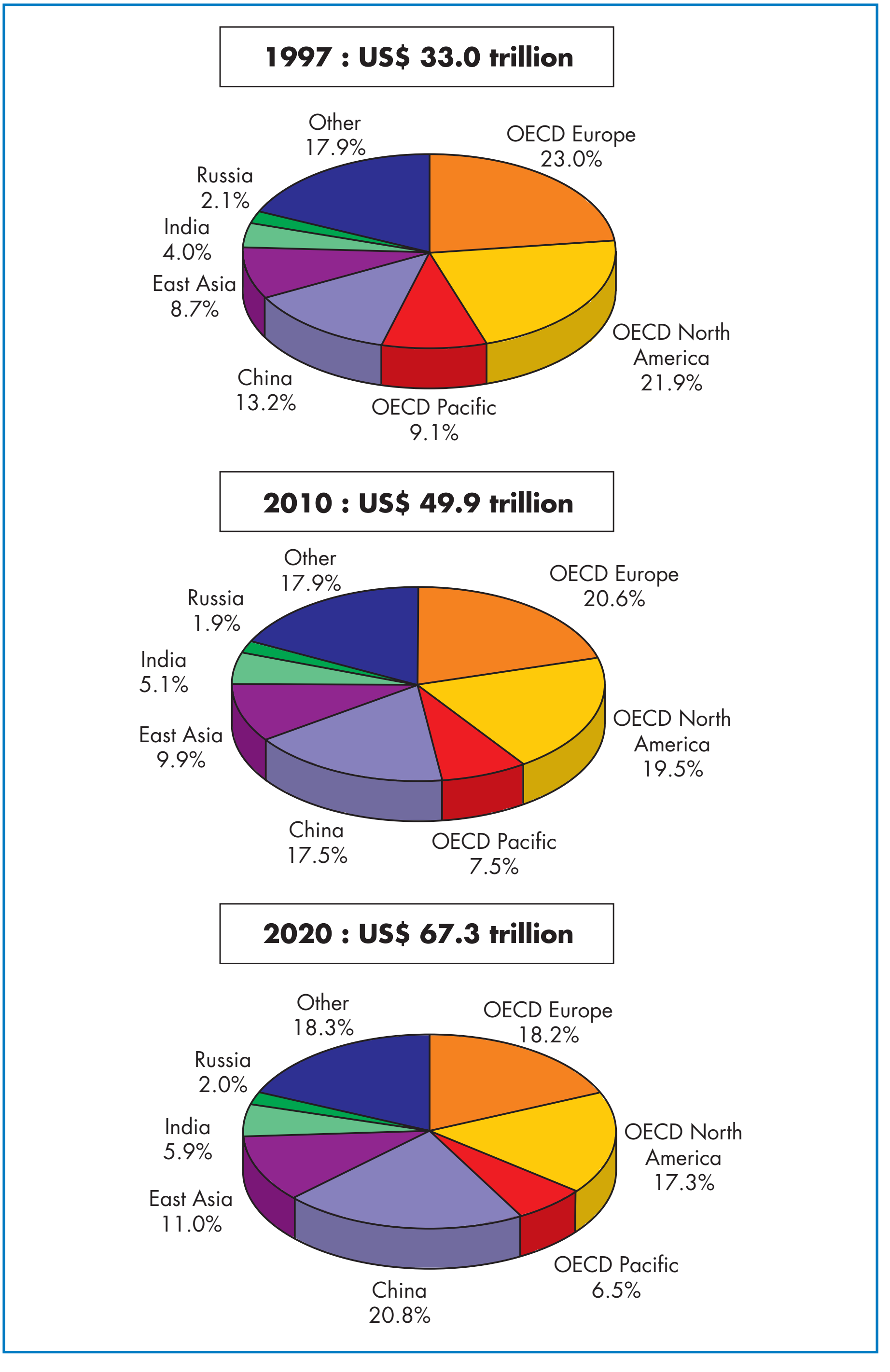
Present conditions favour rapid economic expansion in the East Asian economies. Assumed GDP growth there averages 4.2% per year, still lower than the high rate of almost 7% over the last two decades. The slowdown reflects the maturing of many of the key economies in the region. The economies of Africa and the Middle East are assumed to grow by an average of some 3% a year throughout the outlook period. Assumed GDP growth in Brazil averages 2.5% per annum, somewhat lower than the entire Latin American region's 3.2%.

Population Growth

Population growth also has a strong impact on the size and composition of energy demand. This *Outlook* bases its population growth-rate assumptions on the most recent United Nations population projections.[3] Part D provides detailed assumptions by region. The OECD area's population is assumed to grow by an average of 0.3% per annum over the outlook period. Population in the transition economies remains broadly constant. The population of the developing regions, by contrast, increases by 1.3% per annum through 2020, significantly less than its average rate of 2% in the last three decades.

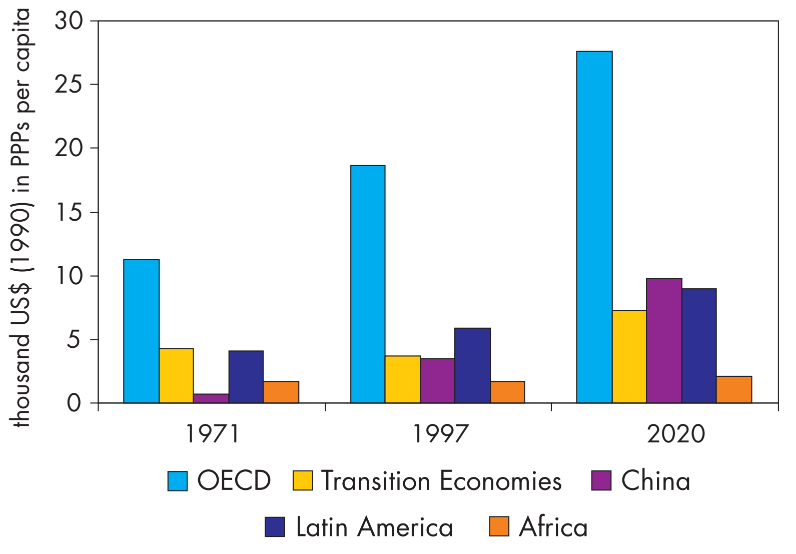
3. United Nations, 1999.

Figure 1.2: **Regional Shares in World GDP** (US$ 1990 in PPPs)



It follows from these projections that the world's population will rise from six billion today to 7.4 billion in 2020 and that the share of the world population living in developing regions will increase from 77% today to 81%. In light of these trends, providing access to commercial energy in developing countries will be an increasingly large and urgent challenge (see Box 1.1). Moreover, the benefits of economic growth in developing regions will be spread over a bigger population, leading to slower growth in per capita incomes than in GDP.

Figure 1.3: **Per Capita Income by Region**



Box 1.1: **Population Growth and Electrification in Developing Countries**

Approximately two billion of the world's six billion people lack access to electricity, primarily in rural areas of developing countries. This ratio has remained constant over the last thirty years as population has expanded at roughly the same pace as electrification. The real number may be considerably higher, however, since "access to electricity" is often defined as grid extension to a village. Many *urban* households cannot gain access to the grid due to high costs of connection, which can run from $50 for a single-phase connection to several hundred dollars. Even when access can be qualified as "easy", as few as half the inhabitants may ultimately use electricity. The challenge, therefore, is to obtain a rate of household electrification that exceeds the rate of population growth.

The economic and human costs of no affordable access to electricity are enormous. They slow improvements in education, health and economic productivity. Electricity is the only effective means of providing many essential services, such as lighting, refrigeration or small water pumps. These arguments have been used to justify widespread subsidisation of electricity, but the waste and inefficiency that subsidies have engendered in the electrified part of the economy have often blocked the expansion of electricity grids. Many developing countries have considerable latent demand for electricity services. Dry-cell and car batteries are frequently used as substitutes in areas without grid access — at costs of several dollars per kilowatt-hour.

According to the World Bank, during the 1990s the private sector alone executed more than 600 electrification projects in 70 developing countries at a cost of $160 billion. As shown in Chapter 3, global generating capacity outside the OECD and the transition economies is projected to increase by nearly 1 600 GW over the next 20 years. This will require investment of around $1.7 trillion. Sums of this magnitude can be raised only if both the public and private sectors contribute. The policy challenge is twofold: first, to attract investment for generating capacity and grid extension and, second, to help poor potential customers to finance connection fees.

A significant reduction in the number of people without access to electricity will require enhanced co-operation between industrialised and developing countries as well as between the private and public sectors.

International Energy Prices

As in previous editions of the *WEO*, the energy projections presented here depend on assumptions about international oil, gas and coal prices (summarised in Table 1.1).[4] These price paths should not be interpreted as forecasts. They do reflect the judgement that the world's energy resources are sufficient to meet increasing world demand over the outlook period at stable or slightly rising prices.

Although the price paths for oil, gas and coal given in Figure 1.4 follow smooth trends, this should not be interpreted as an expectation of stable energy markets. In the last three decades oil prices have fluctuated between around $10 and $65 per barrel (US$ 2000). In fact, an increase in oil-price volatility is to be expected, as a result of the growing share of a few producing countries in global oil supply. In the past two years, oil prices reached both their highest and their lowest levels for the last 10 years. Substantial divergences from the assumed price paths, such as the recent surge, are not likely to be sustained for long, however.

Table 1.1: **Assumptions for World Fossil Fuel Prices** (US$ 1990)

	1997	1998	1999	2010	2020
IEA crude oil import price in US$/barrel	16.0	10.5	13.9	16.5	22.5
OECD steam coal import price in US$/tonne	36.8	32.8	29.3	37.4	37.4
US natural gas wellhead price in US$/thousand cf	1.9	1.6	1.7	2.5	3.5
Natural gas import price into Europe in US$/toe	90.5	79.2	67.3	80.9	132.8
Japan LNG import price in US$/toe	136.2	106.2	102.2	132	182.3

Note: Gas prices are expressed on a gross calorific value basis.

The Reference Scenario assumes an average IEA real crude-oil import price between 2000 and 2010 of $16.50 per barrel in 1990 dollars, equivalent to $21 per barrel in today's money. This price equals the average from 1987 to 1999. Between 2010 and 2020, the price increases steadily to $22.50 per barrel in 1990 dollars or $28 per barrel in today's money.

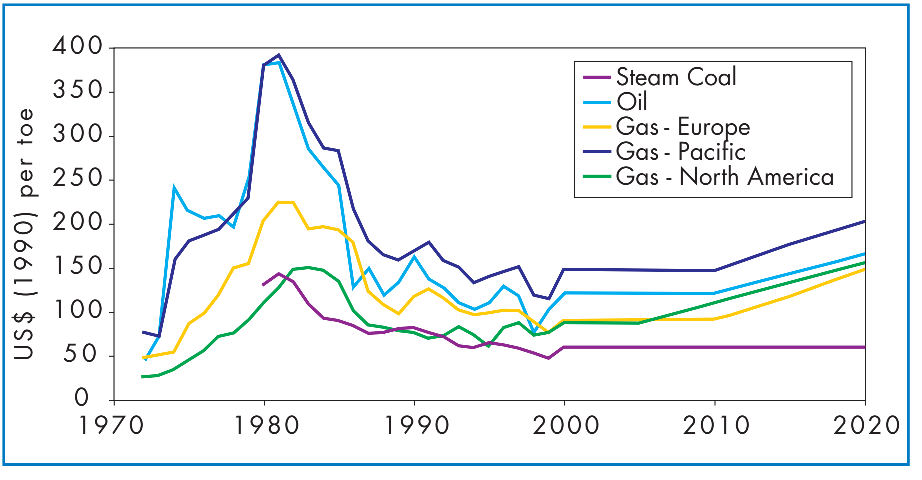
In the first decade of the projection period, the assumption of flat real prices for oil resembles the "base case" or "mid-case" assumptions made by many oil companies. In general, the assumed price of $16.50 per barrel exceeds the full-cycle costs of oil production for new projects outside the

4. Chapter 14 discusses the oil-price assumptions in previous *World Energy Outlooks*.

Middle East OPEC area.[5] Exploring, developing and producing oil is expected to be profitable. Exploration and production spending should be healthy. The price assumption does not constrain non-OPEC supply growth but is a positive factor for production from existing fields, fields under development, probable and possible resources and new discoveries.

In the second decade, the gradual rise in real oil prices to $22.50 per barrel (US$ 1990) is consistent with the maturing and levelling-off of non-OPEC production. This results in a continuing increase in OPEC's market share, which is assumed to exert upward pressure on prices. Chapter 3 discusses global oil supply prospects in detail, including changes since the last *WEO* was published in 1998.

Figure 1.4: **Assumptions for World Fossil Fuel Prices**



Note: Gas prices are expressed on a net calorific value basis.

Unlike the oil market, natural-gas markets are mostly regional, mainly because of high transportation costs. Assumed natural-gas prices in Europe and LNG prices in Japan (the Asia-Pacific price indicator) follow broadly the evolution of oil prices, reflecting the close competition between gas and oil products. Assumed US natural-gas prices stay flat up to 2005, then increase steadily to $4.40 per thousand cubic feet by 2020 (US$ 2000), in line with strong demand growth, a tightening of conventional supplies of US and Canadian gas and increasing reliance on unconventional gas and

5. Full-cycle costs comprise capital and operating costs, including an acceptable rate of return on investment for the oil company.

possibly LNG. Differentials in regional gas prices are assumed to decline during the second half of the projection period.

Assumed international coal prices remain flat in real terms at $46.50 per tonne (US$ 2000) over the entire projection period. This represents a significant downward revision from *WEO 1998*, which assumed an increase to $57.20 (US$ 2000) per tonne by 2020. Sharp improvements in productivity have lowered overall production costs. Further productivity improvements are likely in the second half of the projection period for a number of reasons, including technological advances and increasing competition. The effect on prices will be offset, however, by higher shipping and other costs, resulting partly from the assumed increase in oil prices after 2010.

The Reference Scenario and Alternative Cases

Past editions of the *WEO* provided "Business-as-Usual" (BAU) or similar scenarios as their central projections of future energy demand and supply. These scenarios were built on the underlying assumption that no new policy initiatives would be implemented over the projection period. Projections were derived from analysis of historical data and assumed economic growth and price paths as well as supply constraints. The *WEO* thus provided a forward-looking framework for policy discussions in terms of "what would happen in the absence of policy change" to represent the most likely outcome.[6]

For *WEO 2000*, the BAU scenario has been replaced with a *Reference Scenario*. The main difference is that the Reference Scenario takes account of a range of new policies and measures in OECD countries, most of them designed to combat climate destabilisation. They were all enacted or announced by mid-2000, though many have not yet been fully implemented. Their impact on energy demand and supply does not show up in the historical data, which are available only up to 1997 (1998 in some cases). These numerous initiatives cover a wide array of sectors and a variety of policy instruments. They include voluntary agreements and energy-efficiency programmes, such as mandatory energy-efficiency performance standards and labelling, and support for the deployment of renewable energies. Chapters 4-6 provide detailed lists of the concrete policy measures that have been taken into consideration in the three OECD regions, after

6. As discussed in Chapter 14, past *WEO* projections performed quite well in relation to actual outcomes.

careful vetting with experts from IEA Member countries. The Reference Scenario does *not* include possible, potential or even likely future policy initiatives.[7] Major new energy-policy initiatives will inevitably be implemented during the projection period.

The Reference Scenario includes a number of key assumptions. It assumes that energy-market reforms will proceed, albeit at varying speeds in different OECD and non-OECD regions. As to domestic energy prices in the OECD regions, it assumes that the tax components of final energy prices remain constant in real terms. For non-OECD countries that subsidise energy prices, it assumes that they will progressively phase out the subsidies. Details appear in the relevant regional chapters.

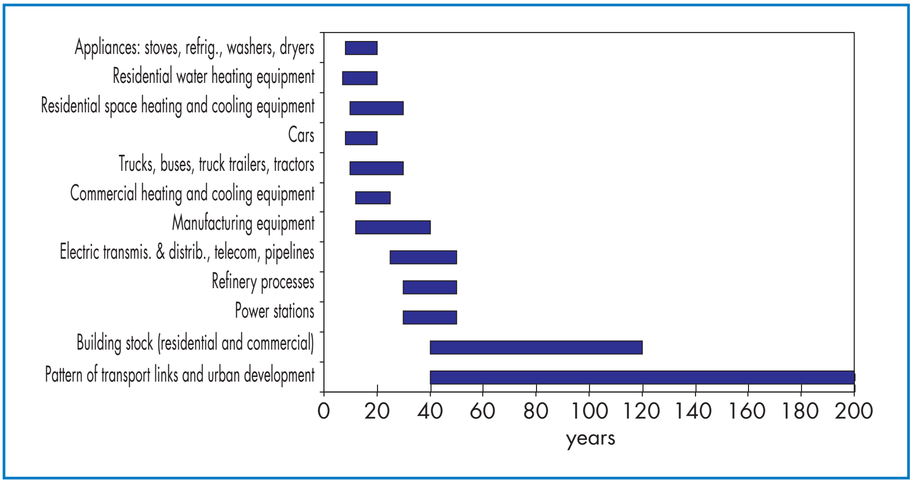
Another set of assumptions relates to technological innovation. Technological assumptions are important for projecting energy trends. Due to the long lifetime of energy-using capital stock (Figure 1.5), however, capital-stock turnover over the time horizon of the Reference Scenario will not suffice to make a substantial change in energy-efficiency trends. Retiring capital stocks before the end of their normal lives is usually costly and would require major new policy initiatives — beyond those assumed in the Reference Scenario — to change significantly the overall rate of improvement in energy efficiency.

The power-generation module of the World Energy Model (WEM) considers several competing technologies. Their efficiencies all improve over the projection period, but at different rates. Advanced power technologies penetrate the market as their capital costs decrease over time. Similarly, the oil and gas supply modules reflect the expected impact of various technological advances in exploration and production techniques, as well as reserve growth.

Three Alternative Cases — *i.e.* alternative to the Reference Scenario — have been developed to analyse the impact on the demand and supply outlook of different assumptions concerning key variables:

7. EC (1999) and DOE/EIA (2000) follow a similar approach. The "baseline scenario" of the EU's *European Union Energy Outlook to 2020* is based on the assumption that current policies will be continued. While this clearly includes a number of ambitious policies, especially environmental policies, it does *not* include, for example, sufficient actions to ensure the achievement of the EU's Kyoto emission-reduction target. Similar to the procedure used in the *WEO 2000*, a policy mix to ensure compliance with this commitment is presented in alternative scenarios. The DOE/EIA's *Annual Energy Outlook 2000* is also explicit in including only laws and regulations in effect as of 1 July 1999. It is even slightly more restrictive than the EU *Outlook* and *WEO 2000* in stating that "potential impacts of pending or proposed legislation… and sections of existing legislation for which funds have not been appropriated are not reflected in the projections." This is a nuance rather than a fundamental difference in approach.

Figure 1.5: **Capital-Stock Turnover**



(1) A study of CO_2 emission trading in Annex B countries[8] calculates the price of a carbon permit that would result from achieving the Kyoto targets, as well as the resulting costs and benefits for participating countries.

(2) A study of the transport sector in the three OECD regions analyses (separately and in combination) the effects of efficiency improvements in vehicle fuel use, a significant modal shift and the implementation of fuel taxes based on the carbon value calculated in the CO_2 emission trading case.

(3) A study of the power sector in the three OECD regions looks at the impact on the fuel mix and CO_2 emissions of rapid advances in the efficiency of fossil fuel technologies, an increased share of renewable energies, an extension of the lifetimes of existing nuclear plants and increased use of combined heat and power (CHP) systems.

The Alternative Cases complement the Reference Scenario by focusing on key issues, and thus will enable readers to formulate their own views about future developments in the energy sector. Their role is to assist

8. Those countries listed in Annex B to the Kyoto Protocol with commitments to reduce or limit their annual GHG emissions, include Russia, Ukraine, most of the countries of Eastern Europe and the Baltic rim, and all OECD countries except Turkey, Mexico and South Korea. The Kyoto commitments are measured in terms of average annual emissions over the "budget period" 2008-2012 and are defined as percentages of a base year, in most cases 1990.

in the formulation of future policies by assessing their likely effectiveness, not to pre-empt discussion.

Major Uncertainties

As with any attempt to project future energy developments, uncertainties surround the projections presented in the Reference Scenario. The main sources of uncertainty fall into six groups: macroeconomic framework conditions, fossil-fuel supplies and costs, energy policies, nuclear power, technological developments and environmental policies.

The issues that pertain to the *macroeconomic framework* include the key determinants of energy demand, such as economic output, structural economic change and population growth. Uncertainties relating to economic growth are especially large in China and Russia, which together account for a significant share of global energy supply and demand. Structural economic change includes the shift from heavy manufacturing industries to services, as well as the increasing use of information and communication technology (ICT) and its role in shaping the "new economy" (see Box 4.1 in Chapter 4). ICT could have significant implications for the energy sector, including the way energy is traded, the creation of new energy services and new demand patterns. Uncertainties in this respect relate more to the speed of change and its impact on the energy sector than to whether the change will in fact take place.

Fossil fuel supplies and their costs remain a major uncertainty. The size of economically recoverable reserves of oil and gas is the subject of keen debate among experts. Previous *World Energy Outlooks* have always paid great attention to projections of the availability of oil. In recent years, the question of adequate supplies of natural gas has also become important due to rapidly increasing world-wide demand. The tightening of gas supplies in some regions may exert upward pressure on prices. Projecting the growth of gas demand, especially in developing countries, depends heavily on assumptions about the development of production and transportation infrastructure. Despite uncertainties about future reserves and the costs of developing them, no physical constraint on supplies of oil or gas is expected to appear during the projection period.

Energy policies are closely linked among countries and will have a substantial overall impact on global energy developments. The issues include the legal framework for energy markets, questions of supply security, pricing policies, infrastructure financing, foreign direct investment and technology transfer. While it is widely assumed that the global trend towards more market orientation, transparency and private entrepreneurship will continue, the precise nature of the energy-market structures that will emerge is difficult to predict. Developments in non-OECD countries will be particularly important, because these countries will generate most of the increase in energy demand over the next 20 years.

Long-term use of *nuclear power* is highly controversial and political. Some governments, including those of several OECD countries, oppose the continued use of nuclear power. Others retain a firm commitment to nuclear development, for economic, energy-security and climate-change related reasons. By generating electricity with no CO_2 emissions, nuclear energy can contribute significantly to reducing greenhouse-gas (GHG) emissions. The increased determination to meet climate-change objectives could lead to a greater role for nuclear in the future energy mix.

Another uncertainty concerns the continuing improvement in the efficiencies of existing *energy technologies* and the development and deployment of new ones. *WEO 2000* assumes that the efficiency of existing energy technologies will continue to improve but that no new "breakthrough technologies" will be deployed on a scale sufficient to make a substantial difference over the next twenty years. In the power sector, for example, improvements in thermal efficiency and reductions in capital costs will occur, but — mainly for reasons of cost — no entirely new technologies, such as fuel cells, will have a decisive impact on energy market trends.

One of the most important sources of uncertainty, at least in the OECD countries, is the course of *environmental policies,* especially those concerned with climate change. The Reference Scenario includes only policy measures already enacted or announced, and its projections indicate that these measures will not be nearly enough to reach the Kyoto targets by 2008-2012. How will Annex B countries handle the gap between targets and current trends? One possible option is emission trading, discussed in detail in Chapter 10. Other options include domestic measures for CO_2 emission abatement. Some of these are analysed in Chapters 11 and 12. It is certain that the next few years will see the introduction of a number of new policies, but it is highly uncertain what their precise form or impact will be.

CHAPTER 2
WORLD ENERGY TRENDS

This chapter presents the principal results of the Reference Scenario. The projection period is through 2020. The last year for which historical data are available for all regions and energy sources is 1997, although 1998 data are used for most OECD countries and some non-OECD countries. The projections lead to the following major conclusions:

- world energy use and related CO_2 emissions will continue to increase steadily;
- fossil fuels will account for 90% of the world primary energy mix by 2020 — up slightly on 1997;
- the shares of different regions in world-energy demand will shift significantly, with the OECD share declining in favour of developing countries;
- a sharp increase will occur in international trade in energy, especially oil and gas;
- the reliance on imported oil and gas of the main consuming regions, including the OECD and dynamic Asian economies, will increase substantially, particularly in the second half of the projection period;
- despite the policies and measures in OECD countries that are taken into account in the Reference Scenario, energy-related CO_2 emissions in 2010 will still be significantly higher than required to meet commitments under the Kyoto Protocol;
- power generation in developing countries will account for nearly one third of the increase in global emissions to 2020.

Primary Energy Demand

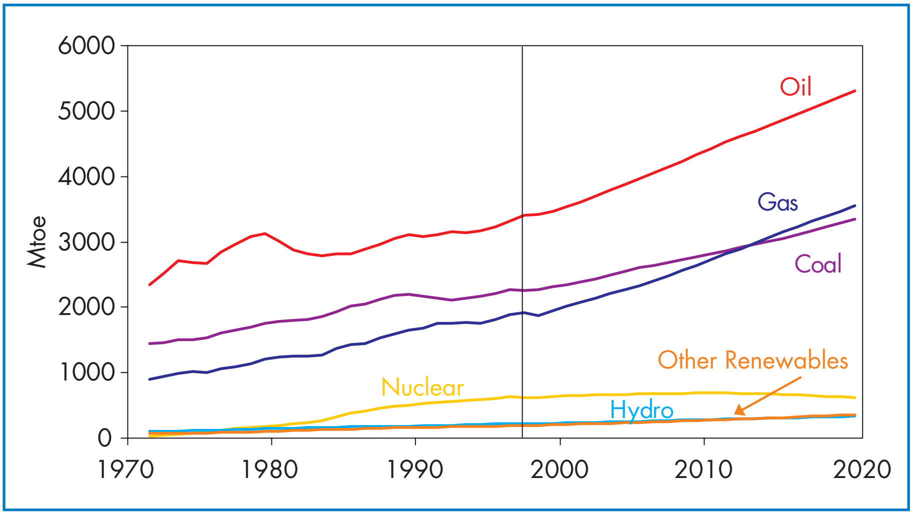
Global Trends

Projected world total primary energy demand[1] in the Reference Scenario increases by 57% between 1997 and 2020, at an average annual

1. Primary energy demand is used interchangeably with total primary energy supply (TPES) and refers only to commercial energy use. The non-commercial energy use (combustible renewables and waste) in developing regions is discussed later in this chapter.

rate of 2%, to slightly more than 13 700 Mtoe. This compares with an annual average growth rate of 2.2% from 1971 to 1997. Figure 2.1 shows projected trends in primary demand by fuel.

Figure 2.1: **World Primary Energy Supply by Fuel, 1971-2020**



Oil remains the dominant fuel, and, with 1.9% annual growth over the projection period, its share will be 40% in 2020. This is almost identical to its share today. The volume of world oil demand is projected to be some 96 million barrels per day in 2010 and 115 million barrels per day in 2020. In the OECD countries, the transport sector accounts for all oil-demand growth. In the other end-use sectors, oil continues to lose market share to other fuels, particularly gas. In non-OECD regions, growth in oil demand is led mainly by transport, but the household, industry and power-generation sectors also contribute.

Natural gas is the second fastest-growing energy source after non-hydro renewables in the global energy mix. Gas demand rises at 2.7% per annum over the projection period, and its share in world primary energy demand increases from 22% today to 26% in 2020. Most of this increase will come at the expense of nuclear energy and coal. Gas demand is expected to surpass coal demand after 2010. New power plants will use most of the incremental gas. Technological advances in combined-cycle gas turbines (CCGT) have shifted the economics of power generation in favour of gas. Its significantly lower content in carbon and other pollutants compared with oil and coal will also be a factor. In many developing regions, the expanded use of gas will require huge infrastructure investments.

Projected world **coal** demand advances by 1.7% a year, slower than total primary energy demand, so that its share declines from 26% in 1997 to 24% in 2020. In the OECD, virtually all the increase in demand for coal stems from power generation. The switch from coal to gas in industrial applications and in household heating continues. While coal's expected share in the primary fuel mix will remain flat or increase slightly in most transition economies, it will decline slightly in Russia's. China and India, with ample coal reserves and strong electricity-demand growth prospects, contribute more than two-thirds to the increase in world coal demand over the projection period.

Nuclear power accounted for 7% of global TPES in 1997, providing 17% of the world's electricity. After peaking around 2010, production of nuclear power is projected to decline slightly by the end of the outlook period. Its share in the primary energy mix falls to 5% in 2020. Nuclear power output increases in only a few countries, mostly in Asia. The expected retirement of a number of existing reactors in OECD countries and in the transition economies leads to a decline in nuclear power output in these two regions.

Hydropower met 3% of the world's primary energy needs and 18% of electricity output in 1997. Expected world hydroelectricity use rises some 50% by 2020. More than 80% of the projected increase will come in developing countries. Hydro's share in the global primary energy mix nonetheless declines to 2% by 2020.

Other renewables[2] are expected to be the fastest growing primary energy source, with annual growth averaging 2.8% over the outlook period. Despite this rapid growth, the share of renewables rises to only 3% by 2020 from the current 2%. Power generation in the OECD countries accounts for most of this increase. Concerns over climate change will encourage the deployment of renewables, but relatively low fossil fuel prices will limit it.

2. This category includes geothermal, solar, wind, tidal and wave energy. It also includes combustible renewables and waste (CRW) for OECD countries but excludes CRW for non-OECD countries. CRW comprise solid biomass and animal products, gas/liquids from biomass, industrial waste and municipal waste. CRW was included in the category of solid fuels in the *1998 World Energy Outlook*.

Box 2.1: **Expansion of International Energy Trade**

This *WEO* projects a substantial increase in energy trade over the next 20 years. The expansion will encompass all fossil fuels as well as electricity, but to differing degrees. The role of countries around the Persian Gulf as global energy suppliers of last resort is likely to become more important. The growth of energy imports will be particularly strong in the dynamic Asian economies. Rising demand and uneven regional concentrations of energy resources will drive international energy trade. Liberalisation of energy markets, which allows consumers to shop for the cheapest suppliers rather than depend on established domestic trading relationships, will stimulate both demand and cross-border trade. Structural changes in energy-supply chains, including the unbundling of vertically integrated structures, could also favour international trade.

By and large, oil and coal can be transported at reasonable cost, which has facilitated the emergence of truly global markets in both commodities. Gas and electricity are largely grid-bound, however, and require enormous infrastructure outlays before trade can take place.

Net inter-regional trade in **oil** is projected to increase from 28 mb/d in 1997 to over 60 mb/d by 2020. In the face of declining oil production, the OECD's import dependence jumps from 54% in 1997 to 70% in 2020. This and fast-growing demand in non-OECD countries such as India and China will increase the market power of exporters — notably the Middle East OPEC countries. Their projected share of global production swells from 26% to 41% over the outlook period.

World trade in **coal** is unlikely to expand much, mainly because overall coal consumption will rise relatively slowly. Trade patterns might change, however. Projected imports by the Asia-Pacific region continue to grow, with Japan remaining the world's largest importer. Imports of most European countries decline, due to relocation and efficiency improvements in steel production and increasing environmental concerns, although imported coal may displace some subsidised, high-cost domestic coal in Germany or Spain.

A combination of regulatory, technical, commercial and environmental factors is expected to increase trade in gas and electricity, although to different degrees in different regions. International trade will, of course, depend on the extension of existing networks, which will require massive investment.

The most rapid expansion in **gas** trade occurs in Europe and the Asia-Pacific region. In Europe, rising demand is likely to lead to further big increases in gas imports and intra-European cross-border trade. European demand will be driven by the increased use of CCGTs, by new technologies, by liberalisation in the gas and power markets and by environmental pressure. Russia, which already provides more than one-third of global coal exports, will remain Europe's primary supplier. The Asia-Pacific gas market, dominated by LNG, will also see continued trade growth. A number of major pipeline and LNG projects are under way or have been announced. China and possibly India are likely to join Japan and Korea as significant gas importers over the next twenty years. In North America, no rapid rise in the ratio of imports to total production is foreseen, due to the maturity of the market, although there may be some extra imports, either by pipeline from Mexico or as LNG from Venezuela and elsewhere over the longer term. Cross-border gas trade in Latin America is expected to increase significantly.

Cross-border and inter-regional **electricity** trade in Europe is likely to increase substantially over the projection period, albeit from a comparatively low base, helped by the relatively short distances between different countries. Liberalisation of the EU electricity market and other EU-led initiatives to promote integration of European grids are also likely to boost intra-European trade. Electricity trade will probably expand in most other regions, notably Latin America, but will probably remain small relative to total production.

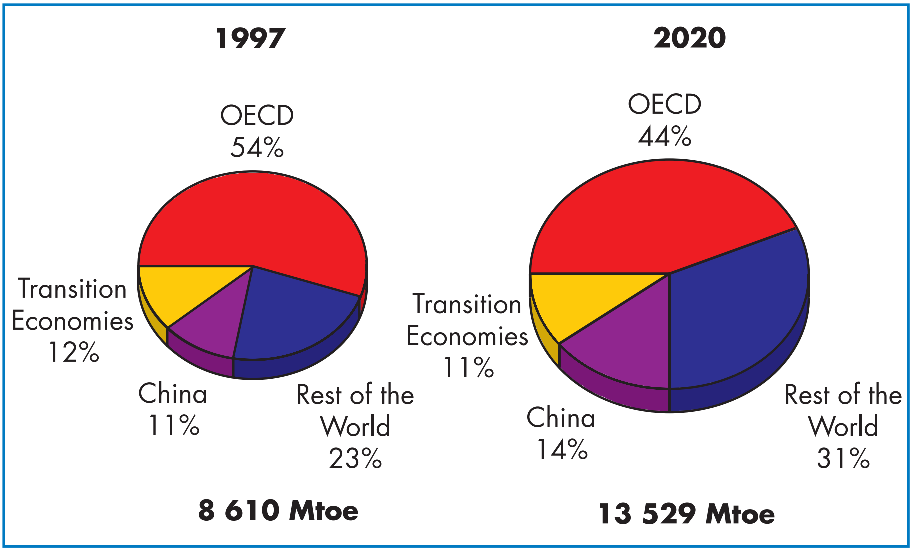
The Regional Outlook

Most of the projected increase in world energy demand will come from the developing regions.[3] They will account for 68% of the increase in world energy demand between 1997 and 2020. OECD countries will account for only 23%. Consequently, the current 54% share of the OECD countries in world energy demand declines to 44% by 2020 while that of developing countries rises to 45% from its current 34%. The transition economies' share declines slightly (Figure 2.2).

The main factors in the strong increase in demand in developing regions include their rapid economic growth and industrial expansion, population increase and urbanisation, and substitution of commercial for

3. China, South Asia, East Asia, Latin America, Africa and the Middle East.

Figure 2.2: **World Primary Energy Supply by Region**



non-commercial fuels. Low energy prices in many developing countries also contribute, although this factor will become less significant as subsidies are reduced (see Box 2.2). Despite this strong increase, however, the uneven distribution of per capita energy use between industrialised and developing countries will not improve much over the projection period.

In line with general energy trends, developing regions will account for a projected 70% of the increase in world demand for oil. Of the 40 mb/d of incremental oil demand between 1997 and 2020, 45% comes from the dynamic Asian regions. Oil demand in China alone rises by 7 mb/d, equivalent to more than current total consumption in the OECD Pacific region (Japan, Australia and New Zealand). Substantial growth in oil use is also expected in OECD North America where demand increases by about 6 mb/d over the projection period.

The share of gas in the fuel mix increases in all regions. Growth rates are highest in East Asia, China, India and Latin America. The largest absolute increment comes from OECD Europe, which accounts for about 19% of world gas demand growth over the projection period. Significant incremental increases are also expected in Latin America, OECD North America and the Middle East.

Box 2.2: **The Removal of Energy Subsidies and Market Reform**

Energy subsidies, particularly those that encourage consumption by keeping prices below cost, impose a heavy burden on economic efficiency, environmental performance and government budgets. Eliminating the under-pricing of energy would reduce consumption and decrease both local and global pollution (including CO_2 emissions). It would boost economic growth through improved efficiency and reduced government outlays.

These facts are well understood in principle. The recent IEA study, *Looking at Energy Subsidies: Getting the Prices Right* (1999), confirms that pervasive under-pricing of energy resources occurs in eight of the largest energy-consuming countries outside the OECD: China, India, Indonesia, Iran, Kazakhstan, Russia, South Africa and Venezuela. On average, end-use prices in these countries are approximately 20% below their opportunity-cost or market-based reference levels, despite substantial progress in recent years towards more market-based policies. Quantitative analysis indicates that the complete removal of energy-price subsidies would:

- reduce primary energy consumption in the eight countries studied by 14%;
- increase GDP through higher economic efficiency by almost 1%;
- lower CO_2 emissions by 17%;
- produce domestic environmental benefits in the form of reduced local air pollution.

Energy-subsidy reform in these eight countries would reduce global energy consumption by 3.5% and world CO_2 emissions by 4.6%. Global energy security would improve through lower energy imports and increased availability of exports, especially of gas and oil. Most important, reform would dynamise the energy sector through improved transparency and accountability, accelerated transfer of technology and a more entrepreneurial approach to exploration, production and distribution.

Developing countries frequently keep prices below the cost of supply in order to encourage commercial energy use by the largest possible number of people. Several OECD countries subsidise domestic energy production to protect local output and employment. In the long run, however, these social-policy objectives are likely to be achieved more efficiently and at less cost through direct financing rather than maintaining artificially low energy prices.

The OECD countries' expected share of world coal use continues to decline (Table 2.1). The highest growth in coal consumption is seen in developing Asian countries, lead by China and India. Although power generation in developing countries mainly determines coal-demand growth, other factors, such as the relocation of energy-intensive industries like iron and steel from the OECD area to developing countries, are also important.

Table 2.1: **World Coal Consumption by Region**

	1971		1997		2020	
	Mtoe	% Share in World	Mtoe	% Share in World	Mtoe	% Share in World
OECD	802	56	1013	45	1091	32
Transition Economies	337	23	203	9	284	9
Developing Countries	308	21	1039	46	1975	59

The projected strong growth of energy demand in the developing world has far-reaching implications for the world energy system. The discussion later in this chapter highlights the increasing share of CO_2 emissions from developing regions, the growing oil-import dependence of those regions and the substantial investment requirements for expanding power generation there.

Energy-Related Services

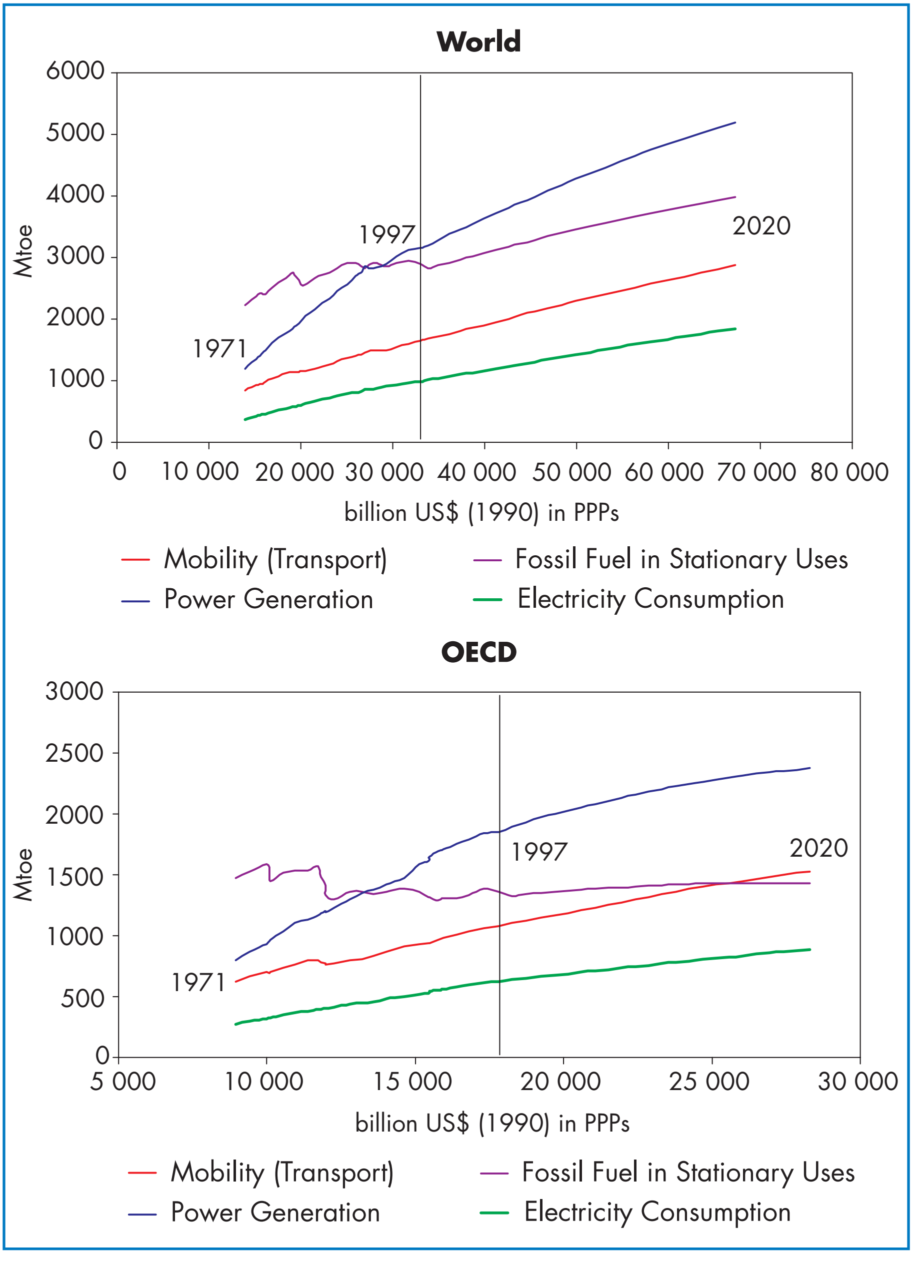
In viewing long-term energy trends, it is important to identify the ultimate services that energy consumption provides. The four main energy services are:[4]

- electrical services (total consumption of electricity by final consumers);
- mobility (non-electricity fuels used in all forms of transport);
- stationary services (mainly fossil fuels consumed for heating in homes, commercial establishments and industrial processes);
- fuels used in power generation.

4. For a more detailed description of the energy-related services concept and a discussion of past trends in these services, see IEA (1998).

Figure 2.3 provides historical data and projected trends in these four services for the world and for the OECD. In both, expected electricity demand closely follows economic activity, as in the past. Fuel inputs to

Figure 2.3: **World and OECD Energy-Related Services**



power generation broadly follow electricity demand, although the trend flattens slightly, especially in the second half of the projection period, mainly because thermal efficiency increases with greater use of high-efficiency CCGT plants.

Demand for mobility in the OECD rises broadly in line with GDP since the second oil-price shock. The impact of rising income on demand diminishes slightly in the second half of the projection period, mainly because of saturation effects and constraints on road traffic, such as congestion, and limits on infrastructure development. World demand for mobility grows in a more linear fashion relative to GDP because of a strong increase in non-OECD demand in the wake of rising per capita incomes.

Projected demand for energy in stationary uses remains relatively independent of GDP growth in the OECD region. In fact, it has remained almost flat over the last two decades despite a substantial real GDP increase. After a very modest rise in the first half of the projection period, demand for stationary uses stagnates after 2010, partly as a result of saturation in household heating. In non-OECD countries, projected demand increases at almost the same rate as GDP in all sectors, in response to rising income levels and rapid growth in manufacturing output. Relocation of heavy industries to non-OECD regions will continue to play an important role.

Energy-Intensity Trends

Energy intensity, measured as total primary energy use per unit of gross domestic product, is an aggregate indicator of the link between economic growth and energy demand over time. Its main determinants include the stage of economic development, energy efficiency, energy prices, climate, geography (which affects average distances travelled), culture and life styles. Improvements in energy efficiency are frequently confused with decreases in energy intensity at the sectoral or national level. Box 2.3 discusses this issue.

World energy intensity is expected to decline over the projection period by 1.1% a year, equal to the rate registered between 1971 and 1997 (Figure 2.4). Substantial differences exist between regions. Intensity falls more slowly in OECD countries compared with past trends. In non-OECD countries, intensity improvements accelerate from past rates. Transition economies have a big potential for energy intensity improvements. Projected regional energy-intensity trends and surrounding issues are discussed in detail in Chapters 4-9.

Box 2.3: **Energy Intensity and Energy Efficiency**

Energy intensity and energy efficiency, as well as the choice of measures to influence them, are key issues in energy policy. Energy efficiency, a technical concept, refers to the ratio between energy output (services such as light, heat and mobility) and input (fuels). Energy intensity is a statistical concept defined as energy consumption per unit of output at different levels of aggregation.

For a single productive process, energy efficiency is the simple inverse of energy intensity. But this does not hold at any higher level of aggregation — the firm, the sector or the economy — where *various* factors, including energy efficiency, determine intensity.

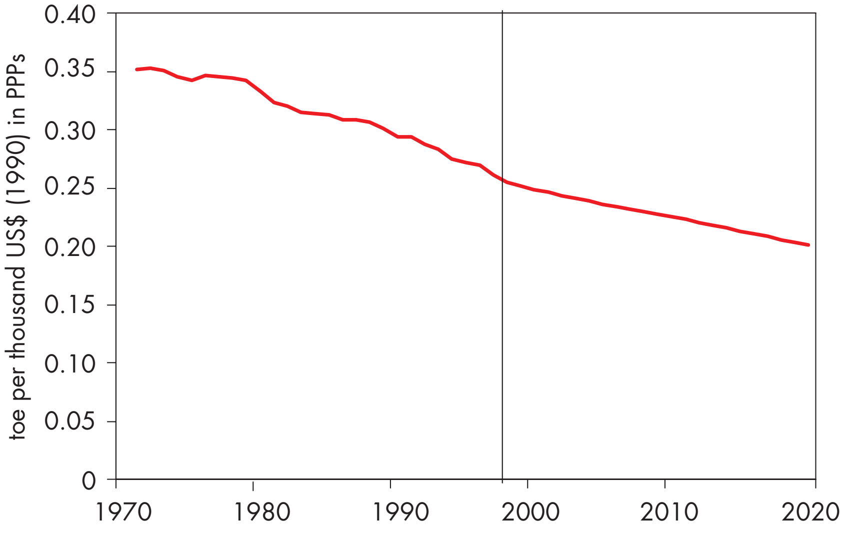
A more energy-intensive country is not necessarily less energy-efficient. The United States and Japan, for instance, have comparable technological knowledge and technical energy efficiency. Due to differences in energy prices, climate, geography and lifestyles, however, the energy intensity (energy consumption per unit of output) of Japan is roughly half that of the US (see Chapter 6).

Policies to improve energy efficiency can involve changes in relative prices and active measures to accelerate technological change. Both sets of instruments have advantages and drawbacks. Price changes will accelerate efficiency improvements but might adversely affect economic growth. Improvements in technical efficiency alone are subject to rebound effects, which make economies grow faster.

The "rebound effect" explains why improved energy efficiency does not always translate into equivalent decreases in energy intensities, as long as the price of energy remains unchanged. Energy consumers adjust to the lower *de facto* prices of energy services by demanding more of them. The rebound effect should not be regarded negatively. *Improved energy efficiency is always desirable.* That firms and households consume more of a now more efficient factor means that overall welfare increases, even if the original energy saving is wholly or partly offset.

Markets, especially energy end-use markets, can have a number of imperfections (i.e. transaction costs, lack of information and incentive incompatibilities) that impede the smooth working of the price mechanism. Markets and government policies, through prices and technology policies, need to complement each other to achieve energy-intensity improvements in growing economies.

Figure 2.4: **World Primary Energy Intensity**



Non-Commercial Energy Use in Developing Countries[5]

The main projections in this *Outlook* do not include the use of combustible renewables and waste (CRW) in developing countries, because it is mostly non-commercial (*i.e.* not traded commercially). Therefore, data are very unreliable. CRW comes mostly from biomass: firewood, charcoal, crop residues and animal wastes. Nonetheless, the *Outlook* contains some data and projections on developing-country non-commercial CRW consumption. The tables in Part D provide information on each region. Table 2.2 suggests that CRW accounts on average for around a quarter of total energy consumption and nearly three-quarters of all energy used by households in developing countries. For large proportions of the rural populations and the poorest sections of urban populations in developing countries, biomass often offers the only available and affordable source of energy for cooking and heating. The share of biomass in total energy consumption is generally lower in countries with higher levels of income and industrialisation (Figure 2.5). It can reach 80% or more in low-income countries.

5. IEA (1998) provides an in-depth analysis of non-commercial energy use in developing countries. It discusses the main characteristics, data issues and methodology used to derive regional projections.

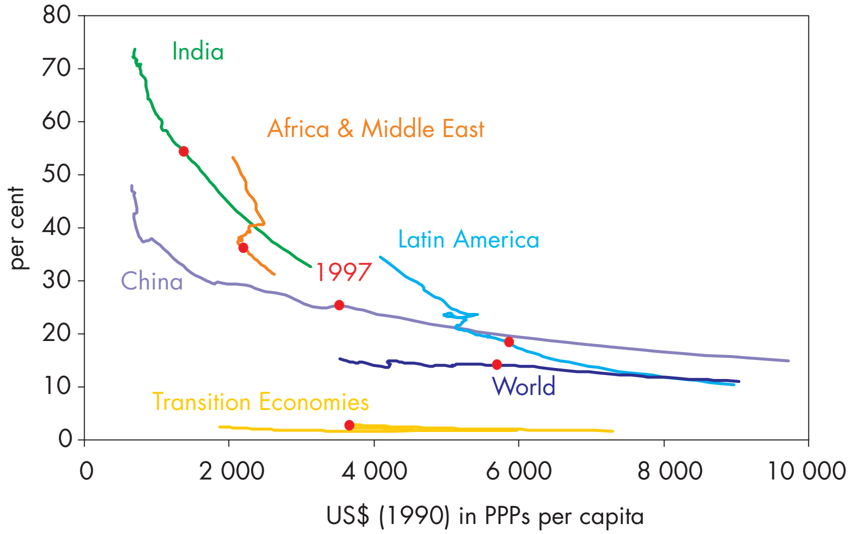
Table 2.2: **TPES in Developing Countries** (Mtoe)

	China	East Asia	India	Latin America	Africa	Other*	Total Developing Countries
1997							
CRW	208	115	193	88	231	51	**886**
Conventional Energy	905	549	268	495	241	401	**2 859**
Total	1 113	664	461	583	472	452	**3 745**
CRW Share (%)	19	17	42	15	49	11	**24**
2020							
CRW	221	140	223	100	347	72	**1 103**
Conventional Energy	1 937	1 279	716	1 004	457	801	**6 194**
Total	2 158	1 419	939	1 102	804	875	**7 297**
CRW Share (%)	10	10	24	9	43	8	**15**
Annual Growth (%) 1997-2020							
CRW	0.3	0.9	0.6	0.5	1.8	1.5	**1.0**
Conventional Energy	3.4	3.7	4.4	3.1	2.8	3.1	**3.4**
Total	2.9	3.4	3.1	2.8	2.3	2.9	**2.9**

* Other South Asia and Middle East.

Expected use of non-commercial CRW grows in all regions, but significantly more slowly than the expansion of commercial energy, mainly as a result of rising income levels (Table 2.2). Consequently, the share of non-commercial CRW in total energy declines in all regions. Substitution is slowest in Africa, reflecting relatively modest increases in projected income levels.

Figure 2.5: **Share of CRW in Total Final Consumption vs. Per Capita GDP, 1971-2020**



Final Energy Demand

Sectoral Trends

Expected world final energy demand increases at 2% a year over the outlook period (Table 2.3), significantly faster in transport (2.4%) than in other sectors (1.8%). Transportation's share increases to 31% in 2020 from 28% in 1997. This makes oil's growth in final demand slightly faster than in primary energy demand and implies a continued shift towards lighter oil products. Expected oil demand for transportation increases by around 1200 Mtoe. Most of the transport-demand growth comes from industrialisation and urbanisation in developing countries, where it averages 4% a year. Several factors could alter the projections for OECD and non-OECD regions, including substantial changes in vehicle efficiency trends and new government policies. A detailed analysis of transport energy demand trends in the Reference Scenario and an Alternative Case for OECD appears in Chapter 11.

Table 2.3: **World Total Final Consumption** (Mtoe)

	1971	1997	2010	2020	1997-2020*
Total Final Consumption	3 627	5 808	7 525	9 117	2.0
Coal	620	635	693	757	0.8
Oil	1 888	2 823	3 708	4 493	2.0
Gas	608	1 044	1 338	1 606	1.9
Electricity	377	987	1 423	1 846	2.8
Heat	68	232	244	273	0.7
Renewables	66	87	118	142	2.2

* Average annual growth rate, in per cent.

Fuel-Mix Trends

Oil and gas grow significantly faster than coal in final consumption. The main renewable energy sources are biomass and wastes, consumed in the industrial and household sectors. Projected consumption growth for these fuels is faster between 1997 and 2020 than in 1971-97. Almost all of it will come from OECD countries, where renewable energy sources enjoy various subsidies under policies likely to continue over the outlook period. Renewables face several barriers, however, including resource constraints (particularly for wood) and the high cost of transportation. The share of all renewables reaches only 2% of world final (commercial) energy demand by 2020.

World demand for electricity grows more rapidly than that for any other end-use fuel. Its 2.8% annual average growth rate for 1997-2020 means that it will almost double over the outlook period. Its projected share in world total final consumption (TFC) increases from 17% now to 20% by 2020 (Figure 2.6). It rises in both the OECD and non-OECD regions (Figure 2.7), but the rate of penetration in the latter is much stronger. Nonetheless, at slightly over 25% in 2020, the share of electricity demand in total final consumption in non-OECD countries still lies below that in the OECD today.

In the OECD countries, which currently use 63% of the world's electricity, projected demand grows by 43%, or 1.6% a year, to 2020, about half as fast as in 1971-97. For the past three decades, electricity demand has expanded faster than the OECD economies. That situation will reverse over the outlook period, due largely to the saturation of end-use markets.

Figure 2.6: **Fuel Shares in World Total Final Consumption**

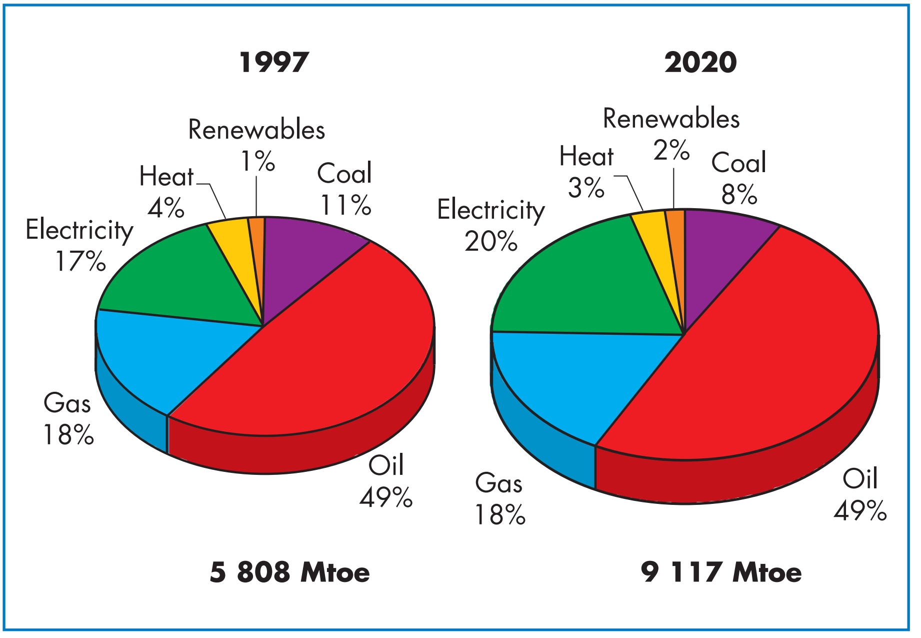
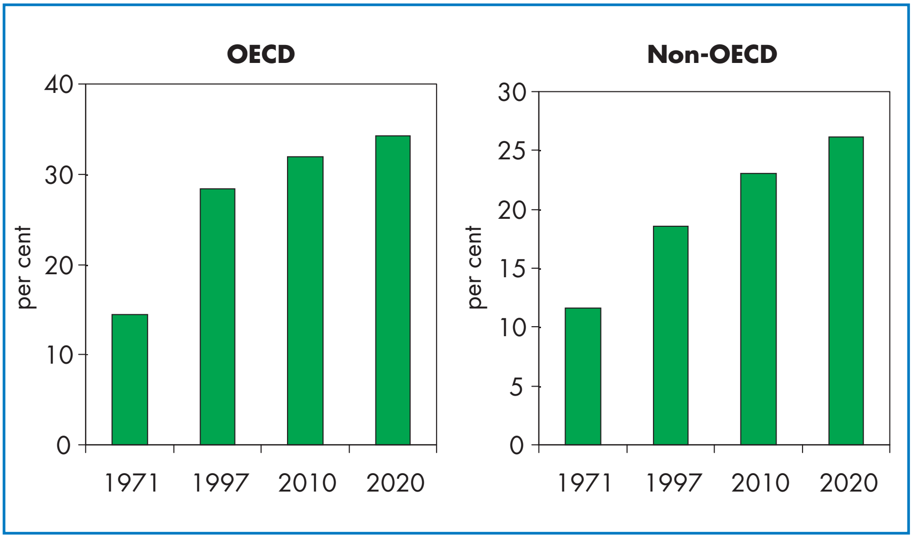


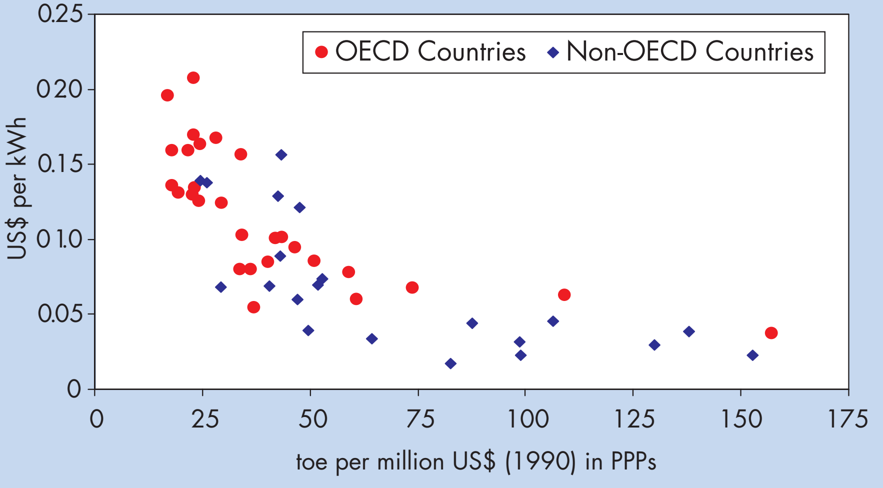
Figure 2.7: **Share of Electricity in Non-Transport Final Consumption**



Box 2.4: **Energy Demand and Prices**

Empirical evidence confirms the intuitive expectation that energy prices are an important determinant of energy demand and the energy mix. Policy makers have several instruments at their disposal to influence the domestic prices of energy. They include taxes on energy use or on energy-intensive products, and subsidies for alternative processes or products. Figure 2.8 provides evidence from 28 OECD and 21 non-OECD countries that electricity prices significantly influence electricity use. The almost hyperbolic shape of the curve indicates that electricity use tends to be lower in countries with the highest retail prices. The recent IEA study described in Box 2.2 discusses the impact of electricity subsidies on energy intensity in developing countries. Prices that reflect the real value of the resources employed in generating electricity ensure that consumers receive correct signals to use it in the most efficient possible way. Efficient prices also allow utilities to gauge electricity demand accurately and match supply capacity to it.[6]

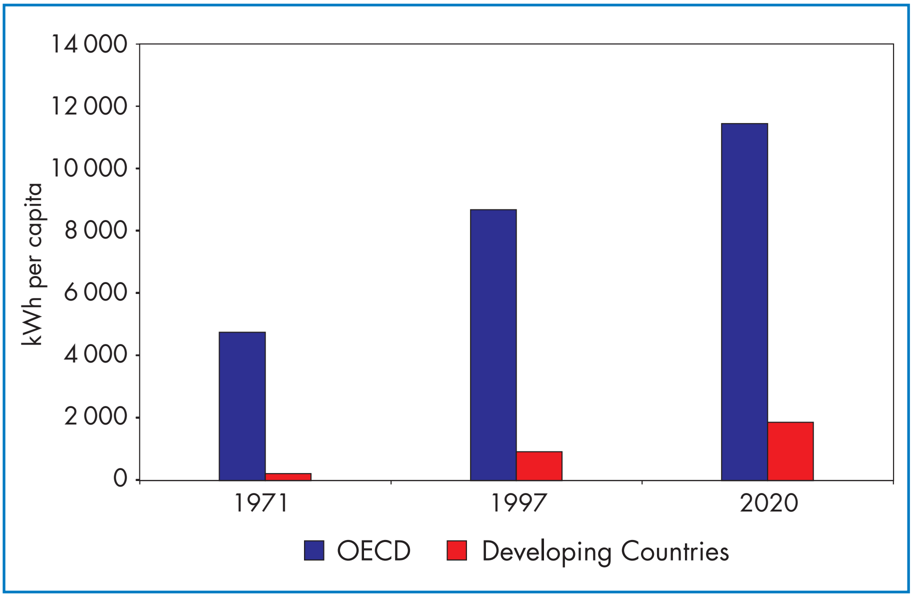
Figure 2.8: **Household Electricity Prices vs. Electricity Intensity, 1997**



6. See Munasinghe (1995) for a comprehensive discussion on the impact of pricing policies on issues related to electricity generation.

Electricity demand grows much faster in developing countries than in the OECD area over the projection period, by 4.6% per year. In 2020, their projected level reaches more than 2.5 times its present one. Demand is projected to increase in all sectors, but the rise is most dramatic in residential and commercial uses. Greater access to electricity and more appliance use as income levels rise will propel much of this growth. *Per capita* electricity consumption in the developing world will still remain low compared with OECD countries. Although it doubles over the projection period, it will still be less than one-sixth of average per capita consumption in the OECD in 2020 (Figure 2.9). By then, 80% of the world's population will consume just over 44% of global electricity output.

Figure 2.9: **Per Capita Electricity Consumption in the OECD and Developing Countries**



The Environmental Implications

Global CO_2 Emissions Outlook

The Reference Scenario's energy-use projections imply a steady increase in global CO_2 emissions, of 2.1% per annum in 1997-2020, for a total of 60% or 13 696 million tonnes. From 1990 to 2010, the projected rise amounts to 42% or 8 697 million tonnes. The year 2010 is midway through the 2008-2012 target period for emission limitations under the 1997 Kyoto Protocol.

Fast-growing developing countries contribute heavily to these increases, as they do to overall energy demand. Table 2.4 shows that the OECD countries were responsible for 51% of global CO_2 emissions in 1997, developing countries for 38% and transition economies for 11%. By 2020, the developing countries will account for 50%, the OECD countries for 40% and the transition economies for 10%. Developing countries provide 70% of the incremental growth in global CO_2 emissions. China's projected CO_2 emissions alone climb by 3 264 million tonnes, while the whole OECD area generates an additional 2 831 million tonnes. East Asia and South Asia also play a large role in the increase. The trend is similar but less pronounced for 1990-2010.

Table 2.4 also identifies the main sources of growth in CO_2 emissions by sector. Power-generation emissions in developing countries, which mount by 4.1% a year between 1997 and 2020, contribute 30% of the total increase in *overall* CO_2 emissions over the projection period, and an even higher share, 35%, in 1990-2010. Clearly, the choice of technology for power-generation equipment in developing countries has paramount importance for successful action to contain global greenhouse gas emissions. The transport sector also contributes heavily — especially in OECD countries. From 1997 to 2020, it accounts for 26% of the increase in total emissions.

Over the past three decades, CO_2 emissions increased at an average rate of 1.7% a year, while TPES grew at 2.2%. Global CO_2 emissions increase faster than energy demand over the projection period and at a higher rate than in the past (Figure 2.10). While the share of fossil fuels in the primary energy mix has declined since 1971, it increases slightly over the projection period. The expected increase in the use of non-hydro renewables cannot make up for the decline in the shares of nuclear and hydro.

Trends in the transition economies are expected to partly offset increased emissions in all other regions. Over 1990-2010, these countries' projected CO_2 emissions decline by almost a billion tonnes. Due to renewed growth after 2010 and a lower 1997 baseline, their emissions will probably increase over the full 1997-2020 period by 1 248 million tonnes. Moreover, despite the strong increase in CO_2 emissions in developing

Table 2.4: **Global CO_2 Emissions by Region and by Sector**
(Million tonnes of CO_2)

Emissions	**World***		**OECD**		**Transition Economies**		**Developing Countries**	
1990	20 878		10 640		4 066		6 171	
1997	22 561		11 467		2 566		8 528	
2010	29 575		13 289		3 091		13 195	
2020	36 102		14 298		3 814		17 990	
Increase	**1990-2010**	**1997-2020**	**1990-2010**	**1997-2020**	**1990-2010**	**1997-2020**	**1990-2010**	**1997-2020**
Power Generation	4 012	5 816	1 202	1 369	–200	446	3 009	4 001
Industry	892	1 698	–157	–91	–244	193	1 294	1 597
Transport	2 469	3 577	1 215	1 285	–164	254	1 418	2 038
Other	1 324	2 450	388	268	–367	354	1 303	1 826
Total	8 697	13 541	2 648	2 831	–976	1 247	7 024	9 462

* Excluding international marine bunkers.

otal of 60% or 13 696 million tonnes. From 1990 to 2010, the projected rise amounts to 42% or 8 697 million tonnes. The year 2010 is midway

Figure 2.10: **Average Annual Growth Rate in World TPES and CO_2 Emissions**

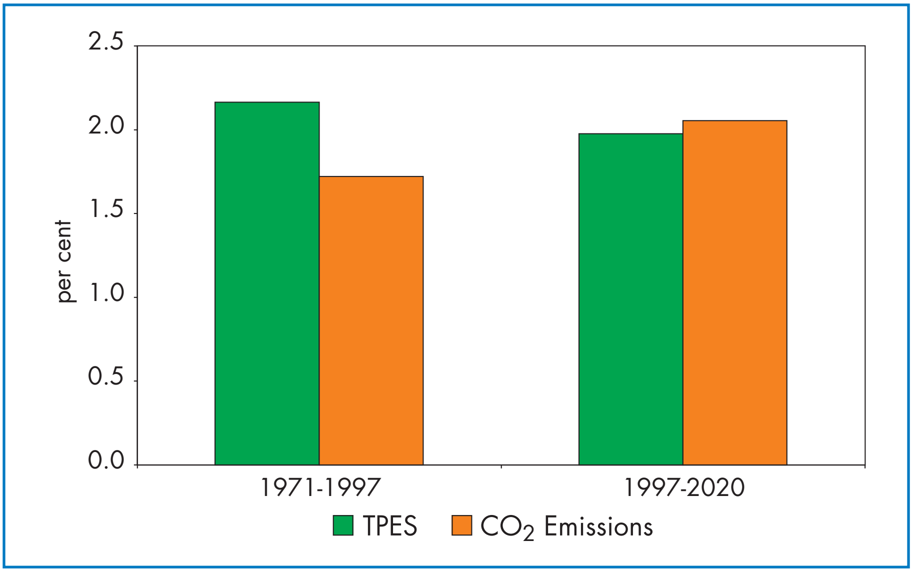
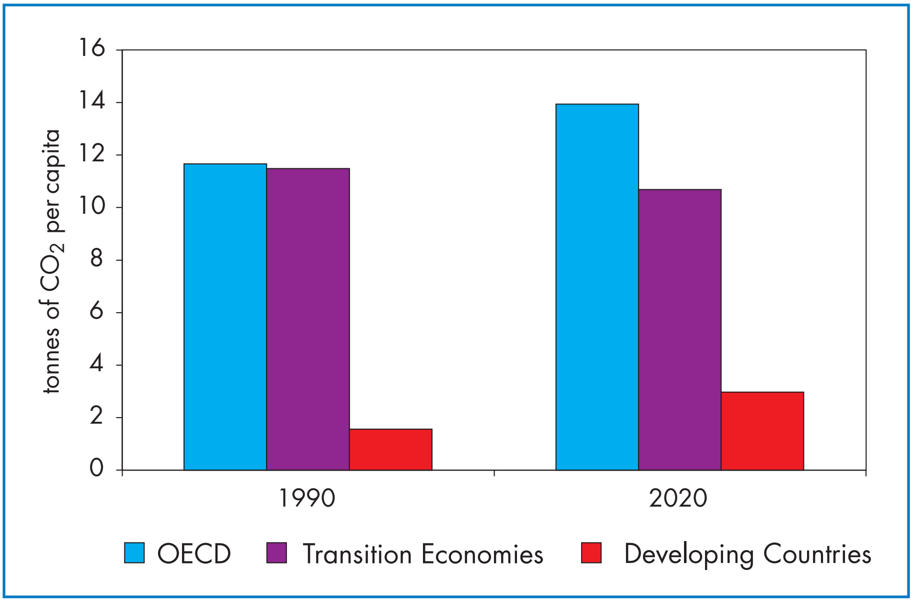


Figure 2.11: **Per Capita CO_2 Emissions by Region**



through the 2008-2012 target period for emission limitations under the 1997 Kyoto Protocol.

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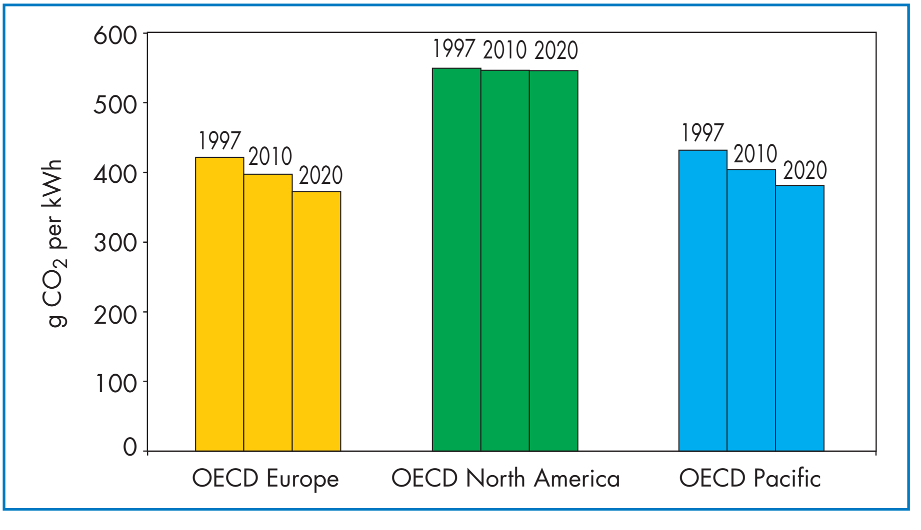
Figure 2.12: **CO_2 Emissions per kWh in the OECD Regions**



Over the past three decades, CO_2 emissions increased at an average rate of 1.7% a year, while TPES grew at 2.2%. Global CO_2 emissions increase faster than energy demand over the projection period and at a higher rate than in the past (Figure 2.10). While the share of fossil fuels in the primary energy mix has declined since 1971, it increases slightly over the projection period. The expected increase in the use of non-hydro renewables cannot make up for the decline in the shares of nuclear and hydro.

Trends in the transition economies are expected to partly offset increased emissions in all other regions. Over 1990-2010, these countries' projected CO_2 emissions decline by almost a billion tonnes. Due to renewed growth after 2010 and a lower 1997 baseline, their emissions will probably increase over the full 1997-2020 period by 1 248 million tonnes. Moreover, despite the strong increase in CO_2 emissions in developing countries, both the OECD and the transition economies will still have far higher per capita emissions in 2020 (Figure 2.11).

Power Sector CO_2 Emissions

Annual global CO_2 emissions from electricity generation are projected to increase 76% by 2020 and to represent a growing proportion of expected total CO_2 emissions, 37% in 2020 as against 34% in 1997. Over the past three decades CO_2 emissions grew at a much lower rate than electricity production, but this trend will not continue over the projection period. From 1971 to 1997, the share of fossil fuels in the electricity mix declined by more than 10 percentage points mainly because of the large-scale development of nuclear power in OECD countries. The power sector is expected to become more dependent on fossil fuels over the projection period. This helps explain why CO_2 emissions grow at a rate closer to that of electricity generation than in the past. However, the projected increase in the thermal efficiency of power generation and higher use of natural gas moderate this effect somewhat.

In the OECD, projected CO_2 emissions from the power sector rise to 21% above their 1997 level in 2010 and 33% in 2020. Improvements in fossil-fuel power-generation efficiency, notably CCGTs, combined with the retirement of some of the oldest plants, keep growth in CO_2 emissions slightly below the growth in electricity demand. Differences emerge among the three OECD regions. While emissions per unit of electricity decrease over time in OECD Europe and OECD Pacific, they remain almost

Table 2.5: **CO_2 Emissions and Targets in Annex B Countries, 2010**
(Million tonnes of CO_2)

	2010 Target Emissions	**WEO: Projected 2010 Emissions**	**Gap* (Per cent)**
OECD North America	4 935	6 995	41.7
OECD Europe**	3 664	4 323	18.0
OECD Pacific	1 307	1 682	28.7
Russia	2 357	1 670	–29.1
Ukraine and Eastern Europe	1 150	867	–24.6
Total	**13 413**	**15 537**	**15.8**

* The gap has been calculated by expressing the difference between target emissions and projected emissions as a percentage of the target emissions. Thus, it indicates the extent to which projected emissions exceed the targets.
** Turkey is not included.

unchanged in OECD North America (Figure 2.12). This occurs mainly because the share of coal in North American electricity generation remains broadly flat and nuclear power declines.

In the transition economies, CO_2 emissions from the power sector increase at 1.7% per year over the projection period. They account for 10% of power sector emissions in 2020, down from 12% in 1997.

The increased contribution of developing countries to global emissions is pronounced in the power sector. They account for more than two-thirds of incremental CO_2 emissions from power generation, and their share increases from a little more than a third now to almost half of global power-sector emissions by 2020. Rapid growth in electricity demand, heavy coal consumption and use of less efficient technology compared with the OECD largely explain this increase. By 2020, the average efficiency of coal-fired power stations in developing countries will lie slightly below that in the OECD now. The new but rather inefficient plants projected for construction over the next two decades are likely to operate far beyond the time horizon of this *Outlook*, releasing large quantities of CO_2 into the atmosphere for many years. There are significant opportunities over the next twenty years to reduce global emissions by improving the performance of developing-country power plants, provided means can be found to accelerate the speed of technology transfer to them.

Transport-Sector Emissions of CO_2

Rising oil consumption in the transport sector is the other major source of increased CO_2 emissions over the projection period in the Reference Scenario. Transport-sector emissions world-wide are projected to rise by nearly 60% over 1990-2010, and by 75% over 1997-2020. Emissions rise strongly in all regions, including the OECD. By 2020, transport accounts for roughly a quarter of global energy-related emissions. These trends, as well as a discussion of an Alternative Case for transportation, are presented in detail in Chapter 11.

CO_2 Emission Projections and the Kyoto Protocol

The CO_2 emissions projections of the *Outlook* have particular relevance to the efforts of Annex B countries to achieve their commitments to reduce or limit greenhouse gas emissions under the Kyoto Protocol. Table 2.5 provides a regional breakdown of Annex B emission projections and the remaining gap in percentage terms between them and the Kyoto commitments.

Clearly, the size of the gap constitutes a major challenge for Annex B countries. It looms large for all three OECD regions, particularly North America and the Pacific. The situation differs for Russia and Eastern Europe (including Ukraine), whose projected emissions are considerably less than their commitments, due mainly to the severe economic downturn in the 1990s. The modalities that are currently under discussion for achieving the Kyoto Protocol targets may allow the different groups mutually to offset their emissions commitments. Emission trading, involving the creation of an international market for CO_2 emission reductions, could reduce the costs of meeting these commitments. Of the alternative policies proposed to reduce emissions, many focus on the highly important transport and power-generation sectors. Chapters 11 and 12 analyse the impact of new policies and measures in these two sectors in OECD countries. Chapter 10 evaluates the emission-trading approach. Together they suggest possible directions for future climate-change mitigation policy.

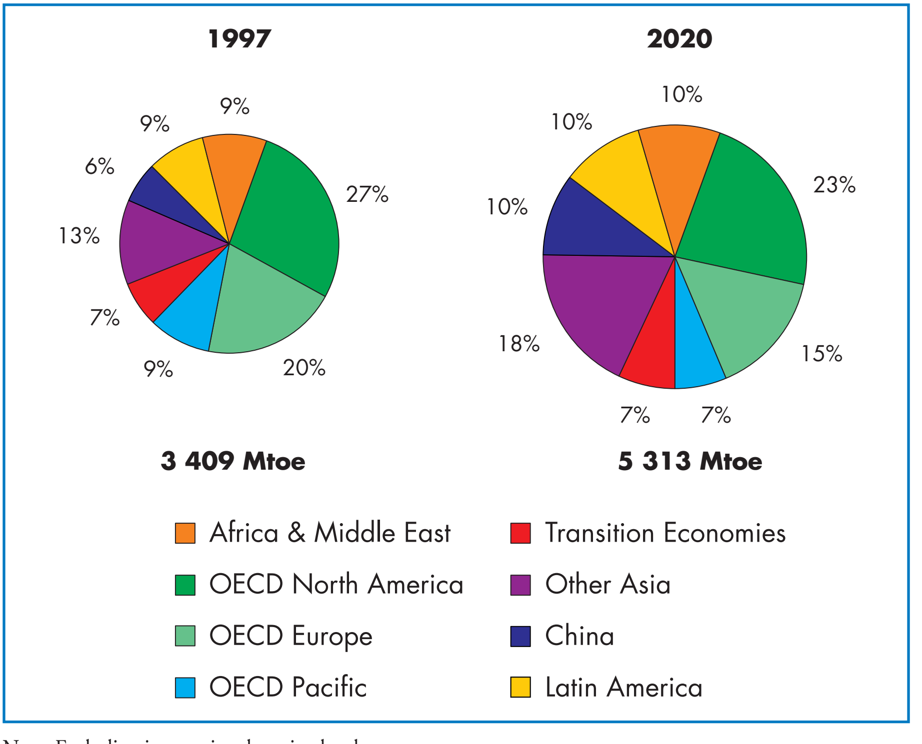
CHAPTER 3
THE ENERGY MARKET OUTLOOK

Oil Market Outlook

Oil Demand

World primary oil consumption is projected to increase by 1.9% per year, reaching 115 million barrels per day (mb/d) by 2020. Demand in non-OECD countries rises three times as fast as in the OECD, reaching 55% of total world oil consumption in 2020, up from 43% today (Figure 3.1). Non-OECD consumption of oil passes that of the OECD

Figure 3.1: **Total World Primary Oil Demand by Region**

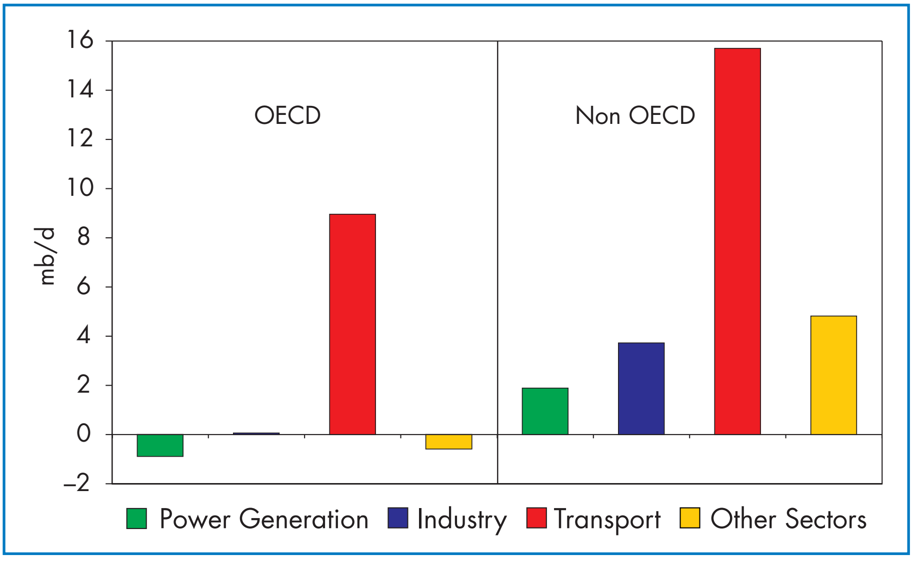


Note: Excluding international marine bunkers.

after 2010 and is 20% larger by 2020. Nevertheless, OECD North America, with a population of 350 million, will still consume more oil than China and India with their combined population of 2.7 billion.

Most of the expected incremental oil demand over the next two decades comes from the transport sector. In the OECD, transportation accounts for virtually all oil demand growth (Figure 3.2). During the 1980s, OECD oil consumption in uses other than for transport (power generation, some industrial applications and space heating) stabilised with substitution by other fuels. Over the outlook period, economic factors will work against the building of new oil-fired plants in the power sector. In industry, consumption remains almost at its current level. In other sectors, oil consumption will decline slowly.

Figure 3.2: **Incremental Oil Demand by Sector, 1997-2020**



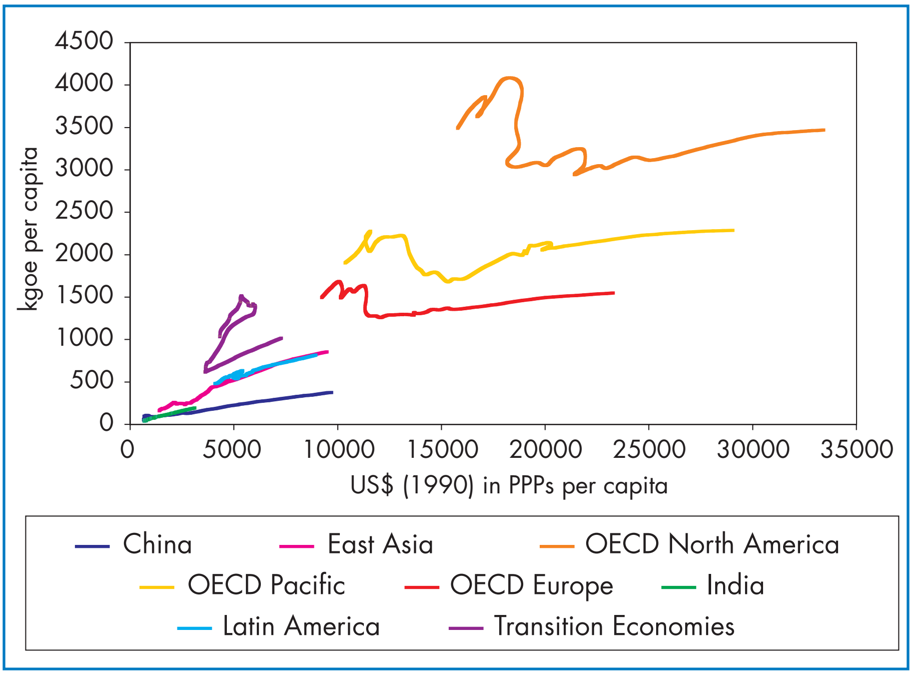
The picture changes somewhat for oil-demand growth in non-OECD countries. Transportation will again account for most of it, but oil will continue to be an important fuel in other sectors. Increasing per capita incomes, industrialisation and switching from non-commercial fuels explain much of the overall growth. China and India alone will account for one-third of incremental oil demand in non-OECD countries. Projected primary oil demand grows by 4.4% a year in China and 4.5% in India. Per capita car ownership in both countries is still very low, at 3.2 vehicles per

1 000 inhabitants in China and 4.5 in India[1]. As per capita incomes rise, the demand for cars and therefore for transport fuel will increase dramatically. By 2020, transport oil demand takes 38% of the total in China compared with 35% today. In India it rises from 47% to 55%. Oil will also play a key role in China's residential/commercial sector. There, consumption triples by 2020 to make oil the sector's most important fuel, replacing coal.

In East Asia, which remains the largest non-OECD oil-consuming region, consumption doubles. Oil consumption will probably recover in the transition economies, although in Russia it is not expected even to reach its 1992 level by 2020. Latin America's projected share of non-OECD oil demand holds constant at about one-fifth over the outlook period.

Figure 3.3 shows the strong link between per capita GDP and both oil consumption per capita and the rate of growth in oil demand. The higher the income per capita, the higher the consumption per capita and the lower the rate of consumption growth. In the first phase of development, economies need more energy to generate additional GDP. As a bigger GDP

Figure 3.3: **Per Capita Oil Consumption vs. Per Capita GDP, 1971-2020**



1. International Road Federation, 2000.

produces higher disposable incomes, private consumption of goods, including energy, rises — until incomes reach a point where saturation effects start to take hold.

It is unlikely that the major regional differences in per capita oil demand patterns will alter dramatically over the next two decades. Per capita oil use in the OECD stays well ahead of that in other world regions. Similar economic structures and strong economic interdependencies among OECD countries have had similar effects on per capita oil consumption in the three OECD regions. As per capita incomes climb over the projection period, expected oil consumption growth in all three regions will slow with saturation in end uses. This is reflected in the gradual flattening of the curves for the OECD regions in Figure 3.3.

Expected per capita oil consumption in non-OECD countries continues to rise with incomes and no significant saturation appears. In Figure 3.3 the curves continue to slope upward at a more or less linearly constant ratio. By 2020, none of the non-OECD regions will have reached the level of per capita oil consumption of the OECD in the early 1970s.[2]

Oil Supply

Assumptions and Methodology

Under the *Outlook*'s combined price and cost assumptions, the upstream oil business will be profitable. Spending on finding, developing and producing oil will be robust on the more fundamental premise that adequate resources exist to be found, developed and produced.

This *Outlook* incorporates more optimistic estimates of the world resource base than did the 1998 *WEO*. The change is based on recent findings, including the latest assessment of conventional world oil and gas resources by the US Geological Survey (USGS)[3] — their first such study since 1994. The USGS estimates that "ultimate recoverable resources" of oil and natural gas liquids, including oil already being produced, total 3 345 billion barrels. This revises upwards the figures given by the 1998 *WEO*. In addition to figures for identified reserves and undiscovered resources, the USGS has published for the first time world-level estimates of "reserve growth" in existing fields. World oil and NGL resources from reserve growth are almost as great as resources from undiscovered fields.

2. Africa, which is not shown in Figure 3.3, is particularly striking. By the end of the projection period, per capita oil consumption there reaches 160 kilograms of oil equivalent, the current level in China.
3. USGS, 2000.

The growth of reserves in existing or known oil fields underlies the medium-term and long-term supply projections. One reason for the phenomenon of reserve growth is definitional — the strict proven-field reserve definitions required by regulations of securities exchanges, for example, tend to result in low initial estimates. Other reasons are more fundamental. They include the natural conservatism of engineers; a higher degree of uncertainty early in the life of a field; technological advances during a field's productive life; new concepts in geology; improvements in field economics; and the increasing use of natural gas, which can make associated reserves of crude oil economic. The typical behaviour of companies in the oil business is also important. Even when companies suspect that reserves may be larger, the costly appraisals needed to turn "probable" or "possible" reserves into "proved" ones are delayed until production is almost ready to begin.

The supply projections in this *Outlook* combine two methodologies: a "bottom-up" or field-by-field approach for the first ten years (medium-term) and a "top-down" or resource-depletion model for the second ten years (long-term). For the medium-term, the field-by-field projections assume significant decline rates for maturing fields, but they are not as steep as the natural or geologic decline rates. Natural decline rates occur when investment stops altogether, which rarely happens in the oil business. Incremental investment can make a field's decline rate gentler by increasing the recovery of oil in place. It can also, in effect, extend the boundaries of oil fields by "proving up" additional reserves and adding new, small satellite fields as they are discovered. Both of these ways of adding reserves exploit existing infrastructure and are therefore cost effective. On a per-barrel basis, the costs are typically less than full-cycle costs for a new field.

For the long-term, the resource-depletion model takes into account ultimately recoverable resources, which in turn depend on the recovery rate. The recovery rate, generally assumed to increase slowly over time, reflects the assumed price of oil and a technological trend. Country and regional production profiles are then determined.

Oil Production

World oil supply[4] is expected to grow from 75 mb/d in 1997 to 96 mb/d in 2010 and to 115 mb/d in 2020. Two key trends emerge:

- Total non-OPEC supply matures and flattens after 2010. The transition economies, West Africa and Latin America will contribute

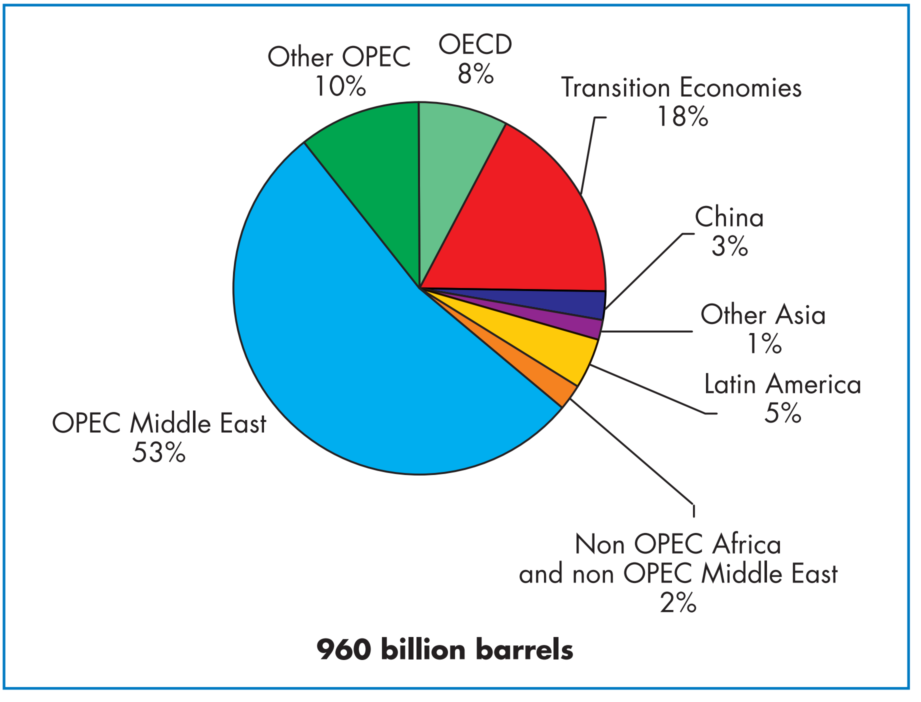
4. Including conventional and unconventional oil.

most to non-OPEC supply gains. Deepwater offshore fields are expected to play a key role, particularly in Angola and Brazil, as well as in the United States.

- Production in OPEC, especially the Middle East countries, increases steadily, accelerating in the second half of the projection period.

The *Outlook* views the world oil-resource base as adequate to meet demand over the projection period. Although oil fields in some regions are maturing and their production will start or continue to decline, the resource base of the world as a whole is not a constraining factor. One need expect no global "supply crunch". To transform these resources into production, however, will demand significant and sustained capital investment, particularly in Middle East OPEC. The issue of investment is more urgent than the resource base itself. Figure 3.4 shows the current distribution of proven oil reserves. Table 3.1 shows the projected world oil balance that supports the following discussion of oil supply.

Figure 3.4: **World Crude Oil and NGL Reserves**



Source: United States Geological Survey, 2000.

Table 3.1: **World Oil Balance** (million barrels per day)

	1997	2010	2020	1997-2020 *
Total Demand	**74.5**	**95.8**	**114.7**	**1.9**
OECD	**40.9**	**46.9**	**50**	**0.9**
North America	20.2	24	26.1	1.1
Europe	14.1	16	16.8	0.7
Pacific	6.5	7	7.1	0.4
Non-OECD	**30.1**	**45**	**60**	**3.1**
Transition Economies	4.7	5.8	7.4	2
China	4.1	7.6	11	4.4
East Asia	6.4	10.1	13.6	3.3
South Asia	2.3	4.1	6.2	4.5
Latin America	6.1	8.7	10.9	2.5
Africa	2.1	3	3.9	2.7
Middle East	4.4	5.7	7	2.1
Bunkers and stock changes	3.6	3.9	4.6	1.1
Total Supply	**74.5**	**95.8**	**114.7**	**1.9**
Non-OPEC	**42**	**46.9**	**46.1**	**0.4**
OECD	18	15.7	13.1	–1.4
North America	10.6	9.9	9	–0.1
Europe	6.7	5.2	3.5	–2.7
Pacific	0.7	0.6	0.5	–1.3
Transition Economies	7.4	10.3	12.3	2.2
Russia	6.1	7.1	7.9	1.1
Other Transition Economies	1.3	3.2	4.4	5.3
China	3.2	3	2.6	–1
India	0.8	0.5	0.4	–2.6
Other Asia	1.4	1.6	1.4	–0.1
Brazil	0.9	2.4	3.2	5
Other Latin America	5.7	6.8	6.8	0.7
Africa	2.7	4.8	4.8	2.5
Middle East	1.9	1.8	1.6	–0.8
OPEC	**29.8**	**44.1**	**61.8**	**3.2**
OPEC Middle East	19.5	30.5	46.7	3.9
Other OPEC	10.3	13.6	15.1	1.7
Unconventional Oil	1.3	2.7	4.2	5.4
Processing Gains	1.6	2.2	2.6	2.2
OPEC Share (%)	40	46	54	1.3
OPEC Middle East Share (%)	26	32	41	2

* Average annual growth rate, in per cent.

Box 3.1: **Mergers and Acquisitions in the Energy Sector**

The energy sector has recently seen much merger and acquisition activity. The $82 billion Exxon-Mobil and the $54 billion BP-Amoco mergers have led a flurry of deals in the oil sector in the past 20 months. Many large utility companies are also growing quickly through acquisitions and mergers, such as FPL/Entenergy in the United States, with a combined market value of $29 billion, and Veba/Viag in Germany ($17 billion). The power-generation equipment, coal production and oil service businesses have also experienced consolidation. Increasingly, energy mergers and acquisitions involve companies based and operating in different countries. The consequence of this activity is increased industry concentration and the emergence of a small number of global energy companies.

Recent mergers have been motivated by intense pressure from shareholders, particularly institutional investors, to improve returns and shareholder value through economies of scale and scope, and international market expansion. The need to improve returns on assets in the face of weak oil prices in 1997 and 1998 spurred the recent wave of oil-company mergers. The opportunities created by market liberalisation animate consolidation in the utilities sector. Many countries are breaking up vertically integrated utilities to encourage competition, creating new acquisition opportunities. Horizontal gas-electric "convergence" mergers and "multi-utility" combinations with water or other services, which aim to exploit synergies in marketing and in developing gas-fired power generation, are also becoming more common.

It is difficult to predict trends in energy-sector consolidation and how they will affect world demand, supply and prices. The current wave of mergers and acquisitions may curb oil production growth in the short term. Investment in oil exploration and development has only recently begun to respond to higher oil prices, at least in part due to merger-related pressures to cut costs. Any improvements in efficiency that do result, however, could boost production in the medium and long term by raising returns on investment. Efficiency gains resulting from competitive pressures may also help lower prices. Governments have a key role to play in supporting such a trend, by establishing appropriate regulatory frameworks for competitive energy markets and by monitoring the competition effects of mergers.

Unconventional oil production[5], as defined in the IEA's monthly *Oil Market Report*, is projected to grow from 1.3 mb/d in 1997 to 2.7 mb/d in 2010 and to 4.2 mb/d in 2020.[6] Most types of unconventional production are economic at the prices assumed here and will continue to be so. As a result, projects should develop in anticipation of market needs. The gains come primarily from synthetics crude production from the Athabasca tar sands in Alberta, Canada and from the Orinoco extra-heavy crude oil belt in Venezuela. In contrast to the 1998 *WEO*, this *Outlook* has no category for "unidentified unconventional oil production", which acted previously as a balancing item for supply.

Non-OPEC production is expected to grow significantly in the first half of the outlook period, from 42 mb/d in 1997 to 46.9 mb/d in 2010. In the second decade, however, many key non-OPEC countries will mature as petroleum producers, and output will level off, reaching 46.1 mb/d in 2020. Projected OECD output declines from 18 mb/d in 1997 to 15.7 mb/d in 2010 and to 13.1 mb/d in 2020. These figures disguise a peak period in 2000-2007, when output will average roughly 18 mb/d.

Expected output in North America follows the profile of the United States, remaining broadly flat in the first half of the projection period then declining gradually to 9 mb/d in 2020. New deepwater fields coming onstream in the Gulf of Mexico will cause US production to rise in the medium term but decline after 2007 or so, when the Gulf fields peak. At the same time, Alaskan output is expected to resume its long-term decline, after several years of plateau as some small and medium-sized new fields come onstream. California, Texas, and the rest of the lower 48 states are mature; their production is likely to decline throughout the projection period.

Canadian production is expected to rise steadily over the next decade, mostly from synthetics output, due to both new projects and major expansions of existing ones. Costs for synthetics crude production (including capital expenditures) are competitive at crude oil prices of $12 to $15/barrel, as evidenced by the growing number of new project announcements. Moreover, the assumed increases in post-2010 oil prices will make these developments even more attractive. The relatively new

5. Unconventional oil production includes the following sources, listed in order from the heaviest to the lightest original resource: oil shales, oil sands-based synthethic crudes and derivative products, coal-based liquid supplies, biomass-based liquid supplies and gas-based liquid supplies.

6. Some analysts, however, project higher levels of unconventional oil; see A. Perrondon, *et. al.*, March 1998, among others.

Atlantic offshore province will also grow quickly. Western Canadian production will decline. Growing output of bitumen and conventional heavy crude oil, the latter for just a few more years, will not offset ongoing declines in light crude from mature fields in that area.

In OECD Europe, production comes almost entirely from the North Sea, where output is expected to reach its peak early in this decade. Output will decline sharply thereafter, by 4% per year, reaching 3.5 mb/d in 2020. Norwegian supply should grow slightly before starting a gradual descent. Although its large mature fields are in decline, Norway still has some big new developments, along with some significant satellite fields. The United Kingdom has fewer new developments, and with fewer and smaller discoveries in recent years, its oil production is more mature than Norway's. While some new fields will undoubtedly still be found, they will be relatively small and economic only when they can use existing infrastructure.

In OECD Pacific, 89% of the 0.7 mb/d of oil produced in 1997 came from Australia. Production in the region is expected to peak at 0.8 mb/d in 2000 and remain there until around 2005 before declining to 0.5 mb/d in 2020. New fields in the Timor Sea have spurred recent growth, but they will not suffice to overcome the decreases expected in the older Gippsland and Carnarvon Basins.

The expected contribution of the transition economies to non-OECD oil supply increases gradually over the projection period. Caspian production will likely grow particularly fast. After bottoming out in 1996, oil supply from the transition economies is projected to rise throughout the next two decades, reaching 10.3 mb/d in 2010 and 12.3 mb/d by 2020. Russian output should follow a steady growth trend of roughly 1% per annum. Production has increased slightly in the last two years. The 1998 rouble devaluation allowed oil companies to drill more with each dollar of export earnings, while the dramatic recovery in oil prices in 1999 and thus far in 2000 has given them more export dollars to spend. As a result, capital spending and development drilling have risen since 1998, helping to boost production. The focus has been almost entirely on increasing recovery from existing fields. For the momentum to continue, however, the emphasis will have to shift toward bringing new fields and reservoirs into production. This is expected, with large fields covered by production-sharing agreements (PSAs) making an increasing contribution to national production. As a result, Russian production is projected to continue growing between 2010 and 2020, reaching 7.9 mb/d by 2020.

In contrast to Russia's slow but steady growth, oil production in Kazakhstan is expected almost to double in the next decade and to continue growing in the following one. Tengiz, Karachaganak, and the recently discovered Kashagan field, which is still being appraised, are of key importance. The first two developments will depend on the Caspian Pipeline Consortium (CPC) pipeline across southern Russia to the Black Sea, which is scheduled for completion in mid-2001. Tengiz production is likely to expand along with CPC export capacity, reaching its planned peak of 700 kb/d in 2010. Projected output in Azerbaijan grows even more dramatically in proportional terms in the next ten years. Gains are expected mainly from the Azeri, Chirag, and deepwater Guneshli fields operated by the Azerbaijan International Operating Consortium (AIOC). AIOC supply is expected to increase from 105 kb/d in 2000 to 800 kb/d by the end of the decade. The *Outlook* assumes that export routes will be available. The main possibilities include the proposed Baku-Ceyhan main export pipeline or further expansion of the Baku-Supsa pipeline.

Oil production in non-OPEC Latin America grows throughout the projection period, from 6.6 mb/d today to 9.1 mb/d in 2010 and slightly more than 10 mb/d by 2020. Brazil will contribute by far the most to this growth, from its large new deepwater fields in the Campos Basin. Brazilian production climbs from 0.9 mb/d in 1997 to 2.4 mb/d over the next decade and to 3.2 mb/d in 2020. Major new fields and field expansions to come onstream in the next few years include Roncador, Marlim and Marlim South, Espadarte, Salema/Bijupira, Barracuda and Caratinga. Mexican oil supply is projected to grow for the next half-decade before starting to level out. Mexico currently is the only non-OPEC country with significant spare capacity, a situation not expected to last very long. The offshore Bay of Campeche will remain the main source of crude in Mexico. Only the shallow waters currently produce, but reserves are thought to exist farther offshore.

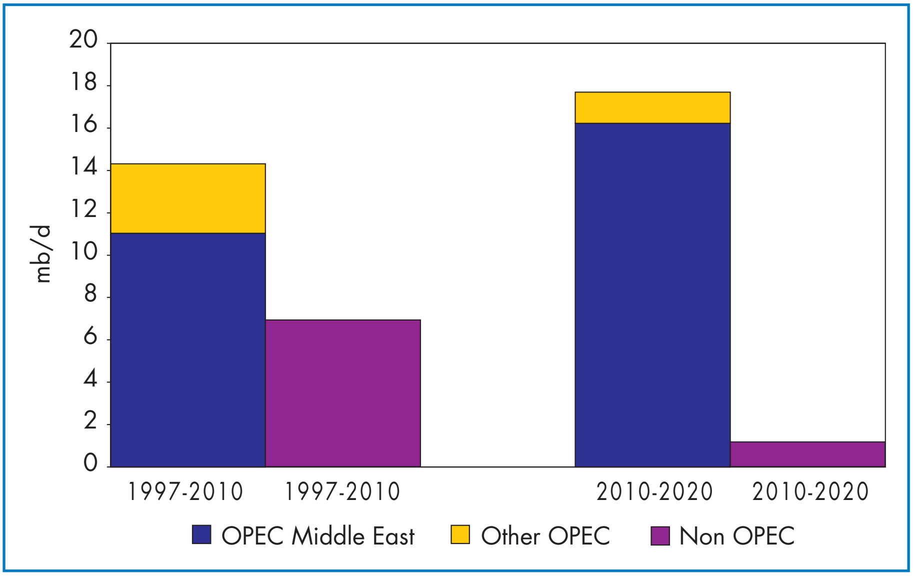
Significant production increases are also expected in non-OPEC Africa. Output is projected to rise from 3 mb/d now to 4.8 mb/d in 2010, propelled mainly by the West African offshore area and remain at around that level until 2020. A large part of the growth will come in Angola, from large, prolific deepwater fields as in Brazil. Eight billion barrels of deepwater reserves have already been discovered, mostly in Blocks 14, 15 and 17, and the number is still growing. Kuito was the first deepwater field to start up last year; the next big one will be Girassol in 2001. Additional production is coming onstream in Equatorial Guinea, the Congo Republic, and onshore in Chad.

Asian output outside China is mature and expected to fall over the next two decades, with few major developments in the offing. China, however, will stave off significant declines until after 2005, due once again to the offshore sector. The recent Penglai discovery in the Bohai Bay region, still under appraisal, already has more than 400 million barrels in recoverable reserves. Overall, current Chinese production of 3.2 mb/d will decline slightly to 3 mb/d in 2010 and to 2.6 mb/d at the end of the projection period.

This *Outlook* assumes that OPEC production will satisfy the portion of world oil demand not met by non-OPEC output. Therefore, OPEC supply (including crude, condensate and natural-gas liquids) is projected to increase from 29.8 mb/d in 1997 to 44.1 mb/d in 2010 and to 61.8 mb/d in 2020. Figure 3.5 shows that OPEC will account for the bulk of incremental global oil needs.

Middle East OPEC output is especially critical, particularly in 2010-2020. During this decade, world oil demand grows by 18.9 mb/d. In order to meet it, Middle East OPEC supply rises by 16.2 mb/d, with only 1.5 mb/d coming from other OPEC producers. There is little argument that the Middle East OPEC countries — Saudi Arabia, Iran, Iraq, Kuwait, the UAE and Qatar — have the resources to cover incremental global oil demand. The key will be for them to attract sufficient, sustained and timely capital investment.

Figure 3.5: **World Incremental Oil Production**



Trade

The projections for oil demand and production described above will entail a significant increase in international trade to meet a widening gap between consumption and indigenous output in many parts of the world. Table 3.2 details the projected net imports and exports of each major region. Net inter-regional trade increases from 28 mb/d in 1997 to over 60 mb/d in 2020.[7]

Table 3.2: **Projected Net Oil Imports and Exports** (mb/d)

	1997	2010	2020
OECD North America	9.0	12.6	15.2
OECD Europe	7.4	10.8	13.3
OECD Pacific	5.7	6.4	6.6
Transition Economies	–2.8	–4.5	–4.9
Africa	–6.1	–9.4	–9.5
China	0.9	4.6	8.5
Other Asia	4.9	10.8	16.7
Latin America	–4.1	–5.4	–4.6
Middle East	–17.0	–26.6	–41.3

Note: Negative numbers indicate net exports.

Regions that depend on imports to meet a significant part of their oil needs — notably the three OECD regions and non-OECD Asia — will become even more dependent on imports over the projection period, both in absolute terms and as a proportion of their total oil consumption (Table 3.3). The OPEC countries will probably supply much of this increase in requirements. In 1997, net imports met almost 45% of OECD North America's total petroleum needs. Middle East OPEC was the single largest source, closely followed by Latin America. With production expected to fall behind steadily rising demand, the region's import dependence[8] is projected to rise to 58% by 2020, despite the increasing production of synthetics in Canada. Oil import dependence in Europe rises from 53% to

7. Total international trade is greater than these figures suggest because of trade within each *WEO* region and re-export between regions.
8. Oil import dependence is defined as the ratio of net oil imports to total primary oil demand.

79% over the projection period. In OECD Pacific, it goes from an already very high 89% to over 92%. Outside the OECD, Asia becomes increasingly dependent on imports. China, which became a net importer of oil products only in 1993, is projected to import more than three-quarters of its needs, over 8 mb/d, by 2020.

Table 3.3: **Oil Import Dependence** (per cent)

	1997	**2010**	**2020**
North America	44.6	52.4	58.0
Europe	52.5	67.2	79.0
Pacific	88.8	91.5	92.4
OECD	**54.3**	**63.3**	**70.0**
China	22.3	61.0	76.9
India	57.4	85.2	91.6
Rest of South Asia	87.2	95.1	96.1
East Asia	53.7	70.5	80.7

All other regions remain net exporters. The Middle East, already the biggest exporting region, will see exports rise from 17 mb/d in 1997 to over 41 mb/d by 2020. Exports from Africa, Latin America and the transition economies also increase significantly.

In nominal terms, the increase in trade flows to non-OECD Asia exceeds those to all the OECD regions combined. This means that an increasing proportion of OPEC production, especially from the Middle East, will go to meet Asian demand. Middle East OPEC countries are expected to meet the bulk of China's oil-import needs.

Gas Market Outlook

Gas Demand

World primary consumption of gas as projected in the Reference Scenario grows at an average annual 2.7% from 1997 to 2020 (Table 3.4). Demand is strongest in the non-OECD regions, growing by 3.5%, while OECD consumption increases by 1.9%. The non-OECD regions' share of total world gas demand reaches 56% by 2020, as against 48% in 1997.

Demand growth is particularly strong in non-OECD Asia, although its share of global demand remains below that of Europe and North America in 2020. Gas use in the transition economies expands more slowly than in any other region except North America, but these countries remain the second largest consuming region and the largest outside the OECD in 2020.

Table 3.4: **Total World Primary Supply of Gas** (Mtoe)

	1997	2010	2020	1997-2020*
OECD	**999**	**1 349**	**1 549**	**1.9**
North America	579	721	778	1.3
Europe	344	522	650	2.8
Pacific	77	107	121	2.0
Non-OECD	**912**	**1 376**	**2 002**	**3.5**
Transition Economies	484	572	714	1.7
Africa	41	73	108	4.3
China	21	56	111	7.5
East Asia	88	176	286	5.2
South Asia	37	87	163	6.6
Latin America	108	205	313	4.7
Middle East	132	207	307	3.8
World	**1 911**	**2 724**	**3 551**	**2.7**

* Average annual growth rate, in per cent.

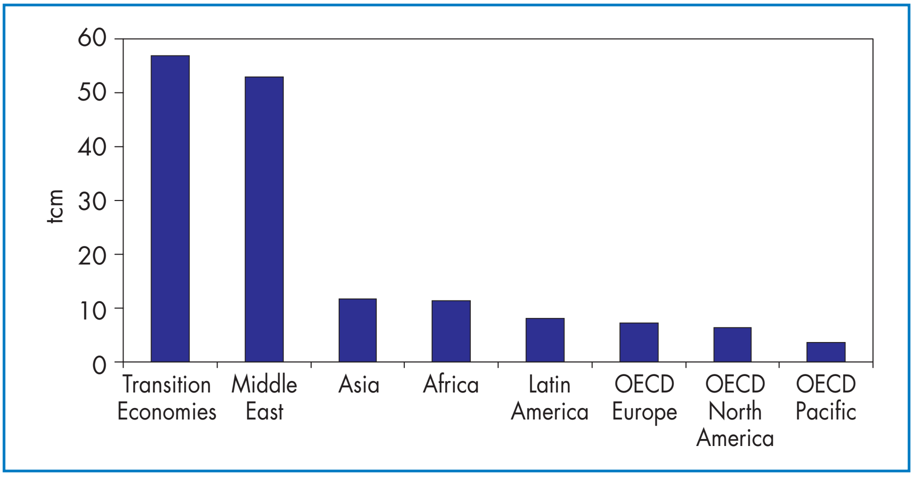
In most regions, gas demand grows primarily to meet the needs of power generation. Gas for power plants increases by more than 4% a year, slightly faster than in 1971-1997. Electricity output from gas-fired plants increases even more rapidly — by 5.7% a year, because of continuing improvements in the thermal efficiency of CCGTs. This factor, plus the inherent environmental advantages of gas over other fossil fuels, including lower emissions of CO_2 and none of SO_x, mean that gas is increasingly the preferred fuel in power stations. Among the non-OECD regions, power-sector gas demand grows most rapidly in absolute terms in Latin America and in the transition economies (by around 100 Mtoe). Russia remains heavily dependent on gas to meet its power-generation needs. Gas use in power generation grows by over 12% a year in China, but volumes remain small relative to other regions because current consumption is very low. In the OECD, the increase in Europe is especially rapid and reaches the absolute level of North America by 2020.

Growth in final gas consumption is less substantial. Global industrial gas demand increases by some 2% a year, while residential and commercial demand rises by 1.6% a year. Final gas use in the OECD countries, where potential expansion is limited by saturation effects and demographic factors, rises by less than 1% per year. Rising industrial output and commercial activity explain the more robust rate of growth in final gas consumption in non-OECD regions.

Supply and Trade

World reserves of natural gas are expected to be more than sufficient to meet the projected 86% increase in demand over the outlook period. Cedigaz puts global proven reserves at 158.3 trillion cubic metres (tcm), while the *Oil and Gas Journal* estimates reserves at 145.7 tcm. Figure 3.6 shows the Cedigaz estimates.

Figure 3.6: **Natural Gas Reserves by Region** (at 1 January 2000)



Source: Cedigaz, 2000.

"Proven reserves", which include only those that have been evaluated, represent a small fraction of total resources. Table 3.5 details the latest USGS assessment of global conventional gas resources — including

Box 3.2: **The Impact of Liberalisation in the Gas Sector**

Governments in many parts of the world are liberalising their gas industries by introducing gas-on-gas competition based on third-party access to gas supply infrastructure and, in some cases, by privatising public gas utilities. Their objectives are to increase efficiency and to reduce costs and prices to consumers. The speed of reform and approaches to it differ markedly among countries, as does success in promoting effective competition and lowering prices. An active regulation policy, to lower barriers to market entry, and diversity of potential suppliers to downstream markets have proven to be critical factors in achieving true competition. Moves to liberalise gas markets generally started earliest and have been taken furthest in OECD countries, notably Canada, the United States, the United Kingdom, Australia and New Zealand. Gas-market opening is currently underway in Europe. Several non-OECD countries, such as Argentina, have also begun to open their gas markets.

To the extent that effective competition emerges, liberalisation should lead to lower end-user prices. Together with the environmental advantages of gas and the widespread availability of exploitable reserves, this consideration lies behind the robust growth in global gas demand in the Reference Scenario. Upstream competition may lead to downward pressure on border or wellhead prices, although this may be mitigated by the higher cost of developing reserves more distant from consuming regions as local supplies are gradually exhausted. International oil prices will remain a key factor in the development of new gas-supply projects.

estimates of undiscovered gas — released in June 2000. These data make a sizeable upward revision to the previous assessment in 1994, reproduced in the 1998 *WEO*. Cumulative production to date amounts to only some 11% of total resources. Unconventional gas reserves are also thought to be significant.[9]

Although the global gas resource base is immense and reserves are abundant, gas is not always located conveniently near centres of demand. Transportation is costly, whether by pipeline or in the form of LNG. For this reason, no truly global market exists for gas. In general, the expansion

9. See Perrondon, et al. (1998).

Table 3.5: **USGS Global Gas Resource Estimates** (tcm)

	Fractiles*		**Mean**
	95%	**5%**	
Undiscovered conventional	76.2	251.2	147.1
Reserve growth	-	-	103.6
Remaining reserves	-	-	135.7
Cumulative production	-	-	49.6
Total	**-**	**-**	**436.1**

* The probability of at least the amount shown.
Source: USGS, 2000.

of regional gas markets will require the development of more distant reserves and their transportation over greater distances to market. Where viable, international trade will take place via pipeline — the most economic way to transport large volumes, especially where it is possible to build lines over land. Pipelines will continue to provide the principal means of transportation for gas from North Africa and Russia to growing gas markets in Europe, for cross-border trade in the Latin American Southern Cone and for exports of Canadian gas to the United States. LNG transportation, economic only over long distances because of the high costs of liquefaction and regasification and of carriers, will nonetheless account for a growing share of the increase in international trade. However, LNG trade will remain confined largely to East Asian markets. It may meet much of the projected increase in gas imports into some countries in the region, particularly India.

Gas-to-liquids (GTL) technology could also provide a means of exploiting gas reserves stranded in distant locations or too small to justify the investment in large-diameter pipelines or LNG chains. Further significant cost reductions through technological advances, and/or a sustained high oil price, will be necessary if GTL is to be adopted widely. The *Outlook* does not expect GTL projects to take off to any significant extent during the projection period.

Cost is both the key to bringing large gas resources to market and the major source of uncertainty regarding the outlook for gas. The longer distances over which new gas will need to be transported to the main consuming centres will exert upward pressure on delivered costs. This may be offset to some degree by advances in technology, which could reduce both field development and transportation (pipeline and LNG) costs. The *Outlook* assumes that it will be possible to supply expanding markets in most regions to 2010 at stable prices, but only higher prices will bring forth higher volumes in the second half of the projection period.

Box 3.3: **Uncertainties Relating to the Outlook for Russian Gas Supplies**

Russia has about one-third of global gas resources.[10] It produced 570.5 billion cubic meters (bcm) of gas in 1997 — equivalent to 25% of total world production. It exported around 17% of it to other transition economies and 16% to OECD Europe.

The prospects for Russian gas production and exports are highly uncertain for a number of reasons:[11]

- the costs of developing new reserves and constructing major new pipeline systems;
- the level and balance of demand from Europe and from new markets in China and the rest of Asia;
- the availability of alternative, competing sources of gas from independent states formerly part of the Soviet Union, including Turkmenistan and countries around the Caspian Sea;
- the pace of economic restructuring and its impact on domestic demand, the fuel mix and, therefore, the amount of surplus gas available for export.

Figure 3.7 compares projected and current regional shares in gas production. Output increases in the transition economies, OECD Europe and North America, but their shares in world production decline because of faster growth in output elsewhere — especially Asia, the Middle East and Latin America. OECD Europe becomes increasingly dependent on imports of gas, as demand outstrips increases in indigenous production (Table 3.6). The transition economies, Africa and the Middle East remain the main sources of gas.

10. USGS, 2000.
11. See Chapter 7 for a detailed discussion of Russian market trends.

Figure 3.7: **Gas Production by Region**

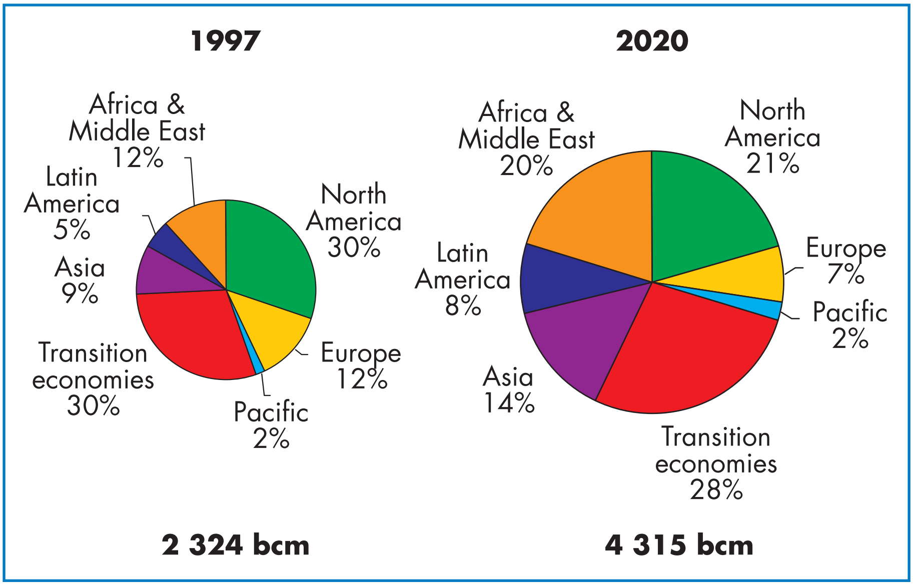


Table 3.6: **Gas Import Dependence** (per cent)

	1997	2020
OECD	**15**	**32**
North America	0	6
Europe	31	62
Pacific	59	38
Non-OECD	**–16**	**–25**
Transition Economies	–17	–36
Asia	–18	10
Latin America	6	4
Africa & Middle East	–28	–74

Note: Negative figures indicate net exports.

Coal Market Outlook

Coal Demand

Over the outlook period, coal demand increases to 3 350 Mtoe, at an expected average annual rate of 1.7% (Table 3.7). Coal's share of world primary energy demand nonetheless declines, from 26% now to 24% in 2020. Trends vary markedly across regions, mainly depending on the availability of competitively priced gas — the principal alternative fuel in all sectors. Coal use will be increasingly confined to power generation, which will account for 85% of the increase in coal demand between 1997 and 2020. Industrial coal demand increases by 1.1% per year, driven by the iron and steel sector in developing countries. Demand for coal in the residential/commercial sector decreases slightly, with the share of coal falling to 5% by 2020.

In the OECD countries, coal consumption increases by only 0.3% per year over the outlook period. This increase is driven by the power sector,

Table 3.7: **World Coal Consumption by Region**

	1997		2020		1997-2020*
	Mtoe	% for Power Generation	Mtoe	% for Power Generation	
OECD	**1 013**	**79**	**1 091**	**86**	**0.3**
North America	541	92	647	94	0.8
Europe	342	66	301	78	–0.6
Pacific	130	57	144	68	0.4
Non-OECD	**1 242**	**47**	**2 260**	**60**	**2.6**
Transition Economies	203	48	284	55	1.5
Africa	87	57	143	57	2.2
China	662	40	1 192	55	2.6
India	153	67	336	76	3.5
Other Asia	103	46	231	71	3.6
Latin America	28	35	56	53	3.1
Middle East	7	83	18	89	4.4
World	**2 255**	**61**	**3 350**	**69**	**1.7**

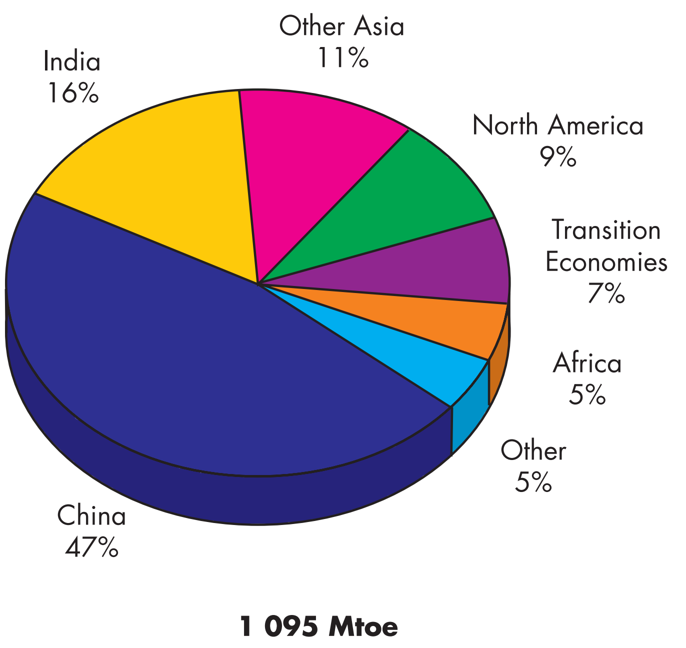
* Average annual growth rate, in per cent.

which now accounts for 79% of total OECD coal demand, a share likely to rise to 86% by 2020. Demand in industry falls by 2% a year, to some 6% of total industrial energy demand in 2020.

Coal demand in developing countries will grow by 2.8% per year. Coal will continue to dominate in China and India. These two countries combined will account for nearly 70% of incremental world coal demand over the outlook period, much of it going to the power sector.

In the transition economies, coal consumption has fallen over the past decade in line with the general economic decline, from roughly 300 Mtoe in 1990 to some 200 Mtoe in 1997. These economies depend mainly on local coal. With economic recovery, coal consumption is expected to increase by 1.5% a year to 2020.

Figure 3.8: **Regional Breakdown of Incremental World Coal Demand, 1997-2020**



Note: Regions where coal consumption is expected to decline are not included.

Coal Reserves and Production

According to *IEA Coal Research*, world coal reserves are roughly one trillion tonnes, enough to last 200 years at current production levels. Four countries account for more than 60% of total world coal reserves: the United States (25%), Russia (16%), China (11%) and Australia (9%).

Coal quality and the geological characteristics of coal deposits are more important to the economics of, and therefore prospects for, production than the actual size of a country's reserves. Quality varies significantly from one region to another. The United States, Australia and Canada are endowed with substantial reserves of premium coals that can be used to manufacture coke.

Since transportation often accounts for an important part of total delivered costs, the world coal industry remains dominated by local production for local use. World hard-coal production has risen steadily since the 1950s. Steam coal has accounted for almost all of the growth since the late 1970s, and coking-coal output has declined over the past decade. Steam-coal production has plummeted by 70% in Europe and by some 40% in the transition economies since 1978. Strong output growth in the United States, Australia and South Africa offset these declines in the early 1990s.

There has been a slight fall in world coal production since 1998. Output in China, the world's largest producer, has been falling since 1996, and saw a 16% plunge in 1999, the result of a restructuring of the coal sector, which brought mine closures, stockpile reductions and reduced coal consumption in the industry and residential sectors. Cost-cutting efforts have also led to production declines in Germany, Kazakhstan, Poland and the United Kingdom. The fall in international coal prices has also contributed to recent declines.

A current resurgence in coal demand, primarily in the Asia-Pacific region is expected to lead to higher production in major exporting countries such as Australia, South Africa and the United States. Coal shipments to the world's three largest importers, Japan, Korea and Chinese Taipei, increased in aggregate by some 10% over the first four months of 2000 compared with the same period in 1999.

Many coal-producing countries, including some OECD countries (Japan and some countries in Europe), give varying measures of financial and other assistance to their domestic coal industries. These subsidies have declined and currently cover some 5% of OECD production. Generally, subsidy removal has occurred simultaneously with increasing environmental concerns, especially about climate change, and with liberalisation in gas and electricity markets. By 2006, only Germany, Japan, Spain and, to a much smaller extent, Turkey, plan to continue subsidising hard-coal production. Significant subsidies remain in developing countries, principally China and India.

Trade Implications

With coal reserves widely spread geographically, coal demand is satisfied mostly on a regional basis depending on price and freight costs; coal trade accounts for only some 13% of total world demand. World seaborne trade continues to grow steadily, reaching 480 Mt in 1999. Steam coal trade has grown most rapidly, 5% in 1998, and now accounts for 63% of total coal trade. Steam coal will probably increase its share at the expense of coking coal in world coal trade over the outlook period, pushed mainly by strong growth in the Asia-Pacific region.

Coal trade has risen recently despite declines in global consumption and production since 1998. Trade growth has focused largely on Japan, developing Asia and Latin America, which lack large domestic coal resources and where the expansion of coal-fired electricity generation capacity and integrated steel production have increased coal demand. European imports have also increased, as the closing of inefficient mines has generated the need for coal from other sources.

World coal prices have fallen in both real and nominal terms over the last 20 years as productivity has improved. In the past decade alone, the international price dropped from US$ 52 per tonne in 1991 to an estimated US$ 37 per tonne in 1999 in nominal terms. These declines are expected to change the geographical composition of world coal trade. The scope for more exports from countries with low-cost reserves and the potential entry of new exporters will tend to dampen any long-term rising trend in coal prices.

Europe's coal-industry restructuring has caused a dramatic fall in domestic production. In Japan, domestic output is now less than 10% of total coal demand, largely due to subsidy reductions. Japan has historically paid for security of supply though a benchmark pricing system and by investment in foreign coal production. The benchmark system has been criticised, however, on the grounds that it subsidises particular sellers, limits market entry and distorts price signals.

These changes stem from abundant supplies of coal and greater competition in electricity markets. Security of coal supply is unlikely to be a problem in the future for these countries. Coal reserves are abundant and widely dispersed geographically. Importing countries will have a choice of suppliers, allowing diversity of supply to ensure reliability and quality.

Power Generation

Fuel Mix

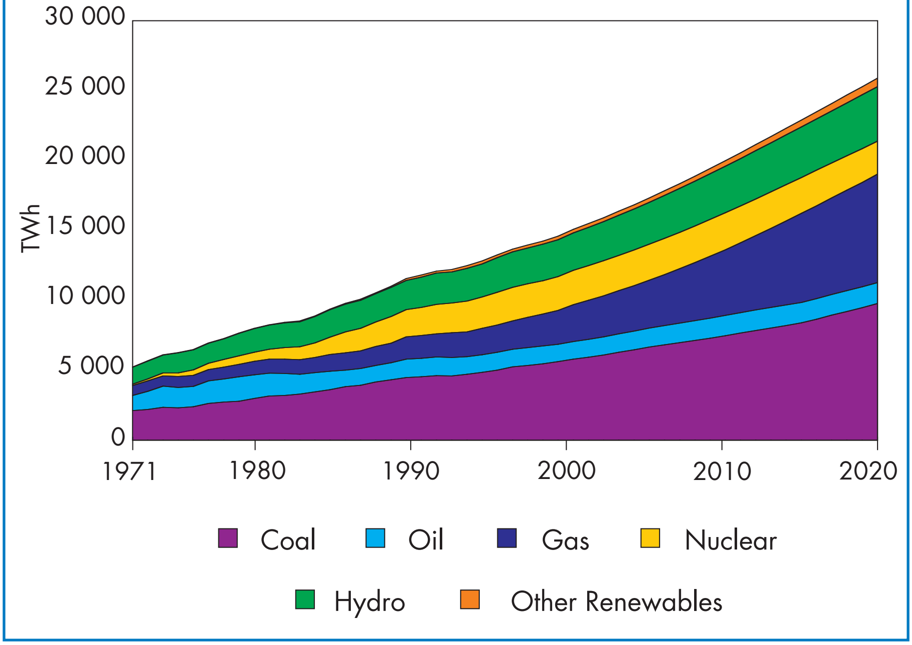
To meet rapidly growing electricity demand, projected world electricity generation will increase by 2.7% per annum from 1997 to 2020. Natural gas will meet most of the incremental demand, where it is available and so long as its price remains low. Coal will be used in countries with an indigenous resource base. The shares of hydropower, nuclear and oil will decline over time. Non-hydro renewables will increase rapidly, but their share in the global electricity mix will remain low. More competitive markets will govern the future development of the power-generation sector. Electricity markets in most OECD countries and in some developing ones are undergoing rapid reform, to promote economic efficiency, reduce prices to consumers and ensure that prices properly reflect the cost of supply.

Coal is likely to maintain its position as the world's largest single source of electricity generation throughout the projection period (Figure 3.9). Its share in global electricity generation has remained almost unchanged for about three decades and is projected to stay more or less the same until 2020.

In the OECD, the importance of coal in electricity generation declines over time. In the absence of more stringent environmental regulations, more coal plants could be built when natural gas prices rise in the second half of the outlook period and coal prices remain flat. Advanced coal technologies, such as supercritical steam technology, become competitive after 2010. The *Outlook* assumes that their capital costs will decline over time, falling to $900 per kW by 2020, and that their efficiency increases to 44%. As 2020 approaches, integrated gasification combined-cycle (IGCC) technology could be an economic option for new power-generation schemes. If emission standards become more stringent, IGCC could be more important relative to other coal technologies. Electricity generation from coal increases in OECD countries from 3 328 TWh in 1997 to 4 278 TWh in 2020, but its share in the electricity mix declines by four percentage points.

Coal will remain the most important source of electricity generation in many developing countries. Electricity production from coal could triple by

Figure 3.9: **World Electricity Generation, 1971-2020**



2020 in those countries. India and China show the largest increase in coal-fired generation and could account for 40% of world coal-fired capacity in 2020. By the end of the projection period, China alone could be producing a quarter of the world's coal-based electricity and half of that in developing countries.

World natural gas-fired generation grows to more than three-and-a-half times its current level, and its share in the electricity mix doubles. Natural gas is expected to become the world's second largest source of electricity generation within the next decade, surpassing both hydro and nuclear. OECD countries account for nearly half of the increase up to 2020.

Natural gas-fired CCGT plants have become the preferred option for many new power-generation plans, particularly in the OECD, for their technical, economic and environmental advantages. They accounted for 45% of the total OECD capacity increase between 1990 and 1998.

Box 3.4: **Distributed Generation**

According to some observers, the share of distributed generation will increase in competitive electricity markets. A distributed utility produces electricity and/or heat close to the load centre, providing benefits such as lower economic size, high power quality, improved reliability and reduced need for long-distance, high-tension transmission compared to centralised units. In the Reference Scenario, centralised plants will not be replaced to any significant degree, but distributed utilities could respond to particular needs in some cases. The real potential for distributed generation is difficult to assess, but any growth will be based on the ability of small generating units to compete with central-station economies of scale plus transmission costs.[12]

Industrial co-generation of heat and electricity is probably the largest potential area of growth for distributed generation. Turbine and engine manufacturers are developing gas turbines, CCGTs and combustion engines for small-scale industrial co-generation. Natural gas or clean distillate fuels are generally their energy sources, because they do not require expensive emission-control equipment. In the future, fuel cells running on natural gas may provide expanded opportunities for distributed generation, but they are not yet cost-competitive except in specialised situations. There is also likely to be a potential for renewables, especially in remote locations with little or no access to transmission networks.

Gas-turbine technology developed rapidly in the 1980s as a result of concentrated programmes of jet-engine development and the end of policies restricting natural-gas use in power generation.[13] Competition between manufacturers has sustained further technical development. Efficiency has improved steadily with increasing combustion temperatures; efficiency is assumed to rise to 60% by the end of the outlook period. The capital costs of CCGT plants can be half those of coal plants, with maintenance costs also low. Consequently, CCGT generation costs are in general, more sensitive to fuel prices than other generation technologies. Equal increases in the prices of different fuels would thus have a more

12. IEA, 1999.
13. Ibid.

serious impact on the economics of CCGTs than on those of other technologies. Rapid growth in gas-fired power generation may lead utilities to hedge against fuel-price increases. An important feature of CCGTs should therefore be their ability to operate with more than one fuel. This issue may receive more attention when natural gas prices begin to rise.

Oil accounts for about 9% of electricity generation globally. Its share in the electricity mix, which has fallen constantly since the first oil shock, is projected to continue falling, to only 6% in 2020. The decline will be steeper in the OECD area, where both the amount of oil-fired generation and its share fall over time. Oil use in baseload operation has shrunk, but it will continue for peaking or as a backup fuel. A similar decline is projected for the transition economies.

Electricity generation from oil increases in developing countries, although not fast enough to maintain oil's share in the electricity mix. Several developing countries are likely to build some oil-fired plants during the projection period. In rural areas, internal combustion engines will continue to find uses, along with renewables, to supply households with electricity.

Nuclear power provided 2 393 TWh of electricity in 1997, or 17% of global electricity output. Today, 435 commercial nuclear units operate in 31 countries with an installed capacity of 352 GW, about 11% of world generating capacity. Nuclear power has provided baseload electricity for several decades. It gained momentum in the 1970s after the oil shocks, when many countries regarded it as a stable and economic source that would ensure security of supply. Annual capacity additions averaged 12 GW in the 1970s and 18 GW in the 1980s. Growth has stalled in recent years, because lower fossil-fuel prices have made generation from coal and gas more attractive economically and because of increasing public concern, particularly after the Chernobyl accident in 1986.

In the Reference Scenario, new nuclear capacity up to 2020 amounts to a little over 100 GW, including reactors coming on line in 1997-2000 and plants under construction or planned. Meanwhile, some 135 GW of existing nuclear capacity is likely to be retired, and the projected share of nuclear in the global electricity mix drops to 9%.

Expected output from nuclear power plants declines more slowly than installed capacity because it is assumed that nuclear plants will operate at higher capacity factors, rising from the current 78% to 84% by 2020. This trend is already confirmed in several OECD countries, where electricity-market reforms have encouraged improved performance to reduce costs. Owners of nuclear plants that do well in competitive electricity markets will probably seek to operate them longer, possibly resulting in lower capacity retirements than the *Outlook* projects. Table 3.8 shows details of the nuclear capacity projections by region.

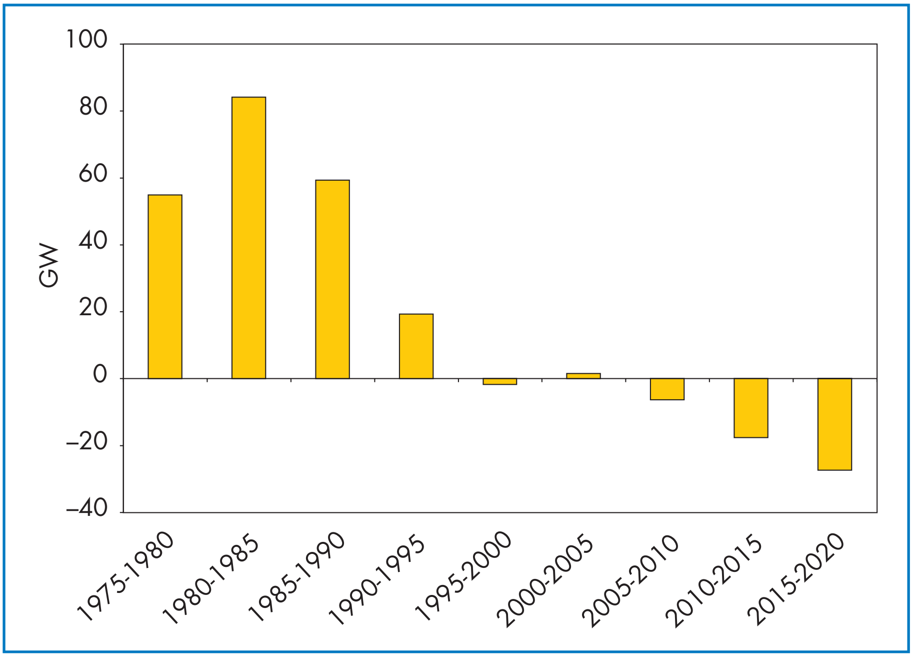
Table 3.8: **Nuclear Capacity by Region** (GW)

	1997	2010	2020	1997-2020 Cumulative Additions	1997-2020 Cumulative Retirements
OECD Europe	131	125	97	4	38
OECD North America	112	95	68	0	46
OECD Pacific	44	57	67	24	0
OECD	**286**	**277**	**232**	**28**	**84**
Transition Economies	**42**	**40**	**28**	**34**	**48**
Africa	2	2	2	0	0
China	2	11	20	18	0
East Asia	15	27	29	16	2
Latin America	3	4	4	1	0
Middle East	0	1	1	1	0
South Asia	2	4	7	5	1
Developing Countries	**24**	**49**	**62**	**41**	**3**
World	**352**	**366**	**323**	**103**	**135**

The OECD countries currently account for more than four-fifths of global nuclear electricity production. Nuclear provides nearly a quarter of the OECD's electricity output and is the second largest single source of electricity after coal. Retirements expected from now to 2020 are about 30% of existing plants. New construction in the OECD will be limited for two reasons. First, nuclear faces strong competition from fossil fuels, especially natural gas-fired CCGT plants. Second, several countries have imposed restrictions on nuclear power. Figure 3.10 compares historical to projected changes in OECD nuclear capacity.

Most future growth in nuclear power is likely to come from developing countries, particularly in Asia. Nuclear electricity production in developing countries will grow by a factor of 2.5 to 2020, its share in electricity generation staying at about 4%. Projected nuclear capacity in the transition

Figure 3.10: **Changes in OECD Nuclear Capacity**



economies declines. These countries have several nuclear reactors under construction, but completion depends largely on the availability of necessary funds, which is uncertain. Financing new reactors currently planned may prove equally difficult. In these circumstances, some existing reactors may be refurbished and operated for another ten years.

Hydro-electric power, the world's second largest source of electricity, provides more than 18% of global power. It is the only renewable electricity source that has been exploited on a large scale. At the end of 1997 installed hydro capacity reached 738 GW world-wide. The *Outlook* expects 340 GW of new capacity to be constructed over the projection period, with global electricity production from hydro plants increasing by 1.8% a year. Nonetheless, hydropower's share in electricity generation declines to 15% by 2020.

Hydro played an important role in the early development years of the OECD area's electricity industries, but its share in generation has since declined in most countries. In 1960 hydro accounted for 82% of electricity generation in Italy, 51% in Japan and 18% in the United States. Those shares dropped to 16%, 9% and 8% by 1997. Most of the best sites in

OECD countries have been exploited, and environmental concerns limit new construction. Even existing hydroelectric dams in the United States face criticism, and several of them may find re-licensing difficult. Canada, Turkey and Japan are expected to develop their hydro resources further. Hydro-electricity in the OECD grows by only 0.5% per year over the projection period.

Developing countries account for 80% of the projected increase in hydroelectricity between now and 2020. Three-quarters of that is expected to appear in China and Latin America. The unexploited economic potential remains large in many developing countries, but much discussion surrounds the environmental and social effects of large-dam construction (an estimated 20% of large dams in the world produce electricity[14]). The development of large-scale hydropower may have negative environmental effects, such as disturbing local ecosystems, reducing biological diversity or modifying water quality. It may also have significant socio-economic impacts when it requires the displacement of local populations. A number of projects in developing countries have been stalled or decreased in size because of such problems. Although these effects can be managed and mitigated to some degree, they could adversely affect the future of hydropower. Obtaining loans from international lending institutions and banks, for example, has become more difficult. The development of mini and micro-hydro systems seems to have relatively modest and localised effects on the environment, particularly if it does not require the construction of a dam, but the kWh cost is generally higher in smaller systems.

Although hydropower is not entirely free of greenhouse-gas emissions on a life-cycle basis (especially because of methane generated by decaying biomass in reservoirs) it can help restrain growth in emissions caused by burning fossil fuels.

Non-hydro renewable energy accounts for a small but growing percentage of global electricity — about 1.5% in 1997, projected to rise to 2.3% (603 TWh) by 2020. OECD countries produce most of it, but several developing countries are among the world's leaders in electricity from renewables. The Philippines and Indonesia rank second and sixth in geothermal electricity. India and China actively promote wind-power development.

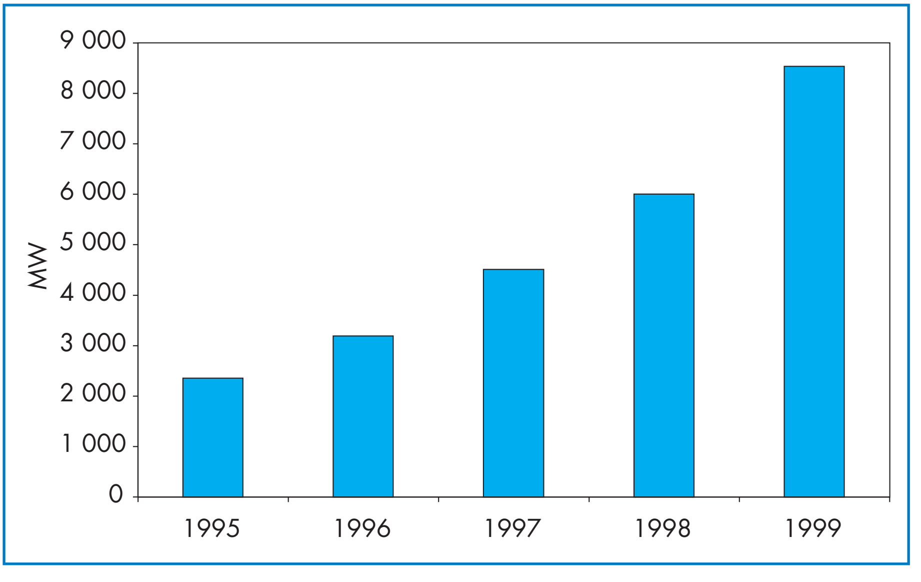
Electricity generation from renewables is generally expensive compared with technologies that use fossil fuels, especially natural gas-fired CCGT

14. IEA, 2000.

plants. The costs of renewables technologies could well decline further, but the capital costs and efficiencies of fossil-fuel technologies are also likely to improve, offsetting fuel-price increases to some extent. Moreover, in liberalised energy markets, utilities will tend to choose the most cost-effective options for power generation as well as technologies that are proven and familiar. Most of the projected growth in renewables is therefore expected to require various forms of financial incentives.

In the OECD area, projected electricity generation from non-hydro renewables grows three times as fast as total electricity demand. The share of renewables in the electricity generation mix doubles, from 2% in 1997 to 4% in 2020. As OECD countries increasingly seek ways to reduce their GHG emissions, the popularity of renewables will grow. While the share of renewables in the electricity mix rises in all three OECD regions, most of the expected growth occurs in OECD Europe, where the annual level of electricity from renewable energy sources more than quadruples from 1997 to 2020. The region currently accounts for less than a third of non-hydro renewables in the OECD area, but could account for roughly half in 2020. In North America and OECD Pacific, renewable electricity generation doubles over the outlook period.

Figure 3.11: **Wind-Power Capacity in OECD Europe**



Note: Data for 1995-98 are from the IEA databases. The 1999 estimate is based on data from the European Wind Energy Association (EWEA).

In developing countries, renewables can play an important role in providing electricity to remote, off-grid locations as part of rural electrification programmes. Renewables are projected to supply a little more than 1% of total electricity in developing countries in 2020.

Wind and combustible renewables and waste (CRW) will supply most of the expected growth in renewables. CRW now provides nearly three-quarters of non-hydro renewable electricity. Wind-power capacity is growing fast, however. Figure 3.11 shows recent increases in wind capacity in OECD Europe, where most of the current growth concentrates. By 2020, CRW is expected to account for nearly half of global electricity production from renewable sources, while wind could supply nearly 30%. Table 3.9 shows detailed projections of non-hydro renewable capacity and electricity generation by region.

Table 3.9: **Renewables Capacity** (GW) **and Electricity Generation** (TWh) **by Region**

	1997		**2010**		**2020**	
	GW	**TWh**	**GW**	**TWh**	**GW**	**TWh**
OECD Europe						
Geothermal	0.6	4.4	1.0	6.8	1.1	7.5
Wind	4.5	7.3	21.3	56.1	37.9	109.5
CRW	6.5	40.6	11.8	73.8	17.3	108.2
Solar/Tide/Other	0.5	0.6	1.6	3.6	3.8	8.2
OECD North America						
Geothermal	2.9	14.9	3.0	17.3	3.8	25.1
Wind	1.7	3.5	5.6	12.3	12.0	36.9
CRW	13.5	67.9	15.6	92.6	17.7	104.6
Solar/Tide/Other	0.4	0.9	0.8	2.1	1.3	3.3
OECD Pacific						
Geothermal	0.9	5.8	2.1	14.9	3.3	23.6
Wind	0.0	0.0	1.0	3.1	2.9	8.5
CRW	5.9	26.0	6.6	28.8	8.0	35.2
Solar/Tide/Other	0.0	0.0	0.3	0.7	1.4	3.7
Transition Economies						
Geothermal	0.0	0.0	0.1	0.6	0.2	0.9
Wind	0.0	0.0	0.2	0.4	0.4	0.8
CRW	1.5	6.5	1.6	7.0	1.7	7.4
Solar/Tide/Other	0.0	0.0	0.0	0.0	0.0	0.0

Table 3.9 (Continued)

	1997		2010		2020	
	GW	TWh	GW	TWh	GW	TWh
Africa						
Geothermal	0.1	0.5	0.3	1.9	0.5	3.1
Wind	0.1	0.0	0.4	0.9	0.7	1.5
CRW	0.2	0.0	0.3	1.4	0.4	1.6
Solar/Tide/Other	0.0	0.0	0.0	0.1	0.1	0.1
China						
Geothermal	0.1	0.0	0.3	1.6	0.4	2.5
Wind	0.4	0.0	2.3	4.9	3.7	8.1
CRW	0.0	0.0	0.1	0.4	0.2	0.7
Solar/Tide/Other	0.0	0.0	0.1	0.1	0.1	0.2
East Asia						
Geothermal	2.1	9.8	3.3	20.1	6.2	38.1
Wind	0.0	0.0	0.0	0.0	0.0	0.1
CRW	0.7	2.2	0.8	3.5	1.2	5.1
Solar/Tide/Other	0.3	0.7	0.4	0.9	0.5	1.2
Latin America						
Geothermal	1.1	6.9	1.4	9.1	1.8	11.2
Wind	0.3	0.6	0.6	1.3	0.8	1.7
CRW	2.8	12.1	4.0	17.3	5.3	23.2
Solar/Tide/Other	0.0	0.0	0.0	0.0	0.0	0.0
Middle East						
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0
Wind	0.0	0.0	0.1	0.2	0.1	0.3
CRW	0.0	0.0	0.0	0.0	0.0	0.0
Solar/Tide/Other	0.0	0.0	0.0	0.1	0.1	0.2
South Asia						
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0
Wind	1.0	0.1	2.8	6.2	4.6	10.1
CRW	0.2	0.0	1.0	4.3	2.1	9.4
Solar/Tide/Other	0.0	0.0	0.2	0.4	0.3	0.7

New Electricity-Generating Capacity and Investment Requirements

Over the outlook period, nearly 3 000 GW of new generating capacity are projected to be installed world-wide. About one-fifth of this new capacity will replace existing installations, and the remainder will meet new demand. Projected annual new-capacity increments amount to 103 GW, from 1997 to 2010 and 158 GW from then to 2020.

Slightly more than a third of the new capacity will be built in OECD countries. Replacement capacity represents almost a third of that amount. Some older steam plants and about 30% of existing nuclear capacity could be retired over the outlook period. Although electricity demand in the OECD countries slows in the second decade, capacity additions increase because of the need to replace retired units.

The transition economies will need new capacity mostly in the second decade. Existing capacity is underused because of low electricity demand. Thus, capacity additions in these countries are only 9 GW per year in 1997-2010, but jump to 2.5 times that in the following decade to meet rising demand.

More than half of the projected new capacity to 2020 will be installed in developing countries. Of the 1 564 GW of new capacity needs, two-thirds will be built in developing Asia. Projections of capacity requirements by region are shown in Table 3.10.

The estimated investment cost of new power plants over the outlook period, excluding the cost of new transmission and distribution lines, is nearly $3 trillion at today's prices (Table 3.11). Investment in new transmission and distribution systems may be about as great, depending on the country and the level of electrification. The additional cost of expanding networks is likely to be higher in developing countries, where geographic coverage is much lower. Thus, total investment requirements could easily double the estimate.

In the OECD, the cost of new capacity is $894 billion. The transition economies will need more than $300 billion. Many existing plants in the region will also need refurbishing because of their age and, more importantly, inadequate maintenance. The cost for this is highly uncertain and not included in the projection. Developing countries will need to invest around $1.7 trillion in new plant.

Clearly, developing countries will need to devote significant funds over the next twenty years to the development of their electricity sectors. In the past, growth in electricity depended on public-sector support. However, insufficient resources often constrained the effort and resulted in large gaps

Table 3.10: **World Power-Capacity Requirements by Region**

	Total Additional Capacity (GW)			Annual Additions (GW per year)		
	1997-2010	**2010-2020**	**1997-2020**	**1997-2010**	**2010-2020**	**1997-2020**
OECD Europe	229	248	477	18	25	21
OECD North America	195	201	396	15	20	17
OECD Pacific	64	75	138	5	7	6
OECD	**488**	**523**	**1 011**	**38**	**52**	**44**
Transition Economies	**116**	**222**	**339**	**9**	**22**	**15**
Africa	47	57	104	4	6	5
China	253	266	519	19	27	23
East Asia	122	156	278	9	16	12
Latin America	139	143	282	11	14	12
Middle East	54	77	131	4	8	6
South Asia	115	135	250	9	14	11
Developing Countries	**730**	**834**	**1 564**	**56**	**83**	**68**
World	**1 335**	**1 579**	**2 914**	**103**	**158**	**127**

Table 3.11: **World Investment in New Capacity by Region**

	Total Investment (US$ billion)			Annual Rate (US$ billion per year)		
	1997-2010	2010-2020	1997-2020	1997-2010	2010-2020	1997-2020
OECD Europe	197	192	389	15	19	17
OECD North America	125	154	279	10	15	12
OECD Pacific	117	109	225	9	11	10
OECD	**439**	**455**	**894**	**34**	**45**	**39**
Transition Economies	**125**	**194**	**319**	**10**	**19**	**14**
Africa	50	46	96	4	5	4
China	285	304	589	22	30	26
East Asia	141	149	290	11	15	13
Latin America	210	154	363	16	15	16
Middle East	57	57	114	4	6	5
South Asia	127	130	257	10	13	11
Developing Countries	**870**	**839**	**1 709**	**67**	**84**	**74**
World	**1 434**	**1 488**	**2 922**	**110**	**149**	**127**

between supply and demand. Many developing countries now see private investment as an attractive option to expand their power sectors. Private participation may not be the only answer to power-infrastructure expansion but, if managed correctly, it can provide significant opportunities for development. In order to generate the necessary funds for power-generation expansion, many countries in the developing world will, however, need to accelerate reform of their public-dominated electricity sectors.

PART B

REGIONAL OUTLOOKS TO 2020

This Part moves from a global to a more geographically differentiated and detailed perspective on the energy projections to 2020. Each of its six similarly structured chapters covers a specific region or a large country central to the *Outlook* projections and key to understanding energy developments within its region. Chapters 4 through 6 focus on the three OECD regions — North America, Europe and Pacific. Chapter 7 discusses the outlook for Russia, Chapter 8 looks at China and Chapter 9 covers Brazil.

CHAPTER 4
OECD NORTH AMERICA

Introduction

OECD North America (the United States and Canada) consumes more energy than any other region covered in this *Outlook*. The largest economy in the world, the United States alone produces more than one-fifth of the world's and close to 40% of the OECD's economic output. It also accounted for almost 26% of global primary energy consumption in 1997 and was the largest emitter of greenhouse gases, with CO_2 emissions equivalent to 24% of the world total. Canada, although significantly smaller in economic size and energy use, is another major economic power and energy consumer. It accounts for 2% of world economic output and 3% of primary energy consumption. With a population of just over 30 million, Canada consumes almost as much commercial energy as India, which has a population of around one billion.

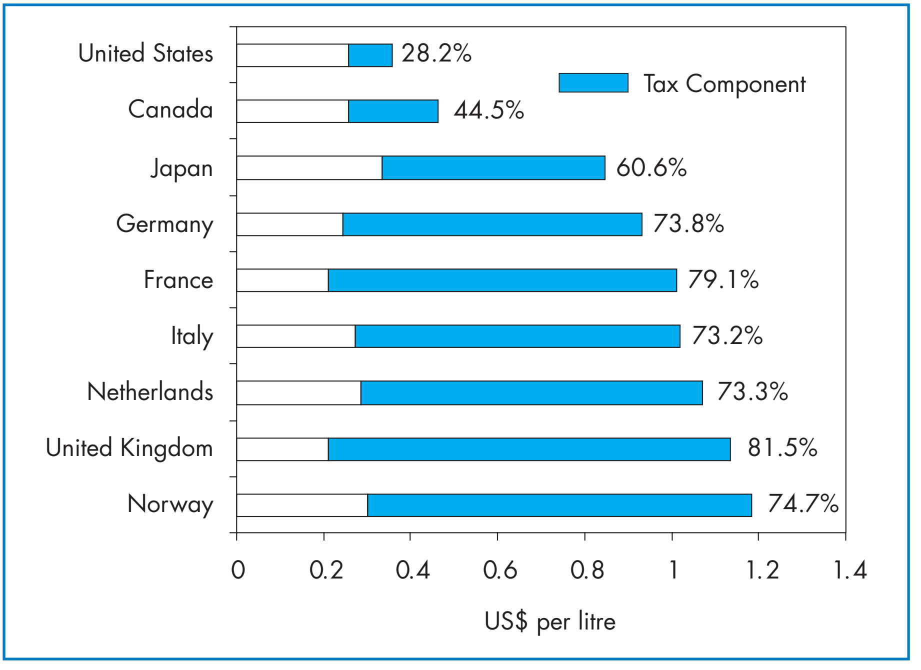
The region is rich in hydrocarbon and hydropower resources. The United States is the second-largest producer of oil[1] after Saudi Arabia, although imports meet just over half of its oil demand. Canada relies heavily on hydropower, which accounted for 12% of its total primary energy demand in 1998. The region has significantly higher energy intensity[2] than other OECD countries — 42% more than the OECD-Europe average in 1997 and twice that of Japan. The several factors that explain this include low energy prices, extreme climate conditions and long distances between urban centres.[3]

The United States and Canada have much lower gasoline prices than other OECD countries, due essentially to lower taxes (Figure 4.1). The limited availability of public transport and high private automobile use resulting from urban sprawl have caused considerable public resistance to increases in gasoline taxes. Although fuel demand is relatively price-inelastic, the low share of taxes in retail transport-fuel costs in North America makes

1. Crude oil and NGL.
2. This persists despite the significant energy intensity improvement in recent years, discussed later in this chapter.
3. See Box 2.3 for a discussion of the relationship between energy efficiency and energy intensity.

fuel demand more sensitive to changes in crude prices than in other OECD countries.[4] Nonetheless, despite surging pump prices, gasoline demand has continued to rise in the booming economy.[5]

Figure 4.1: **Retail Gasoline Prices in Selected OECD Countries, 1999**



Note: Unleaded Gasoline (95 RON) for all countries, except Canada (Unleaded Gasoline 98 RON) and Japan (91 RON).

Macroeconomic Background

The US economy appears to have moved onto a higher sustainable economic-growth path in the last decade compared with the 1970s and 1980s. Over the past four years, the economy has grown very fast — at about 4% per year. The current upswing, which began nine years ago, is the longest in at least a century. Unemployment currently hovers at around 4%, the lowest in 30 years, and some signs of inflationary pressure have emerged, mainly due to increases in world oil prices. They have pushed the

4. See OECD (2000b) which highlights the need for using economic instruments (*e.g.* taxes) more efficiently in the US road-transport sector.
5. Developments in prices in OECD countries are discussed in Chapter 1.

annual growth rate of the US consumer price index to above 3%. Despite these trends, several fundamental indicators still point to sustained economic expansion in the near to medium term. At the same time, the potential risk of a hard landing for the economy persists.[6]

The Canadian economy, which has strong trade and financial linkages with that of the United States, has also grown strongly, averaging more than 3% annually over the last two years. The key drivers of this expansion include strong US demand, rising world commodity prices and a booming manufacturing sector.

Rapidly rising labour productivity has been key to the recent strong expansion of the US economy. The rise has doubled from rates experienced in the 20 years prior to the mid-1990s. Rapid expansion in the role of information and communication technology (ICT) across a wide range of economic sectors appears to have contributed to this improvement. Many economists suggest that this constitutes a fundamental structural economic transformation, often described as the "New Economy", characterised by the use of complex networks, such as the internet, linking businesses and consumers.

The US economy grew by 5.3% in 1997 and by 3.9% in 1998. TPES increased by 1.9% in 1997 and remained stable in 1998, thus causing energy intensity to drop by 3.2% in 1997 and by 3.7% in 1998. Mild weather in 1998, structural economic change towards service activities and energy savings induced by energy-efficiency programmes (such as Energy Star and Green Light) launched in the early 1990s, which have helped reduce energy consumption in buildings, have contributed to the continuing decline in energy intensity in recent years. Structural change in the economy towards less energy-intensive sectors with more value added appears to have played a key part.[7] Because ICT industries (producers of computer hardware and software, communications equipment and services, and instruments) are not very energy intensive and have a very high value-added component, strong growth in the ICT sector has a positive effect on energy intensity. Between 1995 and 1999, ICT industries accounted for an average of 30% of real US economic growth.[8] Box 4.1 discusses the broader impact on energy use of the growing economic role of information technology.

6. See OECD (2000a) for a discussion of the macroeconomic factors underlying short and mid-term economic performance and the risk of a hard landing.
7. See IEA (2000b) which suggests that in 1998 mild weather conditions were responsible for around one-fifth of energy-intensity improvements. Structural change accounted for roughly one-third of the improvement in weather-adjusted energy intensity.
8. US Department of Commerce, 2000.

Recent Energy-Sector Developments

United States

Overall US energy production has stayed broadly flat since the mid-1990s, with increases in coal output offsetting a long-term decline in oil production. Total primary energy demand rose steadily through the 1990s, but was stable in 1998, mainly because of climatic factors. Imports of oil, which meets 40% of the country's primary energy needs, have risen continuously since 1991, reaching just over half of total US oil demand in 1998. Following successive annual increases since 1992, final gas consumption fell back in 1997 and 1998, primarily due to weather-related declines in residential and commercial demand. Coal remains the dominant fuel in power generation, but the share of gas continues to rise.

The rebound in international oil prices since March 1999, combined with relatively low rates of taxation on oil products, has led to sharp increases in retail oil-product prices. The pump price of gasoline, which accounts for half of the US oil-product market, increased from an average $0.33/litre in 1998 to $0.36/litre in 1999 and reached $0.43/litre by June 2000. Problems at refineries in meeting tighter specifications for reformulated gasoline have exacerbated the upward pressure. Higher heavy fuel-oil and distillate prices, together with strong demand and declining domestic deliverability, have also contributed to higher natural gas prices.

The restructuring of electricity markets across the country continues. By May 2000, 23 states had adopted legislation introducing competition in generation and wholesale and retail supply, based on mandatory open access to transmission and distribution networks. Legislation was in preparation or planned in all but seven of the remaining ones. As a result, increasing numbers of consumers have the opportunity to choose their suppliers. At the federal level, the Administration submitted a bill to Congress in 1999 aimed at empowering and encouraging states to establish competitive markets in generation, encouraging investment in renewables and giving states clear authority to establish retail competition. Restructuring is leading to major changes in the ownership of electric utilities and increased industry concentration.

Canada

Canada is a net exporter of all major energy sources. Oil production has risen steadily in recent years, a growing proportion of it from bitumen and oil sands, reserves of which far exceed those of conventional oil. Gas

Box 4.1: **The New Economy and Energy Use**

The overall impact of the "New Economy" on levels and patterns of energy use and energy intensity is uncertain, with two main, opposing forces at work:

- *Energy savings from ICTs:* The "New Economy" reduces energy use and therefore intensity in three key ways:
  - a structural shift occurs, towards less energy-intensive activities based increasingly on creating and disseminating knowledge instead of manufacturing physical goods;
  - ICTs optimise production via automation, computerisation and just-in-time, tailor-made manufacturing, thereby improving energy efficiency;
  - the internet and virtual space save energy and resources by reducing the need for building space and physical stocks, improving planning and logistics, displacing printed materials and reducing the need for transportation through telecommuting and e-commerce. Some estimates[9] indicate a possible reduction of three billion square feet in commercial floor space from 1997 to 2007, which would lower industrial energy consumption by 1% per year. These savings may be offset by the effects of increased personal free time (which may lead to more leisure travel), increased reliance on less efficient product-delivery logistics (*e.g.* overnight delivery by air) and the higher demand for shipping which could result from globalisation.
- *Electricity consumption for information and communication technology (ICT) equipment and appliances:* According to the US Energy Information Administration (EIA, 1999), the energy consumed by personal computers and other types of office equipment accounted for 10% of total electricity consumption in commercial buildings in 1999. The energy/performance ratios of appliances will continue to fall (although at a lower rate than in recent years), but there are two likely offsets. First the interconnections of ICT appliances (the "network effect") produce a growing tendency towards around-the-clock operation. Second, these appliances "leak" electricity: even when turned off, they continue to consume energy as long as they remain plugged in.

9. Romm, *et al.*, 1999.

output continues to increase, albeit more slowly than in the first half of the 1990s. Most of the 61% increment in 1990-98 went to US export markets. Nuclear power production has fallen sharply since 1994 as several poorly performing plants have gone out of service. Oil and gas each account for around a third of total primary energy use, while coal, hydropower and nuclear account for most of the rest.

Box 4.2: **Energy-Market Reform in Canada**

Restructuring of the electricity sector in Canada will have a significant long-term impact on electricity consumption and exports, depending on the nature and take-up of reforms by provincial governments.

In 1998, Ontario (35% of the national population) agreed to introduce wholesale and retail competition by the end of 2000, based on open access to the provincial transmission grid and local distribution networks. Generation was opened to new entrants. Ontario Power Generation (OPG) — the dominant generating company — must reduce its control over price-setting plants to 35% within 42 months of market opening, and its total market share to 35% over 10 years.

In 2000, Alberta (9% of the population) plans to auction the right to sell the output of each of the generating units now owned and managed by three utilities. Each unit will have a long-term power-supply agreement with a marketer and compete in a pool. Open transmission access and a competitive power pool were established in 1995. Retail competition is being phased in over 1998-2001.

Reform in other provinces is less advanced. Reforms have been introduced in Quebec, but wholesale competition has not yet developed.

In gas, buyers have been able to contract directly with producers, marketers and other agents since 1987. Open, non-discriminatory access is assured to all shippers on inter-provincial pipelines. Retail competition has developed, notably in Ontario and Alberta, encouraged initially by falling prices but delayed by consumer reaction to price spikes. Legislation in Ontario in 1998 has allowed competition to re-emerge, but ensuring supply in the last resort remains an issue. Canadian prices should fall to export levels, stimulating consumption[10].

10. IEA, 2000a.

The electricity and gas industries continue to restructure in response to provincial and federal government efforts to promote competitive markets in power generation, gas production and energy supply. Electricity-market reforms are generally most advanced in Ontario and Alberta, while gas reforms now focus on retail competition (see Box 4.2).

Assumptions

The Reference Scenario assumes soft landings for the US and Canadian economies, with GDP growth slowing from recent high rates to a more sustainable long-term path. OECD North American GDP growth will average 2.1% over the projection period — 2.3% for 1997-2010 and 1.8% for 2010-2020 — lower than the average of 2.5% in 1990-1997. A key element in the expected slowing is a lower rate of increase in the active (working) population, with an expected decline in immigration and the progressive ageing of the population. These assumptions imply a deceleration in the rate of growth of labour productivity. On the assumption that the total population grows by an average of 0.7% per annum over 1997-2020, projected per capita incomes will rise by 1.4% per annum.

The prices of oil and coal assumed for North America follow trends in international prices. Natural-gas prices stay flat at $2 per thousand cubic feet in 1997-2005, then rise steadily to $2.50 per tcf by 2010 and $3.50 per tcf by 2020, reflecting robust demand growth, increasingly tight supplies of conventional US and Canadian gas and increasing reliance on unconventional supplies and possibly LNG.

Table 4.1 summarises the principal economic, demographic and energy-price assumptions for OECD North America in the Reference-Scenario projections. The projections also assume that underlying, specific end-use technical efficiencies continue to improve in line with historical trends. Electricity and gas-industry restructuring, expected to lead to improved economic efficiency and lower costs than would otherwise occur, is assumed to continue.

The projections take account of actions already agreed and/or implemented to achieve climate-change objectives under the Kyoto Protocol, notably those included in the 1997 US Climate Action Report and the 1995 Canadian National Action Program on Climate Change (see Box 4.3). New policies and measures that may be put in place or any other future commitments by the United States and Canada are not reflected.

Table 4.1: **OECD North America Reference-Scenario Assumptions**

	1971	1997	2010	2020	1997-2020*
GDP	3 625	7 222	9 747	11 638	2.1
Population	230	297	327	348	0.7
GDP per capita	15.8	24.3	29.8	33.4	1.4
Oil price	6.0	16.0	16.5	22.5	1.5
Coal price	44.2	36.8	37.4	37.4	0.1
Natural gas price	0.6	1.9	2.5	3.5	2.6

* Annual average growth rate, in per cent.
Note: All value figures are in US dollars, at constant 1990 prices. GDP is in billions of dollars, calculated in PPP terms. Population is in millions and GDP per capita is in thousands of dollars. The oil price is per barrel, the coal price per tonne and the gas price per tcf.

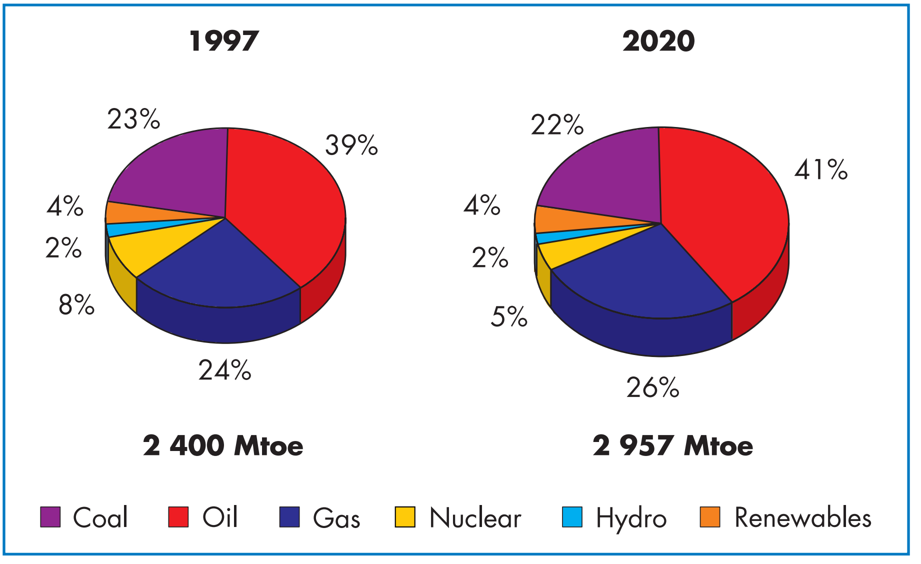
Results of the Projections

Overview

Primary energy demand in OECD North America increases by 0.9% per annum over the projection period in the Reference Scenario. This lies below past rates of increase (1.3% in 1971-1997) and is roughly equivalent to the average projected rise for the OECD as a whole. A sharp deceleration in inputs to electricity generation, resulting largely from increased conversion efficiency in power plants and saturation of markets for electric appliances and equipment, contributes to the slowdown in primary energy-demand growth.

The fuel mix of primary energy supply does not change radically. Figure 4.2 illustrates the projected shares for each fuel. Natural gas shows the fastest expansion among fossil fuels (1.3% per annum); its share in total supply increases from 24% in 1997 to 26% in 2020. Most of the increase is in power generation. Oil's share also rises slightly (from 39% to 41%), due almost entirely to rising transport demand. Non-hydro renewables grow fastest of all, by 1.6% per annum, but from a relatively low base. Nuclear power supply falls by an average of 1.6% per annum and its share in the primary fuel mix drops three percentage points to 5% by 2020.

Figure 4.2: **OECD North America Total Primary Energy Supply**



Total final consumption (TFC) increases slightly faster than primary demand, driven mainly by oil and electricity (Table 4.2). Their shares in TFC each rise by one percentage point, to 54% for oil and 20% for electricity, while the gas share drops three points to 21%. Increased average thermal efficiency in power plants as more high-efficiency gas turbines are commissioned accounts for the difference in the rates of growth of TPES and TFC.

Box 4.3: **Principal Climate Change Policies and Measures Considered in the Reference Scenario**

United States

The primary measures are actions contained in the 1997 Climate Action Report.[11] The package includes standards and voluntary programmes to improve energy efficiency and promote the commercialisation of renewables. Other specific measures include:

- *Industry:* The Energy Policy Act (EPACT), which requires a 10% increase in efficiency in electric motors above 1992 levels for motors sold after 1999, and the Climate Change Action Plan Motor Challenge to develop more efficient cars.
- *Transport:* Corporate Average Fuel Economy (CAFE) standards, assumed to remain at their current level of 27.5 mpg for cars and 20.7 mpg for light trucks.[12]
- *Buildings:* The EPA Expanded Green Lights and Energy Star Buildings[13] and Energy Star[14] products programmes, to encourage the development and production of highly energy-efficient housing and equipment. Also, Executive Order 13123, Greening the Government Through Efficient Energy Management, directs the Federal Government reduce energy use per gross square foot by 30% (from 1985 levels) by 2005 and 35% by 2010 and to increase the use of renewable energy.
- *Renewables:* Several Federal initiatives under the EPACT to support the commercialisation of renewables. Also, a 1999 executive order to speed technical advances and adoption of both bio-energy and bio-based products in various energy-use sectors.

Canada

Federal, provincial and municipal initiatives under the 1995 National Action Plan on Climate Change[15] (NAPCC) include:

- registration of voluntary commitments with the Climate Change Voluntary Challenge and Registry (VCR) organisation, which engages the private sector, governments and other organisations to reduce greenhouse gas emissions on a voluntary basis;
- federal energy-efficiency programmes (including standards, labelling and information dissemination).

11. Second National Communication, http://www.unfccc.de/resource/docs/natc/usnc2.pdf
12. Chapter 11 has a detailed discussion of the impact of this and alternative measures.
13. http://www.epa.gov/buildings/label/
14. http://www.energystar.gov/
15. Second National Communication, http://www.unfccc.de/resource/docs/natc/cannce2.pdf

Table 4.2: **Total Final Energy Consumption** (Mtoe)

	1971	1997	2010	2020	1997-2020*
TFC	1 354	1 633	1 908	2 067	1.0
Coal	83	29	25	22	–1.3
Oil	709	859	1 027	1 126	1.2
Gas	379	389	423	437	0.5
Electricity	140	313	380	422	1.3
Heat	0	8	10	11	1.1
Renewables	42	34	42	50	1.7

*Average annual growth rate, in per cent.

These projections imply an average annual decline in energy intensity of 1.2%. Rising demand for energy services, driven by economic growth, is more than offset by increased technical efficiency in end-use applications and in transformation and structural shifts away from energy-intensive industries. The projected rate of decline compares to 1.4% in 1971-1997 and 0.8% in 1990-1997. Higher energy prices and faster restructuring to ICT-related activities than the Reference Scenario assumes would result in a more rapid fall in energy intensity.

The projections for OECD North America in this *Outlook* do not differ radically from those in the 1998 *WEO*. The average growth rates for both TPES and TFC have been revised upward by just 0.1 percentage point, mainly due to lower price assumptions and stronger transport demand. Projected electricity generation has dropped, while gas supply has gone up, mainly at the cost of coal. Uncertainties affect the current *Outlook* despite these similarities, however. Box 4.4 stresses the most important ones.

Box 4.4: **Summary of Key Uncertainties Specific to OECD North America**

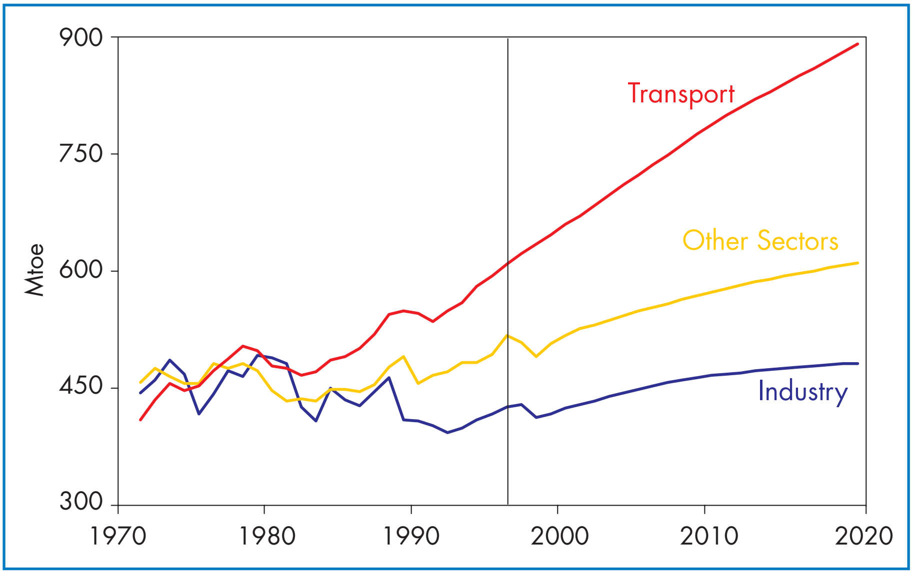
- Pace and impact of electricity market reforms;
- timing of retirement of nuclear plants;
- gas development costs and impact on wellhead prices;
- structural implications of the new economy and impact on energy demand;
- Kyoto policies and emission-reduction measures.

Sectoral Demand Trends

Of the main energy end-use sectors, transport shows the fastest projected growth to 2020 — 1.6% a year, unchanged from the 1971-1997 average (Figure 4.3). Rising traffic volume and a shift towards less fuel-efficient sports-utility vehicles continue to more than offset assumed improvements in car and truck fuel efficiency. The share of transportation in TFC increases from 38% to 43%. Oil as gasoline and diesel fuel accounts for almost all of this increase, although the shares of other fuels (mainly electricity) go up slightly to 5% by 2020. This projection is sensitive to several factors, including developments in fuel efficiency, which a tightening of vehicle fuel-efficiency standards may affect significantly, and alternative-fuel technologies. Chapter 11 analyses the impact of policies relating to these factors.

Industrial energy demand rises at a modest 0.5% per annum, reflecting slower growth in industrial output, in line with the GDP assumptions, and a continuing structural shift towards less energy-intensive manufacturing and services. In the other sectors (residential, commercial and agricultural), demand rises at 0.8% per annum — close to the rate of population increase. Saturation in markets for major household appliances and efficiency improvements contribute to the slow pace of demand growth. Nevertheless, electricity use increases most rapidly, driven mainly by computers, office equipment and telecommunications.

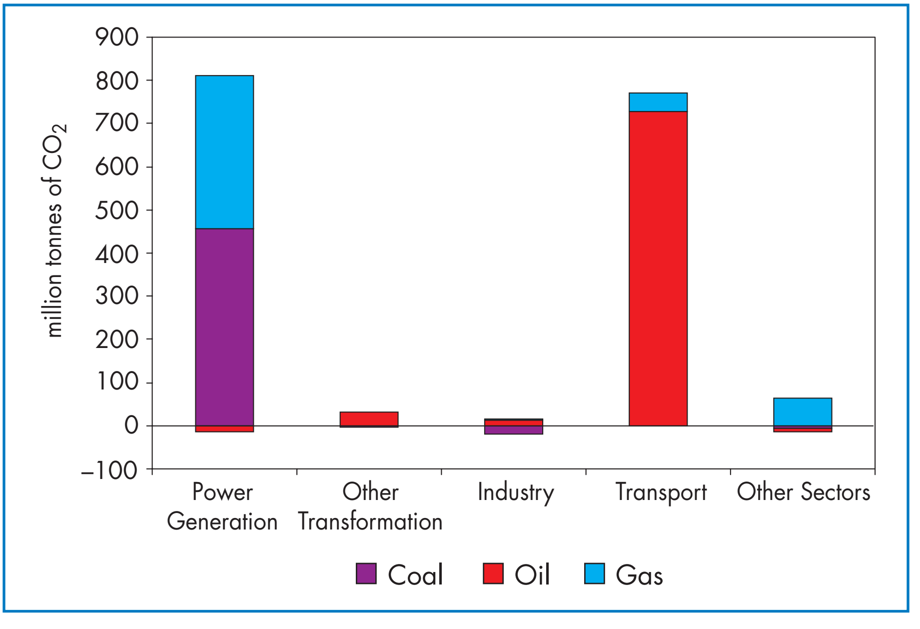
Figure 4.3: **Final Energy Consumption by Sector**



Energy-related CO_2 Emissions

In the Reference Scenario, energy-related CO_2 emissions increase by 1.1% a year over the projection period — slightly faster than during 1971-1997 (0.9%) but less than in 1990-1997.[16] Emissions rise faster than primary energy use principally because the share of nuclear power in the overall fuel mix drops. In absolute terms, emissions increase most in power generation (Figure 4.4), to an annual level 35% above the current one by 2020. Power-sector emissions account for 41% of total emissions at that time as against the current 39%. Emissions per unit of electricity remain unchanged and the highest among the OECD regions. The decline in nuclear power and the increase in coal-fired electricity generation in the second half of the outlook period largely offset emission reductions obtained through higher use of gas in the power sector.

Figure 4.4: **Change in Energy-related CO_2 Emissions by Sector and Fuel, 1997-2020**



Emissions from transportation also increase significantly, while industry emissions fall slightly. Overall, oil is the largest source of incremental

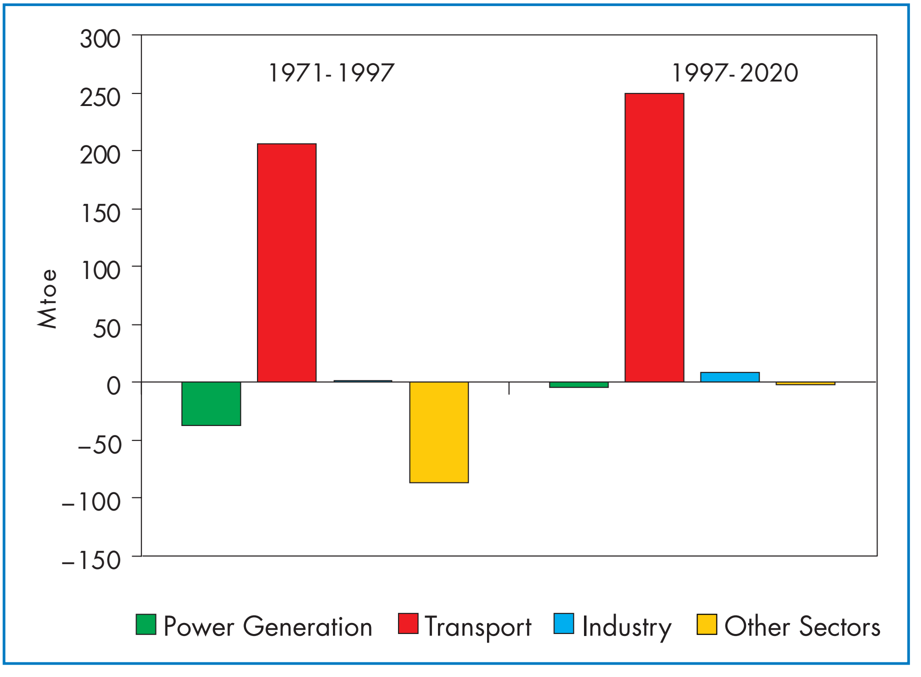
16. US CO_2 emissions from burning fossil fuels rose by 1.0% in 1999, according to preliminary estimates released by the Energy Information Administration (EIA) in July 2000 (see http://www.eia.doe.gov/).

emissions. Opportunities for emission reductions through fuel substitution, especially increased use of gas and renewables at the expense of coal, are likely to be greatest in the power sector. Chapter 12 discusses an Alternative Case, analysing a less carbon-intensive fuel mix in power generation.

Oil

North American primary oil demand expands at an average annual rate of 1.1% over the projection period. The transport sector accounts for nearly all of the incremental demand of 272 Mtoe in 2020 (Figure 4.5).

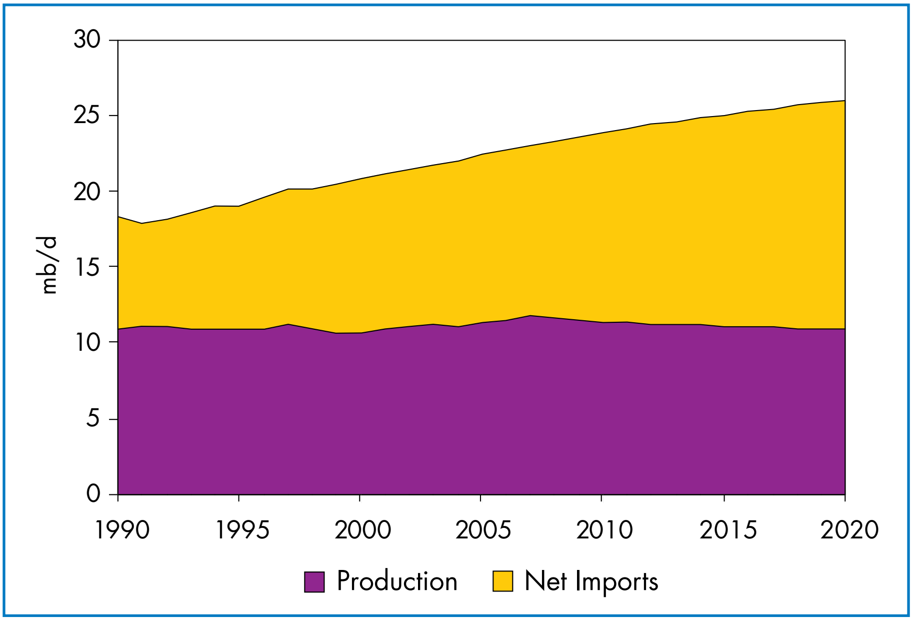
Figure 4.5: **Incremental Oil Consumption by Sector**



Reserve constraints will probably remain the key determinant of oil production trends in the United States and Canada. The *Outlook* expects production to rise slowly until it reaches 11.8 mb/d around 2007, then gradually to resume its long-term decline, as modest increases in offshore production cannot offset a steady fall in onshore output — particularly in the United States. Production of the region decreases to 11.4 mb/d in 2010 and 11.0 mb/d by 2020. The main sources of the initial increased supply will be the Gulf of Mexico — where expected production rises from around

1.5 mb/d in 2000 to a peak of 2.3 mb/d in 2007 — synthetics output based on Canadian oil sands and fields off the Canadian Atlantic coast. Alaskan production will hold steady for most of the first decade, declining thereafter. California, Texas and the other lower-48 states as well as Western Canada are mature; their output is likely to decrease progressively through the entire projection period. As a result of the projected trends in demand and production, net imports of oil into OECD North America rise from 9 mb/d (45% of demand) in 1997 to 15 mb/d (58%) in 2020 (Figure 4.6).

Figure 4.6: **OECD North America Oil Balance**

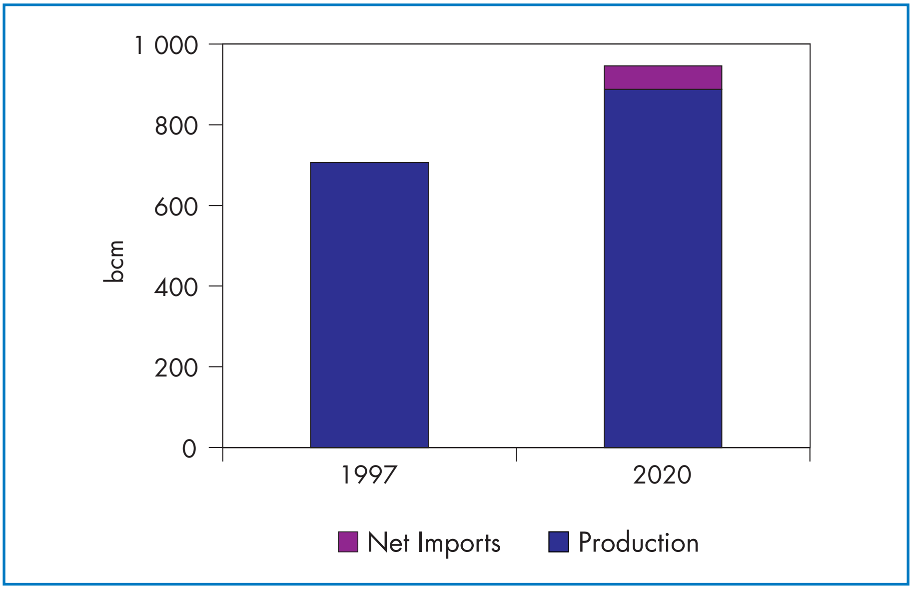


Gas

Expected primary demand for natural gas expands by 1.3% a year to 2020. Power generation accounts for three-quarters of the increase. Indigenous production should meet practically all of it, although imports (notably by pipeline from Mexico and LNG) may make a small but growing contribution (Figure 4.7).

The outlook for North American gas reserves and future production costs, discussed at some length in the 1998 *WEO*, remains subject to considerable uncertainty, particularly for the less explored offshore and unconventional reserves. The US DOE estimated US proven reserves at 4 730 bcm in 1998,[17] while the latest estimate from Cedigaz is 4 590 bcm.[18] Natural Resources Canada (NRC) puts that country's proven reserves at 1 840 bcm.[19] The *Oil and Gas Journal* estimates end-1999 reserves at 4 647 bcm for the Unites States and 1 809 bcm for Canada.[20] On the basis of the proven-reserve figures from DOE and NRC, the North American reserves-to-production ratio stood at just over nine years (6570/704 bcm) in 1998. This is low in comparison with the rest of the world, but it does not reflect the large potential thought to exist in as yet undiscovered gas resources.

Figure 4.7: **OECD North America Gas Balance**



Estimates of unproven resources vary significantly. The DOE estimates the resources that could be economically recoverable with current technology at around 29 000 bcm for the United States, and total recoverable resources using conventional and new technology at 46 000 bcm. Canada estimates its total resources at 16 300 bcm. A 1999

17. US DOE/EIA, 1999.
18. Cedigaz, 2000.
19. Natural Resources Canada, 1999.
20. *Oil and Gas Journal*, 1999.

National Petroleum Council study assessed combined Canadian and US resources (proven and assessed additional) at 68 900 bcm.[21] Successful exploration activity in both countries is expected to grow rapidly over the next two decades. New imaging and modelling technologies will enable production from tight, inaccessible or fractured reservoirs, which contain a major portion of future oil and gas resources.

This *Outlook* assesses North American gas resources as sufficient to meet almost all of the projected demand growth to 2020, but only with a gradually rising price from 2005 onward to cover expected increases in marginal wellhead production costs. Imports of LNG will grow during the second half of the projection period, as prices increase to levels that make LNG economic, although volumes are likely to remain modest in relation to total supply.

Cyclical imbalances between deliverability and demand, caused by sudden demand spurts as new gas-fired power plants are commissioned, weather-related demand swings, oil price volatility and/or fluctuations in drilling activity, will undoubtedly remain a feature of the North American gas market. While short-term production capacity tends to respond quickly to changes in drilling rates, especially onshore, a lack of rig availability due to under-investment and the lead time of two to three years for construction of new rigs can lead to periods of higher prices.

The expected expansion of the North American gas market will require considerable investment in new pipeline capacity from more distant resources. Major new pipeline expansions between Canada and the United States have recently been completed. Further capacity additions will be required to support the continued growth in exports of Canadian gas to the United States from established producing areas in Western Canada, as well as supplies from less mature areas in the eastern Canadian Scotia Shelf and the Northwest Territories. In the longer term, Mexico, which has important gas resources, could provide additional piped supplies to US markets.

Coal

In the Reference Scenario, primary coal demand rises by 0.8% per annum to 2020, with all of the increase going to power plants, which already accounted for 92% of primary coal consumption in 1997. The prospects for coal-fired generation are sensitive to developments in combustion technology (for coal and gas), environmental regulations and relative fuel prices.

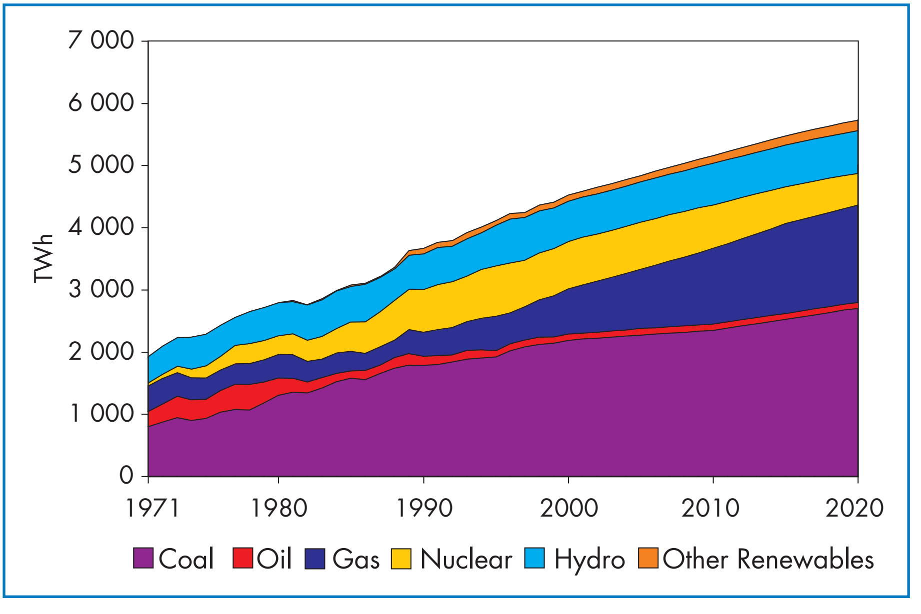
21. NPC, 1999.

The United States and, to a lesser extent, Canada have enormous coal resources that account for nearly one-third of the world total.[22] Expectations of future demand and domestic prices largely govern investment in new production capacity in the United States. US coal has struggled in recent years to compete in export markets against lower-cost producers like Australia and South Africa. International coal prices fell heavily in 1999, which led to a sharp decline in US exports. Canada's coal industry, by contrast, is largely based on export sales. Tighter emission regulations would lead to a further shift towards low-sulphur coal, with surplus high-sulphur grades diverted to exports.

Electricity

North American electricity generation grows at a projected 1.3% per year. By 2020, annual generation could reach 5 729 TWh, one-third above present levels. Coal and gas will be the key fuels in the projected electricity mix (Figure 4.8, Table 4.3). Gas-fired generation generally is the most economic option for new plant, particularly in the first half of the outlook period. In the second half, higher gas prices associated with higher

Figure 4.8: **OECD North America Electricity Generation**



22. IEA Coal Research, 2000.

production costs could change the economics to favour coal. Natural-gas generation increases from 12% of the total in 1997 to 27% in 2020. Coal will continue its preponderance over any other single fuel, although its projected share will decline by two percentage points. Oil's role will remain confined largely to meeting peak load requirements. Both the share in total generation and the level of output from nuclear plants fall over the projection period, as no new plants are built and plant retirements accelerate in the second half. Hydropower shows a small increase. Other renewables increase their share in the electricity mix, but their overall contribution remains limited.

Table 4.3: **Electricity-Generating Capacity by Fuel** (GW)

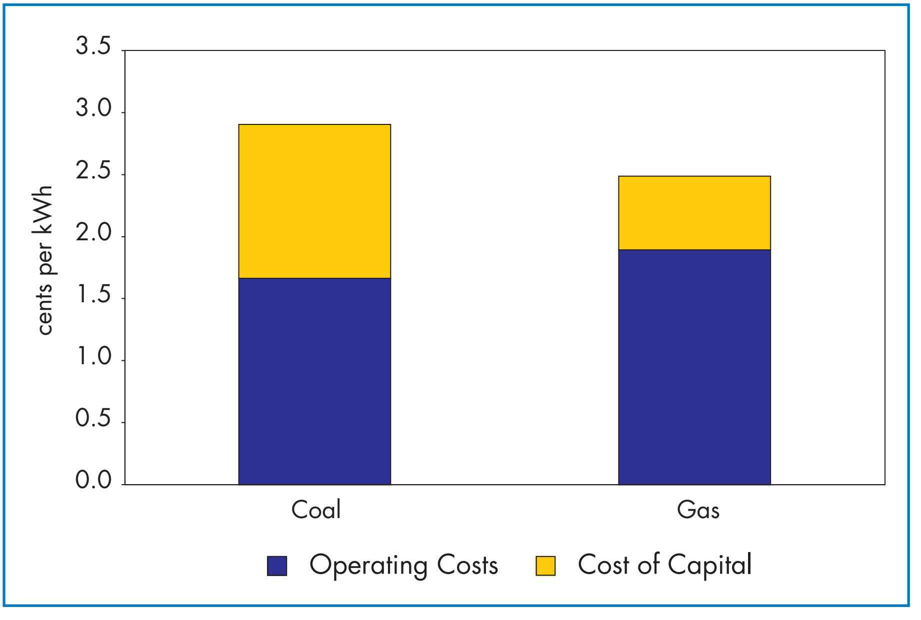
	1997	**2010**	**2020**
Coal	345	348	397
Oil	39	36	34
Gas	224	396	457
Nuclear	112	95	68
Hydro	166	172	177
of which Pumped Storage:	*20*	*20*	*20*
Other Renewables	18	25	35
Total	**904**	**1 073**	**1 168**

Most of the region's expected new capacity will come from natural gas-fired plants, in the form of CCGTs where medium to base-load capacity is required, and single-cycle combustion turbines where new or replacement peaking capacity is needed. Gas-fired capacity has increased significantly over the past few years and the trend should continue while gas prices remain low. Lower gas prices since the mid-1980s have made gas attractive for power generation. The removal of most of the restrictions of the US Power Plant and Industrial Fuel Use Act in 1990 eliminated an important barrier to increased use of gas by utilities. The New Source Performance Standards impose capital-intensive technological controls on new coal plants.

Projected coal-fired generation increases by 1.2% per annum. Coal currently accounts for nearly half of North American electricity output. Coal-fired capacity is likely to be used more intensively in base load, particularly when base-load nuclear units are retired. Greater use of existing plants could result from the current restructuring of the electricity industry. Figure 4.9 compares the costs of new coal and CCGT plants using current cost estimates. Overall, CCGT plants are more economic to build, but coal plants have lower running costs and therefore, once they are built, are more economic for base-load use.

Oil use in power generation in North America is the lowest in the OECD. Its current share of just 3% of total generation is projected to fall to 2% by 2020.

Figure 4.9: **Comparison of Current Generating Costs of New Steam Coal and CCGT Plants in OECD North America**



The region's nuclear capacity was 112 GW in 1997. Neither the United States nor Canada has any plans to build nuclear power plants in the foreseeable future. Unfavourable economics combined with siting and permit problems for new plants and the retirement of 44 GW of existing capacity by 2020 will lead to a significant decline in nuclear power in the region. However, any trend to keep nuclear plants operating could result in a lower rate of retirement than this *Outlook* assumes. The performance of US nuclear power plants has improved significantly over the past few years. Several have already applied for extensions of their licence periods.

In Canada, the A units of the Pickering and Bruce power stations have been shut down for an indefinite period. The 4x500 MW Pickering units are expected to come back into service within the next few years. Significant investment will be required for the Bruce A units to resume operation.[23] This *Outlook* assumes that they do not come back into service because of increased competition from low-cost hydro and fossil-fuel plants.

North American hydroelectric capacity is assumed to increase by about 11 GW in 1997-2020. Most of the increase will come from new plants in Quebec. In the United States, capacity additions will be marginal, because of lack of new sites, high construction costs, environmental considerations and competing uses for water resources.

The share of renewables in electricity generation increases from 2% in 1997 to 3% by 2020. Most incremental generation comes from CRW and wind. The cost of renewables, although expected to fall, remains high compared with conventional fossil-fuel technologies, so increased use of renewables would need encouragement by specific supportive strategies. In the United States, for example, a key measure is the renewable portfolio standard, which specifies a certain percentage of electricity that must be supplied by renewables. A high-renewables scenario is discussed in the Alternative Power Generation Case in Chapter 12.

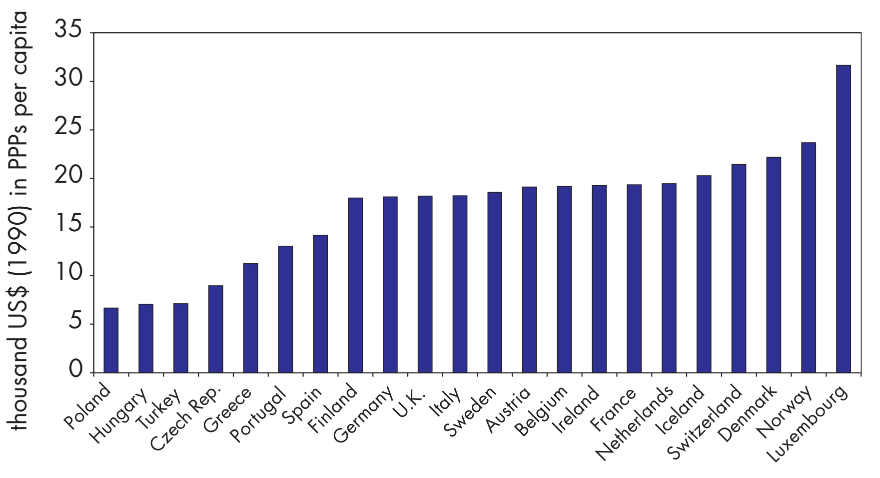
23. IEA, 2000a. Also see Natural Resources Canada (1999).

CHAPTER 5
OECD EUROPE

Introduction

OECD Europe is the second largest energy-consuming region after North America and the largest net energy importer. Heterogeneity marks and characterises this region of 22 countries[1] — in terms of demography, economy, geography, climate and culture. The growth of the European population as a whole slowed from over 1% per annum in the early 1960s to less than 0.5% in 1997. Yet the population is growing fast in Turkey (1.8% a year between 1990 and 1997), and falling rapidly in Hungary (down 0.3% a year over the same period). European GDP grew on average by around 2.3% in 1999,[2] yet national growth varied substantially, from recession in the Czech Republic (GDP fell by an estimated 0.2% in 1999)

Figure 5.1: **GDP Per Capita in OECD Europe Countries, 1998**



1. Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.
2. OECD, 2000.

and Turkey (down 5%) to boom in Ireland (up almost 11%). Income per capita averages $15 300, but ranges from $6 700 in Poland to $29 000 in Luxembourg (Figure 5.1).

Despite these differences, signs of economic convergence abound, especially within the European Union (EU), as growing economic interdependence stimulates growth in once-laggard economies. The average GDP per capita of the three EU countries with the lowest figures surged 39% between 1986 and 1998, while the average for the top three rose by 19%.

National energy profiles and trends are diverse. OECD Europe's total primary energy supply (TPES) amounted to 1 737 Mtoe, about one-third of OECD demand in 1998. Net imports accounted for 37% of these needs. At the same time, patterns and trends in energy production, supply and consumption varied markedly across the region. Nuclear power accounts for a major proportion of electricity output in some countries — notably France, Sweden and Belgium — but is absent from the fuel mix in half of them. Natural gas penetration also varies, mainly according to accessibility to supply sources and the degree of historical dependence on locally produced coal. Energy intensity averages 226 toe per million US dollars (toe/m$), but ranges from 159 toe/m$ in Turkey to 441 toe/m$ in Iceland.[3]

Poland is now included in OECD Europe, but was not in the last *Outlook*. This significantly affects both regional historical trends and prospects for energy demand and supply, primarily because of the importance of coal in the Polish energy balance. Poland accounts for 21% of European primary coal consumption and 35% of production. It is the source of nearly 9% of the region's energy-related CO_2 emissions, although its share of primary energy use is only 6%. Inclusion of Poland also significantly increases the measured dependence of OECD Europe on the FSU and especially Russia. Gas imports from the FSU represent 24% (22% from Russia) of OECD Europe's gas consumption and 66% (52% from Russia) of Poland's.

Macroeconomic Background

OECD Europe's economy grew by 1.8% per annum from 1990 to 1997, recovering from 0.6% in 1991-1993 to 2.8% in 1994-1998, then slowing to an estimated 2% in 1999. Growth may surpass 3% in 2000,

3. Expressed in constant (1990) dollars in PPP terms. Using market exchange rates results in a substantially different ranking of countries.

despite a sharp increase in oil prices since 1999 but boosted by buoyant global trade and investment. It should be highest — more than 5% — in Poland, Hungary, Turkey, Ireland and Finland. Across Europe, services are driving growth. They now account for around two-thirds of GDP, while industry's share has dropped to 30% and agriculture has levelled off at around 4%. OECD Europe's population, around 509 million in 1997, is ageing. The proportion aged 65 and above in OECD Europe went from 9.7% in 1960 to 14.1% in 1998.

The countries of the European Union dominate the region. They took a major further step towards economic and monetary integration in January 1999 with the first phase of introducing the single currency, the Euro, in 11 EU Member countries, although full monetary union will not be completed until 2002. Other measures aimed at liberalising European markets are also being introduced.

Increasing economic interdependence within the European Union will extend to other countries of OECD Europe, especially through European Union enlargement. The Union has accepted applications from 13 countries, although accession negotiations will be protracted. Of the applicants, the Czech Republic, Hungary, Poland and Turkey are included in the *WEO* definition of OECD Europe. Enlargement will require policy convergence and compliance with EU laws and norms in the applicant countries, as well as reform of European Union institutions. In the meantime, the enlargement process itself will encourage stronger economic and political ties between the European Union and applicant countries.

Recent Energy-Sector Developments

As elsewhere, liberalisation of the European energy sector is underway. Some countries, such as the United Kingdom, Norway and Sweden, liberalised their electricity markets several years ago, introducing competition in generation and supply based on third-party access. European Union electricity markets are opening to competition in phases, as required by a 1997 directive. At a minimum, 26% of each country's power market must be open to competition by 2000 and 33% by 2003. Some countries go beyond these requirements. Germany, for example, has already introduced full retail competition. Prices across Europe have been falling, in some cases in response to these moves (Table 5.1).

Although also moving ahead, gas-market reforms lag those in electricity. EU Member states had to implement the requirements of a 1998 gas directive by August 2000, providing for minimum degrees of market

Table 5.1: **Electricity and Gas Prices in Selected European Countries**
(Changes in real end-user prices in 1993-1998, in per cent)

	Electricity Price		Gas Price	
	Industry	**Household**	**Industry**	**Household**
Austria	6	0	0	0
Belgium	–10*	–3*	–2*	–2*
Denmark	–8	13	n.a.	n.a.
Finland	–6	5	30	30
France	–16	–13	0	0
Germany	–25	–7	0*	0*
Greece	–27	–16	n.a.	n.a.
Ireland	–5	–3	–44	–44
Italy	–4	0	5	5
Netherlands	–6	9	–2	–2
Portugal	–29	–14	n.a.	n.a.
Spain	–30	–13	9	9
Sweden	–13*	12*	n.a.	n.a.
United Kingdom	–24	–16	–36	–36

*1993-1997
Source: IEA (2000), *Energy Prices & Taxes,* Paris.

opening according to a prescribed timetable, as for electricity. At least 20% of each national market must now be open, rising to 28% by 2005 and 33% by 2010. Implementation proceeds at varying speeds. The United Kingdom and Germany have already introduced full retail competition, although in Germany effective competition and customer switching have been slow to develop. Several other countries, including the Netherlands and Spain, also plan to open their markets more extensively and more quickly than the directive requires. The regulatory structures going into place differ in types of access regimes, transportation tariff regulations and institutional arrangements. Most countries, except Germany, have opted for regulated (as opposed to negotiated) access, and most prefer independent regulatory bodies.

Early market reforms in the United Kingdom led initially to dramatic falls in wholesale and retail gas prices. They have since rebounded in response to higher domestic demand and, with the commissioning of the UK-continent interconnector in 1998, demand from Europe, where the recent surge in oil prices has led to sharp increases in gas prices due to indexation in long-term supply contracts.

Assumptions

The Reference Scenario assumes that the European economy will grow by 2.1% a year from 1997 to 2020, but this average masks important differences over time and among countries. Growth expectations, high for the first half of the projection period (2.4%), slow down in the second (1.8%). Differences in growth between countries should diminish with convergence and economic and monetary integration. Population is assumed to grow very slowly, by 0.2% per annum, as high growth in countries such as Turkey offsets decline in others, such as Germany and Italy. Per capita income gaps between countries should narrow progressively. With an assumed average GDP per capita of $23 280 in 2020, OECD Europe will remain the third-richest region, behind North America ($33 000 per capita) and OECD Pacific ($29 000 per capita).

The price assumptions for oil and coal track those for international markets. For gas, which is traded on a regional basis, prices are assumed to stay flat in real terms up to 2010, then rise steadily until 2020, reflecting a growing reliance on more distant and costly import sources. The main economic, demographic and price assumptions are summarised in Table 5.2.

Table 5.2: **OECD Europe Reference-Scenario Assumptions**

	1971	1997	2010	2020	1997-2020*
GDP	4 085	7 589	10 288	12 267	2.1
Population	443	509	524	527	0.2
GDP per capita	9.2	14.9	19.6	23.3	2
Oil price	6.0	16.0	16.5	22.5	1.5
Coal price	44.2	36.8	37.4	37.4	0.1
Natural gas price	-	90.5	80.9	132.8	1.7

* Average annual growth rate, in per cent.

Note: All values are in dollars at constant (1990) prices. GDP is measured in billions of dollars on a PPP basis. Population is in millions and GDP per capita is in thousands of dollars. Prices are per barrel for oil, per tonne for coal and per toe for gas.

Box 5.1: **Principal Climate Change Policies and Measures Considered in the Reference Scenario**

- *Industry sector:* The Voluntary Energy Efficiency Programme (VEEP) 2005 is implemented by the European chemical industry. The programme involves a unilateral commitment to reduce the industry's specific energy consumption by 20% between 1990 and 2005.[4] A 1996 EU directive on integrated pollution prevention and control includes energy efficiency among criteria for the determination of best available techniques on which the setting of emission-limit values and the issuing of operating permits must be based.
- *Transport sector:* The voluntary agreements that car manufacturers of Europe (ACEA in 1998), Japan (JAMA in 2000) and Korea (KAMA in 2000) agreed with the European Union to cut CO_2 in exhaust fumes from 180 g/km to 140 g/km by 2008 (2009 for JAMA and KAMA). In 2003 the prospects for further reduction towards the objective of 120 g/km by 2012 will be evaluated and progress towards the intermediate target of 170 g/km will be assessed.[5] Attainment of the targets is assumed here. Detailed analysis of the impacts of these agreements and of other measures appears in Chapter 11.
- *Buildings sector:* 1996 legislation under the European Union's SAVE programme concerns labelling and energy-efficiency requirements for selected household electric appliances. It includes standards for household electric refrigerators, freezers and combinations, and energy labelling for washing machines and washer-dryers.[6] The European Commission also has negotiated agreements with manufacturers of certain appliances and equipment, including boilers and dishwashers, covering efficiency performance and labelling.
- *Renewables:* Most European countries have established programmes and, in some cases, targets for the deployment of renewables technologies, including direct and indirect subsidies and renewable-energy purchase obligations.

4. European Chemical Industry Council, 2000.
5. Association des Constructeurs Europeens d'Automobiles, 1999.
6. Directive 96/60/EC.

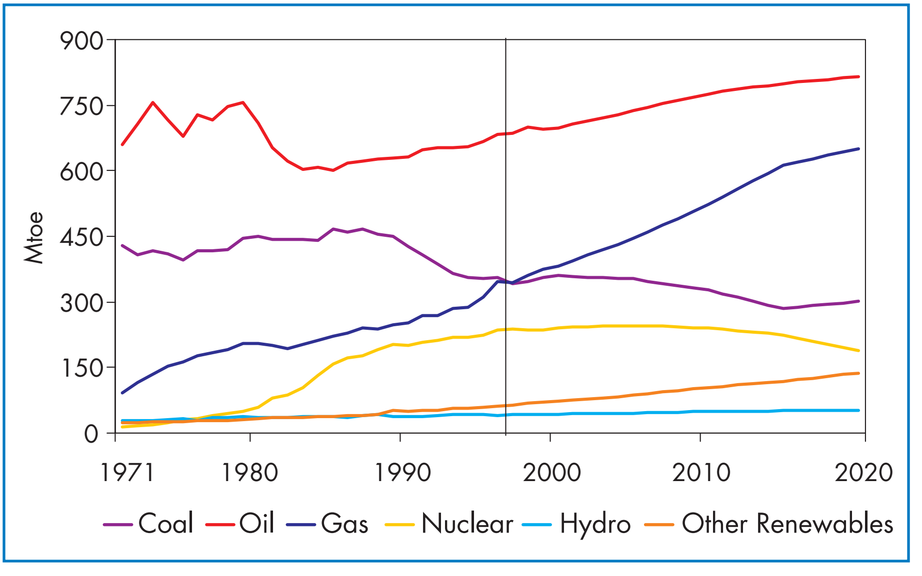
The Reference Scenario assumes no major changes in energy or taxation policies.[7] Electricity and gas restructuring thus proceed as planned. Account has been taken of EU policies and measures that have already been announced and approved, some relating to Kyoto Protocol commitments. The EU member states accounted for 83% of energy consumption and 80% of CO_2 emissions in 1997. Box 5.1 summarises the principal measures taken into account in the Reference Scenario.

Results of the Projections

Overview

Projected TPES in OECD Europe will grow by 1% annually in 1997-2020, marginally slower than the 1.2% of 1971-1997 (Figure 5.2). TPES grows faster to 2010, following higher assumed economic growth in the first projection decade, then slows to 0.6% per year to 2020.

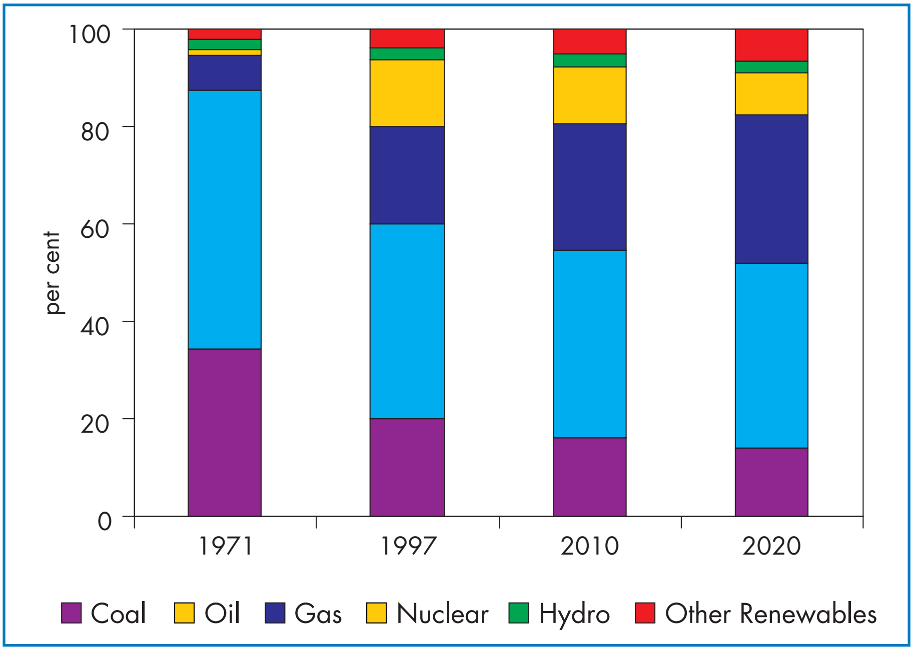
Figure 5.2: **OECD Europe Total Primary Energy Supply**



7. Some countries have recently proposed but not yet implemented taxes on carbon emissions. These taxes are not included in the Reference Scenario. A separate analysis of the introduction of a carbon tax appears in the emission-trading scenario in Chapters 10 and 11.

Significant changes occur in the fuel mix of primary energy supply (see Figure 5.3). The share of coal continues to fall steadily, due mainly to its replacement by gas in power generation, from 20% of primary supply in 1997 to 14% by 2020. The share of nuclear power also drops, from 14% to 9%. Gas makes up most of these losses, with its share rising from 20% to 31%. Rising by 3% a year on average, gas supply increases its penetration in all sectors, particularly power generation. Non-hydro renewables grow steadily, but their share gains only one percentage point.

Figure 5.3: **Breakdown of OECD Europe TPES by Fuel**



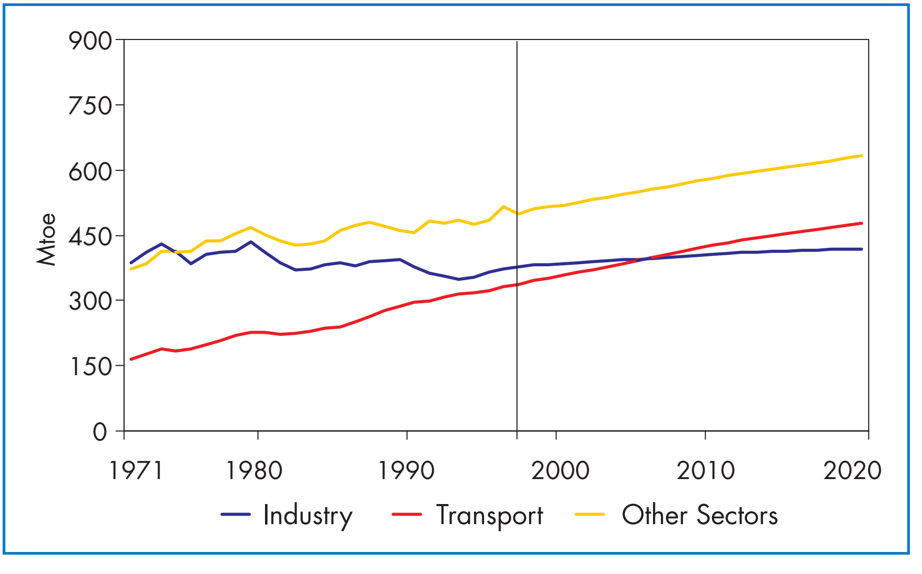
Projected total final consumption (TFC) advances by 1% per annum between 1997 and 2020 — the same as over the past 30 years and parallel with TPES. Growth rates vary among sectors and fuels. The transport sector provides the primary demand push, increasing by 1.5% a year, raising its share in TFC to 31% in 2020 from 28% in 1997 and displacing industry as the largest end-use sector by 2005. Demand growth is stronger in the first half of the projection period. The residential and commercial sectors increase at the same pace as TFC, while industry grows by only 0.5%. Although primary energy production holds more or less steady, mounting demand leads to a further rise in the region's already high import dependence. Among the WEO regions, OECD Europe will remain the most important energy importer.

As it has since 1971, energy intensity continues to fall, by a projected 1.1% per annum. The decline is likely to be slower in countries like Turkey, where industrial output will lead economic growth, than where growth emanates from less energy-intensive activities. At the other extreme, the scope for higher performance through improvements in energy efficiency throughout their economies is greatest in the eastern European countries — Poland, Hungary and the Czech Republic. Their energy intensity will improve faster in the first half of the projection period.

Sectoral Demand Trends

Industrial energy consumption has stayed remarkably stable over the last three decades (Figure 5.4), but its fuel mix has changed significantly. Within the sector, coal and oil consumption fell by nearly 2% a year from 1971 to 1997, while gas consumption soared by 3.5% and electricity by 1.9%. These trends should continue but rather more slowly. Consumption of coal shrinks by more than 2% a year and that of oil by 0.4% a year. Gas and electricity become the most important sources, together accounting for more than a half of industry's total energy consumption in 2020.

Figure 5.4: **Final Energy Consumption by Sector**



Increases in both passenger traffic and freight demand propel the transport sector towards the fastest growth in final consumption. Considerable scope still remains for more car ownership in many OECD Europe countries, especially in Eastern Europe, where the number of vehicles per capita is relatively low. Expected increases in both numbers and sizes of cars will offset ongoing improvements in vehicle fuel efficiency. Air transportation is expected to expand with a continuing increase in passenger traffic. The opening of the EU air-travel market could drive ticket prices lower, further stimulating demand especially for leisure travel.

The residential and commercial sectors will hold about the same relative positions in TFC in 2020 as they do today, 38%. This results from two opposing forces. Energy-efficiency improvements in appliances and equipment and better insulation will tend to reduce consumption levels, but rising living standards will stimulate demand for larger homes and new appliances. The growing importance of services also boosts demand for energy, especially electricity, in the commercial sector.

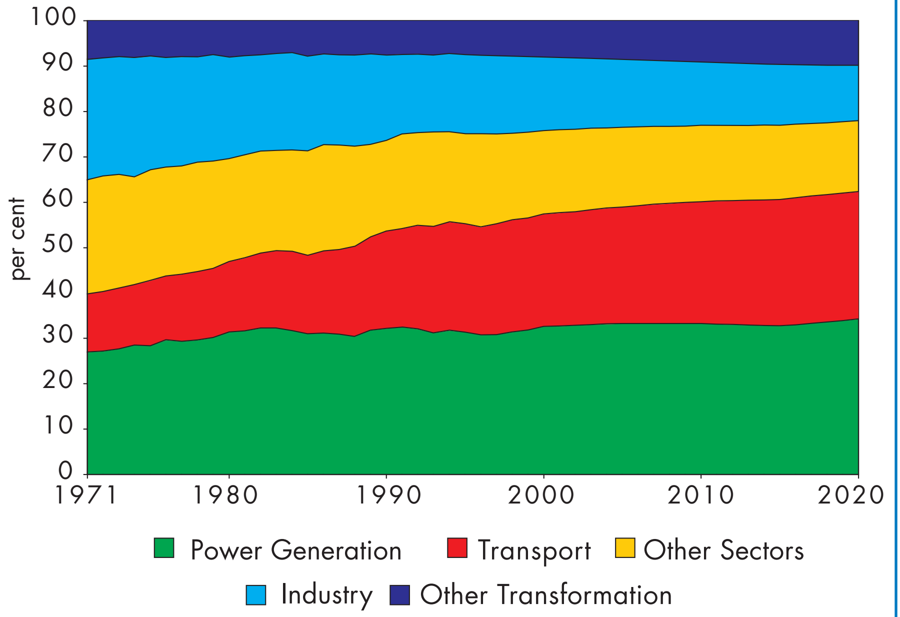
Energy-related CO_2 Emissions

CO_2 emissions are projected to rise significantly, in contrast to their stability since 1990, due to rising fossil-fuel demand. In the Reference Scenario, CO_2 emissions grow from 4 007 Mt in 1997 to 4 916 Mt in 2020 — an average annual increase of 0.9%. Transportation will remain an important contributor (28% of total emissions in 2020, compared to 24% in 1997), as it registers the most rapid increases in energy consumption and remains almost entirely dependent on oil because of few substitution possibilities to less carbon-intensive fuels (Figure 5.5). Although projected CO_2 emissions per unit of electricity output will decline, the power sector will account for an increasingly higher share of total CO_2 emissions, reflecting high growth in electricity demand relative to most other types of energy and increased reliance on fossil fuels for power generation. That share will mount from 31% in 1997 to 33% in 2010 and 34% in 2020. Total CO_2 emissions from the sector will reach 24% above 1997 levels in 2010 and 36% in 2020.

These projections imply that, without major new initiatives to limit energy demand growth and stimulate switching to less carbon-intensive fuels, the European Union as a whole (which accounts for the bulk of energy consumption in OECD Europe) will fall considerably short of achieving its greenhouse-gas emissions target, unless exceptionally big savings are made in non-energy related emissions.[8] The global EU

8. Given that energy-related CO_2 emissions account for the bulk of greenhouse gases.

Figure 5.5: **OECD Europe CO_2 Emissions by Sector**



commitment is to reduce greenhouse gas emissions 8% below the base-year level by 2008-2012, with national objectives allocated among the Member countries (see Chapter 10).

Oil

Oil remains Europe's largest energy source in the Reference Scenario, with primary demand increasing by 0.8% per annum over 1997-2020. Its weight in TPES falls slightly, to 38% in 2020 from 40% in 1997. More than 90% of incremental demand comes from the transportation sector, which will continue to skew the product mix towards transport fuels. In road transport, steady growth in road freight and a continued trend towards dieselisation of the car fleet will boost diesel demand, assuming that countries continue to tax diesel more lightly than gasoline (Table 5.3).

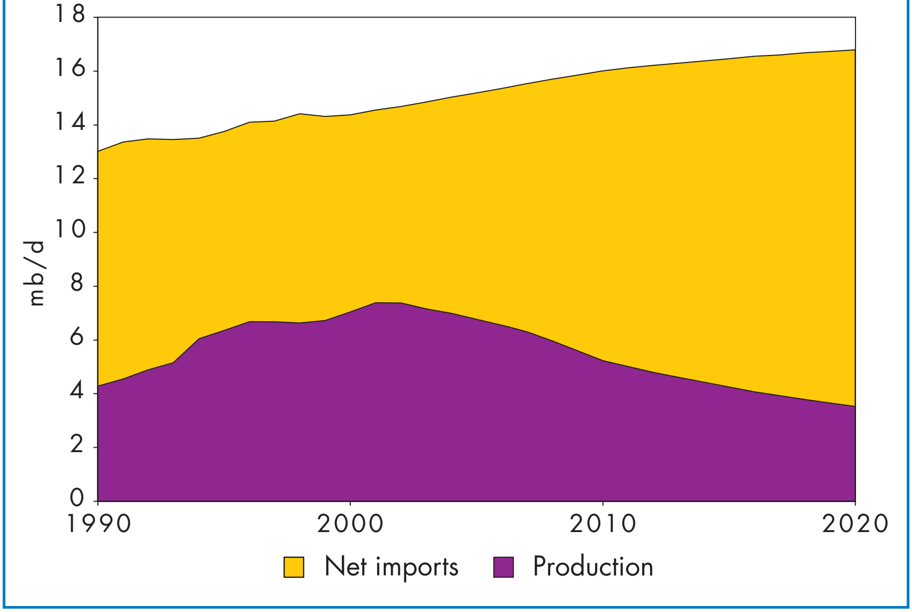
Almost 95% of European oil production comes from the North Sea. Output has risen since 1990, as technological advances, cost-cutting and efficiency improvements have enabled the development of previously unprofitable fields, particularly small ones. Despite further technological developments, expected production will decline, most steeply in the

Table 5.3: **Gasoline and Diesel Prices and Taxes in Selected European Countries, 1999**

	Premium unleaded gasoline (95 RON)		Automotive diesel	
	Final price (US$/toe)	Tax in final price (%)	Final price (US$/toe)	Tax in final price (%)
France	1 213	79	871	73
Germany	1 154	74	783	67
Italy	1 288	73	1 021	70
Netherlands	1 352	73	930	65
Spain	893	67	720	62
United Kingdom	1 436	82	1 486	81

Notes: Final prices include taxes. Automotive diesel is for non-commercial use.
Source: IEA (2000) *Energy Prices & Taxes,* Paris.

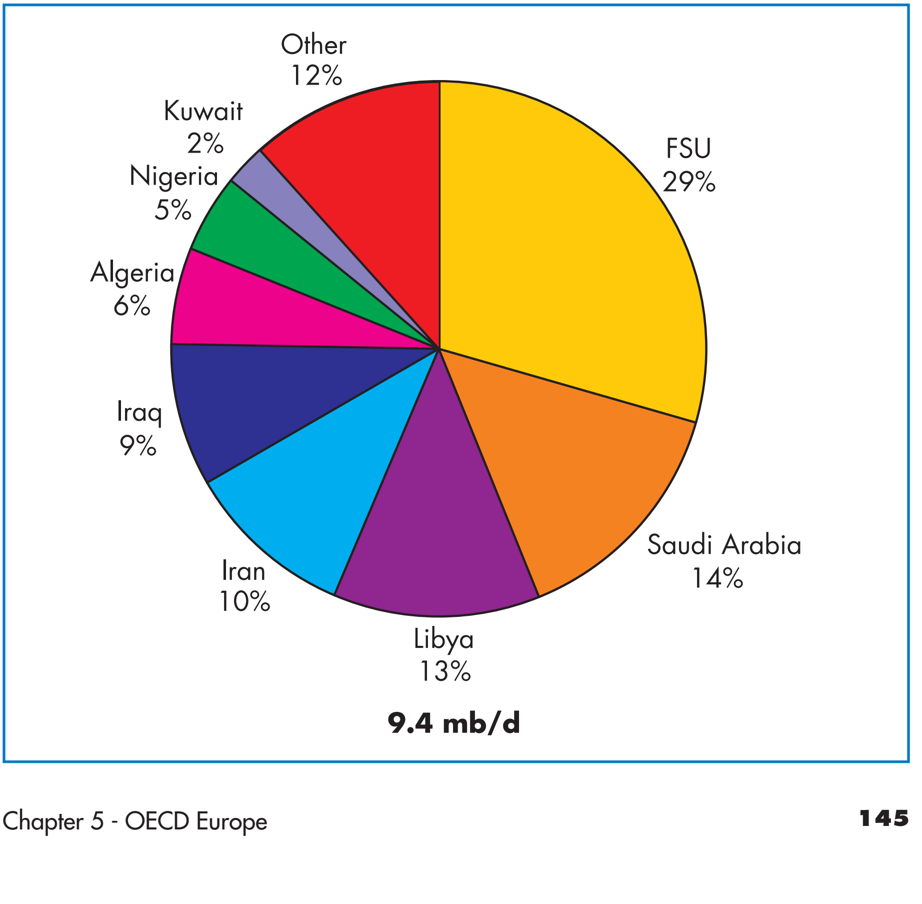
Figure 5.6: **OECD Europe Oil Balance**



relatively mature UK sector, where production is expected to peak in 2001 at around 3.1 mb/d with the commissioning of three new large fields (Elgin, Franklin and Shearwater). While new fields will still be found, they will most often be relatively small and probably economic only where they can take advantage of existing infrastructure. In the Norwegian sector, new-field developments will struggle to keep pace with the decline in output from old, large fields. Overall, production should peak in 2002 at 3.6 mb/d and decline gradually thereafter. Nevertheless, considerable uncertainty clouds prospects for new discoveries, which could allow Norwegian output to remain steady through the projection period. The Reference Scenario projects a fall in total OECD Europe oil production from 6.7 mb/d in 1997 to 5.2 mb/d in 2010 and 3.5 mb/d in 2020 (Figure 5.6).

Declining production and increasing demand result in a significant increase in net oil-import requirements. This means a rise in the

Figure 5.7: **OECD Europe Total Oil Imports by Source, 1999**

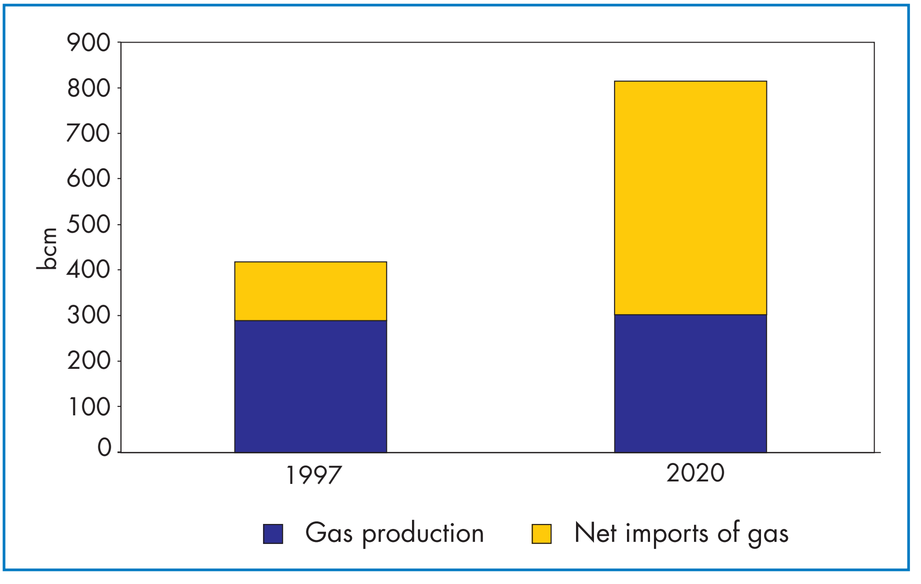


dependence of OECD Europe on imports of oil from OPEC countries, which currently account for 61% of Europe's oil imports (Figure 5.7).

Gas

Total primary gas supply (Figure 5.8) is projected to increase faster than any other energy source, at an average rate of almost 3% per annum, which nonetheless falls well below the 5.2% of 1971-1997. Gas will rapidly become the second fuel after oil, with 31% of TPES in 2020. Gas penetration increases in power generation and all end-use sectors.

Figure 5.8: **OECD Europe Gas Balance**



Europe's gas reserves, mainly in Norway, the Netherlands and the United Kingdom, account for less than 5% of global reserves. Norway has the least mature industry of the three and offers the best prospects for higher output, which should help to offset expected declines elsewhere, particularly in the United Kingdom. Projected total production in OECD Europe will remain broadly unchanged to 2020, with Norway accounting for a growing share. Given steady growth in gas consumption, increasing imports will be needed. Russia and Algeria are expected to remain the primary sources

(Figure 5.9), but new ones will supplement them, such as LNG from Nigeria, Trinidad and Tobago and Qatar.[9] A major uncertainty concerns the ability of Russia to deliver gas. Box 5.2 discusses the outlook for the security of European gas supplies in the context of increasing competition.

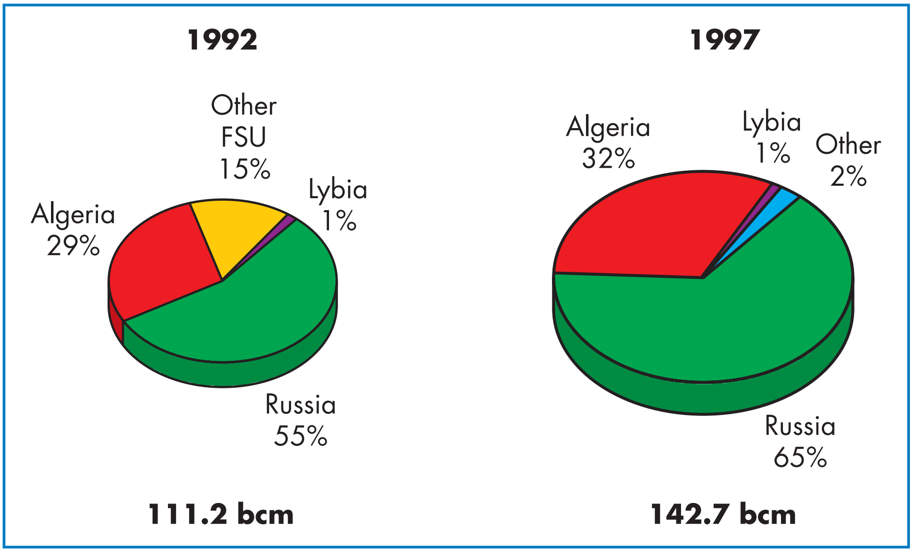
Box 5.2: **Supply Security in the European Gas Market**

The emergence of competition has raised concerns over long-term gas-supply security, given growing reliance on distant sources, marketers' need for shorter-term, more flexible supply contracts and increased risk associated with upstream projects. Almost all imported gas is now supplied under long-term, take-or-pay contracts. North American and British experience suggests that major, high-cost gas-field developments and pipeline projects can succeed in competitive markets. Long-term contracts will likely remain the primary sales vehicle, but short-term trading will increasingly complement them by providing outlets for surplus contractual volumes that gas merchants may hold. Two major challenges face the European gas industry in meeting the need to secure long-term gas supply:

- Europe does not have a monopsony over potential new sources of supply and will have to compete with other regional gas markets. It will need to offer competitive price terms to producers.
- The development of additional reserves and transportation capacity will need huge investments. This in turn will probably require strong alliances and increased vertical as well as horizontal integration — already becoming evident in a wave of European merger activity and the increasing involvement of European downstream gas companies in reserve development and transportation projects. Algeria has started to open its upstream industry to outside companies such as BP Amoco, while Russia's Gazprom has signed strategic alliances with several companies, including ENI and Shell.

9. Other potential supply sources include Turkmenistan, Iran, Yemen, Venezuela and Egypt.

Figure 5.9: **OECD Europe Net Imports of Gas by Origin**



Coal

Coal demand will remain stagnant, becoming increasingly focused in power generation and specialised industrial uses. As environmental policies and measures continue to depress it, projected primary coal use will fall at an average annual rate of 0.7% to 2020 — slightly less than the 0.9% decline since 1971. Coal all but disappears from residential and commercial uses by 2020. The power sector will account for over 75% of primary coal consumption in 2020 as against 66% in 1997.

Political decisions concerning the financial support that some European governments provide to their indigenous hard-coal industries will remain a key uncertainty in the coal outlook. Reduced subsidies have led to large-scale mine closures in several countries, but support remains significant in Germany, Spain and Poland. Further progress in eliminating it can be expected. In Spain, the Government reached agreement with the unions in 1998 on reducing production from 18 Mt in 1997 to 14.7 Mt by 2001. Germany plans a reduction of 11% in 1998-2002. A 1998 Polish plan (revised in December 1999) calls for production cuts from 132 Mt to 110 Mt and a slash in coal employment from more than 240 000 to 128 000 employees in 1997-2002. France intends to halt all coal production by 2005. The United Kingdom eliminated its subsidies in 1998, but announced in April 2000 that it was investigating with the European

Commission a scheme to provide up to £100 million to the coal industry as a temporary measure over 2000-2002. Overall, this *Outlook* expects a significant reduction in European coal production, outstripping the fall in demand and resulting in more imports.

Electricity

Expected final electricity consumption will mount by 2% per year in 1997-2020, almost as fast as GDP, compared with 3% in 1971-1997. Electricity use expands in all end-use sectors. In industry, electricity replaces coal and, to a lesser extent, oil. Increased steel production in electric arc furnaces makes a major contribution. Structural changes, such as the re-orientation of industrial production toward higher value-added products, the development of electro-technologies and automation in general, are also likely to help boost the share of electricity used in industry. In the residential and commercial sectors, the rise in electricity demand reflects increasing use of electrical appliances and higher standards of living.

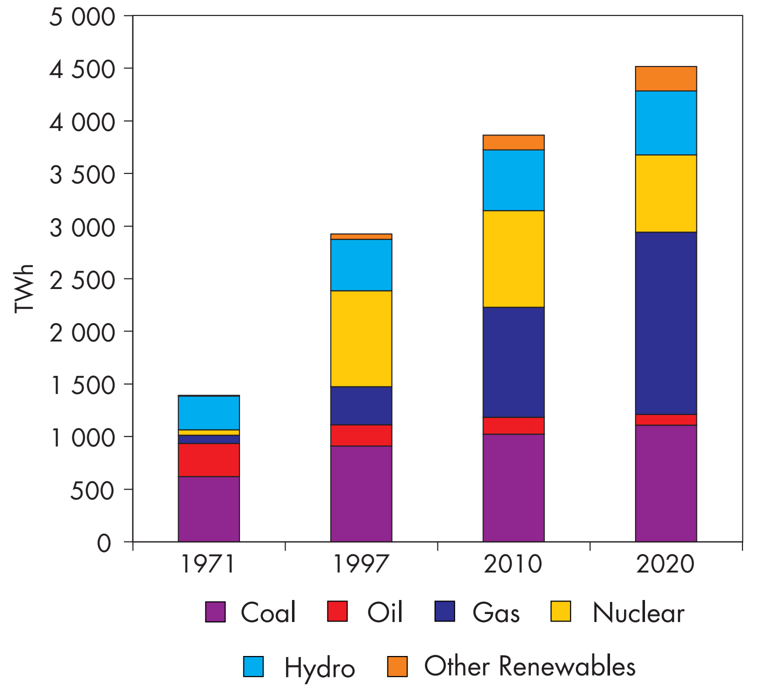
Projected electricity generation will rise at an average annual rate of 1.9%, increasing from 2 925 TWh in 1997 to 4 514 TWh in 2020 (Figure 5.10). Over the same period, installed capacity increases to 967 GW from 678 GW. The shift towards higher use of natural gas that started in the early 1990s is expected to continue; gas will meet most of the incremental demand for electricity. Its share in generation increases rapidly, from 12% at present to 38% in 2020.

Most new capacity is expected to be gas-fired, particularly in CCGT plants, because of their economic and environmental advantages. CCGT capacity has increased rapidly over the past few years, from 3.6 GW in 1990, to about 31 GW in 1998. The economics of power generation have moved in the direction of natural gas, as has the requirement to fit pollution-control equipment to coal-fired generation plants. Increasing electricity deregulation favours the use of gas in power generation, as its lower overall cost, shorter lead times and lower capital costs attract smaller companies entering the market.

Coal's decline — to a projected 25% of electricity generation in 2020 — has two sources. Not only is most new capacity likely to be gas-fired, but many existing coal-fired units will also be decommissioned, especially after 2010. Towards the end of the period, however, higher gas prices and improvements in coal technologies will make new coal-fired generation competitive.

Although its significance in electricity generation decreases, coal is likely to maintain its position in base-load generation, particularly as oil and

Figure 5.10: **Electricity Generation in OECD Europe**



gas prices begin to rise. Only further tightening of environmental controls, responding to concerns about future emission levels of particulates, SO_2, NO_x and CO_2 could threaten this outcome.

Since 1971, the share of oil in the electricity-output mix has fallen from nearly 25% to less than 10%. The first oil-price shock in 1973 effectively ended oil's advantage as the least expensive power generation fuel.[10] Concerns about security of supply also contributed to its decline. At current oil prices, heavy fuel oil is too expensive for normal base-load generation, and its main use is in delivering power at peak periods in existing oil-fired boilers. Over the outlook period, projected electricity output from oil continues to decline, to around 2% of output and 4% of capacity by 2020.

Nuclear power grew strongly in the 1970s and 1980s, by some 15% a year. It was perceived at the time as economically viable and as enhancing

10. IEA, 1997.

the security of electricity supply. This *Outlook* sees nuclear power increasing slightly in 1997-2010, as new plants in France and the Czech Republic come on line and existing plants are upgraded and operate at higher capacity factors.

Box 5.3: **Nuclear Power in Germany**

In June 2000, the German government reached an agreement with the nuclear industry on the progressive phasing out of nuclear power plants. On the basis of an assumed standard lifetime of 32 years, a quantity of electricity has been agreed upon that may still be produced in the future by each nuclear power station. The right to generate this amount of electricity can be transferred to another plant. The total amount of electricity remaining to be produced is 2 623 TWh. Owners of the nuclear power plants agreed not to claim any damages which might be caused by this decision. Reprocessing of nuclear waste will end in the year 2005. These elements are to be included in a law to be voted by Parliament.

Germany has 22 GW of nuclear capacity in 20 nuclear plants that produced 162 TWh in 1998 or 29% of the country's electricity. They accounted for 5% of OECD Europe's total electricity production and for 18% of nuclear power in the region. The decision to phase out nuclear is assumed to result in almost all of the country's nuclear plants being shut down by 2020.

After 2010, capacity decreases, as many nuclear plants reach the end of their lifetimes and are decommissioned. About 38 GW of existing nuclear plants should be retired. Plants have an assumed operating life of 40 years, in the absence of different information (most plants in the United Kingdom, for example, are expected to operate for more than 45-50 years). The Reference Scenario also reflects Germany's decision to phase out nuclear power (Box 5.3). Until recently, Turkey had plans to build a nuclear plant at Akkuyu, in the southern part of the country, but postponed them indefinitely in July 2000, on environmental grounds and because of difficulty in obtaining financing. The liberalisation of electricity markets in European countries will certainly affect nuclear-plant lifetimes. Many can compete successfully and are likely to seek to operate longer. Plants with high costs may have to close early. Some countries could extend the lives of their nuclear plants to achieve emission-reduction targets. The impact on CO_2 emissions from the extension of the lifetimes of existing nuclear reactors is discussed in the Alternative Power Generation Case in Chapter 12.

Hydroelectricity increases by 1% per annum over the projection period. Most hydro sites in OECD Europe have already been exploited, with little current activity in new hydro building. The largest additions are expected in Turkey, which has significant untapped hydro resources and a rapidly growing electricity sector.

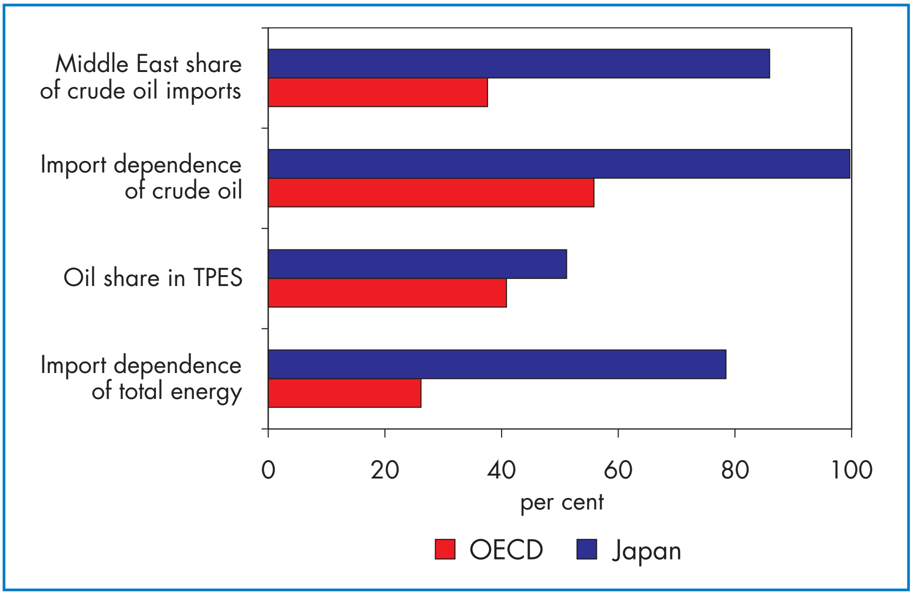
Non-hydro renewable energy is growing fast, as it receives increased attention in most of OECD Europe's countries. The development of renewables is expected, however, to continue to rely on policy support. The most significant increase will come in wind power, which could grow from seven TWh in 1997 to 110 TWh in 2020, becoming Europe's most important non-hydro renewable-energy source. The share of non-hydro renewable energy for electricity generation increases from about 2% at present to more than 5% of total electricity generation in 2020.

CHAPTER 6
OECD PACIFIC

Introduction

The OECD Pacific region consists of Japan, Australia and New Zealand. The three have diverse energy structures. Japan is the world's third largest economy (measured in PPPs) and fourth largest energy consumer, accounting for more than 80% of the region's total primary energy demand. It is highly dependent on imported energy, especially oil (Figure 6.1). Australia, by contrast, is an important exporter of gas and the world's largest exporter of coal, of which Japan is the largest importer. New Zealand relies on indigenous resources of coal, gas and hydropower, while it is a net oil importer.

Figure 6.1: **Japan's Dependence on External Energy Sources, 1998**



In 1997, the region accounted for 13% of total OECD primary energy demand, compared with 10% in 1971. Relatively high economic growth

(3.4% per annum from 1971 to 1997 compared with 2.7% for the entire OECD), partially offset by a rapid fall in energy intensity, goes far to explain this increase in share. A key feature of the region's energy profile is its lower energy intensity compared with other OECD regions, entirely a Japanese phenomenon due to Japan's limited energy resources and traditionally high energy prices. Table 6.1 illustrates the differences in some key energy indicators between the three countries and the OECD.

Table 6.1: **Key Energy Indicators of OECD Pacific Countries, 1998**

	Japan	Australia	New Zealand	OECD
TPES (Mtoe)	510	105	17	**4 786**
TPES/GDP*	0.20	0.29	0.31	**0.24**
Energy production/TPES	0.22	2.02	0.81	**0.74**
Per capita TPES (toe)	4.0	5.6	4.5	**5.0**

*toe per thousand US$ (1990) in PPPs.

End-use prices in Japan, significantly higher than in the United States, compare to those in some European countries. High energy costs and tax rates are the main reasons. Taxes account for more than half of the retail prices of automotive fuels. Gasoline prices in Japan are almost twice as high as in Australia and in the United States (Figure 4.1). Conversely, industrial energy has historically faced very low taxation in comparison with other OECD countries.

Macroeconomic Background

The OECD Pacific region also has differences in economic structure.[1] Manufacturing accounts for 24% of GDP in Japan, compared with 15% in Australia and 18% in New Zealand.

Japan's economy now appears to be on a path of cyclical recovery, after having contracted in 1998 for the first time in more than two decades. A budget stimulus package and a policy of low interest rates are boosting activity. Exports and fixed investment lead the recovery, with investment propelled by spending on information and communication technology

1. This section draws on OECD (2000) and IMF (2000).

(ICT) and a marked improvement in corporate profits from restructuring and inventory adjustment. Some temporary strengthening of private consumption, which accounts for 60% of GDP, is likely but may prove short-lived as continuing corporate restructuring holds back the growth of wage incomes. The possibility of a deflationary spiral has diminished, while inflation pressures remain subdued. Uncertainties remain about how solidly based the recovery is and about the economy's long-term growth potential, given its need for further restructuring.

Australia enjoyed steady economic expansion in the 1990s, with low inflation and strong domestic demand. Growing exports are expected to keep the economy buoyant and employment levels high. Prospects for the US economy, among others, could affect growth expectations. Australia's income per capita rose through the 1990s, reaching close to $20 000 (US$ 1990 in PPPs) by 1998 — similar to that of Japan.

The corresponding figure for New Zealand was about $15 000. Its economy rebounded strongly in 1999 after weak performance, mainly because of drought, in 1997 and early 1998. A large current-account deficit, while narrowing somewhat, will remain a downside risk for further economic expansion.

Recent Energy-Sector Developments

Japan

Energy-consumption growth in Japan slowed in the 1990s due to economic stagnation. Total primary energy supply (TPES) declined along with GDP in 1998 for the first time in two decades as industrial energy demand fell.

The Japanese Government's Advisory Committee for Energy is now reviewing long-term energy objectives and policies, and should finish by early 2001. Its report is expected to seek more effective development, use and mix of fossil fuels, nuclear and renewables, in order to enable the country to achieve its Kyoto target and to secure stable long-term energy supply. The discussions reportedly include further diversification of energy sources with greater roles for natural gas and renewables, in recognition of the difficulty in increasing nuclear capacity as fast as planned.

Japan is progressively pursuing liberalisation of its energy sector. The government now seeks to build a more competitive market, in which private companies will conduct more effective oil exploration. Deregulation of the oil sector is now largely complete, with a goal of full deregulation and institutional reform by 2001. Reforms in electricity and gas, launched later than in oil, could contribute significantly to lower energy prices. The partial liberalisation of the electricity market, which started in 2000, allows independent producers to enter the market.

Australia and New Zealand

In Australia, TPES increased at close to 3% a year during the decade from 1988 to 1998, in line with buoyant economic activity. Energy intensity fell slightly. It increased in New Zealand, where TPES rose by more than 3% a year, while GDP growth lagged at slightly less than 2%. In other developments, the Australian coal industry is undergoing consolidation and rationalisation, prompted by the decline in world coal prices.[2] Broken Hill Proprietary (BHP) Company Limited, the country's largest producer and exporter, cut its benchmark sales price in early 2000 and is expected to announce some mine closures. Shell Coal announced a year ago its intention to sell off its Australian operations. Australia also is introducing electricity reform progressively. The National Electricity Market (NEM) aims for full competition by 2002, when all customers are expected to be able to choose their suppliers.[3]

Assumptions

The Reference Scenario assumes that GDP in the region will increase at an average of 1.7% annually over the outlook period, significantly less than the 3.4% achieved between 1971 and 1997. The region's economy remains highly dependent on trade with the dynamic Asian countries, where expected economic growth will be less rapid in the next two decades than in the past. The OECD projects economic recovery for Japan[4], but with slower growth than in the 1970s and 1980s. The region's population is assumed to increase by only 0.1% per annum over the outlook period, compared with 0.8% from 1971 to 1997; the population could even start to fall at some point before 2020.[5]

2. Recent signs point to a rebound in spot coal prices mainly as a result of strong demand for steam coal for power generation in the Asia-Pacific region.
3. IEA, 1999.
4. OECD, 2000.
5. Japan's working-age population, which peaked at about 90 million in the mid-1990s, could shrink to about 70 million by 2030, as ageing becomes significant (see *Japan Review of International Affairs,* 1997).

Box 6.1: Principal Climate Change Policies and Measures Considered in the Reference Scenario

The Reference Scenario takes account of established programmes and, in some cases, targets in all three countries to promote the development and use of renewable energy. Other elements are listed below.

Australia

In 1999, Australia introduced new Minimum Energy Performance Standards for household refrigerators, freezers and electric storage water heaters. These standards and appliance energy-labelling regulations have been included in the Reference Scenario, but it reflects no major policies and measures for the industry and transport sectors.

Japan

Japan in 1999 revised the Energy Conservation Law, adopted a Law on the Rational Use of Energy and Recycled Resources Utilisation and enacted a Law Concerning the Promotion of Measures to Cope with Global Warming. The Reference Scenario includes energy-conservation measures that are obligatory under these laws. Key ones include:

- *Industry:* A range of measures for achieving energy conservation standards and targets and aimed at saving 18 Mtoe of energy in 2010.
- *Buildings:* Existing standards for heating and cooling loads in houses as well as standards for prevention of heat loss for six kinds of buildings. For equipment and appliances, Japan has introduced the "top runner" concept, whereby energy-efficiency targets for certain equipment are governed by the most energy-efficient, comparable products on the market. The government expects the system to save roughly 4 Mtoe in 2010.
- *Transport:* Application of the same concept, with targeted energy savings of 4 Mtoe in 2010. Fuel-economy standards for passenger vehicles and small trucks depend on size class and fuel. Current average fuel economy is 12.1 km/l (gasoline equivalent). The Reference Scenario assumes that average fuel economy will reach 14.6 km/l in 2010.

New Zealand

Key measures comprise voluntary agreements with industry, including energy producers, and energy efficiency programmes, such as energy performance standards and building codes.

Table 6.2: **OECD Pacific Reference-Scenario Assumptions**

	1971	1997	2010	2020	1997-2020*
GDP	1 250	3 015	3 739	4 393	1.7
Population	121	148	153	151	0.1
GDP per Capita	10	20	25	29	1.6
Oil Price	6.0	16.0	16.5	22.5	1.5
Coal Price	44.2	36.8	37.4	37.4	0.1
LNG Price	-	136.2	132.0	182.3	1.3

* Average annual growth rate, in per cent.

Notes: GDP and prices are in constant dollars at 1990 prices. GDP is in billions of dollars, calculated in PPPs. Population is in millions. GDP per capita is in thousands of dollars. Prices are in dollars per tonne for coal, per barrel for oil and per toe for LNG.

The Japanese CIF import price for LNG has broadly followed crude-oil prices over the past two decades. The *Outlook* assumes that it will continue to do so, remaining essentially flat in real terms to 2010 and increasing thereafter. Abundant world supply should keep the real price of internationally traded hard coal constant over the entire outlook period.

The 1998 edition of the *World Energy Outlook* discussed the possible impact on end-user prices of planned deregulation and institutional reform in the Japanese energy sector. The speed and extent of the implementation of reforms, especially in electricity, remain a key source of uncertainty in the energy demand projections for the region.

Results of the Projections

Overview

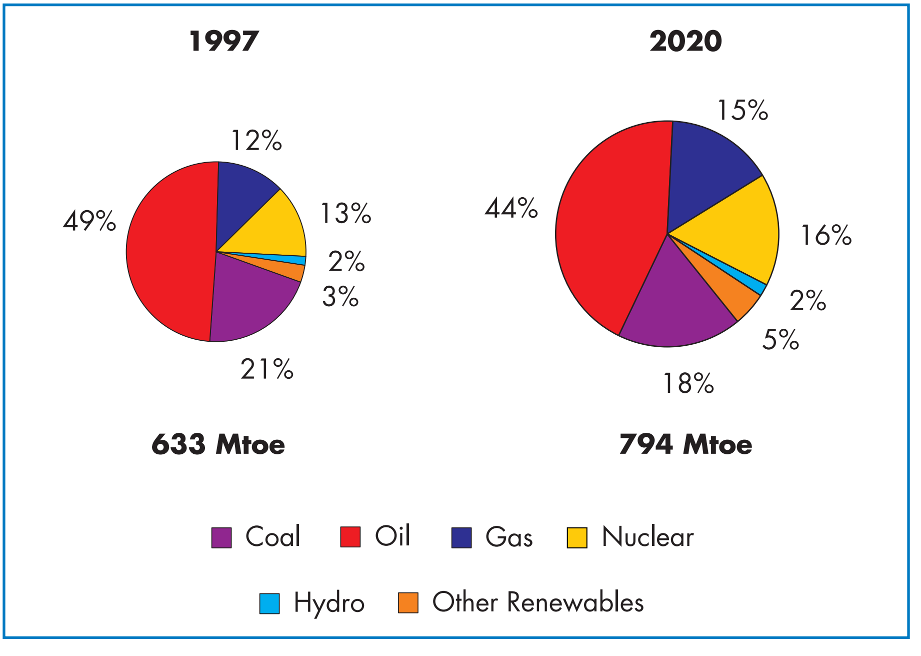
The Reference Scenario projects primary energy consumption to grow by 1% annually over the outlook period as against 2.6% in 1971-1997. Demand is thus projected to climb as fast as in OECD Europe and slightly faster than in OECD North America. Table 6.3 and Figure 6.2 show expected oil use growing slowly, with a steadily declining share in TPES. Consumption of gas, nuclear power and other renewables, in contrast, grows strongly. Japan is the only country in the region with a nuclear programme.

Table 6.3: **Total Primary Energy Supply** (Mtoe)

	1971	1997	2010	2020	1997-2020*
Total Primary Energy Supply	329	633	730	794	1.0
Coal	78	130	134	144	0.4
Oil	229	313	339	346	0.4
Gas	5	77	107	121	2.0
Nuclear	2	83	109	131	2.0
Hydro	9	11	13	13	0.7
Other Renewables	5	19	29	40	3.3

*Average annual growth rate, in per cent.

Figure 6.2: **Total Primary Energy Supply, OECD Pacific**



The average growth of 1% in primary energy use in this *Outlook* is little changed from the *WEO98*, which projected 1.2% growth for 1995-2020. The fuel mix for 2020 also remains broadly similar. The shares of gas and coal in primary supply are slightly lower at the end of the projection period. Nuclear power has been revised downward.

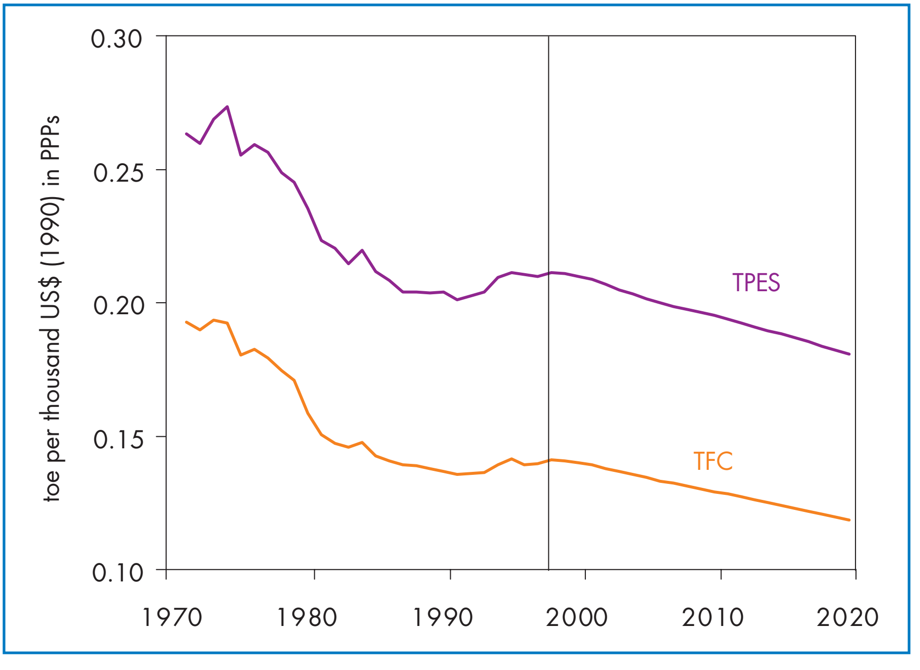
Projected total final consumption (TFC) expands by 0.9% a year over the projection period (Table 6.4). Oil consumption, driven mainly by rising transport demand, rises in line with total final consumption.

Table 6.4: **Total Final Consumption** (Mtoe)

	1971	1997	2010	2020	1997-2020*
Total Final Consumption	241	424	483	521	0.9
Coal	25	27	25	23	–0.6
Oil	170	256	287	304	0.8
Gas	8	34	42	45	1.2
Electricity	34	94	116	132	1.5
Heat	0	0	2	4	9.7
Renewables	4	9	11	13	1.7

* Average annual growth rate, in per cent.

Figure 6.3: **Energy Intensity in OECD Pacific**

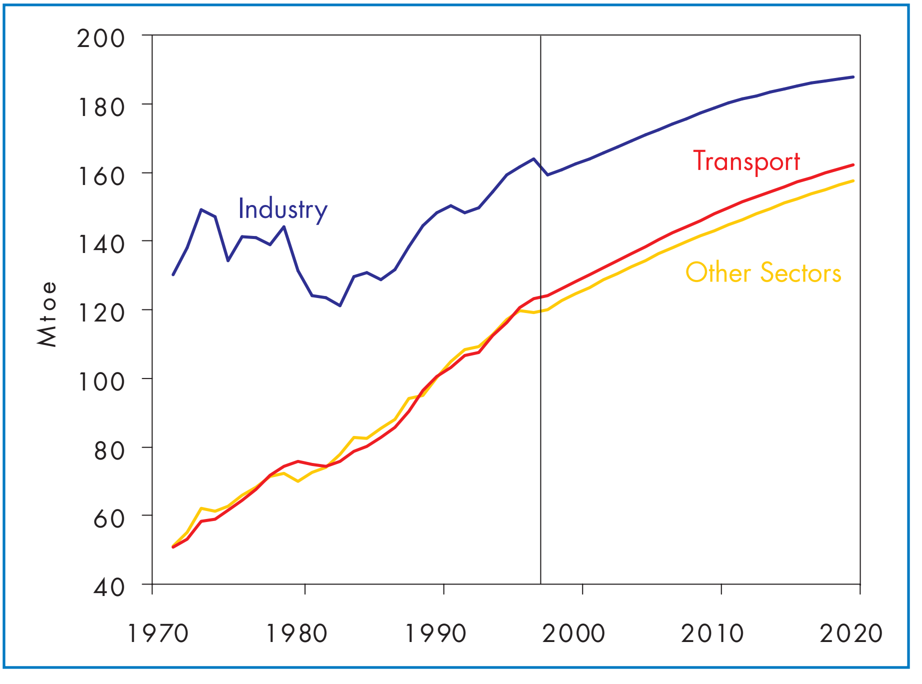


Energy intensity, measured as primary demand per unit of GDP, shows a projected decline of 0.7% per annum in 1997-2020. This reverses the recent 1990-1997 trend (0.4%), but lies close to the longer-term average annual decline of 0.9% from 1971 to 1997 (Figure 6.3). The decline results from a continued shift towards low energy-intensity, high value-added manufacturing and services, as well as improvements in unit efficiency with the uptake of new technology.

Sectoral Demand Trends

Although the share of industry in final consumption remains high, demand in the transport and residential/commercial sectors will continue to grow more rapidly than industrial energy demand. Figure 6.4 illustrates historical and projected demand trends by end-use sector.

Figure 6.4: **Final Energy Consumption by Sector**



Energy use in industry increases by 0.6% per year over the projection period. Structural changes in Japan's economy and continued efforts toward more energy efficiency help to restrain demand.

Demand for energy in transport in the region should rise in line with GDP (1.2% per year), but at a decelerating rate that will reflect saturation, structural effects and higher oil prices in the second half of the projection period. Demand thus increases by 1.4% per annum in 1997-2010 and by 0.9% in 2010-2020 — a significant slowdown from the 3% of 1990-1997. Transport accounts for 80% of the increase in total final oil demand. By 2020, the expected share of transport in total final oil demand will have risen to 52% from 47% in 1997. OECD Pacific car ownership levels are still significantly lower than in other OECD regions. In 1997, passenger-car ownership per 1000 people in Japan was 385, compared with 486 in the United States and 442 in France.[6] Nevertheless, several factors limit road-traffic growth in Japan, including congestion, infrastructure limitations, possible saturation in vehicle ownership later in the projection period and activity levels. Changes in the structure of the economy, away from heavy industry towards services and lighter materials could also reduce the additional tonne-kilometres required for freight transport.

Projections, for residential/commercial and agricultural energy demand combined, reflect expected saturation for residential space and water heating. Electricity will grow fastest (1.7% per annum), followed by gas (1.5%). Electricity will account for close to half of the energy consumption in these sectors in 2020, while the share of oil falls substantially.

Energy-related CO_2 Emissions

CO_2 emissions in the Reference Scenario increase at an average annual rate of 0.7%. This implies a steady decline in carbon intensities, either measured in terms of emissions per unit of GDP (where the decline arises mainly from the projected drop in energy intensity) or per unit of energy consumed (where it reflects the increased shares of gas and nuclear in the primary energy mix). By 2020, the region's emissions are 18% above 1997 levels.

Emissions from the transport sector rise one-third above current levels and they account for 26% of total CO_2 emissions in 2020, compared with 24% in 1997. Projected emissions from electricity generation in the region will be 15% higher in 2010 and 23% higher in 2020, the lowest increase among the OECD regions. Emissions rise much less (at 0.9% annually) than electricity generation (1.5%), largely because of the decreasing share of fossil fuels in the generation mix.

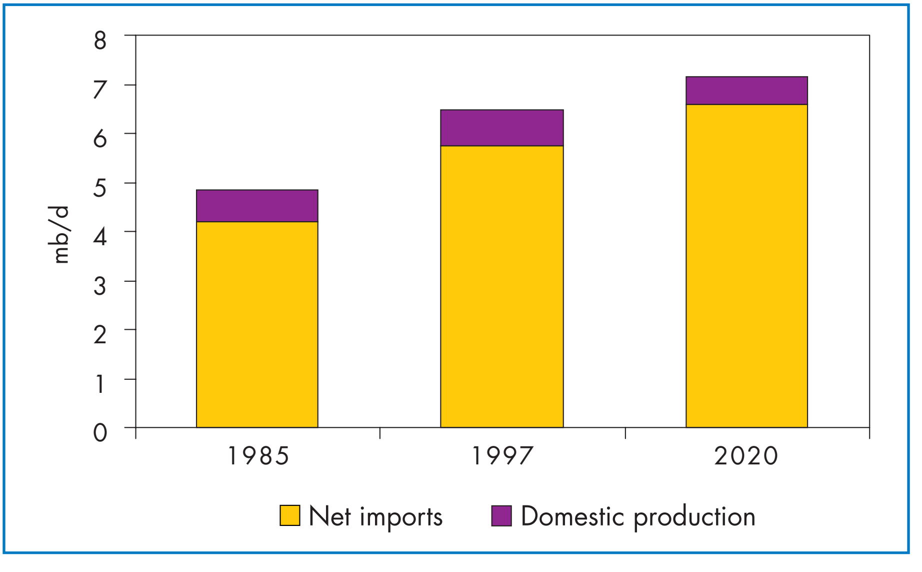
6. International Road Federation, 2000.

Oil

Primary oil demand increases by an average of 0.4% per annum in the Reference Scenario, from 6.5 mb/d in 1997 to over 7 mb/d in 2020. As in most other regions, transportation accounts for most of this increase. The prospects for oil production are poor. Australia has the bulk of it and, although offshore output there will increase in the near term, relatively modest remaining reserves point to declining production over the next two decades. The *Oil and Gas Journal* estimates the country's remaining proven reserves at 2.9 billion barrels.[7] Based on this estimate, reserves are equivalent to only six years' output at current production rates. Australian output is expected to peak in 2000, then decline to around 600 kb/d in 2010 and to 500 kb/d in 2020. Reserves in Japan and New Zealand amount to only 6% of the regional total.

With the expected sluggish prospects of indigenous output and the projected increase in oil demand, net imports are set to rise even further — in both volume and proportion of total supply. Imports will meet 92% of the region's oil requirements in 2020, compared with 89% in 1997 (see Figure 6.5). All three countries are net importers of oil. Import dependence and volumes are highest for Japan (Table 6.5).

Figure 6.5: **OECD Pacific Oil Supply**



7. *Oil and Gas Journal*, 1999.

Table 6.5: **OECD Pacific Net Oil Imports by Country, 1999**

	Japan	Australia	New Zealand
Oil Consumption (mb/d)	5.6	0.9	0.13
Net Imports (mb/d)	5.6	0.3	0.08
Net Imports/Consumption (%)	99.8	30	62

Source: *Oil Market Report,* IEA.

Most of Japan's imported oil comes from the Middle East. Official efforts to diversify import sources bore fruit when Middle East oil fell to 65% of total imports in the 1980s, but the fraction has since increased to well over 80%. With the weight of Middle Eastern oil in global supply projected to rise throughout the projection period, its role in the imports of Japan and the region as a whole is likely to continue to expand. This increases the importance of policies relating to oil-supply security.[8]

Gas

The region's two main gas markets contrast starkly. Japan, with limited reserves, is a large net importer, and Australia is a large net exporter. This has created strong links, because Japan provides the primary market for Australian exports. Both countries trade gas solely as LNG. Japan accounted for 58% of the world's LNG imports in 1999, mostly from Southeast Asia and more than one-third from Indonesia alone. The Asia-Pacific region is the world's largest market for LNG. Japan, South Korea and Chinese Taipei account for about three-quarters of total world LNG trade.

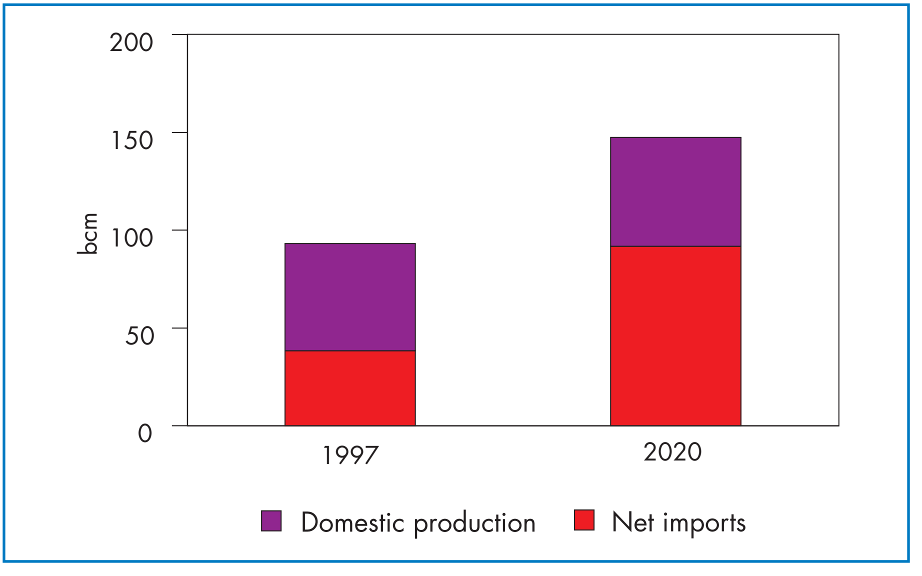
The Japanese Government is likely to give more priority in its long-term policy to promoting the use of natural gas, because of its environmental advantages and the greater diversity of supply sources compared with oil. Australia also has scope to expand gas consumption. Aggregate regional demand is projected to grow by an average of 2% per annum from 1997 to 2020, faster in the first decade, before assumed higher prices after 2010 dampen the rise in demand.

Production from Australia's abundant resources should increase significantly over the next two decades, to fill rising domestic and export

8. Asia-Pacific Economic Co-operation (APEC), which includes five IEA Member countries, is investigating ways of strengthening emergency preparedness in the event of an oil-supply disruption (see APERC, 2000).

demand. Cedigaz estimates Australia's proven reserves at 3 450 bcm[9] at the end of 1999, equivalent to more than 110 years' production at current levels and 97% of proven reserves in the region. Australia also has the world's fourth largest coal-seam gas resources, after Russia, Canada and China. This industry is expected to develop significantly over the next two decades.[10] In the Reference Scenario, OECD Pacific gas production increases by 3.9% per annum in 1997-2020, enough to stabilise the region's net import position (Figure 6.6).

Figure 6.6: **OECD Pacific Gas Balance**



Much of the expected increment in Australian output will go to export markets. A deal to sell large volumes to Chinese Taipei is under negotiation, and proposals are on the table for LNG sales to India and China. Japan, with its burgeoning gas-import needs, may absorb a significant portion. Net imports in OECD Pacific are projected at around 55 bcm (38% of primary supply) in 2020. The considerable investment in new LNG facilities and pipeline infrastructure that this will require may not occur without a rise in LNG prices, which the Reference Scenario assumes hold stable to 2010 before rising 38% in real terms in 2010-2020.

9. Cedigaz, 2000.
10. IEA (1997) provides a detailed assessment of gas production trends for Australia.

Box 6.2: **Prospects for International Gas Pipelines**

In Japan, the prospects for the construction of a national transmission grid connected by pipeline to an external source of supply remain highly uncertain. The Government is keen to see a pipeline developed as a means of reducing dependence on LNG and enhancing supply security. A proposal to develop natural gas reserves in Sakhalin, Russia and pipe the gas south to Japan has been under discussion for several years. The project has stalled because of the major risks and obstacles involved, including a long-running dispute over the sovereignty of Sakhalin, difficulties in negotiating offshore routes through fishing grounds and the high cost of laying pipes in mountainous areas and offshore. The success of this or alternative projects to bring gas from mainland Russia to Japan, possibly via China or Korea, will probably require the construction of a national trunk-line connecting regional centres of demand. High land costs would make such a project very expensive.

Plans to develop a long-distance line from Papua New Guinea to Queensland in Eastern Australia — the first-ever cross-border line in Australia — are well advanced. The line, which will have a capacity of around 5.5 bcm per annum, is expected to be commissioned in 2003.

Coal

The Reference Scenario projects OECD Pacific coal consumption to increase at a relatively slow 0.4% per annum. Coal's share in total primary energy supply drops to 18% in 2020 from 21% in 1997. By 2020, more than two-thirds of total coal consumption will occur in power generation. Expected supply will comfortably meet this modest growth in demand. Production will remain concentrated in Australia, which has most of the region's reserves. Australia is the world's largest exporter and sixth largest producer of coal, selling more than three-quarters of its output abroad. Japan remains its largest single coal market. Expected growth of production in the region as a whole implies a continued increase in net exports, mainly to rapidly expanding markets in China and elsewhere in Asia.[11]

11. The Australian Bureau of Agricultural and Resource Economics (ABARE) forecasts that exports will account for more than 70% of the increment in coal production through to 2015. See ABARE (1999).

Electricity

Electricity demand rises almost as fast as GDP. Its estimated income elasticity of slightly less than one results in growth of electricity consumption at 1.5% a year, as GDP rises by an assumed 1.7%. The income elasticity has fallen gradually from about two in the 1960s. The share of electricity should rise to 25% by 2020, up from 22% in 1997 and 14% in 1971. Nevertheless, the effects of regulatory reforms and the possible saturation of electricity demand in the household and services sectors constitute major uncertainties in projecting demand trends.

The electricity-generation mix differs significantly between the three countries of the region: Australia uses domestic coal to generate some 80% of its electricity, New Zealand taps hydropower for more than 60% of its generation and Japan produces nearly a third of its electricity from nuclear power (Table 6.6). Japan accounts for 82% of the region's total generation.

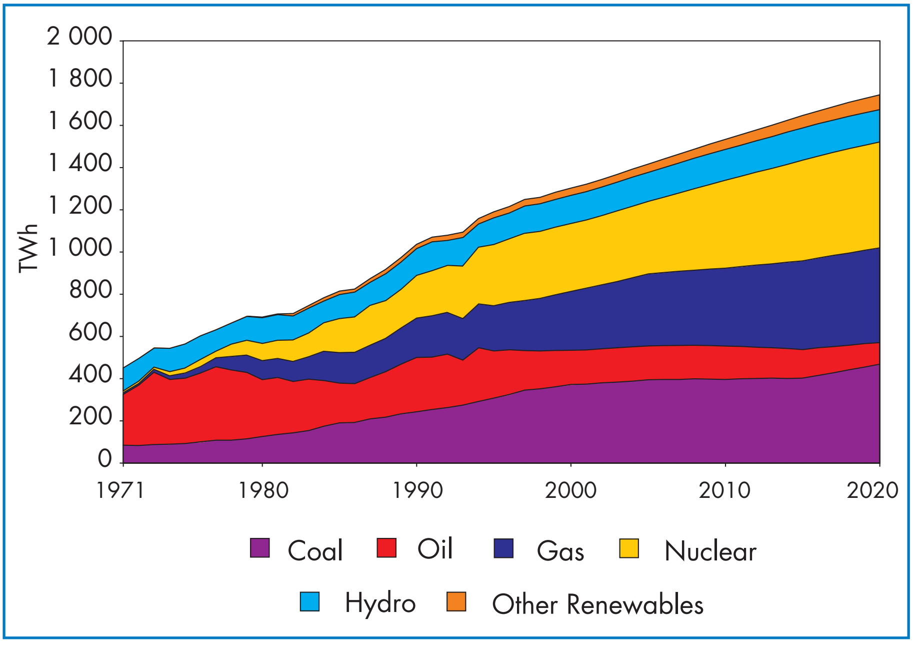
Table 6.6: **Electricity Generation Mix in OECD Pacific Countries, 1997**
(TWh)

	Australia	Japan	New Zealand	OECD Pacific
Total	**183**	**1 029**	**37**	**1 249**
Coal	146	196	2	344
Oil	2	187	0	190
Gas	14	211	9	234
Nuclear	0	319	0	319
Hydro	17	90	23	130
Other Renewables	3	26	3	32

Projected electricity generation climbs by 1.5% per year to bring annual power output in the region to 1 745 TWh in 2020. Installed generating capacity will expand by about one-third, to 395 GW in 2020 from 289 GW in 1997. Coal-based electricity is projected to grow by 1.3% a year, and its share in total generation could decline slightly by 2020. Both Japan and Australia have plans to increase coal-fired capacity. The projected electricity mix is shown in Figure 6.7.

As elsewhere in the OECD, natural gas will find increasing use in electricity generation. Gas-fired generation grows by nearly 3% per year over the projection period, and its share in electricity output rises to 26% in 2020 from 19% in 1997. All three countries have plans to increase gas

Figure 6.7: **Electricity Generation, OECD Pacific**



use in their power generation sectors. In Japan, the fuel will take the form of imported LNG. It is used along with coal to cover daily mid-load demand, while oil covers seasonal, mid and peak-load demand. Some increases in gas-fired capacity are also expected in Australia and New Zealand. In Australia especially, where hard and brown coals account for most of the electricity produced, natural gas is likely to benefit from market reforms; it will exert competitive pressure on coal-fired generation. The gas pipeline linking south-west Queensland to the Mount Isa region provides a potential link to alternative energy sources in north-west Australia. Another proposal, to link Tennant Creek and Mount Isa, would make Timor Sea gas available.[12]

Oil–fired generation is marginal in Australia and zero in New Zealand. Oil accounts for more than 18% of electricity generation in Japan, but its share has been declining. Oil-fired generation in the OECD Pacific region is projected in this *Outlook* to fall to about half its present level, with its portion of total generation dropping from 15% to 10% in 2010 and to 6% in 2020.

12. ABARE, 2000.

Nuclear power provides nearly a third of Japan's electricity. At the end of 1997 Japan had 44 GW of nuclear capacity. Until recently, the government's target was to raise nuclear capacity to 66-70 GW by 2010, but the nuclear programme has come under review by the Japanese Government's Advisory Committee. The decision due in 2001 is likely to reduce the number of reactors planned for construction by 2010. The *Outlook* assumes that nuclear capacity in Japan reaches 57 GW in 2010 and 67 GW in 2020.

Electricity generation from hydro power plants in the region is expected to increase by 0.7% per annum. Japan plans to construct a number of hydro plants, while there is little activity expected in Australia and New Zealand. New Zealand already depends heavily on hydropower, but has no plans to build large new hydro stations because of their relatively high cost.

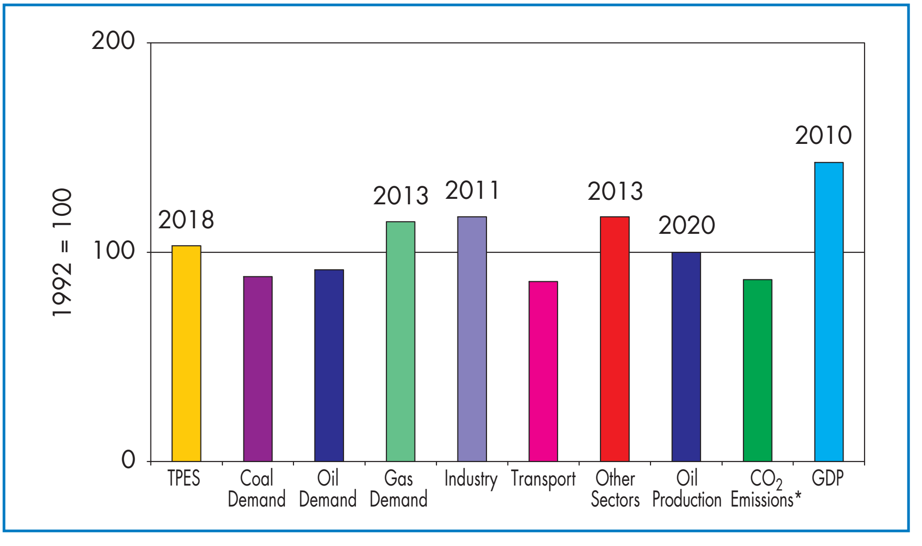
Annual generation from renewable energy sources other than hydro doubles by the end of the projection period, with its share increasing to 4.1% in 2020 from 2.5% in 1997. This estimate leans on the assumption that support for renewable energy will continue over the projection period. More than 80% of renewable electricity comes from CRW; it is assumed to grow from 26 TWh in 1997 to 35 TWh in 2020. Japan and New Zealand use geothermal energy. Total expected geothermal capacity reaches 3 GW in 2020. Wind and solar power generation are also expected to increase, reaching 8.5 TWh and 3.7 TWh respectively by 2020.

CHAPTER 7
RUSSIA

Introduction

Russia is the world's largest producer and exporter of natural gas and the third largest producer of oil. It is also the world's third largest energy consumer, after the United States and China. Severe economic decline following the break-up of the former Soviet Union (FSU) resulted in a 25% drop in GDP and a 26% plunge in primary energy demand from 1992 to 1997,[1] but Russia remains a major energy exporter with a large, recovering economy. Figure 7.1 provides a snapshot of the current *Outlook* projections for Russia.

Figure 7.1: **Energy Indicators, CO_2 Emissions and GDP**
(2020 Relative to 1992 Levels)



* CO_2 emissions are compared with their 1990 level (*i.e.* 1990=100) because of the implications for the Kyoto Protocol.
Note: The year in which each variable is expected to achieve its 1992 level is indicated above the bar. For example, GDP will reach its 1992 level in 2010 and will be 43% higher than the 1992 level in 2020.

1. Reliable energy statistics for Russia, which are accurately separated from statistics for the former Soviet Union, exist from 1992.

These projections indicate that primary energy demand will reach its 1992 level of some 780 Mtoe only towards the end of the outlook period. Because economic recovery and expansion are likely to proceed somewhat faster, the *WEO* projects significant average declines in energy intensity of 1.4% per year. CO_2 emissions will not have reached their 1990 level by 2020.

The energy projections for Russia are subject to some amount of uncertainty, mainly as to the pace and stability of economic growth and the investment required to meet the expected growth in energy demand. Additional ambiguities surround the progress of energy-sector reforms, which have been lacklustre in the past, and the ability of Russia to remain a major energy exporter to Western Europe and to Central and Eastern European countries.

A sustained economic recovery in Russia will depend on legal, fiscal and price reforms. The same reforms will be required to secure progress on restructuring in the energy sector. The potential for improvements in energy efficiency is high. In the past, Russia's economic activity has been highly energy intensive, mainly because the country's immense resource base put no constraint on consumption, while the absence of adequate energy pricing mechanisms conveyed a sense of unlimited resources. Lack of investment, due to an unstable economic environment, has led to low reserve replacement and limited turnover in the capital stock, both of which trends have exacerbated the problem. These factors and also climatic and geographical conditions have led to an energy intensity three times over that in OECD Europe. Given its status as an Annex B country, the pace of reform in Russia has great importance for its ability to meet its future CO_2 emissions commitments.

Russian gas supplies about 30% of the EU market and 80% of the Central and Eastern European market. Export growth will depend critically on Russian producers' ability to meet increasing domestic energy demand and on an efficient and well-regulated transport system. Russia is expanding its oil-export capacity, as well as that for gas. Pipeline access is one of the most important commercial issues yet to be resolved, despite recent progress on Production Sharing Agreements (PSAs), on Transneft's[2] tariff rates and in the work of the Federal Energy Commission in increasing the transparency of the transport system.

In this first *WEO* effort to provide a detailed model of Russia, separate from the rest of the FSU, the projection of energy demand presents many

2. Transneft is the Russian pipeline owner.

statistical and methodological difficulties. The approach used here relies on the expectation of an increasing sensitivity of consumers to energy price changes over time, as more elements of a market economy are introduced. However, the pace and structure of economic activity are the primary drivers of energy demand.

Macroeconomic Background

A slight improvement in the macroeconomic situation, stimulated mainly by the government's extensive domestic borrowing and portfolio investors' increasing interest in emerging markets like Russia, led to a much-awaited but modest economic recovery in 1997. An unsustainable fiscal balance, however, coupled with excessive domestic and international government borrowing, resulted in major debt defaults and the devaluation of the rouble in August 1998. Low oil prices and the Asian economic collapse contributed to the Russian financial crisis in 1998, when real GDP fell by nearly 5%.

The rouble devaluation and higher international oil prices led to eventual recovery. Domestic industrial production benefited from a dramatic reduction in rouble-based costs. Devaluation also helped the import-substitution sector. Estimated real GDP grew by some 3% in 1999[3] and growth will probably be even stronger in 2000.

The economic revival and the new presidential administration present an opportunity to institute far-reaching structural reforms. The new government adopted a comprehensive reform programme in June 2000. It focuses on promoting economic and social reform, improving the investment environment, transparency and property rights, providing fair competition, reforming the tax system and pricing policy, and stimulating corporate restructuring.

Recent Energy-Sector Developments

Table 7.1 gives an overview of key Russian energy indicators. It shows trends over the recent past; economic reform will determine the future structure of the energy sector.

The oil industry rests upon a highly depleted and mature reserve base. New fields, increasingly hard to access and geologically more difficult to exploit, need to be developed. While the 1998 rouble devaluation lowered production costs and some companies took advantage of low oil prices to

3. GDP data from *Goskomstat*.

Table 7.1: **Key Energy Indicators for Russia**

	1997	1992-1997*
TPES (Mtoe)	575	–6
TPES per capita (toe)	4	–6
TPES/GDP (toe/US$ thousand)	0.8	–0.2
Oil Production (mb/d)	6.1	–5
Gas Production (Mtoe)	460	–2
Net Oil Exports (mb/d)	3.4	3
Gas Exports (Mtoe)	153	–2
CO_2 emissions (million tonnes)	1 456	–6
CO_2 emissions per capita (tonnes)	10	–6

* Average annual growth rate, in per cent.

streamline operations, considerable inefficiency remains. The legislation on PSAs passed in February 1999 took an important step in establishing the stable legal and fiscal regimes necessary to attract long-term investment. But implementing the PSAs will require improving the Russian regulatory framework as well as the commercial environment.

The draft of the main provisions of the *Energy Strategy of Russia for the Period ending 2020*, submitted to the Russian Government at the end of March 2000, provides an energy forecast and policy outlook covering the next 20 years. The proposed strategy emphasises the need for energy price reform to regulate the activities of electricity and gas monopolies and thus to ensure lower production costs and greater transparency. In the longer term, the government envisages a competitive environment with independent producers and better conditions for non-discriminatory third party access to gas and electricity supply systems.

The Russian gas monopoly, Gazprom, is concerned about the prospects of ongoing liberalisation of the European Union's gas market, which could lead to growing gas-on-gas competition and to a decline in gas prices in Europe, Gazprom's main export market. This would put Gazprom's earnings at risk as it seeks to meet the investment requirements both of new fields and of the maintenance and expansion of its pipeline network. Gazprom plans to deliver 76 billion cubic feet to Europe over the next 20 years through long-term contracts.

Box 7.1: **Energy Price Reform in Russia**

Price reform and removal of energy subsidies are critical. Artificially low domestic energy prices weaken incentives for installing new energy-efficient technologies and more efficient energy use. They also deprive the energy sector of much-needed resources for investment. Despite some progress, non-payment remains a major problem in the electricity, gas and coal industries. Large enterprises, such as Gazprom and the electricity company, United Energy Systems (UES), have been officially prevented from cutting off energy supplies when customers do not pay, because non-payment indirectly finances social welfare. In 1997 the government did narrow the list of customer categories protected from disconnection. Gazprom and UES have since made some progress in improving collection and increasing cash payments. The share of cash in total payments to Gazprom rose from less than 30% in 1998 to an estimated 45% in 1999.

The 1999 IEA publication, *Looking at Energy Subsidies: Getting the Prices Right,* estimated that, if price subsidies were removed, energy consumption in Russia would drop by 18%. Natural gas use would fall by more than one-third and electricity use by 25%. Russian gas prices currently lie well below those in Western Europe and those that Gazprom charges to its export customers. Industry and power plants pay gas prices much higher than those charged to households. Heavy electricity-price subsidies contain the same distortion. The lack of cash payments for electricity supply has put the financial viability of many power companies at risk and has hampered their ability to maintain and improve operating efficiency.

Initial steps have been taken toward establishing a coherent and rational regulatory framework for gas and electricity, but the introduction of competition and pricing to reflect supply costs will remain important long-term policy objectives.

Assumptions

The *Outlook* assumes that the pace of reform will accelerate and that GDP will expand faster in the second half of the outlook period, based on solid internal policy changes rather than on the external factors that mainly fuel current growth. Over the long term, the economy will stabilise, with market institutions more firmly established. Significant oil and gas exports will continue, based on the expected long-term rise in world oil and gas prices. Consequently, government revenues from energy exports will increase.

GDP is assumed to grow on average by 2.4% a year to 2010 and faster thereafter, with annual growth of 2.9% from 1997 to 2020.[4] The population, which declined by some 0.3% per year from 1992 to 1997, will continue to shrink by 0.2% annually over the outlook period. If GDP growth is as robust as assumed, per capita income will almost double, reaching some $9 500 by 2020.

The *Outlook* assumes that the non-payment problem in the energy sector will be addressed before the removal of price subsidies. The currently very low domestic energy prices will rise to approach international levels. Domestic relative energy prices are also assumed to change, eventually approaching international ratios.

Box 7.2: **Uncertainty Regarding Future Russian Economic Activity**

The GDP growth assumptions depend fundamentally on accurately measuring the size of the Russian economy. Official GDP figures probably do not precisely reflect economic activity, because they cannot accurately measure informal or hidden economic activity. Goskomstat, the Russian statistical authority, augments recorded GDP by roughly 22% to 25% to try to capture informal economic activity (Masakova, 2000). While many analysts believe that unrecorded GDP may be even higher, it is not entirely clear that official statistics are negatively biased. Considerable uncertainty surrounds the effect on Russian GDP of the likely contraction of the informal economy, although it is widely believed that the pace of tax reform will accelerate this development.

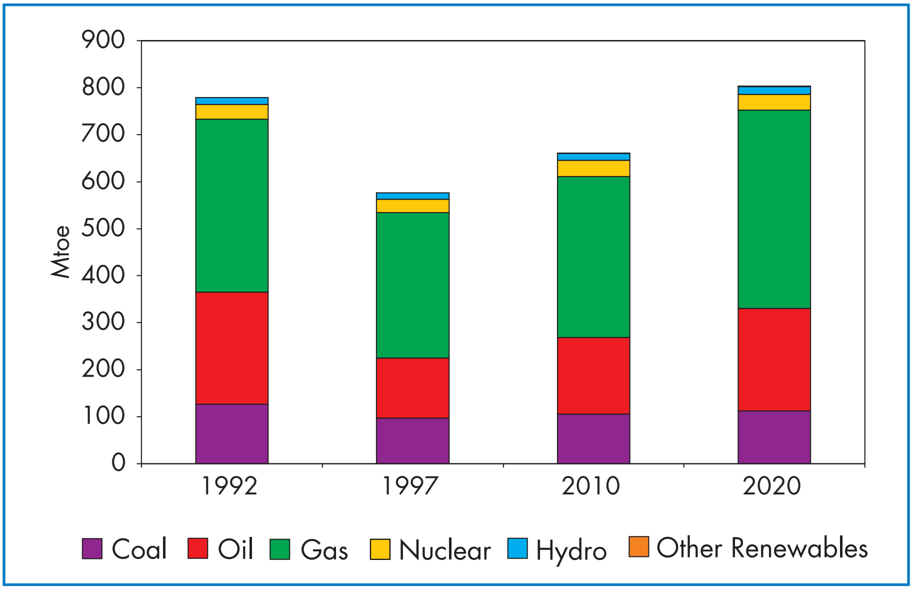
4. The Russian Energy Ministry's projections are based on a higher economic growth rate of some 5% to 6% per year from 2000 to 2020. (Ministry of Energy, 2000).

Results of the Projections

Overview

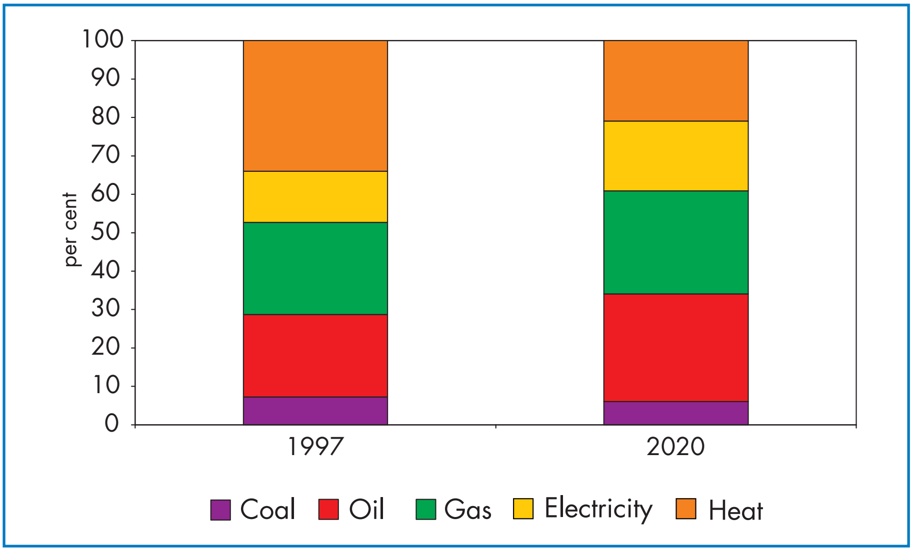
Total primary energy supply (TPES) is expected to grow by 1.5% per year on average over the outlook period, much slower than the assumed GDP growth of 2.9%. This implies improvements in energy intensity of 1.4% per year on average, mainly reflecting structural changes in the economy and in the energy sector. Oil demand will grow the fastest among fuels, and its share will gain 5 percentage points by 2020. Coal demand will rise by only 0.6% per year. Gas will still account for over half of TPES in 2020 and will be the only fuel to reach its 1992 level over the outlook period. Nuclear power will account for 4% of TPES in 2020 and hydro-electricity for 2% (Figure 7.2).

Figure 7.2: **Total Primary Energy Supply**



Total final consumption (TFC) declined by over 9% a year from some 610 Mtoe in 1992 to 380 Mtoe in 1997. Over the outlook period, TFC is expected to grow slightly faster than TPES, due primarily to assumed efficiency gains in the power generation sector. Rapid growth in oil, gas and electricity will characterise growth in final demand (Figure 7.3). The transport sector will account for nearly 70% of the incremental final oil demand.

Figure 7.3: **Total Final Consumption**



Sectoral Demand Trends

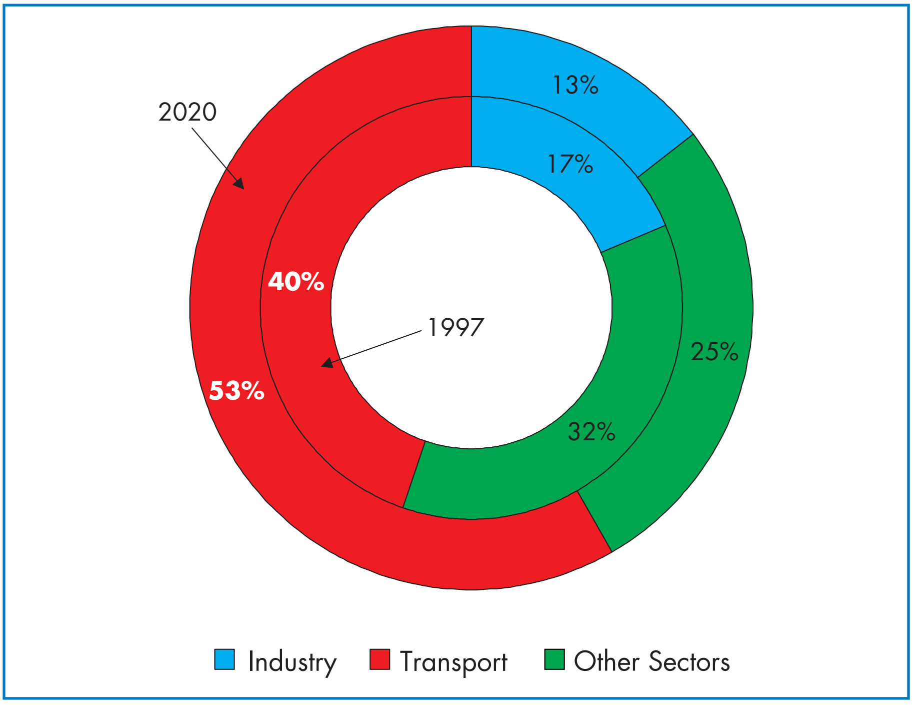
In the Soviet era, central planners focused on industrial and agricultural production and did not treat services as an important economic activity and measured them poorly. Yet value added in services climbed from 35% of GDP in 1990 to roughly 57% in 1998, and industry's share fell to some 35% from 50%.[5] Services are expected to continue to expand relative to other sectors over the outlook period, with implications for energy demand and improvements in overall energy intensity. Energy demand in other sectors (which include residential, commercial, agricultural and public service demand) fell at a much slower pace in the 1990s than did industrial energy demand, probably as a result of pricing policies and government guarantees of energy supply. In these sectors demand will accelerate after 2010, growing by 2.2% per year over the second half of the outlook period. Electricity demand, expected to double up to 2020, will fuel this strong growth.

Industry's energy demand growth will also accelerate after 2010, although at a slower pace. Electricity's share gains at the expense of heat and reflects improvements in overall efficiency as new capital replaces older technologies.

5. World Bank, 1999.

Energy demand in the transport sector will rise considerably, by 3.1% per year, faster than GDP growth. Oil demand for transport will increase by 4.1% per year, rising to 81 Mtoe in 2020 and accounting for 70% of incremental final oil demand. Other fuels, primarily gas used as fuel by pipelines, have held a considerable share in the transport sector in the past (38% in 1997), but the share of oil will rise to 76% in 2020. Private car ownership is low, at 100 vehicles per 1000 persons compared with 210 in Poland and 510 in Germany[6], but the demand for mobility is expected to rise with per capita income over the outlook period.

Figure 7.4: **Final Oil Consumption by Sector**



Note: Non-energy use is not shown.

Oil

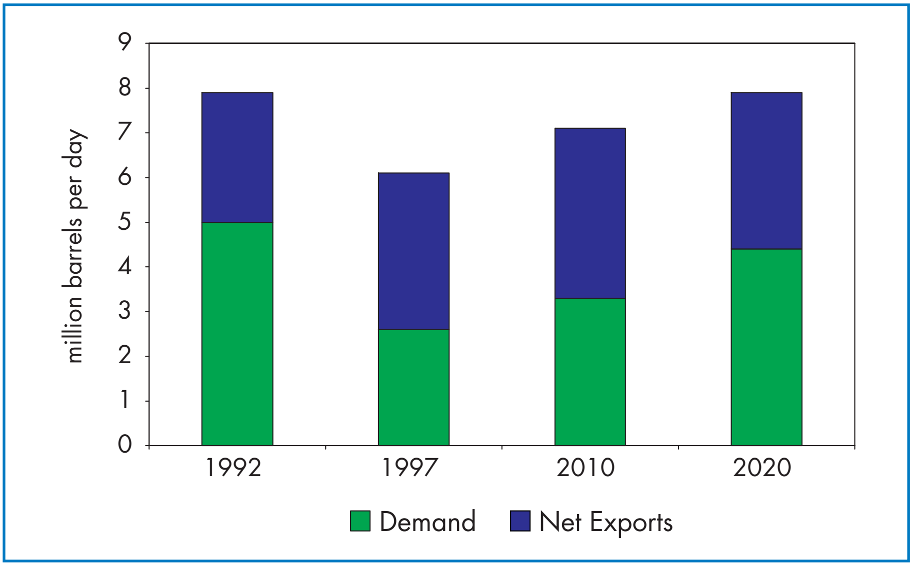
Russian oil consumption plummeted from 5 mb/d in 1992 to 2.6 mb/d in 1997, almost 12% per year. Supplies available for domestic consumption declined, as producers favoured export markets. Despite a

6. OECD, 1999.

near-term recovery due to the recent economic upturn, Russian demand in 2000, measured as production less exports, is estimated to be only 2.6 mb/d. The *Outlook* sees this situation changing, with oil demand growing by 3.7% per year until 2010 and by some 4.6% per year thereafter. Projected primary oil demand will reach 4.4 mb/d in 2020, with the increment going almost entirely towards increasing mobility. The transport sector will account for roughly 40% of primary and 53% of final oil demand in 2020. Oil use for power generation will decline, to some 3% of total generation by 2020.

Oil production fell from 7.9 mb/d in 1992 to 6.1 mb/d in 1997, due mostly to declines in investment in existing mature fields and to the impact of the economic decline on domestic demand. Higher world oil prices brought a moderate recovery in 1999, but the current investment climate is expected to produce only a modest increase to 6.3 mb/d in 2000. Only large investments in existing fields as well as new ones can attain the projected production level of 7.9 mb/d in 2020, identical to that in 1992 (Figure 7.5).

Figure 7.5: **Russian Oil Balance**



Oil production is concentrated in a few large fields. Four fields in West Siberia account for over half of Russia's oil output, with a substantial decline over the next seven to ten years. Other production occurs in the Volga-Urals (less than 25% of the total). The Arctic region, a much smaller producer, is the location of many Western joint ventures. New oil developments focus on West Siberia's Tyumen region, East Siberian oil fields and offshore Sakhalin in the Far East. These fields will attract the required investment only after effective implementation of the PSA legislation. Producers in West Siberia can send only one-third of their production to world markets because of bottlenecks in export routes. This limited access creates a barrier to investment, given that the domestic price is below the world market price, which is exacerbated by current risks and uncertainties in the internal market.

Box 7.3: Investment Requirements to Meet Expected Growth in Energy Demand

The investment environment in Russia remains depressed in comparison with other transition economies. Barriers to investment include the need to improve corporate governance and enforcement of the rule of law; general uncertainty due to past erratic and retroactive changes to the fiscal regime; ambiguity and lack of clarity in the administrative and legal bases for investment projects; disparities between regional and federal laws and their interpretation; continued price subsidies for residential electricity and heating; and the non-payment of energy bills. Poor transparency and law enforcement contribute to investor uncertainty, which will continue to obstruct critically needed infusions of capital.

Sustaining oil production depends heavily on attracting minimum investment of $5 to $7 billion per year. In gas, up to 85% of Gazprom's productive fields are in decline and need investment estimated at about $2 billion per year for five years to maintain the production necessary for domestic and export markets and to settle domestic debts and tax arrears.

Net oil exports increased to 3.5 mb/d in 1999, a level not seen since the mid-1980s. This rise was a result of high oil prices and the oil companies' need to increase hard-currency revenues following the 1998 financial crisis. In the first half of the outlook period, domestic oil production is expected to grow faster than domestic demand, with net exports rising to 3.8 mb/d in 2010. Production then slows relative to demand, which accelerates towards the end of the outlook period, and net exports fall back to their 1997 level of 3.5 mb/d in 2020. Sufficient capacity will probably be in place by then to accommodate the projected exports. The problems lie more in efficient and proper regulation by the Federal Energy Commission; effective implementation of legislation allowing long-term contracts; and the creation of a commercial regime that will empower Transneft and producers to resolve transportation requirements. An end will also have to be put to the system of interministerial allocation of export access.[7]

Gas

Gas demand in Russia fell from just below 370 Mtoe in 1992 to 310 Mtoe in 1997, much less than the decline in oil demand. Demand is expected to grow by 1.4% a year over the outlook period, reaching 422 Mtoe in 2020 — provided that significant domestic price reform takes place.

Gazprom produces almost 95% of Russian natural gas. If investment in new gas fields does not occur, Gazprom expects production, which fell by 2.4% a year in 1992-97, to decline further by 2010 because of advanced depletion in the major existing fields.[8]

Gas exports to OECD Europe accounted for roughly half of total Russian gas exports in 1997, up from a third in 1992 (Table 7.2). In an effort to improve its export revenues, Gazprom has diversified its export strategy. Expanding the export market would raise export revenues, which may help to offset Gazprom's losses from low domestic prices and non-payment. In 1999, total exports rose by 9%, underpinned by exports to Germany, Italy and France, in particular.

Table 7.2: **Russian Gas Exports by Destination** (bcm)

	1992	**1997**
OECD Europe	62	92
Transition Economies	123	96
Total exports	**185**	**188**

7. This system was set up to protect local market supply.
8. Remizov *et al.*, 1999.

Domestic gas tariffs are set at about one-tenth of export prices, and only some 45% get paid in cash. Gazprom has pressed the Russian government to raise gas tariffs. In late December 1999, gas prices to industrial users were increased by 40% to 50%. Gazprom also reduced gas supplies to UES in the second quarter of 2000, in response to the utility's inability to meet its first-quarter payment obligations.

With its immense gas resources, Russia will continue to be a major gas exporter over the outlook period. There are indications that Gazprom may give priority to earning hard currency from exports over increasing supplies to the domestic electricity market. While gas demand is expected to recover to its 1992 level by 2020, this projection depends on Gazprom's ability to maintain production and on government action on price reform.

Coal

Coal demand fell by 25%, from some 130 Mtoe in 1992 to 97 Mtoe in 1997. While coal accounted for 17% of TPES in 1997, its share is expected to fall to 14% (112 Mtoe) by 2020.

Coal production also fell steadily over the past decade, to about half its 1988 level. The reasons include reduced demand after the removal of subsidies, which resulted in gas prices a third those of coal, declining production due to the failure to pay miners their salaries, and mine closures. Since 1993, 150 mines have been closed. Plans call for continued shutdowns of inefficient mines.

The few financial resources that have been forthcoming in recent years have been mostly directed to closures of uneconomic mines. The World Bank's Second Coal Sector Adjustment Loan of $800 million was approved at the end of 1997, and the first tranche of $400 million was paid. The second tranche of $200 million was issued in 1998 after the condition that private companies produce at least 45% of coal output was met. The final tranches depend on more progress in privatisation and in social support related to mine closures. The Loan is not aimed at increasing coal production, but rather at furthering efforts to liquidate the national coal company, RosUgol, and to improve the social subsidy-management system.

Coal exports fell from 11 Mtoe in 1992 to some 4 Mtoe in 1997. Recovery has been slow due to variable quality, contamination and delivery delays. Increasing coal exports in the long term requires significant investment in upgrading or building port facilities for them. This *Outlook* does not expect exports to recover to the level of the early 1990s.

Production, however, is expected to cover domestic coal demand over the outlook period.

Box 7.4: **Russia's Possible Gas to Coal Programme**

Gazprom is putting pressure on the government to increase domestic gas tariffs to cover costs and to realign the relative prices of gas and coal. One option under consideration by the Russian government for meeting the expected increase in electricity demand is to replace gas with coal. Gas would then be redirected to export markets, which pay world prices. In the second quarter of 2000, UES already found itself 12% short of its quarterly requirements, and this will have to be made up by more expensive coal or heavy fuel oil. Nevertheless, given the difficulties facing the Russian coal sector in its ongoing restructuring process and in its ability to attract necessary investments, it is questionable whether it will be able to match potential decreases in gas supplies to Russia's power sector.

Electricity

Final electricity demand grows by 3% per year over the outlook period, after declining by 5% a year from 1992 to 1997. Generation should increase by 2.4% per year, substantially more slowly than consumption, as reductions in system losses take hold.

Russia's installed capacity was 214 GW in 1997; gas was the fuel used for 40%, coal for 21%, hydro for 20%, nuclear for 9% and oil for 8%. The average capacity factor was 44%, as against 54% in 1992. This low capacity factor means that there is surplus capacity sufficient to meet additional demand growth for a few more years. Most plants are old and poorly maintained, however, and investment must be found to refurbish them and to extend their lifetimes, or to build new capacity. Fossil-fuel plants currently operate at especially low capacity factors. The lower running costs of nuclear and hydro plants create an incentive to operate them as much as possible. Consequently, the share of fossil fuels in electricity output dropped from 71% in 1992 to 67% in 1997.

Electricity generation based on gas is projected to expand to 61% of total generation over the outlook period (Table 7.3). As in OECD countries, gas is likely to become the preferred fuel for new capacity, particularly in combined-cycle gas turbine (CCGT) plants. Higher tariffs and enforcement of payment will be critical to attract the necessary investments in more efficient power technologies.

Table 7.3: **Russian Electricity Generation** (TWh)

	1997	2020	1997-2020*
Total	**833**	**1 443**	**2.4**
Coal	140	198	1.5
Oil	44	37	–0.8
Gas	377	874	3.7
Nuclear	109	128	0.7
Hydro	157	197	1.0
Other renewables	6	9	1.4

* Average annual growth rate, in per cent.

The share of coal in electricity generation is expected to increase slightly in the first half of the projection period and then to decline, as some coal-fired power stations are retired and replaced by gas-fired plants. The share could, however, be higher if Gazprom's proposed policy to reduce gas supplies to UES is realised and maintained over the long term.

Nuclear generation has been increasing since 1994, rising to 120 TWh in 1999.[9] The *Outlook* assumes that the present 20 GW of nuclear capacity will remain roughly constant to 2020, as construction of new nuclear plants, and completion of plants currently under construction, balances reactor retirements. In 2020, nuclear generation is expected to be some 128 TWh. The Russian government, however, envisages some 160 TWh to 172 TWh from nuclear power stations in 2005, 205 TWh to 224 TWh in 2010 and 235 TWh to 372 TWh in 2020.[10]

The *Outlook* projection for hydropower involves only a modest increase, because of high capital costs and long lead times. A number of plants currently under construction will reach completion by 2010. Installed hydro capacity will rise from 44 GW currently to 53 GW by 2020.

Combined heat and power is widely used, but conversion efficiencies are low, and losses high. Heat output will decline over the outlook period, because of structural changes in the economy and savings in heat

9. Electricity generation data for 1999 are from the Uranium Institute.
10. Ministry of the Russian Federation for Atomic Energy, 2000. These projections are based on high and low growth scenarios.

consumption. Future demand for heat in the industry and service sectors is likely to be met by individual sources rather than large centralised heat systems.

Industrial electricity tariffs in Russia are about one-sixth of average rates in OECD countries. Residential rates, cross-subsidised through higher industrial tariffs, are about 40% lower. The government envisages an end to this cross-subsidisation by 2002 and the introduction of residential tariffs that reflect costs. The non-payment of electricity bills has left the electricity sector without sufficient working capital for maintenance of the existing infrastructure and is likely to continue to limit investment in this sector.

Estimates of power-sector investment requirements vary greatly. The *Outlook* sees them as being on the order of $150 billion (in current prices), with annual investment rates of $5 billion up to 2010 and $9 billion from 2010 to 2020.[11] UES estimates that new capacity needed after 2005 will require some $7 billion per year from 2000 to 2010. Investment bank analyses are more conservative in their estimates of investment needs, on the order of $2 to $2.5 billion per year, based on electricity demand growth of 1% to 2%, until 2010.[12]

Environmental Issues

Russia has carried out important environmental policy reforms during its transition to a market economy. Yet, because of its emphasis on heavy industry and the under-pricing of energy and raw materials, and despite the decline in output during the 1990s, the Russian economy is still very intensive in resource use and pollution. A lack of investment, particularly in industry, and difficulties in implementing institutional and structural changes have largely offset the achievements of the past decade. A key element in providing an attractive investment environment in the energy sector over the outlook period is the streamlining of Russia's environmental and safety regulatory systems.

From 1992 to 1997, pollution levels in Russia declined with economic output. Emissions contracted less than GDP, however, due in large part to a 73% growth in private vehicle ownership between 1990 and 1996.[13] Russia is currently the world's third largest emitter of carbon dioxide after the United States and China. In major urban centres, pollution from other

11. This estimate does not include investment in transmission and distribution or in refurbishment of existing plants.
12. *Troika Dialog*, 3 April 2000.
13. OECD, 1999.

emissions, including particulates, sulphur dioxide and nitrogen dioxide, far exceeds international norms, often causing respiratory diseases.

Under the Kyoto Protocol, Russia committed itself to limit its average annual greenhouse-gas emissions in 2008-2012 to their 1990 levels. Due to the decline of economic activity during the 1990s, emissions are likely to be substantially lower than that. This may allow Russia to sell emission permits as part of an emission-trading system established under the Kyoto Protocol. The outcome, however, is very sensitive to uncertain economic-growth assumptions. The sensitivity analysis in Table 7.4, based on variations of one percentage point (per year) above and below the Reference Scenario's growth assumption, demonstrates the effect of higher and lower growth on energy demand and carbon emissions in 2020.

Table 7.4: **GDP Sensitivity Analysis**

		2020	
	Low Growth	**Reference**	**High Growth**
GDP (billion US$)	–20	1 335	25
TPES (Mtoe)	–19	802	23
CO_2 (Mt)	–20	2 041	24

*Change in per cent relative to the Reference Scenario.

Relative to 1990 (not shown in the table), TPES in the high-growth case is 11% higher and carbon emissions are 7% higher. In the event of relatively high growth, therefore, there may be only a limited supply of tradable emission reductions.

CHAPTER 8
CHINA

Introduction

China,[1] the world's most populous country, has over 1.25 billion inhabitants, over 20% of total world population. Measured in PPPs, its GDP of $3.8 trillion in 1998 made it the second largest economy in the world after the United States. A key player in the world energy market, China is the second largest consumer of primary energy behind the United States and the third largest energy producer after the United States and Russia. It will become a major importer of crude oil in the very near future. Now ranked 11th, it may soon take a place among the world's top ten trading economies. Table 8.1 highlights China's growing importance in the world in terms of energy consumption and economic growth.

Table 8.1: **China's Rising Importance in the World**
(percentage of world total)

	1971	1997	2020
Primary Energy Demand	5	10	14
Coal Demand	13	29	36
Oil Demand	2	6	10
Power Generation	3	8	14
CO_2 Emissions	7	14	18
GDP in PPP terms (US$ 1990)	3	13	21

Two key features of China's energy system are its very high reliance on coal and the uneven geographical distribution of its energy resources. The world's largest consumer of coal, China accounted for nearly 30% of world consumption in 1997. Coal accounted for some three-quarters of primary consumption and almost 90% of fuel consumption in the electricity sector in 1997. Government efforts to reduce dependence on coal by shifting away

1. Hong Kong is included with China in the historical data and projections presented here.

from energy-intensive manufacturing, by developing oil and gas infrastructure and by promoting energy-efficiency and renewables programmes are outlined in the Tenth Five-Year Plan (2001-2005). The country is responsible for 14% of total world CO_2 emissions, over 3 160 million tonnes in 1997, making it the second largest CO_2 emitter in the world.

Energy resources are very unevenly distributed. Significant oil and coal, and more recently gas, resources lie in the North and Northwest, but the main energy-consuming areas are in the eastern and coastal regions. Overcoming these imbalances by improving the country's transport infrastructure will require substantial investment. The World Bank has estimated the cost of necessary energy-infrastructure investment over the ten-year period to 2004 at $1.5 trillion, of which transport accounts for $600 billion and energy for $490 billion.[2]

The *WEO* projections for China depend on many assumptions, some of them based on relatively limited information. Data on much of the Chinese energy system and on important energy demand drivers are scarce, making quantitative analysis difficult. Thus, important uncertainties affect the projections of future economic growth and energy demand. The uncertainties include, but are not limited to, problems with Chinese GDP data, the effects of price reform on the fuel mix and on energy production, and the planned expansion of the natural gas infrastructure.

Macroeconomic Background

China's economic growth averaged over 11% per annum from 1990 to 1997, but has slowed over the past several years, to 7.8% in 1998 and an estimated 7.1% in 1999.[3] Recently, domestic demand has picked up as the government has introduced measures to encourage private consumption. Government expenditure has increased for social programmes and to fund infrastructure projects, mainly in the underdeveloped western regions. Regional trade with the rest of Asia has also begun to recover as the Asian crisis has waned.

Despite moves toward privatisation, China's economy remains largely controlled by state owned enterprises (SOEs), many of which are unprofitable. Restructuring the SOEs is a major priority, and the Chinese government plans to return the majority of them to profitability over the

2. World Bank, 1997.
3. IMF, 2000.

next several years. Downsizing and restructuring are expected to accelerate as the entry date for World Trade Organisation (WTO) membership looms closer. The landmark trade agreements with Japan in July 1999, with the United States in November 1999 and with the EU in May 2000 boosted the chances of early entry into the WTO. Membership could increase the transparency of China's economy and augment foreign direct investment flows, which declined in 1999. Protective measures, price controls and import restrictions used to support the SOEs are likely to need reform under WTO rules.

Box 8.1: **China's GDP**

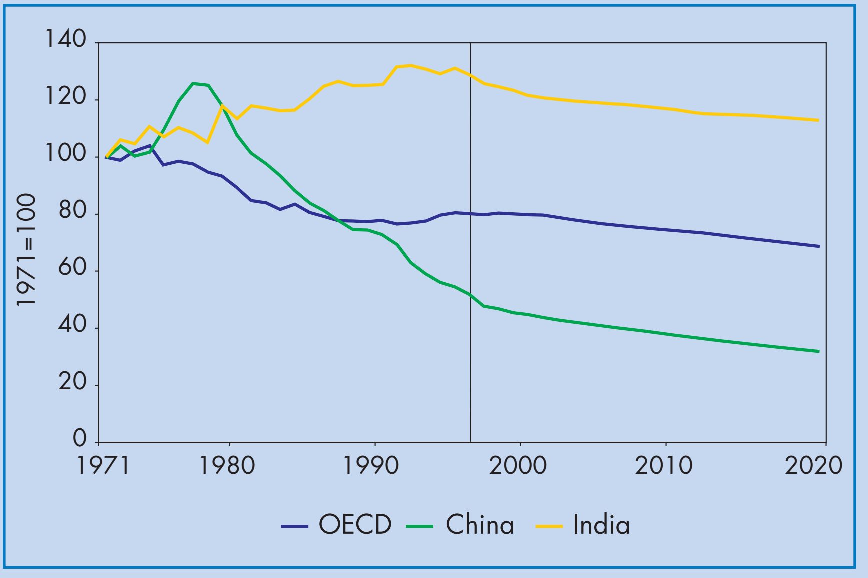
A major uncertainty for the energy analysis of China concerns the reliability of its GDP statistics. It is widely acknowledged that China's official figures understate GDP and overstate economic growth rates. Two OECD studies produced estimates of China's GDP using internationally accepted methodological approaches (Maddison, 1997; Rouen, 1997). In the first study, Maddison claims that official statistics underestimate the level of national income in Chinese currency, largely because national income is deflated by a price series that understates inflation and overstates the growth rate of real income. Maddison estimates that average annual GDP growth from 1978 to 1994 was 7.4% rather than the 9.8% official rate. The similar study carried out by Ren Rouen applied the producer-price index to official GDP figures and found the average growth rate to be 6% per year from 1986 to 1994, down nearly four percentage points from the official figure.

That China's GDP growth rates may have been overstated implies that improvements in energy intensity may also have been overstated. Based on official figures (Figure 8.1), energy intensity decreased by 5.6% per year over the past two decades. Typically in developing countries, energy intensity increases in the development phase (in India it increased by 1.4% per year over the past decade and a half), then peaks and, after the country reaches a certain level of development, begins to fall. Using Maddison's GDP figures, the decline in energy intensity in China falls to 3.4% per year, much less than the official claims.

The National Bureau of Statistics (NBS) has recently tried to increase the reliability of official Chinese statistics by adopting internationally comparable standards and punishing those who seek to benefit from inflating production figures. Over 5 000 industrial

(continued)

Figure 8.1: **Energy Intensity in China, OECD and India**



enterprises have recently been connected directly to the NBS through the Internet (*Le Monde,* January 2000). Improvements in statistics in one sector, however, often lead to more inconsistencies in the sectors that remain. A comprehensive discussion of the reliability of Chinese GDP statistics can be found in the 1998 *WEO*. While official GDP statistics are used for the projections here, the reliability of these figures represents a key uncertainty for this analysis.

Recent Energy-Sector Developments

The key Chinese energy indicators appear in Table 8.2. In March 1998, the government undertook a major restructuring programme of government administrations and state industries, with the goal of increasing the effectiveness of the government and improving the performance of public companies. The restructuring programme produced a dramatic effect on the energy sector. The oil industry was regrouped geographically into two integrated state oil companies, Sinopec (China Petroleum Corporation) and CNPC (China National Petroleum Corporation).

Table 8.2: **Key Energy Indicators for China**

	1997	1990 – 1997*
TPES (Mtoe)	905	4.5
TPES per capita (toe)	0.7	3.4
TPES/GDP (toe/US$ thousand)	0.2	–5.8
CO_2 emissions (million tonnes)	3 162	4
CO_2 emissions per capita (tonnes)	2.6	2.9
Net oil imports (mb/d)	0.9	0.2

Notes: * Annual average change, in per cent. Only commercial energy consumption is included in the demand figures for China. Non-commercial energy consumption, which accounts for some 20% of total energy consumption, is discussed later in this chapter.

The Ministry of Coal Industry was downgraded into the State Administration of Coal Industry (SACI), and over 30 000 small coal mines, considered illegal, unsafe, inefficient or polluting, were closed down by the end of October 1999. The Ministry of Power, which owned about 80% of China's power industry, was abolished, with the regulatory function allocated to the Department of Electric Power of the State Economic and Trade Commission (SETC) and its assets transferred to the China State Power Corporation. The government also took steps to reform its oil price regime and restricted diesel and gasoline imports. State enterprises were urged to improve efficiency by reducing the workforce and restructuring.

Assumptions

China's GDP growth is expected to surpass 7% in 2000, supported by rising domestic demand, expansionary fiscal policy and strong export growth. Its economy is assumed to grow at close to 6% per year up to 2010 and by some 5% per year over the entire outlook period.

China successfully limited its population growth to 1.5% per year from 1971 to 1997. The *Outlook* assumes further restraint, with growth of 0.7% per year over the outlook period. Despite this low growth rate, the population will still stand at over 1.4 billion in 2020, thus remaining at roughly one-fifth of the world total.

Another assumption involves gradual removal of energy price subsidies. Domestic energy prices should begin to follow trends in international energy prices towards the middle of the outlook period. Box 8.2 discusses energy price subsidies and market reform in more detail.

Box 8.2: **Energy Pricing and Market Reform**

Due to the large size of its energy sector, China's pricing policies have global repercussions. The predominance of coal in its energy system also has consequences for local pollution levels and for CO_2 emissions. Given the high carbon intensity of China's fuel mix, efforts at energy-market reform have high relevance to global attempts to reduce greenhouse-gas emissions. China's energy sector is slowly developing towards a system of markets based on economic criteria. One effort has forced the closure of illegal and semi-legal township mines for coal, to reduce a supply glut due partly to past price subsidisation. Steps were also taken to liberalise the market for petroleum products and to encourage private participation in the oil giants, Sinopec and CNPC.

In addition to direct transfers, subsidies in the Chinese energy sector are often administered through soft budget constraints, government guarantees for profits and revenues, tax rebates and the under-pricing of government services. The price reform of June 1998 linked domestic crude oil prices to international (Singapore) prices, but it did not affect state-set retail prices for major refined products. Coal still receives indirect subsidies through rail transport subsidised at about 20% less than the actual cost. A geographical mismatch between producing and consuming regions, as well as massive under-pricing, have led to a freight intensity per unit of GDP ten times that of India or Brazil. In 1995, coal used a staggering 45% of China's rail-freight capacity. Power shortages, once a serious brake on economic development, no longer give concern. The current problem is *overcapacity,* the result of a lack of demand and a rapid capacity build-up in 1997 and 1998, stimulated by subsidies.

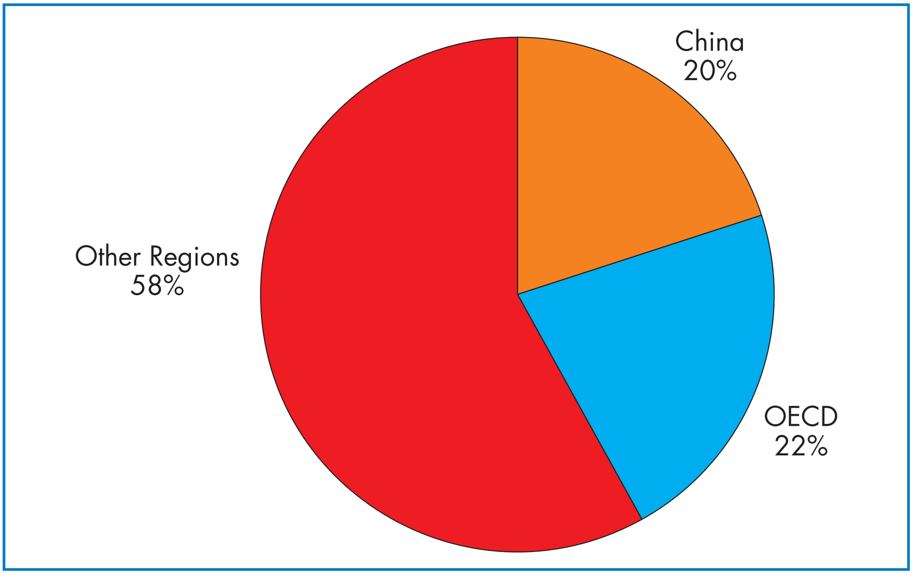
The 1999 IEA publication, *Looking at Energy Subsidies: Getting the Prices Right,* estimated the average rate of price subsidisation in the Chinese energy sector at about 11%. The removal of these distortions would lead to energy savings of over 14% and a reduction in CO_2 emissions of some 13%. Subsidy removal would also allow efficiency gains of 0.4% of annual GDP, without accounting for the dynamic benefits that would flow from the rationalisation and increased transparency of energy markets. In order to capture more of these benefits and to attract foreign investors with access to advanced technologies, further reform would have to discontinue remaining price controls, gradually free enterprises from social obligations while building a general social safety net, and ensure transparency and the rule of law.

Results of the Projections

Overview

Over the outlook period, total primary energy supply (TPES)[4] in China will grow by 3.4% per annum, compared with 4.5% from 1990 to 1997. It will reach some 1 940 Mtoe in 2020, not much less than energy demand in OECD Europe. China will have the largest incremental energy demand growth of any country in the world (Figure 8.2). Total energy consumption will more than double by 2020, while energy consumption in the OECD area increases by some 25%. The rate of decline in energy intensity is expected to slow, but it will still average some 1.8% per year over the outlook period.

Figure 8.2: **Breakdown by Region of Incremental World Primary Energy Demand, 1997-2020**

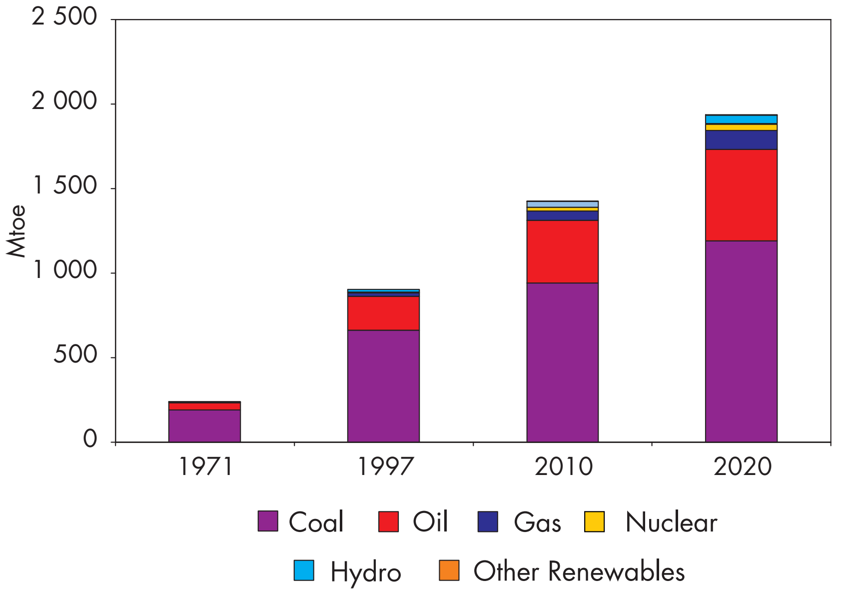


Coal will still account for the largest share of TPES in 2020 (Figure 8.3), even though its growth will slow to 2.6% per year from 3.5% in 1990-97. Coal demand is projected at 1 192 Mtoe by 2020, nearly 16% less than the 1998 *World Energy Outlook* projection. Recent evidence

4. This discussion focuses on commercial energy demand. Non-commercial energy demand in China is discussed at the end of this section.

confirms this adjustment; it indicates a decline in coal consumption over the past few years.[5] Most of the incremental coal demand will come from power generation. The share of oil will rise to 28%, while that of coal will fall to 62%, down over ten percentage points from 1997. Primary oil demand is expected to grow by 4.4% per year, with the transport sector accounting for most of the increase.

Figure 8.3: **Total Primary Energy Supply by Fuel**



Primary gas demand will rise by 7.5% per year over the outlook period, but will still account for only 6% of TPES in 2020. While expected growth in nuclear power demand will be a strong 10.5% per year over the outlook period, its share in TPES will still reach only about 2% in 2020. Hydropower will account for the remaining 3% of TPES in 2020.

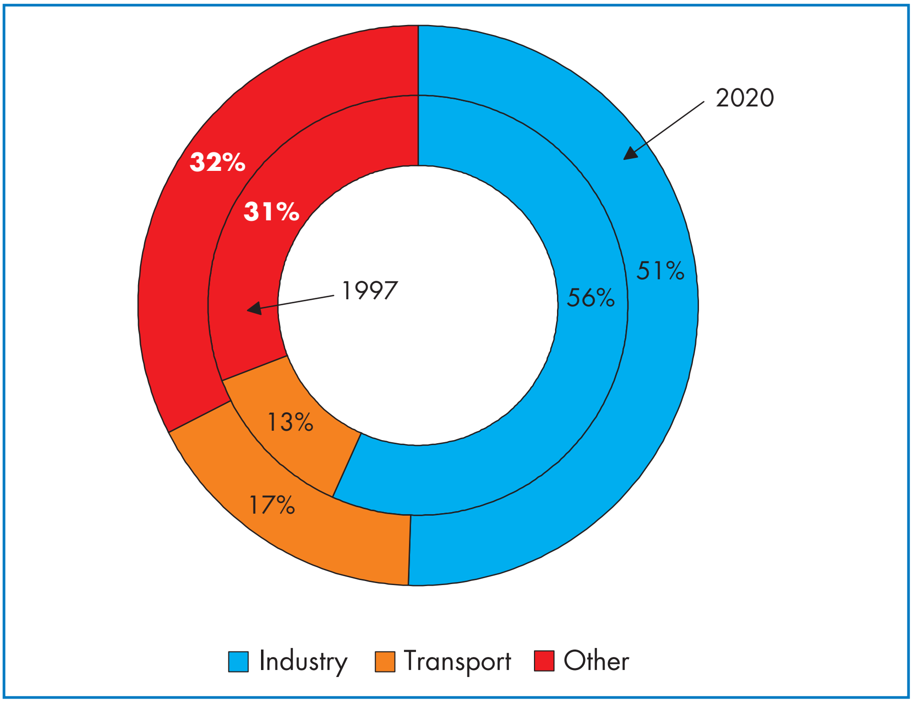
Final coal consumption will grow by just 1.3% per year, and its share is expected to decline dramatically, from 54% in 1997 to 35% in 2020. In contrast, the share of oil rises to 36% of final energy consumption. Gas will become the fastest-growing fuel for final consumption, at 6.6% per year,

5. China's production and primary consumption of energy declined in 1998 over 1997 levels. For a discussion of recent energy trends in China and several reasons for the decline in energy output and consumption, see Sinton and Fridley (2000).

although from a very low base. Its share in final consumption will be 6% in 2020, while electricity's share will rise by seven percentage points to 19%. In industry, electricity and gas will substitute for coal, helping increased energy efficiency and environmental improvement. The share of electricity used in industry will rise significantly to 21%, compared with 14% in 1997. In other sectors, which include residential, commercial, agricultural and public service energy demand, electricity's share moves to 30% from 16%. Use of coal in these sectors will remain constant over the outlook period, and its share will halve.

One of the key features of the Chinese economy is the historically very high share of industry, most likely a result of the emphasis placed on heavy industry prior to 1980. Industrial energy demand accounted for 57% of final energy consumption in 1997. Over the outlook period, however, transport will be the fastest-growing energy-consuming sector, with its share gaining four percentage points (Figure 8.4).

Figure 8.4: **Total Final Energy Consumption by Sector**



Energy demand in the transport sector is primarily for oil, although coal will account for 3% of total transport demand in 2020, down from

10% in 1997. Trends indicate a rapid expansion in transport oil demand, fuelled by rising mobility. Expected road-transport fuel demand for freight and passenger travel will account for a significant portion of this increase, given China's current very low ratio of car ownership to GDP and its increasing dependence on road and air transport. Freight-tonne kilometres by road grew twice as fast as by rail from 1990 to 1997, while road passenger kilometres more than doubled and passenger air travel leaped by over 230%.[6]

The Chinese government has actively encouraged the transport sector with increased investment; in its Ninth Five-Year Plan (1996-2000), it allocated $30 billion for railway investment and $20 billion to expand and upgrade the highway network.[7] Investment in highways has increased their competitiveness and has led to a shift in non-bulk commodity transport from rail to road.

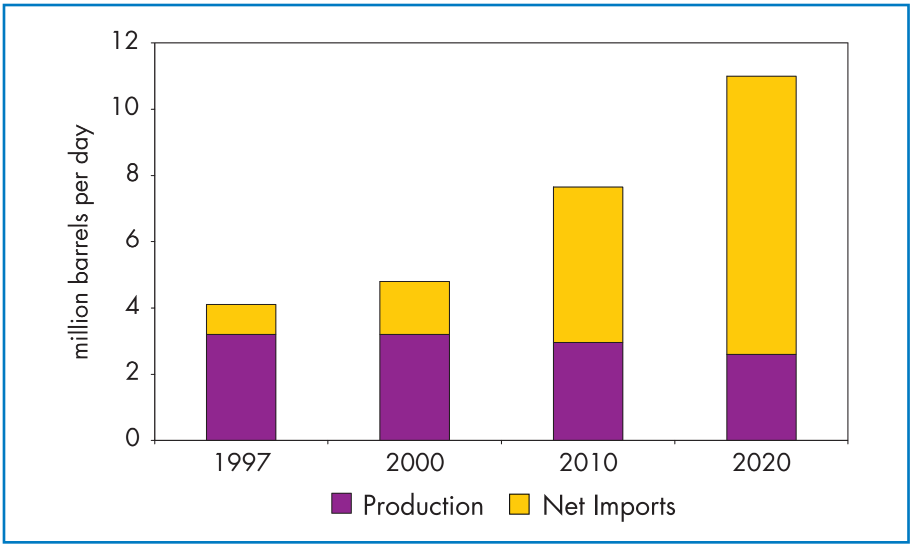
Non-commercial energy, or traditional biomass — shown separately in the projections presented in the *Outlook* — currently accounts for some 19% of China's total primary energy demand. Energy demand including biomass is expected to increase from 1 113 Mtoe in 1997 to some 2 158 Mtoe in 2020, implying gains in total energy intensity (*i.e.* commercial and non-commercial energy) of 2.2% per year. The share of biomass, however, is expected to fall to 10% of total energy demand over the outlook period, driven mainly by increasing urbanisation and the government's emphasis on rural electrification. The shift away from biomass will contribute to the expected increase in China's greenhouse-gas emissions but will reduce local pollution, especially particulates, with significant benefits for public health. Because biomass is generally used in very inefficient ways, its substitution with conventional fuels results in overall energy-efficiency gains and a decline in energy intensity.[8]

Oil

In the 1990s, oil demand in China grew by nearly 7% per year, from 2.3 mb/d in 1990 to 4.1 mb/d in 1997 and to an estimated 4.4 mb/d in 2000. Having nearly doubled over the last decade, it will still climb steeply over the outlook period, reaching 11 mb/d in 2020 (Figure 8.5). Demand for oil will be driven by a rapidly expanding transport sector.

6. Lui Hong, 1998.
7. ABARE and ERI, 1999.
8. The 1998 *World Energy Outlook* provides a comprehensive overview of China's non-commercial energy consumption.

Figure 8.5: **Oil Balance in China**



China became a crude-oil importer in 1996, although it had been a net importer of oil products since 1993. Since 1996, Chinese crude-oil production has averaged some 3.2 mb/d, 90% of it onshore. In the medium term, production will fall slightly, and demand will grow by nearly 60%, implying imports of some 5 mb/d by the middle of the outlook period. In the long term, expected production will decline to roughly 2.6 mb/d, demand will rise to 11 mb/d and imports will exceed 8 mb/d by 2020. Thus, net import dependence increases from 22% in 1997 to 76% in 2020.

The Daqing field in northeast China accounts for roughly one-third of total production, but it is a mature field and its output will decline. The Shengli field, also significant, currently produces some 500 kb/d. A significant proportion of recent oil finds have been offshore. In mid-1999, Philips China Inc. discovered a potentially huge oil field, Penglai (PL) 19-3 in the southern part of the Bohai Sea, with proven reserves estimated at more than 2.1 billion barrels.[9] The China National Offshore Oil Corporation (CNOOC) plans to develop the field jointly with Philips China during the second half of 2000 and put it into operation by 2004.

Other projects include exploration of the giant Tahe field in the Tarim Basin in western China, expected to yield 3.6 billion barrels; a potentially significant discovery in the Pearl River Mouth Basin of the South China

9. FACTS, 2000a.

Sea; and construction of the first shallow-water offshore operation in the Shengli oilfield, with estimated proven reserves of 2.3 billion barrels. The Bohai discovery and other planned developments have reversed the previously projected stagnation and ultimate decline of China's offshore oil production. Nevertheless, to sustain current levels in the medium-term, China would need to focus on maintaining production at the Daqing and Shengli fields through the continued use of enhanced oil-recovery technology.

To develop its pipeline network for crude and refined oil and gas, CNPC merged its pipeline construction and operation activities. A proposed pipeline running from Western Siberia in Russia to China remains in the very early stages but could indicate the beginning of a positive long-term relationship between the two regional giants. China has sought foreign investment in exploration and infrastructure development, but, so long as the Chinese partner must hold a controlling interest in such ventures, it is questionable whether the investment climate really is encouraging.

Almost all of the incremental oil demand will be sourced in the Middle East. Oman is the leading exporter of crude oil to China but Yemen, Indonesia, Iran, Angola, the United Kingdom, Norway, Saudi Arabia and Nigeria all are significant. China has acquired interests in exploration and production abroad, in Kazakhstan, Venezuela, Sudan, Iraq and Peru. Russia's Far East is also a potential source of oil imports.[10]

Gas

China has largely undeveloped natural gas resources, estimated at 38 billion cubic metres.[11] Proven reserves are quite low, however, with many known fields located in remote areas. The largest reserves are in western China.

Given the estimated level of China's gas resources and the environmental benefits of using gas, the Chinese government has focused on expanding gas production and consumption. China currently consumes very little gas, just over 2% of the energy mix in 1997, much of it used in the production of fertilisers. Gas demand will grow by 7.5% per year over the outlook period, from some 21 Mtoe in 1997 to 111 Mtoe in 2020, but its share in primary energy demand will reach only some 6% in 2020. Gas

10. China's efforts to secure its oil supply are described in the recent IEA publication, *China's Worldwide Quest for Energy Security* (IEA, 2000).
11. FACTS, 1999.

demand for power generation will be particularly strong, rising by over 12% per year, but will still capture only 3% of the power market in 2020. The Chinese have preferred to use coal for power, mainly because of supply security and economic concerns, but power generation may provide a significant market for gas over the long term.

The government still controls natural-gas prices in many urban areas. The state also regulates and prices distribution to large industrial users, mainly fertiliser plants. Gas prices are likely to rise towards the end of the outlook period, to accommodate planned infrastructure developments, but questions remain whether consumers will be willing to pay more for a cleaner fuel.

China does not currently import natural gas; production has matched demand over the past three decades. Current production is regionally diversified, with roughly one-quarter produced in Xinjiang, which includes the Tarim Basin, and the remainder spread among Qinghai, Shaanxi and Gansu provinces, Ningxia Hui Autonomous Region, Sichuan-Chongqing, and the Chinese East. Most gas is produced onshore, some 83% in 1998, but China has targeted several large onshore and offshore fields for future development. The largest offshore field, at Yachieng, provided the impetus for accelerated gas production in the second half of the 1990s. In the first half of 1999, China had 12 460 km of gas pipelines.[12] Provided that the gas industry is freed from the constraints placed on it at various levels of government, that fiscal impediments are lifted and that coal subsidies drop, gas supply and use could increase faster than any other source of energy.

Coal

China's coal industry faces severe problems of oversupply and high stock levels, and many large, state-owned mines operate at a loss. Government reforms aim to close down small coal mines without operating licenses or which are unsafe for operation. The closure of 30 000 small mines has had a positive effect on local coal prices, but provincial authorities resist closing marginal mines.

Coal accounts for the largest share of energy consumption in China, and demand increased fivefold from 1971 to 1997. Over the outlook period, expected growth in coal demand will slow to 2.6% per year, but demand will still double, rising to 1 192 Mtoe by 2020. Most of the increase will be in power generation.

12. Ibid.

Box 8.3: **Financing China's Natural-Gas Infrastructure**

Meeting the expected increase in gas demand depends heavily on finding capital for the necessary investments in infrastructure. This creates considerable uncertainty for the gas sector projections. China's plans to meet the expected increase in gas demand involve successfully increasing supply on three fronts: expansion of the national gas pipeline grid; construction of planned and proposed pipelines; and building terminals for LNG imports. Construction of the first large pipeline from the Northwest, from western Qinghai province east to Lanzhou City, began in April 2000 with expected completion by October 2001. Construction of China's longest pipeline, 4 200 km from Lunnan gas field in the Tarim basin in western China to Shanghai, also started in April, at an expected cost of $40 billion. PetroChina, the main entity of CNPC, is building it and seeks foreign participation. The government expects the pipeline to be completed in 2003, ahead of its original 2007 target, and to have an initial capacity of 12 bcm per year (*Financial Times,* 3 April 2000). Expansion of the national pipeline grid, of which the Lunnan pipeline constitutes a major portion, will proceed in three stages; it focuses on bringing gas from the remote Tarim basin into the main consuming markets in central and eastern China.

The five current proposals to import gas from Russia and Central Asia involve a total of over 28 000 km of pipelines and costs of some $65 billion. The earliest expected date of completion of the Russian pipeline is 2015; the others are not likely to come on line until 2020 (FACTS, 1999). Given the economic challenges involved, these projects remain speculative. In January 2000, China gave approval for a three million tonne LNG terminal and 400 km pipeline in the southern province of Guangdong (*Financial Times,* 13 January 2000). Australia, Indonesia, Malaysia and Qatar are competing to supply the natural gas. Completion of the terminal near Shenzhen is expected in 2005; it will supply two power plants yet to be built and gas for households to replace manufactured gas.

China has some 110 billion tonnes of proven recoverable reserves, 11% of the world total. Steam coal accounts for 83% and coking and gas coals[13] for the remainder. The proportion of coal reserves available to depths of 150 metres is limited, and future production will need to focus on mines exceeding that depth, which is more costly and possibly less productive. Coal production more than doubled from 1980 to 1996, but declined by 3.5% in 1997 to roughly 690 Mtoe. Estimated production fell further in 1998 and 1999. The domestic market is still characterised by oversupply, and exports are expected to increase by nearly 30% in 2000 over their 1999 level.

In the long term, however, imported coal could become economic in some regions of China, if import tariffs are reduced under the WTO and price subsidies are removed further.[14] The subsidised domestic price of coal in the Southeast is less than the true economic cost of production and delivery. The vast distances between coal consuming and producing regions cause transport costs to account for some 50% of the delivered cost of coal in southeastern China.

China is opening its coal sector to foreign participation, especially for modernisation of existing large-scale mines and for the development of new ones. New technologies, including coal liquefaction, coal-bed methane production and slurry pipeline transport, could aid the government's effort to improve the environment. Co-operation has started with South Africa to develop coal liquefaction technology, although this project will be costly and is very long-term in nature.

Foreign investment can benefit the Chinese coal sector only if major changes in property laws, export rights and regulations concerning coal transportation and the repatriation of profits enable it. The long-term future for coal production in China remains highly uncertain.

Electricity

Final electricity demand is expected to increase by 5.2% per year, roughly equivalent to the assumed GDP growth rate. The share of electricity in total final consumption will grow significantly, from 12% in 1997 to 19% in 2020. Technological improvements and an assumed shift in the industrial structure towards less energy-intensive industries will cause electricity to replace coal in some industries over the outlook period. Only some 80% of the population is currently connected to the electrical grid, so substantial room exists for expansion in this sector.

13. Gas coals include lower quality coals and brown coal/lignite which can be gasified in gasworks to make coal gas (often substituted for natural gas).
14. ABARE and ERI, 1999.

In 1997, electricity generation in China was 1 163 TWh, about three-quarters of it coming from coal-fired plants (Table 8.3). It is projected to grow by 5.1% a year over the next 20 years, slightly less than final electricity demand growth because of assumed reductions in transmission and distribution losses. Nearly one-quarter of the present combined output of electricity and CHP plants is heat. This share, on the order of 20% to 25% for several years, is slowly declining.

Table 8.3: **Electricity Generation in China** (TWh)

	1997	2010	2020
Total	**1 163**	**2 408**	**3 691**
Coal	863	1 711	2 568
Oil	83	145	197
Gas	7	57	149
Nuclear	14	83	143
Hydro	196	406	622
Other Renewables	0	7	12

Installed capacity in 1997 was 263 GW, 67% coal-fired, 23% hydro, 7% oil-fired and 1.6% gas-fired; nuclear and non-hydro renewables accounted for less than 1% each. To meet rapid demand growth, more than 500 GW of new or replacement capacity will have to be installed before 2020, bringing total capacity to 763 GW.

The power sector will continue to rely on coal, although its share in the electricity generation mix will fall to a projected 70% by 2020. The average efficiency of Chinese coal-fired plants is very low, 28% in 1997 compared with 38% in OECD countries. Reasons for the current low efficiency include the small size of power plants, inconsistent coal quality and often low plant availability. In 1997, units with capacities of less than 300 MW accounted for nearly 90% of thermal capacity.[15] Recent trends indicate construction of an increasing number of larger units. At the end of 1997, 28 GW of coal units larger than 300 MW were under construction. Plans foresee shutting down by 2004 plants with capacities of less than 50 MW and retrofitting older plants. Such trends will boost coal burning efficiency, which rises by 5 percentage points by 2020.

15. China Electric Power Information Centre, 1998.

Electricity generation from gas increases from 7 TWh in 1997 to 149 TWh (4% of total generation) in 2020, particularly in coastal regions and the South, in several projects to use imported LNG. Preference for gas over coal and oil will cause the share of oil-based electricity to decline by 2% over the projection period, although in absolute terms oil-fired power output will rise from 83 TWh in 1997 to 197 TWh in 2020. The growth in gas-fired power generation is particularly uncertain because it depends on the availability of infrastructure (pipelines or LNG terminals) and on gas demand in other sectors as priority goes to residential and industrial customers.

China started producing electricity from nuclear power in 1991 and now has 2.1 GW of nuclear capacity. Official long-term plans call for 20 GW of capacity by 2010 and 40 GW by 2020, but this target may be too optimistic, given the long lead times and the high capital costs entailed (about three times more per kW than a Chinese-manufactured coal plant). The *Outlook* assumes that nuclear capacity reaches 11 GW by 2010 and 20 GW by 2020.

China has extensive hydro-electric resources. Official estimates place total potential at 675 GW, of which 290 GW are economically exploitable. Hydro-power capacity stood at 60 GW in 1997; the *Outlook* assumes 171 GW by 2020. The most significant hydro project is the Three Gorges dam on the Yangtze River, which will have a capacity of 18 GW when completed around 2010. This timing has become uncertain because of concerns raised both inside and outside China about its environmental and human-settlement impacts.

China has abundant renewable energy resources. Their development can be economic in some areas, particularly remote, off-grid locations. Rural electrification programmes often include renewable energy projects. Wind power has the largest potential. Wind-power capacity could grow by a factor of ten over the next 20 years.

Significant uncertainty surrounds funding to finance new power projects and to retrofit existing ones. The estimate of investment required from both local and foreign sources amounts to more than half a trillion US dollars over the outlook period, equivalent to 1.2% of the country's GDP over the same period. Sources may include commercial banks, international development banks, export credit agencies, Chinese and foreign joint ventures and investors in fully foreign-owned projects. Insufficient or uncertain rates of return, administrative constraints and the lack of an adequate legal framework hamper private investment. The government has under development a "Framework for the Implementation of the Plan for

Grid and Plant Separation and Establishment of a Generator-Oriented Power Market (For Trial Implementation)". If implemented, it would restructure the power industry and introduce competition in generation.

Environmental Issues

Environmental problems, particularly local and regional effects of energy-related emissions (SO_x, NO_x, volatile organic compounds and particulates) receive increasing attention in China. The State Environmental Protection Agency gained ministerial status in 1998 with a mandate to focus on pollution control. Climate-change issues have a much lower priority, despite their interest to the international community.

The main sources of local and regional pollutants are industry (steel, cement, oil and chemicals), power plants, cars, dust and coal-based residential heating and cooking. Coal burning produces 85% of total SO_2 emissions, with 30% coming from power plants, which also contribute 28% of total particulate emissions. Emissions from power plants may be the easiest to control. With the progressive installation of electrostatic precipitators and scrubbers for particulates, concentrations have fallen from 16.5 grams per kWh in 1980 to 4.2 grams per kWh in 1996. Flue-gas desulphurisation (FGD) are used in some cases for SO_2 control.[16]

Due to its large population and its heavy reliance on coal, China's contribution to global GHG emissions stands quite high. CO_2 emissions in particular were 14% of the world total in 1997. The vast population makes per capita CO_2 emissions low by international standards, 2.6 tonnes per capita in 1997 compared with 11.2 tonnes per capita in the OECD. CO_2 emissions are expected to climb to nearly 6.5 billion tonnes by 2020, or roughly 18% of the world total. Per capita emissions will remain relatively low, rising to 4.5 tonnes in 2020, compared with 14 tonnes in the OECD.

16. IEA/CIAB, 1999.

CHAPTER 9
BRAZIL

Introduction

Brazil is Latin America's major energy consumer. Its total primary energy supply (TPES) of 132 Mtoe in 1997 accounted for roughly one fourth of the region's total energy demand. In the last five years, its energy sector has undergone profound regulatory and structural changes, including chiefly the opening of the electricity generation and distribution markets, the end of monopoly over oil and gas exploration and production (E&P) concessions, and projects for transnational pipelines and transmission lines. In oil, the exploitation of deepwater off-shore resources is likely to push Brazil towards the goal of self-sufficiency. Uncertainties continue to surround the outlook for both the reforms and oil output. Developments in Brazil have been considered sufficiently important for this *Outlook* that it has been modelled separately from the rest of Latin America.

Brazil ranked as the world's ninth-largest economy in 1997, with average annual growth of 4.2% since 1971. Its population of 164 million and GDP of $906 billion (measured in PPP terms) represent one-third of the Latin American totals; GDP per capita, at $5 500, ranks fifth, after Chile, Uruguay, Argentina and Venezuela.

Oil and hydro dominate Brazil's energy sector. In 1997, 65% of primary energy came from oil, roughly half of which was imported. In 1998, the import bill for oil and its derivatives reached some $10 billion, one sixth of the total import bill[1]. Pursuing policies aimed at reducing dependence on foreign energy, Brazil's federal government succeeded in decreasing oil's share in TPES from more than 80% in the early 1970s. National oil production has increased steeply since the second oil price hike in 1979, further reducing import dependence. Since 1984, Brazilian oil production has accounted for 50% or more of supplies despite a continuous increase in national oil demand. The recent, important upward revision[2] of the estimated undiscovered oil resources in Brazil's offshore fields and the

1. The Economist Intelligence Unit, 1999.
2. USGS, 2000.

liberalisation of exploration and production activities should both significantly boost domestic oil production. Over the next two decades Brazil is driving towards self-sufficiency and may become a minor net exporter by the end of the outlook period.

Hydro represented 18% of primary energy supply in 1997. It drove 87% of Brazil's 63 GW of installed power-generation capacity. The liberalisation of the electricity market is expected to help attract the investment required to meet increasing electricity demand. The new regulatory framework and international gas pipelines will facilitate the penetration of gas in the power sector; its share in TPES, only 4% in 1997, will grow to a projected 13% in 2020. Table 9.1 highlights Brazil's main energy indicators.

Table 9.1: **Brazil's Main Energy Indicators**

	1997	**1971-1997***	**OECD 1997**
TPES per capita (kgoe)	804	3.2	4 977
TPES per capita including CRW (kgoe)	1 051	1.5	5 135
Net oil imports (per cent)	50	2.7	56
Electricity consumption per capita (kWh)	1 805	5.5	8 350
TPES/GDP (toe/US$ thousand)	0.15	1.0	0.27
CO_2 / TPES	2.3	–0.7	2.4

Note: * Average annual growth rate, in per cent.

Macroeconomic Background

More than 60% of Brazil's GDP arises in the service sector. Industry accounts for 29% and agriculture for 8%.[3] This economic structure resembles those in the OECD. In Europe, for example, services provide 64% of GDP, industry 33% and agriculture 3%. Geographical differences in output are large in Brazil, with corresponding variations in economic welfare. The richer Southeast (the states of Sao Paulo, Rio de Janeiro, Minas Gerais and Espirito Santo) accounts for over half of GDP. Economic growth averaged 4.2% a year for the past 30 years, which included disruptive cycles of contraction and recovery in the 1980s and 1990s.

3. World Bank, 2000.

In 1994, the federal government launched the *Plano Real*[4], which introduced economic reforms, including reforms in the energy sector, and accelerated the opening of the Brazilian economy to international competition. The *Plano Real* successfully kept the Brazilian currency stable. Towards the end of six years of currency stability (1992-98), however, the Real became seriously overvalued against the US dollar, creating insurmountable vulnerabilities for the Brazilian economy in the wake of the Asian and Russian crises of 1997-98. In January 1999, Brazil had its own monetary crisis and devalued the Real by about 50% by allowing it to float. The crisis raised external financing costs, limited capital inflows[5] and contributed to the recession in Latin America as a whole; Argentina, Brazil's principal Mercosur[6] partner, felt the primary effects. The decision to allow the Real to float carried a strong risk of re-igniting high inflation and compromising the whole *Plano Real*. The Brazilian central bank therefore increased interest rates sharply. Short-term capital inflows held up, but higher rates impeded long-term private financing for new productive projects, including those in the energy sector.

Declines in agricultural and industrial production and in exports were shorter than expected, as the lower exchange rate supported export revival. Balance-of-payments pressures from oil imports have exceeded expectations, however, due to higher international oil prices since January 1999.

Economic growth stagnated in 1999. In 2000, the modest impact of the exchange-rate depreciation on inflation, which averaged only 8%-9% in 1999, became clear. This provided a first, positive, confidence-raising signal to the private sector, both domestic and foreign. Moreover, the Brazilian central bank has reduced interest rates, from over 40% a year in January 1999 to about 17% a year in July 2000, despite rising rates in the international markets. The primary public deficit (excluding interest payments) returned to equilibrium. Brazil's GDP is expected to grow by 3% in 2000, underpinned by rising private consumption and investment.[7]

Recent Energy-Sector Developments

Three main developments, now radically modifying the structure of Brazil's energy sector, will probably determine its future path. They include

4. Brazil's currency is called the Real.
5. In 1997, Brazil's foreign debt reached $198 billion, about one-fifth of GDP (World Bank, 2000).
6. Argentina, Brazil, Paraguay and Uruguay formed the Mercosur common market in 1991. Chile and Bolivia joined Mercosur later as associated members.
7. OECD, 2000.

reform of the electricity sector, international gas pipeline and transmission-line projects and the end of monopoly over E&P activities by state-owned companies.

Box 9.1: **Restructuring the Brazilian Electricity Sector**

Market reforms, together with Brazil's vast hydro potential, the gas pipelines already built or planned and the rising demand for electricity, are expected to make Brazil's electricity sector increasingly attractive for private investment. They already have had some success. The privatisation programme succeeded in increasing FDI from $9.9 billion in 1996 to $22 billion in 1998. The privatisation of the federal generators was a condition of the agreement Brazil signed in late 1998 to obtain emergency economic aid from the IMF. Before privatisation, the state-owned firm, Eletrobras, controlled Brazil's electricity market. It had four main subsidiaries, responsible for regional generation and transmission of electricity. State governments generally owned the distribution companies. The utilities with better results transferred their surpluses to a fund that financed utilities with worse performance, which thus had no economic incentive to increase their efficiency.

Due to this inefficient mechanism and to a severe financial crisis, estimated total electricity-sector debt reached $20 billion in 1993. In that year, Law 8631 required tariffs to reflect costs and permitted utilities to retain profits from efficiency gains. In 1995, Law 9074 provided a legal basis for Independent Power Producers and the electricity grid was opened to them. In 1996, consumers of more than 10 MW were allowed to buy electricity from any utility. Public bidding was mandated in the selection of concessionaires and open access to the transmission grid was guaranteed. In December 1996, Law 9427 established a new power regulatory agency, *Agencia Nacional de Energia Eletrica* (ANEEL). Privatisation of public-owned electric assets generated revenues of about $10 billion in 1997 (from 13 utilities), but only $5.6 billion in 1998 (from five utilities), as the programme slowed. Most of the assets sold were distribution utilities, because the economic risk is lower and the potential to improve productivity is larger for these assets.

The privatisation programme in the electricity sector is key to attracting capital, to reduce the government debt and interest payments on it. By September 1999, three electricity-generation companies, 16 distribution companies and the natural-gas distribution systems of Sao Paulo and Rio de Janeiro had been privatised. Currently, private investors own 26% of generation and 63% of distribution. The financial crisis slowed privatisation in 1998 and 1999, but the economic recovery now under way should raise investor confidence and re-launch the privatisation at a faster pace (Box 9.1).

Brazil plays an important role in the creation of a regional energy market, to promote efficient use of natural resources among energy consumers (Brazil, Uruguay and Chile) and energy producers (Venezuela, Argentina, Paraguay and Bolivia). Energy integration represents a key factor in economic integration. In Latin America, the first steps came during the 1970s and 1980s with the construction of large multinational hydroelectric dams (*e.g.* Itaipu, 12.6 GW, between Brazil and Paraguay; Yacyretá, 3.1 GW, between Argentina and Paraguay; and Salto Grande, 1.9 GW, between Argentina and Uruguay).

The integration process now has new momentum. Brazil signed new agreements with Venezuela and Argentina in early 2000. These accords, although different, call for greater co-operation in hydrocarbon markets and in regulation. They would allow an open market for petroleum, derivatives and natural gas within Mercosur and Latin America in general. Projects for transmission grids and gas pipelines also boost integration. Brazil will satisfy part of its growing demand by importing electricity from Argentina; it also plans to create grid connections with Uruguay and Venezuela. Because the federal government has designated gas-fired power as a high priority, gas imports have become a priority too. Imports from Bolivia began early in 2000 and imports from Argentina are planned.

Box 9.2 describes how the Petrobras oil-sector monopoly is ending. Despite the systematic growth of domestic oil production, which Petrobras led during the 1980s and 1990s, Brazil never reduced its external oil dependence below 40%, because demand kept growing steeply. Brazil relies primarily on Argentina, Venezuela and Nigeria to meet its oil demand.

Box 9.2: **Future Development of the Oil Industry**

The year 1997 was a watershed for the Brazilian petroleum industry. The approval of the New Petroleum Law (NPL) in August 1997 brought substantial progress in the transformation of Brazil's oil institutions by establishing a new oil and gas regulatory agency, *Agencia Nacional do Petróleo* (ANP).

In 1998 ANP announced that 92% of Brazil's sedimentary basins would go up for bidding, ending *de facto* the 45-year Petrobras monopoly. The first round of auctions, in June 1999, achieved a premium of over 50% above the minimum price and brought in $180 million. The second round in June 2000 earned $262 million.

According to the NPL, Brazil was to free imports of gasoline, diesel, jet fuel and other petroleum products by August 2000. Difficulties with a major tax reform, which includes changes in the taxation of refined products, will delay this opening of the national market to refined-product imports until December 2001.

Whether Petrobras will have to sell some of its refineries and pipelines is under discussion. Proponents see this as an urgent priority to make Brazil's oil sector more competitive. Petrobras owns 11 of Brazil's 13 refineries. According to ANP, the average fee for transporting oil products in the United States is about one-third lower than it is in Brazil.[8] Proponents thus consider open access to the Petrobras transportation and logistic infrastructures as essential to reduce those extra costs through more competition. Nevertheless, some argue that splitting the Petrobras downstream activities may not make sense in the new global oil world.

Despite the uncertainties regarding how a new oil market will evolve, Petrobras certainly will retain its leading role in the Brazilian economy. The government has rejected total privatisation of the company. Instead, it intends to offer about 35% of its shares on the national and international capital markets, thus keeping majority control. ANP estimates that the petroleum industry as a whole, including numerous new players, will invest $40 billion over the next five years. Some 70% of the Petrobras outlays will go to exploration and production, focusing on deep water, for which Petrobras maintains the world's drilling record. The company also plans to increase its domestic oil production from 1.1 mb/d in 1999 to 1.85 mb/d by 2005.

8. *Oil and Gas Journal*, 1999.

Assumptions

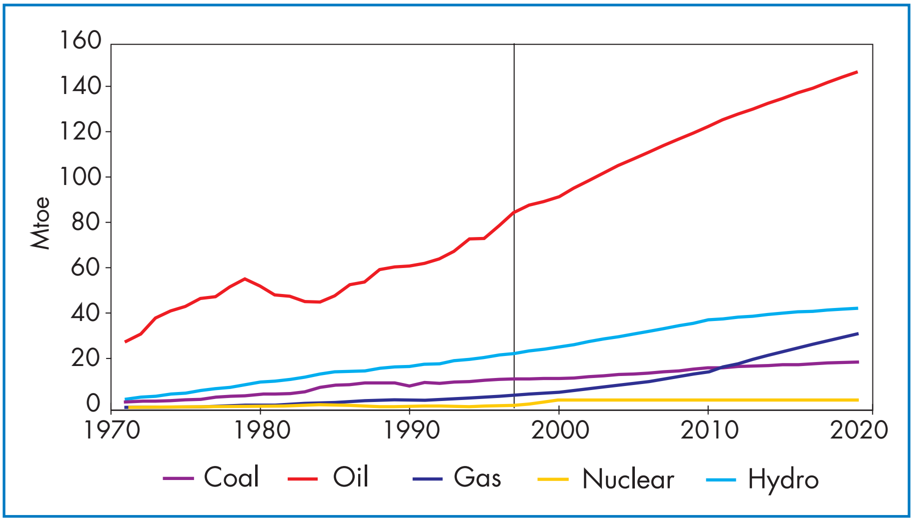
The projections in this *Outlook* assume that the Brazilian economy will grow on average at 3% per year from 2000 to 2010, after which growth will slow to bring down the average for the entire outlook period to 2.5%. The population will increase at 1.1% per year, reaching 209 million by 2020. In the short and medium term, both private consumption and investment should support somewhat faster growth, but as the economy matures they will be less buoyant. A stronger economic performance than these assumptions imply could induce higher energy consumption. The *Outlook* also assumes that energy prices will become more market-oriented as reforms proceed and that, consequently, prices of all energy products will follow the international price trends presented in Chapter 1.

Results of the Projections

Overview

Over the outlook period TPES will grow on average by 2.8%, compared with 5.2% from 1971 to 1997. It will reach 250 Mtoe by 2020, almost double the 1997 value. Per capita consumption will increase from 0.8 toe to 1.2 toe, still only one-third of the current average for OECD Europe. Energy intensity, which grew by 1.5% per year from 1990 to 1997, will increase by a slower 0.8% a year to 2010, then reverse its trend to decline by 0.3% per year in the second outlook decade. Gas is expected to be the fastest growing fuel in TPES, with average growth of 8.2% per year. The bulk of expected gas demand will come from power generation. By 2020, gas will account for 13% of TPES, tripling its current share of 4%. Oil's share will drop modestly but still take almost 60% of TPES in 2020. Coal (2.1% growth) and hydro (2.6%) will also contribute slightly less to TPES by 2020. Electricity demand will grow by 3% per year over the outlook period, averaging 3.7% between 1997 and 2010. Figure 9.1 shows actual and projected primary energy supply, by fuel, from 1971 through 2020.

Figure 9.1: **Total Primary Energy Supply by Fuel**



Sectoral Demand Trends

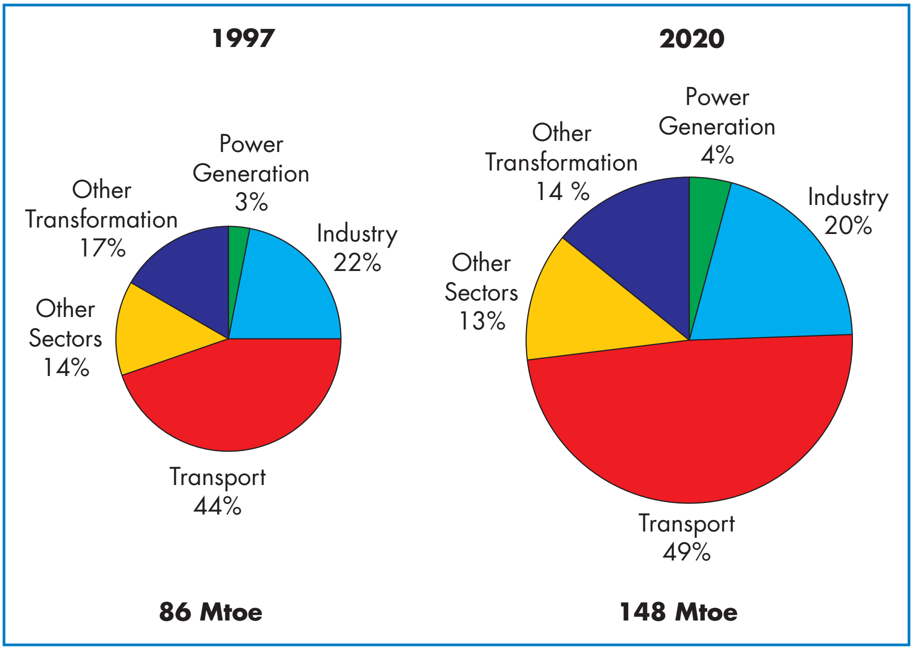
Expected total final consumption will increase by 2.7% per year, reaching 195 Mtoe in 2020. Energy consumption growth in industry, at 2.7% per year, will closely follow GDP growth. Oil will still dominate industrial energy use, although gas is expected to double its share from 9% in 1997 to 19% in 2020. Expected consumption in other sectors should reach 47 Mtoe by 2020, almost double that in 1997.

Increases in per capita incomes will spur the number of electric appliances per household. Growth will also be strong in the commercial sector where, for example, rising tourism-related activities will boost electricity demand. Electricity consumption in these two sectors and service will double, and its share will reach 57% in 2020, up from 52% in 1997.

Oil demand in transportation is expected to increase at an average rate of 2.8%, and to reach 72 Mtoe in 2020 almost doubling its current consumption (Figure 9.2). A substantial potential remains for more vehicle ownership as incomes rise. Brazil had 77 vehicles per 1000 people in 1996, well below 172 in Argentina, 137 in Mexico and an average of 92 among the Mercosur countries.[9]

9. International Road Federation, 2000.

Figure 9.2: **Oil Demand by Sector**



Oil

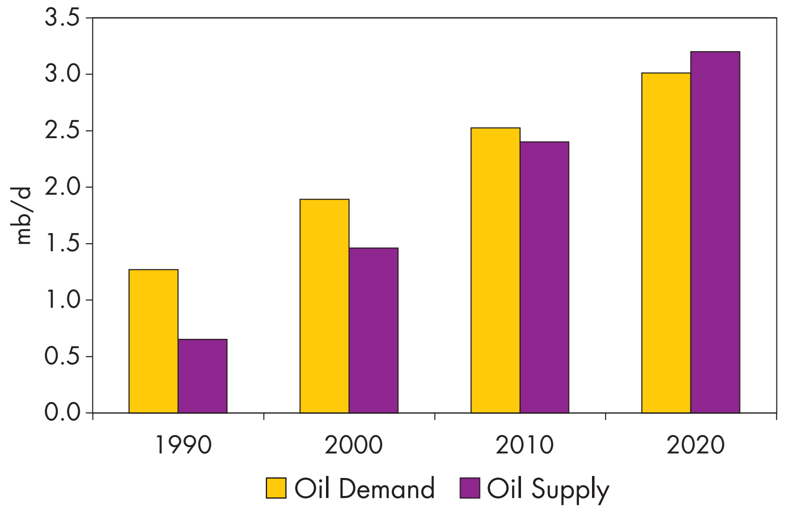
Brazil relies heavily on oil. Expected primary oil consumption will rise from 86 Mtoe in 1997 to 148 Mtoe in 2020, at an annual average rate of 2.4%. While oil's share will fall to 59% from 65%, it will still dominate Brazil's energy use. The transport sector will account for most of this growth.

The US Geological Survey estimates that Brazil has some 47 billion barrels of undiscovered oil, almost all in offshore fields, with about 35% in the offshore Campos basin.[10] With such improvements in the resource base, the peak in Brazilian domestic production can theoretically occur after 2020. Brazil produced 1.36 mb/d of oil in 1999. Increases in production are likely to emerge from the introduction of private capital, the more competitive environment and increasing foreign participation in exploration and production. Expected production should reach 2.4 mb/d in 2010 and 3.2 mb/d in 2020, while demand moves to 2.5 mb/d in 2010 and 3.0 mb/d in 2020 (Figure 9.3). The *Outlook* thus expects that Brazil will be

10. USGS, 2000.

self-sufficient sometime after 2010 and may become a small net exporter in the future.[11] If demand were to increase faster, chiefly as a result of higher GDP growth, any export availability could be less than projected. Moreover, renewed macroeconomic and political difficulties as well as costly exploration and production activities could slow the arrival of foreign investors, attract less capital than expected, constrain production growth and impede achieving or sustaining self-sufficiency. These issues remain uncertain in the energy outlook for Brazil.

Figure 9.3: **Oil Balance in Brazil**



Gas

In 1997, gas contributed only 4% of total final consumption and total primary energy supply. Industry consumed two-thirds of primary gas demand, 3.5 Mtoe out of 5.3 Mtoe of gas in TPES. The share of gas in the other sectors (residential, commercial and agriculture) was only 1%. Over the outlook period, gas in TPES is expected to grow by 8.2% a year, to 13% of TPES in 2020. Most of the expected growth will occur in power generation, where projected gas demand in 2020 reaches 16 Mtoe, a large multiple of 1997's 0.3 Mtoe. Government plans to promote gas use in the power sector are described in Box 9.3.

11. Other sources share this view, although the timing is uncertain. See, among others, *Petroleum Intelligence Weekly*, 2000 and *The Petroleum Finance Company*, 2000.

Box 9.3: **Recent Government Gas Development Plans**

In February 2000, the Brazilian government announced ambitious plans to build 49 gas-fired power stations by 2009, to avoid serious energy shortages during the next few years. The new plants would add an estimated 15 GW to total installed capacity, and consume around 70 million cubic metres per day (cmd) of natural gas. In June, the government decided to accelerate construction of some of the new stations. Under a published Emergency Plan, the government foresees the construction of plants totalling 11 GW by 2004, corresponding to some 40 million cmd of gas consumption. At least ten of them (approximately 2 500 MW) should be built by the end of 2001 or the beginning of 2002.

The government promotes gas use in the power sector mainly by selecting plants to receive special advantages. The recent financial crisis slowed privatisation and increased uncertainties about the availability of markets for new plants. Through the state-owned Eletrobras, the government offers the necessary power-purchase agreements and assumes the role of ultimate buyer of the electricity generated. To reassure investors concerned about gas-price fluctuations, the government, through Petrobras, will set price ceilings in 20-year fuel-supply contracts signed with developers before 2003. Although prices are subject to changes, the current proposal offers $1.94/MBtu for domestic gas and $2.26/MBtu for imported gas, not including taxation or margins for local gas distributors. The state-owned national development bank, BNDES, will offer a special loan programme to developers of thermal and small hydro plants contracted before 2003.

Despite the availability of gas and the high potential for major natural gas projects between Brazil, Argentina and Bolivia, several problems can still endanger plans to boost gas-fired power generation quickly. Obstacles include project financing, bureaucratic delays in getting the necessary environmental permits, the shortage of turbines in the international market and the lack of trained manpower to operate the planned power stations. Considering all these potential difficulties, the increase of power-sector gas consumption planned by the government appears too ambitious. The *Outlook* projects consumption to increase at a somewhat slower rate.

The pace of any increase in gas consumption in the industry and the other sectors depends mostly on the availability of resources to build the necessary infrastructure. At the moment, only Comgas (the largest Sao Paulo natural-gas distributor), CEG and Riogas (Rio de Janeiro's distributors) and Bahiagas (Bahia's distributor) have significant distribution infrastructure in place. Current Comgas customers comprise some 500 industrial users and roughly 300 000 buildings. The projection here assumes that gas will go first to fuel power plants. Industry will have second priority, and other sectors third, reflecting cost differentials for connection to the grid.

Brazil produced 5.6 bcm of natural gas in 1997, just meeting domestic demand. Most of the gas is associated with oil in offshore fields. Reserves are estimated at around 260 bcm. Like oil production, gas output should rise with liberalisation of exploration and production activities.

To meet future gas demand, Brazil plans to import gas from neighbouring countries. The *Gasbol* Bolivia-Brazil pipeline, recently completed at a cost of $2 billion, links fields in southern and central Bolivia to Sao Paulo and ends in Rio Grande do Sul. Plans had called for the pipeline to move eight million cmd during the first year of operation, rising to 17 million cmd by 2006 with a potential for 30 million cmd. In 1999, however, delays in gas-plant construction reduced demand much below expectations; only 800 000 cmd were imported. Other new pipelines planned or under construction will bring gas from fields in Argentina to southern Brazil, via Uruguay and/or the Brazilian city of Uruguaiana on the Argentine border. *Transportadora de Gas del Mercosur* (TMG), an extension of the Argentine pipeline *Transportadora de Gas del Norte* (TGN) now being built, will supply 2.5 million cmd of gas from Argentina's Neuquen province to Uruguaiana, where a 450 MW gas-fired power plant is being built. Plans call for a further extension to Porto Alegre (Rio Grande du Sul). In a competitive project to provide Argentine gas to Porto Alegre, the pipeline connecting Buenos Aires and Montevideo will be extended. This project is called the *Gasoduto Cruz del Sur*.

Coal

Coal in TPES is expected to increase by 2.1% per year over the outlook period, substantially more slowly than the 6.5% growth rate between 1971 and 1997. The share of coal in TPES will decline slightly, from 9% in 1997 to 8% in 2020. Coal finds use mainly in the iron and steel industry, with a smaller quantity going to electricity generation. In 1997, consumption of coal was 4.4 Mtoe in industry and 1.6 Mtoe in power generation. Brazil, the world's ninth-largest steel-maker, produced 25 million tonnes of crude steel in 1999, some 3% less than in 1998 due to the sluggish economy. Both the maturing of the iron and steel industry and technological progress over the outlook period will slow down coal consumption in the industry.

The *Outlook* projection assumes that Brazil will need 3.5 Mtoe of coal to fuel power plants by 2020. Local coal is promoted as an alternative to imported gas in areas with no gas infrastructure, but the major coal reserves occur mainly in the southern states, where competition from imported Bolivian and Argentinean gas will be strong.

Brazil has coal reserves of 32 billion tonnes, most of them unmarketable due to high sulphur and ash content. To meet domestic demand in 1997, Brazil produced 5.6 million tonnes of hard coal and imported 12.9 million tonnes. Half the hard-coal imports come from the United States and roughly another fourth from Australia. Brazil will continue to be one of the world's major coal importers.

Electricity

Expected final consumption of electricity will increase by 3% per year over the outlook period, faster than the assumed GDP growth rate and implying almost a doubling of electricity demand. Nearly 60% of the increase will come from the residential and commercial sectors. Average monthly electricity consumption per residential customer increased from 148 kWh in 1994 to 179 kWh in 1998. Brazil currently has only 43 million electricity consumers, and some villages still have electrification rates less than 50%. The *Outlook* expects electrification to increase, with more households connected to the grid. The fastest growth will occur in isolated systems located in states in the Northern region. The South/Southeast/Midwest interconnected system, linked to the North/Northeast grid in January 1999, will slightly decrease its consumption share of some 80% in 1998.

To face demand growth, Brazil will need to double its installed capacity, adding some 64 GW by 2020. In 1997, electricity generation reached 307 TWh. Nearly 87% of the installed capacity was hydro and the rest came from thermal plants (Table 9.2). The expected generation mix will move gradually to gas-fuelled (single and combined-cycle) power plants. By 2020, gas plants will represent 11% of installed capacity. Brazil will continue to rely on hydro, although its share will decline to 80%.

Table 9.2: **Electricity Generation in Brazil** (TWh)

	1997	2010	2020
Total	**307**	**516**	**637**
Coal	5	9	12
Oil	10	17	22
Gas	1	20	69
Nuclear	3	11	11
Hydro	279	445	507
Other Renewables	9	12	16

Brazil has an estimated hydro potential of 247 GW, of which 143 GW are economically exploitable. About 40% of the potential lies in the Amazon basin, particularly in the state of Para. Technologies such as low and ultra-low-head hydropower will allow exploitation of the basin's rivers, which are characterised by large discharges and low heads. The challenge of building transmission systems through dense jungle will persist.

Two big hydro expansion projects are currently under development. In the Tocantins River basin, a 4.1 GW expansion of the existing 4.2 GW Turucui plant is under construction, along with a 1.4 GW expansion of the world's largest hydro station, the 12.6 GW Itaipu Binacional, a joint project with Paraguay. Completion of these plants will probably signal the end of building large power stations located far from consumers. The main forces working in this direction are the privatisation and liberalisation of the power sector and environmental considerations. A requirement introduced in 1986 for an Environmental Impact Report on every proposed power station added significantly to project costs, often making the development of new projects uneconomic.

Much of the increase in hydro capacity will come from upgrading large power stations, installing medium-sized ones (30-200 MW) and reactivating or building small hydro plants (up to 30 MW).[12] These options can help deal with environmental concerns and will more easily attract private investors.

Expansion in the North and Northeast should occur almost solely with the expansion of hydro plants. Amapa will rely on small hydro and local oil-fired generation. Amazonas and Roraima will use electricity from Urucu (in

12. Some 475 small stations now operate, with an installed capacity of 926 MW. (*Olade Energy Magazine*, 2000).

Amazonas) and imports from Venezuela. In the South, South East and Midwest, new capacity will be a combination of new hydro and gas plants, the latter fuelled primarily by imports from Bolivia.

As noted in Box 9.3, the federal government has created incentives to help investment in gas power plants that have stalled because of market uncertainties. The Ministry of Mines and Energy has designated 49 proposed gas-fired plants as high priorities for the next few years. Nevertheless, lingering uncertainties about the costs of gas and of local gas-distribution infrastructures could delay the projects. Moreover, the integration of large, gas-fired power plants operating on baseline with Brazil's unique, mainly hydro system appears more complex than was expected.

The Ministry of Mines and Energy, in partnership with ANEEL (Box 9.1), has a programme to award concessions for 94 hydro and 17 thermal projects, for a total of 37.1 GW and a total investment of $37.6 billion.[13] Although ANEEL hoped to award concessions for new hydro plants totalling 3 765 MW in 1999, it managed to award only some 200 MW. New installed capacity in 1999 was 2.5 GW. The breakdown is shown in Table 9.3. Total investment over the projection period is estimated to be on the order of $127 billion.

Table 9.3: **Additional Installed Capacity, 1999**

Capacity (MW)	Hydro plants (number)	Gas plants (number)	Per cent of 1999 capacity
< 30	11	-	10
40-42	5	2	11
101	3	-	12
150-162	1	2	18
310	4	-	49

Source: Operacao do Sistema Interligado Nacional (1999), *Operador Nacional do Sistema Eletrico,* Brasilia.

Brazil currently has two operating nuclear power plants, the 657 MW Angra I and the 1.3 GW Angra II, near Rio de Janeiro. Construction of the 1.3 GW Angra III unit started in 1981, but the plant was never completed

13. *International Private Power Quarterly*, 2000.

because of lack of funds. The *Outlook* assumes that Angra III does not start to operate within the projection period.

Among alternative energy sources, photovoltaics in rural communities and wind power have received attention. In 1997 installed wind capacity was 3.7 MW. Wind-power generation should double over the outlook period.

Combustible Renewables and Waste (CRW)

Brazil consumed 40 Mtoe of CRW in 1997, or 23% of total primary energy demand. Industry accounted for half the consumption. By 2020 CRW use will reach only 49 Mtoe, with its share in energy demand declining to 16%. The power sector will account for most of the growth: an additional 4 Mtoe will fuel 2 GW of new capacity by 2020. Among CRW fuels, bagasse (sugar-cane waste) plays an important role. Installed bagasse-fuelled capacity in 1998 was 995 MW, with the economic potential estimated at 4 GW and suitable for co-generation schemes. Brazil produces the daily equivalent of 270 000 boe of bagasse. Apart from power generation, bagasse represents a major fuel input for the food and beverage industries, whose consumption of CRW in 1997 equalled 19 Mtoe. CRW consumption in industry will increase by 1.1% per year over the outlook period, compared with 2.2% in 1990-97. A draft law proposal to include renewables in the "Isolated Systems Fossil Fuel Consumption Account", if implemented, will encourage further use of CRW.

Brazil launched its Pro Alcohol Programme at the end of the 1970s. In an attempt to stimulate domestic resource use and to reduce dependence on imported oil, the government introduced measures to promote the use of biomass-based ethanol — pure or as a blending component in gasoline — as car fuel. In 1985 ethanol-car sales took 96% of the market, with sales of 4.5 million cars by the end of the 1980s. In 1990 ethanol consumption equalled that of gasoline. As the incentives have diminished, however, ethanol-car sales have plunged (to nearly zero in 1996), and ethanol has lost share in final transport-sector fuel consumption. By 1997 consumption had fallen to 6.7 Mtoe, compared with 14 Mtoe for gasoline and 21 Mtoe for diesel.

Brazilian legislators seek to increase ethanol use to fight urban pollution and to reduce CO_2 emissions. Nonetheless, the liberalisation of oil-product markets is likely to affect the programme adversely. Although the market for pure ethanol is likely to shrink further in the absence of new incentives, there still remains some potential for ethanol blending. The

Outlook projections assume that alcohol consumption will increase slightly, by 0.2% per year, over the next two decades.

Environmental Issues

Brazil hosted the United Nations Framework Convention on Climate Change (UNFCCC) in June 1992 at the Rio Earth Summit. In 1994 it ratified the Convention. The Brazilian government has looked especially at how the agricultural and forestry sectors can contribute to the mitigation of climate change, because Brazil contains 16% of the world's forest area. In 1997 CO_2 emissions due to deforestation were estimated, depending on the source, to produce from two to three times the CO_2 emissions from fossil fuels in the energy sector.

In 1996 the government enacted the Provisional Act to regulate land use in forested areas. Among other measures, the Act provides for the prohibition of further conversion of forested areas to agriculture in the North and in the northern part of the West-Central region. Given the institutional constraints and geographic characteristics of these regions, however, such regulation has no practical effect, because these regions have neither the facilities nor the capital to monitor and enforce the Act.

Expected energy-related CO_2 emissions will reach 570 million tonnes by 2020. Brazil has very low per capita emissions due to its heavy reliance on hydro. Even if per capita emissions increase as projected, from 1.8 tonnes to 2.7 tonnes, they still will lie far below the OECD average of 14 tonnes. The change in the energy mix over the outlook period will not alter the 2.3 tonnes of CO_2 emitted per toe of TPES, because the decline in the share of hydro will be balanced by the substitution of gas for coal.

PART C

SELECTED ISSUES ARISING FROM THE *OUTLOOK*

Building on the foundations laid by the projections of the Reference Scenario, this Part explores several key issues currently under discussion or raised by the *Outlook* itself. Chapter 10 leads off with an analysis dealing with the problem of greenhouse-gas emissions and Annex B countries' commitments for emission abatement under the Kyoto Protocol. It focuses particularly on emission trading, currently under global discussion as a mechanism for meeting those commitments. Chapters 11 and 12 shift the perspective to issues arising from the *Outlook* projections themselves. Given that projected global increases in energy use — and CO_2 emissions — to 2020 are likely to be concentrated in transport (Chapter 11) and power generation (Chapter 12), these chapters posit alterations to the policy and/or technical assumptions of the Reference Scenario. These Alternative Cases permit exploration of how effectively changed policies or technological conditions could mitigate the problems raised by the *Outlook's* projected heavy energy use in these two sectors. Chapter 13 makes a special study of the energy outlook for India, an increasingly important country on the world energy scene not regularly covered in depth in the *WEO*. Finally, Chapter 14 presents a self-examination, in the form of an evaluation of past *WEO* projections.

CHAPTER 10
GREENHOUSE-GAS EMISSION TRADING

Introduction

Energy production and consumption are linked to a number of economic, environmental and social issues. The large scale of energy installations, the environmental risks they can pose, their importance for employment and economic development and the inevitable political connotations of supply security — all of these prevent energy from being "just another commodity."

Energy issues are critical to efforts to assure sustainable development. The focus has shifted increasingly towards the risks energy use poses to public health and the environment. One risk relates to the emission of greenhouse gases (GHGs), their accumulation in the earth's atmosphere and the danger of global warming.

In the wake of new scientific data collected in the late 1980s, the UN General Assembly mandated an Intergovernmental Negotiating Committee (INC) to draft a climate convention. The UN Framework Convention on Climate Change (UNFCCC) was opened for signature at the "Earth Summit" in June 1992 and came into force in March 1994. Today more than 180 countries have acceded to it. Commitments under the UNFCCC became concrete with the Kyoto Protocol in December 1997, under which most of the OECD countries have specified commitments to limit GHG emissions. Countries with specified commitments are also referred to as Annex B countries in the language of the Kyoto Protocol.

Past *World Energy Outlooks* have looked at energy-related environmental issues, particularly CO_2 emissions, but this *Outlook*, for the first time, models the trading of CO_2 emissions among Annex B countries as an important instrument for fulfilling the Kyoto commitments.[1] The results confirm emission trading as an efficient instrument to reach emission

1. The IEA also studies other issues related to the design and implementation of international emissions trading, such as liability, market power and access as well as the financial dimension of the mechanism.

targets and provide policymakers with a realistic view of its costs and benefits.

In its modelling, the IEA has chosen as its base case a configuration that lies between two extremes — namely immediate, full efforts to implement the Kyoto commitments from 2001 onwards or no action until 2008. This middle ground, which is called the *progressive action scenario*, assumes that each country or region begins with limited action in 2001, which it gradually increases until 2008, whereafter the Kyoto constraint on annual emissions is fulfilled. The "early action" and "late action" scenarios receive brief discussion at the end of the chapter, for comparisons and sensitivity analysis.

The trading of emission permits lies at the heart of the progressive action scenario. Before launching a discussion of the scenario itself, the sections below are meant to give it context and justification. They present the flexibility mechanisms of the Kyoto Protocol, the relationship between CO_2 emissions and energy consumption and the case for emission trading.

The Kyoto Protocol and Its Three Dimensions of Flexibility

The Kyoto Protocol lists six GHGs relevant for country commitments: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbons (HFCs), perfluorcarbons (PFCs) and sulphur hexafluoride (SF_6). These six gases (or groups of gases) have different global-warming potentials (GWP). The magnitude of that potential per tonne of gas is expressed as the number of tonnes of CO_2 that would have an equivalent global warming effect (Box 10.1).[2]

Box 10.1: **Global Warming Potentials**

Estimates over a Hundred-Year Horizon*

Carbon dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous oxide (N_2O)	310
Hydrofluorcarbons (HFCs)	140 – 11 700
Perfluorcarbons (PFCs)	6 500 – 9 200
Sulphur hexafluoride (SF_6)	23 900

* Typical uncertainties are about +/- 35 per cent.
Source: Houghton, J. et al. eds. (1996) p. 121.

2. Or "anthropogenic carbon dioxide equivalent emissions".

The Kyoto Protocol defines countries' commitments as percentages of their emissions of greenhouse gases in a given "base year", 1990 for most of them (see Table 10.6). The actual levels are expressed in tonnes of carbon dioxide, while the contributions of other greenhouse gases have been converted into carbon-dioxide equivalents.

An ability to fulfil the cumulative commitment by choosing among the six greenhouse gases can lower the total costs of emission reduction. Each GHG has different marginal abatement costs per tonne,[3] and a country can choose the least costly among the six for each tonne of reduction towards its commitment. This is one of three cost-reducing "flexibility mechanisms" built into the Kyoto Protocol.

The other two are temporal and spatial. Because countries' compliance with their commitments is judged by their *average* annual emissions during the "budget period" 2008-2012, they can avoid possible cost peaks associated with full compliance in a given year. Most important, they also can choose *where* to achieve reductions in greenhouse gas emissions. The per-unit costs of achieving such reductions can differ greatly from country to country. A country with low marginal costs could reduce an additional tonne of carbon dioxide *beyond* its commitment at less cost than a country with high marginal costs that is struggling to fulfil its own commitment. Both would gain if the second country paid the first to shoulder some of its commitment burden. The basic mechanism to transfer abatement efforts in this way is called "emission-permit trading"; each tonne of emissions abated and sold constitutes a permit for the buyer to emit an additional tonne.

This basic rationale for emission trading has several ramifications. First the location of emissions does not matter. Second, concerns are voiced occasionally that emission trading allows countries to "shirk" their commitments.[4] The issue of "hot air" fuels these concerns. "Hot air" occurs when countries produce fewer emissions than the Kyoto Protocol allows. For some, their emissions decline because of extraneous events since the base year, 1990. For example, several countries of Eastern Europe and the former Soviet Union experienced substantial declines in economic activity during the early 1990s. These developments resulted in drastically reduced GHG emissions, so several of these countries could sell their surplus, allocated but unrealised emissions — their "hot air" — to other countries.

3. Refers to the cost of abating one additional tonne of CO_2.
4. In the negotiations following the conclusion of the Kyoto Protocol, the European Union demanded "caps" on trading, to limit the percentage of a country's total commitment that could be met through emission trading.

From the point of view of environmental efficiency, such concerns seem unfounded. So long as the agreed-upon environmental goal is met, there is no reason not to meet it at the least possible cost, even including "hot air". The implicit question — whether more ambitious targets could have been formulated — is valid. It refers to negotiating dynamics, however, and is independent of the mechanism of emission trading *per se*.[5]

Third, emission trading requires substantial monitoring and enforcement in the participating countries. The absence of credible monitoring of emissions and reduction efforts would quickly lead to a situation in which the least diligent countries could offer the lowest prices for reductions and attract the largest market share. This would erode the credibility of emission trading and ultimately squander the advantages that it should offer to all participants.

Fourth, should emission trading be limited to countries with commitments under Annex B of the Kyoto Protocol? It is well established that many countries without commitments, notably many developing countries, can achieve emission reductions at costs lower than those that prevail in many Annex B countries. In fact, the Kyoto Protocol holds open the possibility for Annex B countries to pay for and be credited with emission-reduction efforts in developing countries on a project-by-project basis. This project-based approach is referred to as the Clean Development Mechanism (CDM) (See Box 10.2).

Emission trading has received more attention from governments than the CDM, mainly because of its ability to account for large, countrywide efficiency gains in a comparatively short time. It has become a distinct policy option elaborated among politicians and experts alike.

Carbon Dioxide Emissions and Energy Consumption

The World Energy Model (WEM), the basis of the *Outlook*, includes an energy-demand model, a cost-minimising linear-programming module with several technologies for the power generation sector and a module for fossil-fuel supply prospects.[6] Projected energy-related emissions of CO_2, by far the most important energy-related greenhouse gas, are derived from the energy-consumption projections. Energy-related CO_2 emissions accounted

5. One should note, however, that total emissions during the budget period with Annex B trading are *higher* than without emission trading. The reason is that in the no-trade case the inevitable reductions in the countries with "hot air" are added to the efforts of Annex B countries. In the with-trade case the two magnitudes are netted out.
6. See Appendix 1 for a description of the World Energy Model.

for 84% of total GHG emissions of Annex B countries in 1990. If land use and forestry are excluded, the figure is 80%.[7]

Box 10.2: **The Clean Development Mechanism (CDM)**

The CDM has two objectives: (1) to help developing countries achieve sustainable development; and (2) to assist Annex I Parties in meeting their emission obligations under the Protocol. Unlike emission trading, which is based on Annex I Parties' Kyoto emission objectives, the CDM concerns emission reductions generated by individual *projects* in developing countries. Such projects must lead to reductions "additional" to any that would occur in their absence. A CDM project generates emission "credits" that can be used by an Annex I Party to offset an increase in its own emissions. By providing a way to reduce emissions in countries and regions with lower mitigation costs, the CDM can help Annex I Parties to meet their emission objectives most cheaply. Specific rules, modalities and guidelines for the CDM still need to be worked out through the formal UN negotiating process.

Will the CDM work? Various analyses point to its economic attractiveness. An IEA paper includes a survey of eight global macroeconomic models with scenarios that show the potential for cost reduction through emission trading augmented by the CDM.[8] On average, they estimate marginal abatement costs without use of the Kyoto mechanisms on the order of $45 per tonne of carbon dioxide for the United States, $71 for Europe and $76 for Japan.[9] Emission trading lowers the cost to $22. Adding the CDM brings it down even further to an estimated $8 per tonne of carbon dioxide. These results point to a potential for cheaper reductions in the developing world that benefit both parties involved in CDM projects. Efficiently tapping it depends on how the mechanism will be implemented. Some observers fear that the incentives the CDM creates for both project hosts and investors

7. To calculate total accounting emissions relevant for the Kyoto targets, emissions from land-use change and forestry *need to be included*. Deforestation counts as additional emissions and afforestation as a *sink*, or negative emissions. The share of CO_2 *energy*-related emissions is larger when land-use change and forestry are included because forest areas in Annex B countries were expanding in 1990.

8. The study, *Emissions Trading, and the Clean Development Mechanism: Resource Transfers, Project Costs, and Investment Incentives*, can be obtained at http://www.iea.org/climat.htm.

9. Expressed in 1995 US$.

(continued)

could lead to credits that do not correspond to real reductions and that might weaken the environmental benefits of the mechanism. Other concerns include a desire by some developing countries to ensure an equitable distribution of projects among regions and, by others, to limit the types of projects (*e.g.* to renewable energy sources, and excluding certain fossil-fuel, nuclear and forestry projects), at least temporarily. The difficulty in elaborating rules for the CDM reflects the tension between these issues and the desire to encourage as many projects as possible. Uncertainty about the rules makes it virtually impossible to model CDM effects with any reasonable confidence.

The remaining 20% of total greenhouse gas emissions in 1990 came from CH_4 (13%), N_2O (6%) and the three groups of trace gases HFCs, PFCs and SF_6 (1%). The main sources for methane or natural gas (CH_4) in the energy sector are losses from natural-gas pipelines and coal mines. Agriculture (enteric fermentation, rice cultivation and waste) is another important source. Nitrous oxide (N_2O) emissions arise in the energy and transport sectors through incomplete oxidisation, and agriculture (through fertilisers and manure management) is again a large contributor. The trace gases come from specific industrial processes.[10]

CO_2 emissions arise from any fossil-fuel combustion. In the three OECD regions, energy-related emissions amount to more than 98% of total CO_2 emissions. Industrial processes and agriculture contribute very little. Besides switches to less carbon-intensive sources of energy, reducing the consumption of primary energy remains critical to reducing climate-relevant GHG emissions.

The Case for Trading

Any modelling exercise depends crucially on the data that it has available — CO_2-emission data in this case. Based on its energy-consumption projections, the *Outlook* provides estimates of energy-related

10. HFCs, a by-product of HCFC manufacture, are used in mobile air conditioning. PFCs are emitted during the production of aluminium and semiconductors. SF_6 is also used in semiconductor production and as an electric insulator. Their low current contribution should not obscure that they constitute the fastest rising component of total GHG emissions and remain in the atmosphere for particularly long periods of time.

Table 10.1: **CO_2 Emissions and Commitment in the Five Trading Regions**

Region	Countries (Base year, if different from 1990)	Base year Emissions (1)	Kyoto Commitment (2)	2010 Target (1)	WEO 2010 (1),(3)	Gap (per cent)
North America	Canada, United States	5 301	93.1	4 935	6 817	38.1
Europe	Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary (average 1985-1987), Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland (1988), Portugal, Spain, Sweden, Switzerland, United Kingdom	3 961	92.5	3 664	4 295	17.2
Pacific	Australia, Japan, New Zealand	1 350	96.8	1 307	1 625	24.3
Russia	Russian Federation	2 357	100.0	2 357	1 449	–38.5
Ukraine and Eastern Europe	Bulgaria (1988), Croatia, Estonia, Latvia, Lithuania, Romania (1989), Slovakia, Slovenia (1986), Ukraine	1 188	96.8	1 150	750	–34.8
Total	Annex B	14 158	94.7	13 413	14 936	11.4

Notes: 1. In millions of tonnes of CO_2. For modelling, established convention measures CO_2 emissions in tonnes of carbon. One tonne of carbon corresponds to 44/12 (or 3.7) tonnes of CO_2. The CO_2 measure is kept here in order to facilitate readability. 2. The commitments under the Kyoto Protocol are formulated as percentages of base year emissions. The regional commitment was calculated as a weighted average percentage of base year CO_2 emissions. 3. WEO projections.

CO_2 emissions until 2020. All data are broken down along the lines of the five geographic regions, in which countries with emission reduction commitments under the Kyoto Protocol (Annex B countries) have been grouped. These are North America, Europe, Pacific, Ukraine and Eastern Europe, and Russia. Table 10.1 shows the regional breakdown as well as base-year emissions, the required emission reductions and the emission projections for 2010.

As an energy model, the WEM considers only CO_2 emissions. The contracted emission reductions expressed in percentage terms are applied to CO_2 emissions. The CO_2 emission data taken as the basis for the present modelling effort come from the IEA databases. For most Annex B countries they were within 5% (but only 3%, on average) of the data provided by countries to the UNFCCC Secretariat under their Climate Convention reporting requirements.[11] These divergences are not large enough to affect the qualitative results.

As Table 10.1 shows, the *Outlook's* Reference Scenario projects a considerable gap between the Kyoto commitments and projected CO_2 emissions by 2010 for the three OECD regions. In contrast, Russia and Ukraine/Eastern Europe will have emissions in 2010 much lower than their Kyoto commitments.

Total CO_2 emissions evolve differently in each of the three OECD regions — fastest in North America, where they will be up 33% from 1990 levels by the Kyoto-relevant year 2010, but slower in OECD Pacific (25%) and slower still in OECD Europe (13%). In the two non-OECD regions, Russia and Ukraine/Eastern Europe, expected CO_2 emissions in 2010 lie *below* 1990 emissions.

CO_2 emission factors (tonnes of CO_2 emitted per unit of energy) vary considerably among fuels (Table 10.2). This explains why part of the Annex B countries' efforts to fulfil their commitments under the Kyoto Protocol will focus on substitution towards less carbon-intensive fuels.

The Reference Scenario indicates that the three OECD regions will not reach their Kyoto targets without additional government action. An emission-trading scheme would contribute to economically efficient, least-cost

11. Divergences may occur for a number of technical reasons including different national data sources, country-specific net calorific values and emission factors, the treatment of aviation bunkers, stored carbon, autoproducers, military use and blast furnaces. In addition, the IEA data have been calculated using the IPCC Reference Approach, while most countries do detailed sectoral calculations. Since the latter include emissions only when the fuel is actually combusted the IEA data include, in addition to statistical differences, some emissions that are normally included under Fugitive Emissions such as product transfers, transformation and distribution losses.

Table 10.2: **CO_2-Emission Factors for Different Fossil Fuels**
(Tonnes of CO_2 per tonne of oil equivalent)

Brown Coal	Steam Coal	Heavy Fuel Oil	Diesel & Light Fuel Oil	Gasoline	Liquefied Petroleum Gas	Natural Gas
4.23	4.12	3.24	3.10	2.90	2.64	2.35

Source: IEA (1998), *CO_2 Emissions from Fuel Combustion 1971-1996,* Paris, p. I.19.

solutions, if technical problems such as monitoring and enforcement, and political problems such as acceptance and social impact, can be overcome. In principle, the more countries participating, the lower the total cost.

The gaps between projected CO_2 emissions and commitments vary between 16% and 30% in the three OECD regions. Reducing those emissions — which are closely linked to economic activity — through domestic measures alone would carry high economic costs. Emission trading thus becomes critical to achieve the emission objectives of the Kyoto Protocol at politically acceptable economic cost. Should it be instituted in time — not certain but distinctly possible — its main contours are already clear. The three OECD regions will be net buyers of emission permits; Russia, Ukraine and Eastern Europe will be the suppliers. Their "hot air" will play a major role in keeping down the costs of compliance.

The WEM indicates that "hot air" could contribute around 46% of what the OECD area needs to achieve. The rest would have to come from domestic emission-reduction efforts and, possibly, some CDM project credits. "Hot air" would allow the two supplier regions to increase their net foreign-currency earnings substantially.

The Results

The outcome of the emission-trading modelling exercise combines CO_2-emission projections, the construction of marginal-abatement cost curves and the imposition of cost-minimising market clearing among the five trading regions. This combination determines a trading price, the quantities traded and the respective costs and benefits. It requires one additional specification: the time-path of government action.

Countries can choose between taking action now or delaying it until the beginning of the budget period. Presumably, each will choose the course that will minimise its economic costs over the whole period from 2001 to

2012, the end of the budget period. Early action would give economies time to adapt and avoid drastic shocks when the time for commitment sets in, but this choice also implies absorbing some costs early. The advantages and disadvantages of delaying action are exactly the reverse. It would completely avoid costs in the early years, but drastic action later might impose additional adjustment costs when the budget period begins.

The choice between the two options will be heavily influenced by the rate of discount: the degree to which future costs are considered less damaging than present ones. Two additional factors might influence the choice. First, with economic growth, future costs might constitute a smaller percentage of total welfare than equivalent present costs. Second, technological progress might also reduce the costs of acting later. These are cogent points, but the costs of waiting (failure to provide incentives for adaptation, accumulating risks of climate change) weigh in on the other side of the balance. Given these considerations, the *progressive action scenario* has been chosen as the base case.

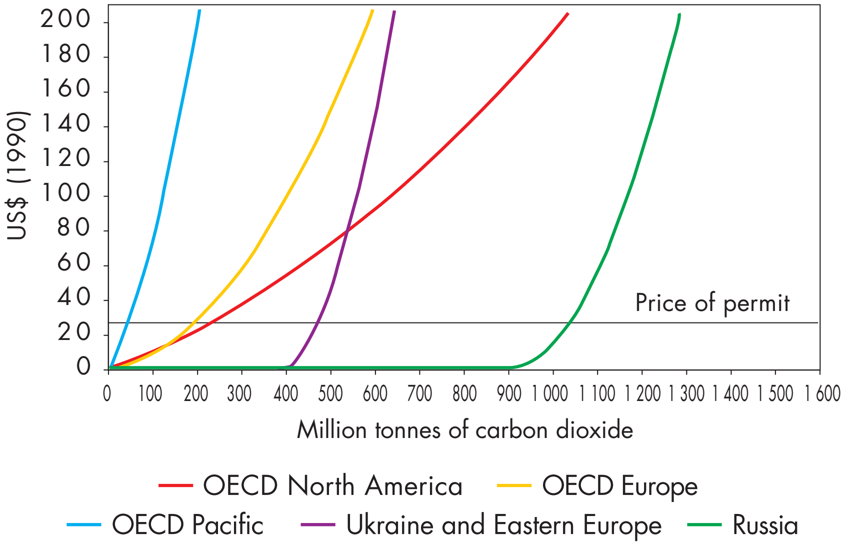
The Base Case — Progressive Action

The progressive action scenario assumes that participants start cautiously and continuously augment their emission-reduction policies from 2001 through 2008. To a certain extent this is the most realistic view, in the sense that countries will probably begin to implement their policies and measures just that way. It also is the scenario with the least cumulative economic cost.

The model measures policy "effort" by the size of an assumed carbon tax. The first year sees only a limited effort — a low tax — the second year has a slightly stronger one, and so forth until the full required effort emerges in 2008. Each year's effort (expressed in terms of a carbon tax) intensifies the previous year's by 50%. Once the top tax rate applies in 2008, it holds for each of the five following years. Figure 10.1 shows the marginal abatement-cost curves for the five trading regions as well as the emission-permit trade price during the budget period 2008-2012.

The marginal abatement cost curves were calculated by imposing successively rising carbon-tax rates on the WEM. At each rate, the model yielded different carbon-dioxide emissions *lower* than the Reference Scenario. Thus each carbon-tax rate corresponded to a certain gap between emissions with taxes and emissions without taxes. To derive a marginal abatement cost curve, these gaps were taken as *abated emissions* corresponding to the different carbon tax rates, identified as implicit cost

Figure 10.1: **Marginal Abatement Cost Curves for the Five Trading Regions**



figures. The procedure thus produced for each region a number of points indicating relationships between abated emissions and related cost. Interpolation and econometric estimation yielded smooth curves from these points.

Under the progressive action scenario, the annual costs in 2010 of fulfilling the Kyoto targets with the help of emission trading would amount to $56 billion or 0.22% of the combined GDP of the three OECD regions. The total undiscounted costs over the period 2001-2012 would be $294 billion. This includes the full effort during the five years of the budget period 2008-2012 (each year requiring on average the $56 billion calculated for 2010), as well as the progressively increasing effort during the years 2001-2007. The cumulative (total) costs of $294 billion would correspond to 1.43% of the combined annual GDP of the three OECD regions in the year 2000.

Discounting the costs in each of the years 2001-2012 by a discount rate of 3%, the cumulative costs would be $220 billion or 1.07% of GDP in 2000. While there are disagreements about the discount rate that should be applied for public policy, 3% is a widely used compromise figure close to the actual interest rate observed in financial markets.

The trading price in the progressive action base case is $26 per tonne of carbon dioxide, or $95 per tonne of carbon.[12] Table 10.3 presents more detailed results.

The results for the different regions reflect a certain scepticism about the ability of the energy sector in countries of the former Soviet Union and Eastern Europe to react to economic incentives such as those provided by emission trading. Discussions with IEA experts, as well as with government and private-sector contacts in the countries concerned, have consistently highlighted the limited flexibility of their energy industries and their energy customers. Decades of central economic planning have established output maximisation as the only measure of success.

Two further considerations also point to limited responsiveness of the energy sectors in these countries in providing emission reductions beyond "hot air." First, the creation of the legal and institutional infrastructure for emission trading is a formidable challenge in all five regions. Given the scale of recent structural change in Russia, Ukraine and Eastern Europe the challenge is even larger there than elsewhere. Second, the most promising way of reducing emissions in all regions is the substitution of gas for coal in power generation. Possibilities for such substitution might be limited in Russia. Its share of gas in power generation is already around 50%, far higher than elsewhere. However, there still remains room for efficiency improvements in gas-fired generation.

Moreover, rising gas demand in Europe, due in part to efforts to limit GHG emissions,[13] will make gas exports more attractive to Russian producers and could induce a switch back to coal. Decision-makers, particularly in Russia, will have to weigh profit opportunities in emission trading against those in gas trading. Given the familiarity with established ways of generating profits through energy trade, the margins in emission trading will have to be considerably higher to capture attention.

On balance, the contribution of Russia, Ukraine and Eastern Europe beyond the amount of "hot air" available through their initial commitments seems limited, although not non-existent. As elsewhere, attractive permit prices and an early, convincing establishment of the necessary institutional structures will increase the responsiveness of their energy sectors.

12. These figures are expressed in 1990 US dollars. The trading price of $26 corresponds to $32 in today's (2000) prices. Expressed per tonne of carbon, the trading price of $95 in 1990 US dollars corresponds to $118 in 2000 prices.
13. Current economic conditions also favour CCGT over coal-based power plants, which will be decisive in an increasingly liberalised European power market.

Table 10.3: **CO_2 Emission Trading (Progressive Action)** (Million tonnes of CO_2 and million 1990 US$ per year from 2008 to 2012)

Trading price for a tonne of carbon dioxide: US$ 26						
	2010 Reduction Target (Mt)	**Traded Quantities (Imports '+', Exports '–') (Mt)**	**Domestic Abatement (Mt)**	**Cost of Commitment with Trading (million US$ 1990)**	**Trading Cost (% of GDP)**	**Trading Benefits (% of GDP)**
North America	1 882	1 274 (68% of target)	608	39 842	0.36	0.61
Europe	631	240 (38% of target)	391	9 831	0.10	0.04
Pacific	318	204 (64% of target)	114	6 593	0.14	0.17
Russia	–908	–1 166 (hot air 78%)	258	–27 925	–5.87	5.87
Ukraine & Eastern Europe	–401	–552 (hot air 73%)	151	–12 761	–4.62	4.62
Total: Gross (net)[2]	2 831 (1 522)	1 718 (61% of total)	1 522	56 266 (15 579)	0.22 (0.06)	0.31 (0.49)

Notes: 1. The average annual benefit from trading indicates the difference between the costs of fulfilling the Kyoto commitments without trading and the costs with trading during the budget period. Given that carbon permits would be internationally traded commodities, the underlying GDP figures have been calculated on the basis of US dollars converted at real exchange rates. 2. The "gross" numbers indicate the sums for the three OECD regions. The "net" numbers indicate the sums of the respective magnitudes for *all* Annex B regions.

Several points about the interpretation of these results should be made. First, as regards timing, the WEM works with stable technical and structural parameters and provides little bonus for early action. In reality, the penalties in adjustment costs for sudden, year-on-year changes might be somewhat larger than those calculated. Second, the cost figures presented correspond only to the costs of fulfilling the Kyoto targets for CO_2 emissions. Under the very strong assumption that abatement costs (on the basis of global warming potentials) for non-CO_2 greenhouse gases are comparable to those for CO_2, it can be argued that the total costs of fulfilling the Kyoto targets are about 25% higher. Under this assumption, the cumulative discounted costs of complying with the Kyoto targets in the progressive action scenario amount for the OECD countries to around 1.33% of their combined GDP in 2000. Costs are minimised under steady progress towards the Kyoto constraints. Immediate full-scale action would impose costs now without substantially reducing them later, and no action at all before 2008 would not provide enough time for the energy system to adapt.[14] The current, tentative actions of the Annex B countries bear this out. Table 10.4 provides a synopsis of the different cost estimates.

The third and final issue regards the potential use of monopoly power in setting the price of CO_2 emission permits. Under almost any assumption, Russia will by far be the largest seller of permits. The analysis has assumed that the Russian government would sell them at a competitive price. Some analysts perceive a risk that it would withhold some of the permits and offer the remainder at a higher price, *i.e.* act as a profit-maximising monopolist. Because supply options from other sources (Ukraine and Eastern Europe as well as domestic abatement in the OECD regions) are limited, some permits would in fact be bought at those higher prices.[15] Although profitable for the monopolist, these prices would decrease the overall efficiency of emission trading and raise costs for the permit-importing countries. The OECD estimated in a recent study that such monopoly power can raise the trading price of a permit by 20%, lowering the gains from trade by roughly the same amount.[16]

14. This reasoning assumes that the objective function of Annex B countries is *exclusively* the achievement of the Kyoto targets.

15. The profit-maximising point is defined by the elasticity of the demand for carbon-emission permits and the cost savings achieved by engaging in less domestic abatement effort. The price offered will continue to correspond to the marginal abatement cost in the importing countries, but the price asked will be *higher* than the marginal abatement cost in the exporting country thus yielding extra profits.

16. OECD (2000). See Baron (1999) for a diverging viewpoint.

Table 10.4: **Costs of Complying with Kyoto Targets in the OECD**

Scenario	Annual costs 2010		Cumulative costs 2001-2012				
			Undiscounted		Discounted at 3% p.a.		
						% of 2000 GDP	
	Million US$	% of 2010 GDP	Million US$	% of 2000 GDP	Million US$	CO_2 only	All GHG*
Progressive Action **Permit price US$ 26**	56 266	0.22	293 606	1.43	219 794	1.07	1.33
Late Action **Permit price US$ 33**	70 636	0.28	353 180	1.72	263 029	1.28	1.60
Early Action **Permit price US$ 20**	42 317	0.17	507 804	2.47	421 224	2.05	2.56

Note: 1. One cannot emphasise enough the purely indicative character of these numbers, derived simply by multiplying the cumulative discounted CO_2 abatement costs by 1.25. See also the section in Annex 1 on "The Multi-Gas Approach to GHG abatement".

Box 10.3: **The Alternative Cases — Late Action and Early Action**

A comparison of the base-case progressive action scenario with the two alternatives — late action and early action — demonstrates the sensitivity of the results to the timing of policy action. All other assumptions remain unchanged, notably technological change and the existing policies contained in the Reference Scenario. In the late action case the participants in a future emission-trading system postpone all adjustment measures until 2008, when the Kyoto commitments become binding. As expected, the resulting trade price in 2008 rises to \$33 per tonne of CO_2, as the adjustments necessary to fulfil the Kyoto targets occur without any preparation. The costs of fulfilling the Kyoto targets in 2010 with the help of emission trading would amount to \$71 billion or 0.28% of the combined annual GDP of the three OECD regions. The undiscounted total costs over 2001-2012 would amount to \$353 billion or 1.72% of 2000 GDP. Discounted at 3% they come to \$263 billion or 1.28% of 2000 GDP. The difference in accumulated total costs between the progressive action and late action cases is slightly reduced with discounting, because the costs of late action all accrue in later years and discounting reduces their present weight. The higher the discount rate, the smaller the difference.

The importance of the discount factor becomes even more evident for the early action scenario, which assumes that all participants will implement the necessary CO_2 constraints in 2001. The relatively low permit-trading price of \$20 per tonne of CO_2 indicates that the annual costs during 2008-2012 will be relatively low. Yet because these costs must be borne every year beginning in 2001, the cumulative total costs go considerably higher than in both the other scenarios. The difference becomes even more notable if the costs are discounted, as a large share of the costs of the early action scenario accrues in the only slightly discounted early years. The total discounted costs in fact amount to 2.05% of the combined 2000 GDP of the three OECD regions.

What the Others Are Doing

Model results are the function of different data, different economic and technical relationships and different theoretical structures. It is nevertheless instructive to compare the results of different models in order to highlight specific characteristics. Here, the progressive action scenario is compared to the results of three other studies: the GREEN model of the OECD, the Emissions Prediction and Policy Analysis (EPPA) model of Massachussets Institute of Technology (MIT) and the POLES world energy model of the Université Pierre Mendès-France of Grenoble that was developed largely in the context of projects financed by the European Commission.

One of the most significant differences between models is whether they are partial or general equilibrium models. Partial-equilibrium models such as the WEM or POLES have much more detailed representations of the energy sector, but take into account only incompletely (if at all) second-order interactions with the rest of the economy. General-equilibrium models such as GREEN or EPPA capture those interactions, but at the expense of energy-sector detail. The MIT model is not a "pure" general-equilibrium exercise; it works with the partial-equilibrium concept of marginal abatement cost curves, but estimates their parameters in a general-equilibrium fashion. General-equilibrium models are usually more flexible than partial-equilibrium energy-sector models, which tend to extrapolate stable economic relationships. This flexibility would indicate a high responsiveness to price-based measures such as emission trading. It speaks for the richness of the energy-sector options modelled in the two energy-sector models, WEM and POLES, that their final trading prices are in both cases *lower* than the prices in the two general-equilibrium models.[17]

Another difference between the models is their treatment of adjustment. The GREEN model deals with it in a manner similar to the progressive action scenario in the WEM. Beginning in the year 2000, a linearly increasing emission constraint will rise to the full trade price in 2010. The high emission figures for 2010 in the EPPA model indicate what is essentially a "no action" scenario. The POLES model assumes early action beginning in 2000 and thus yields the lowest permit trading price in 2010.

Perhaps the most significant difference in the emission trading results (Table 10.5) concerns Russia as well as Ukraine and Eastern Europe. Compared to other models, the detailed energy-sector representation for the two regions in the WEM revealed only a limited GHG-reduction potential beyond the "hot air". "Hot air" estimates, however, lie on the upper side of the range of estimates from other models. The reasons for this divergence from conventional wisdom are straightforward. GHG emissions in Russia

17. In general equilibrium models, however, the impact of price-based measures such as emission trading is limited by a decline of the underlying energy price due to demand reductions. This tends to increase permit prices.

are driven to an even larger extent than elsewhere by economic growth, mainly due to the inflexibility of inherited structures in the energy sector. Moderate economic growth assumptions for Russia, Ukraine and Eastern Europe employed in the WEM (between 2.9% and 3.5% of real annual growth) produce moderate CO_2 emissions and lead to substantial amounts of "hot air."

Conclusions and Policy Implications

The modelling of emission trading among five Annex B regions in this *WEO* reinforces two increasingly evident messages:

- First, a large gap will most likely arise between the GHG-reduction commitments of most OECD countries and their average annual emission in the budget period, 2008-2012. Russia, Ukraine and several Eastern European countries, however, will probably emit less CO_2 than allowed by their commitments.
- Second, for most OECD countries closing the gap between commitments and emissions with domestic measures alone would imply high economic costs.

In this situation, emission trading is a realistic and cost-effective option, especially if "hot air" can help reduce the total costs of compliance. Emission trading is an efficient economic instrument, given adequate transparency and monitoring.

Its costs are sensitive to the timing of government action. This chapter adopts *progressive action* as its central case; it assumes that policy action will phase in gradually over the next seven years, with deployment of the full effort only in 2008, the first year of the budget period. With progressive action, the countries of the OECD area can indeed achieve their Kyoto targets for CO_2 emissions — with the help of emission trading — at a projected average annual cost of 0.22% of their combined GDP during the five years of the budget period 2008-2012. The cumulative costs over the whole period from 2001 through 2012, discounted at 3% per year, would amount to around 1.1% of their GDP in the year 2000. A tonne of CO_2 reduced anywhere in the world (which becomes a permit to emit an additional tonne) would trade at $32 (in today's money, $117 per tonne of carbon).

The projected average annual costs differ considerably among the three OECD regions: 0.36% of GDP in OECD North America, 0.14% in OECD Pacific and 0.1% in OECD Europe. This variation arises from differences in the gaps between commitments and projected emissions and

Table 10.5: **Comparison of Annex B Emission Trading Simulation**

		WEM	GREEN[1]	MIT-EPPA[2]	POLES[3]
Trade price (1990 US$)		**26**	**25**	**35**	**14**
Gap between Commitments and Forecasts ($Mt\ CO_2$)	TOTAL	1 522	4 132	4 404	1 756
	NAM	1 882	2 537	2 097	1 852
	EUR	631	880	1 126	660
	PAC	318	495	528	367
	RUS	–908	–440	–407	–1 118
	U&EE	–401	139	433	–4
Quantities traded ($Mt\ CO_2$)	TOTAL	1 718	1 610	1 287	1 419
	NAM	–1 274	–880	–389	–946
	EUR	–240	–378	–389	–271
	PAC	–204	–161	–348	–202
	RUS	1 166	1 503	1 265	1 401
	U&EE	552	106	22	22
Annual costs with trade % of 2010 GDP (Gains from trade)[4]	TOTAL	0.06 (0.49)	0.13 (0.38)	0.25 (0.31)	0.05 (0.14)
	NAM	0.36 (0.61)	0.41 (0.08)	0.47 (0.04)	0.20 (0.10)
	EUR	0.10 (0.04)	0.35 (0.43)	0.29 (0.09)	0.08 (0.04)
	PAC	0.14 (0.17)	0.20 (0.04)	0.44 (0.57)	0.10 (0.07)
	RUS	–5.87 (5.87)	–8.70 (10.4)	–8.63 (8.63)	–1.30 (1.30)
	U&EE	–4.62 (4.62)	–1.04 (0.91)	2.04 (0.01)	–0.06 (0.06)

Notes: **1.** OECD (2000), *Action Against Climate Change: The Kyoto Protocol and Beyond*, Paris, OECD. NAM includes only the USA, PAC is Japan, RUS is FSU and U&EE is Eastern Europe. ALL also includes Other OECD (Canada, Australia and New Zealand). Several results not contained in the original publication were provided by Jean-Marc Burniaux, OECD Economics Directorate. The "costs of trade" in the GREEN model correspond to changes in the real income of households. This figure is very sensitive to assumptions about tax re-cycling and should be treated with caution. **2.** D. Ellerman and A. Decaux (1998), "Analysis of Post-Kyoto Emissions Trading Using Marginal Abatement Curves", MIT Joint Program Paper No. 40; NAM includes only the USA, EUR corresponds to the EC-12 as in 1992, PAC to Japan, RUS to FSU and U&EE to Eastern Europe. ALL also includes Other OECD countries. **3.** CRIQUI, Patrick and Laurent VIGUIER, (2000), "Kyoto and Technology at World Level: Costs of CO_2 Reduction under Flexibility Mechanisms and Technical Progress," *International Journal of Global Energy Issues* 14, pp. 155-168. Slovakia is included in the EUR category, Russia, Ukraine and the Baltic countries are grouped under RUS and U&EE only includes Eastern Europe. **4.** "Costs with trade" indicates the costs of reaching the Kyoto targets with an emission-trading scheme. "Gains from trade" indicates the cost difference between reaching the targets with emission trading and without.

in the shapes of the marginal abatement cost curves that describe the costs of reductions.

CO_2 emissions constitute only about four-fifths of the global warming potential of all greenhouse gases. Extending the analysis to other greenhouse gases would, under the simplest possible assumption of a linear extension of costs, lead to a 25% increase in annual and cumulative costs.[18] Under this assumption, the projected total average annual costs of achieving the Kyoto targets during the budget period would thus lie between 0.22% and 0.28% of the annual GDP of the three OECD regions. The undiscounted cumulative costs would fall between 1.4% and 1.8% of their GDP in the year 2000 (between 1.1% and 1.3% when they are discounted at 3% per year).

For the OECD regions, these projected costs are significant but not enormous. While Russia and Ukraine would benefit, the costs to the three OECD regions would not bring major economic difficulty. Moreover, carbon taxes with compensation through tax recycling in the permit-importing regions could offer an even lower cost option.

Nevertheless, due to the asymmetrical distribution of the impact, fulfilment of the Kyoto targets remains a highly ambitious policy objective. The social and political importance of even small fractions of GDP intensifies if they fall largely on one particular sector of the economy — the energy sector and its customers. Coal producers as well as energy-intensive industries like iron and steel and chemicals will face particular hardship, with implications for output and employment. They might in some cases move their operation to non-Annex B countries.

As discussed in Chapter 1, energy-sector projections are subject to uncertainties relating to economic growth, energy prices or technological development. These uncertainties are compounded with the modelling of emission trading, as neither the precise modalities of trading nor the available abatement options are known today. They include the policy choices of major energy players. Will, for instance, a switch from gas to coal in Russia leave significant amounts of "hot air" available? The inclusion of gases other than CO_2 adds another important layer of uncertainty.

Climate change and sustainable development are long-term issues involving great uncertainties. Gradual action that allows for adjustment and learning characterises current steps underway in the UNFCCC process. As part of the clarification task, this study has identified emission trading among Annex B countries as a viable policy choice to achieve the Kyoto targets and to help keep global development on a sustainable path.

18. Clearly, this is an assumption made for illustrative purposes only. More advanced analysis highlights the cost savings that are achievable by making use of the flexibility allowed under the Kyoto Protocol to achieve the targets by choosing the least-cost option among different gases. This would imply an increase of less than 25% for the full costs of reaching the Kyoto targets.

Table 10.6: **Commitments of Annex B Countries under the Kyoto Protocol**

	Base Year	**2008-2012 Commitment** (Base Year Emissions = 100)	**Base Year Emissions** (thousand tonnes of CO_2)
Australia	1990	108	262 986
Austria	1990	92	59 360
Belgium	1990	92	109 113
Bulgaria	1988	92	85 670
Canada	1990	94	427 528
Czech Republic	1990	95	141 829
Denmark	1990	92	52 931
Estonia	1990	92	39 422*
Finland	1990	92	54 361
France	1990	92	378 309
Germany	1990	92	981 423
Greece	1990	92	72 284
Hungary	1985-87	94	78 198
Iceland	1990	110	2 221
Ireland	1990	92	33 236
Italy	1990	92	408 147
Japan	1990	94	1 061 771
Latvia	1990	92	25 836*
Liechtenstein	1990	92	n.a.
Lithuania	1990	92	41 234*
Luxembourg	1990	92	10 856
Monaco	1990	92	n.a.
Netherlands	1990	92	161 274
New Zealand	1990	100	25 350
Norway	1990	101	29 764
Poland	1988	94	449 062
Portugal	1990	92	41 474
Romania	1989	92	193 710
Russian Federation	1990	100	2 356 875
Slovakia	1990	92	54 170
Slovenia	1986	92	14 370
Spain	1990	92	215 017
Sweden	1990	92	52 648
Switzerland	1990	92	44 245
Ukraine	1990	100	734 044*
United Kingdom	1990	92	585 289
United States	1990	93	4 873 419

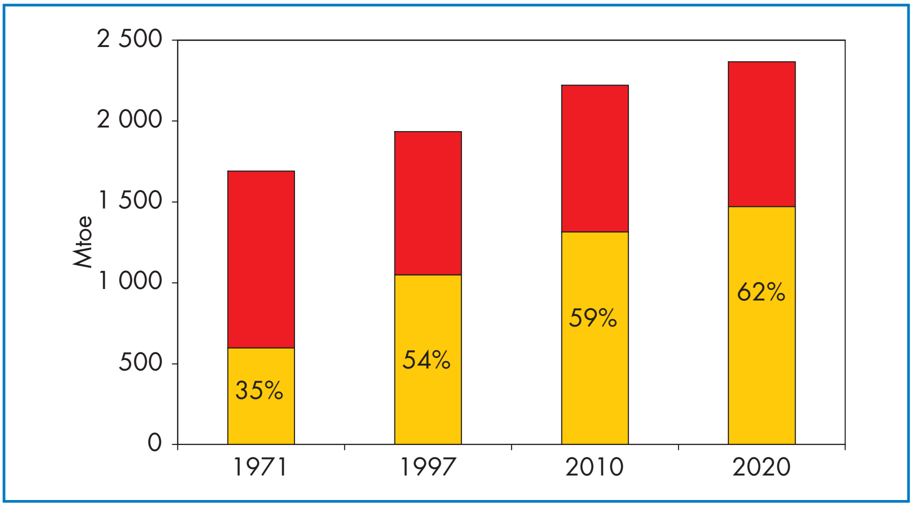
Source: IEA (1998), *CO_2 Emissions from Fuel Combustion 1971-1996;* no data is available for Croatia that has yet to submit a National Communication; * Estimated.

CHAPTER 11
THE ALTERNATIVE TRANSPORTATION CASE

Introduction

The Reference Scenario expects that over the next two decades world-energy demand in transportation will climb faster, at 2.4% per year, than in any other end-use sector. By 2020, transport is likely to account for more than half of world oil demand and roughly one-fourth of global energy-related CO_2 emissions. The share of transport increases steadily over the outlook period in the OECD area (Figure 11.1). Oil consumption in transportation has thus become a policy concern in the context of both increasing oil-import dependence and rising CO_2 emissions. Transport's central economic role and its deep influence on daily life have made rapid changes difficult to achieve. Its weak responsiveness to energy price movements and the slow turnover of its infrastructure[1] make it a crucial and difficult factor in oil security and climate change.

Figure 11.1: **Share of Transport Sector in OECD Primary Oil Demand**



1. See Figure 1.5.

This chapter tries to shed some light on the policy issues facing OECD countries. Data problems, as well as uncertainties about possible policies in non-OECD regions, explain our focus on the OECD area. The chapter begins by exploring the underlying transportation trends in the Reference Scenario, the "base case" for the *Outlook*. An Alternative Case, in which the assumptions of the Reference Scenario are altered to introduce new policy trends, is then analysed to uncover their potential effects on oil demand and CO_2 emissions in the transport sector. The Alternative Case has four parts, defined by their policy content: efforts to improve vehicle fuel efficiency; programmes to increase the use of alternative fuels; strategies to induce changes in transport demand; and pricing measures, such as tax policy. Each part is presented and analysed separately, then combined and studied as a package.[2]

Transport-Energy Demand Trends in the Reference Scenario

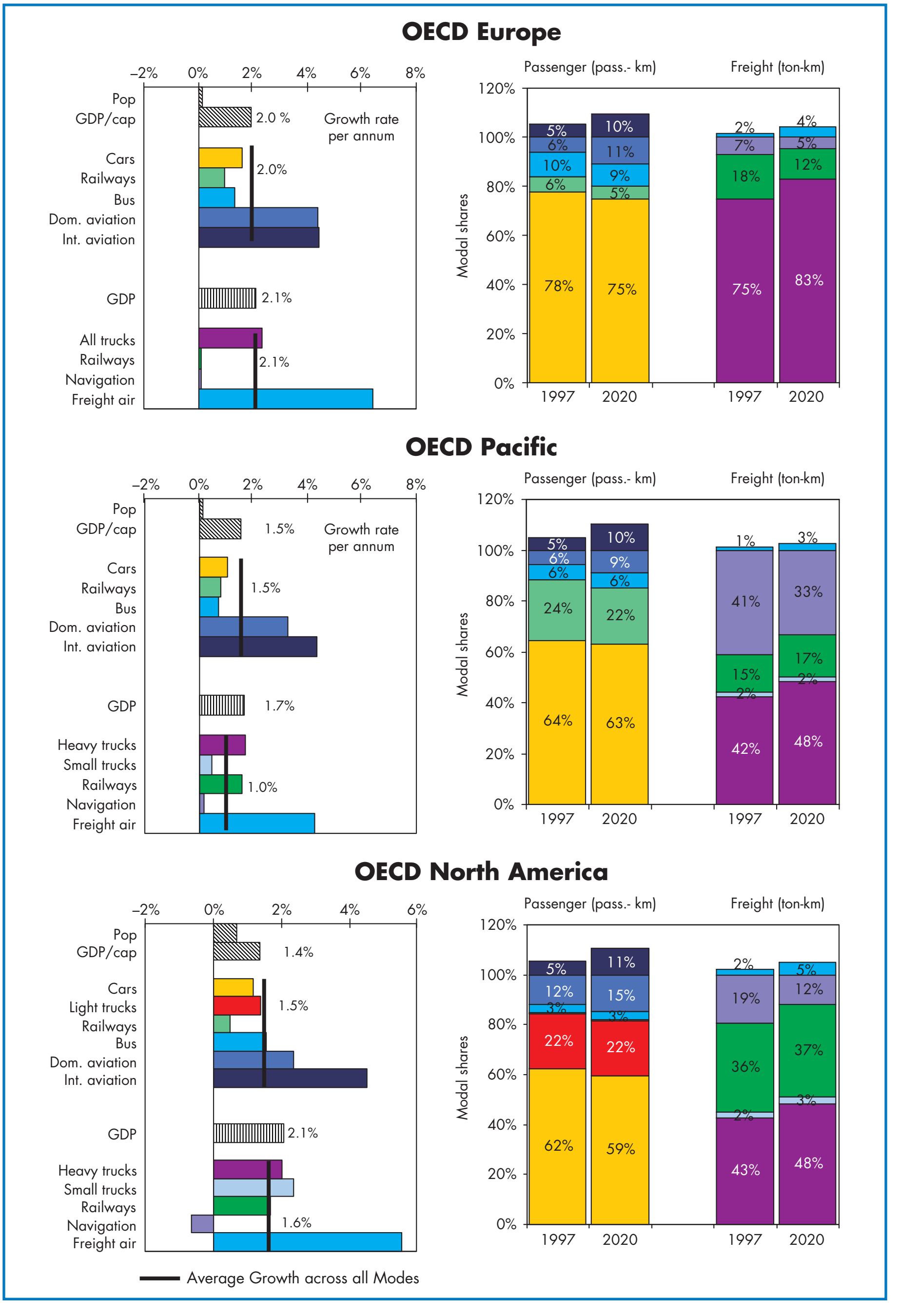
Passenger and freight activity and the modal mix, together with fuel intensity, determine transport energy demand. Figure 11.2 provides a snapshot of regional differences and the main implications of the Reference Scenario for activity and the modal mix. The following paragraphs explore expected demand trends in more detail, focusing on where increases in transport energy demand are most important (Figure 11.8).

Passenger Transport

Passenger travel generates two-thirds of transport energy demand in the OECD area. Transport activity has increased substantially since 1970, by 2% to 3% annually, but its expected future growth will be somewhat slower, at 1.3% a year in the Pacific region, 1.6% a year in North America and 2% a year in Europe. The explanation lies partly in slower economic growth, partly in demographic changes and partly in saturation effects in some modes. In North America, some growth in population is expected, unlike the rest of OECD. Fuel-price changes play a minor role. Moreover, the expansion of road infrastructure is likely to slow and congestion to increase, especially in urban areas. Modes facilitating higher speeds and longer trips will be favoured.

2. The analytic approach is described in Box 11.1 and in Appendix 1.

Figure 11.2: **Transportation Activity and Modal Mix in the Reference Scenario**



Note: throughout this chapter, modal shares are given as percentage of intraregional passenger-km or tonne-km, i.e. excluding international aviation and freight aviation. They therefore add up to values greater than 100%.

Box 11.1: Approach to Studying the Reference Scenario and the Alternative Case for Transportation

Increased detail and disaggregation: The analysis disaggregates energy demand in each transport mode into physical activity, measured in passenger-km or tonne-km, and fuel intensity (energy consumed per passenger-km or tonne-km). This "bottom-up" view establishes precise links between energy trends, on the one hand, and, on the other, changes in the transportation system, transport technology and its use. The *passenger transport* modes include cars, light trucks (which are included in "cars" for OECD Europe and Pacific), buses (scheduled and charter), railways (metros, tramways, ordinary rail and high-speed rail), domestic aviation and international aviation. *Freight transport* includes small commercial vans and trucks (included in "trucks" for Europe), heavy trucks, freight shipping by rail (bulk goods and "combined" transport), inland waterways and aviation.

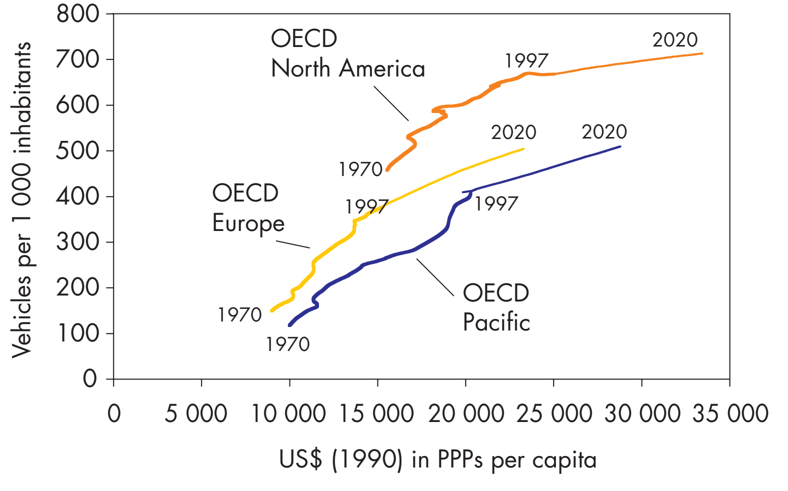
Accounting model: Using a more detailed model of the transport sector allows us to study the impact of government policies aimed at efficiency improvements, modal shifts and demand restraint. Some detail of the accounting model, which is based on the disaggregated indicators of physical activity and fuel intensity in each mode, is given in Appendix 1.

Regional separation: The results are presented mostly in terms of average trends between 1997 and 2020. The study also confines itself to the OECD area, disaggregated into three main regions. OECD North America includes the United States and Canada. OECD Europe consists of two areas modelled separately: Western Europe (the EU, plus Switzerland, Norway and Iceland) and Eastern Europe (Poland, Czech Republic, Hungary and Turkey). OECD Pacific includes Australia, New Zealand and Japan, which is modelled separately. The focus is on aggregated trends in each region; intra-regional differences in transport systems are not shown.

Limitations of the analysis: The use of regional averages in the OECD regions reveals an approximate picture. Also, the transport-demand projections do not contain a spatial dimension (urban vs. non-urban) and some modes, like trucking, are still described in rough terms. The price elasticities of fuel demand are uncertain due to the wide ranges of available estimates. Modelling the transport sector separately from the rest of the economy, a necessary simplification, misses possible secondary effects on energy demand. If transport-sector policies do dampen fuel demand, for example, the model cannot pick up any feedback of lower oil demand to world-oil prices. Finally, the policies and measures analysed are far from being exhaustive. Assumptions about them abound, and the regional approach necessarily neglects useful and promising national or local initiatives.

Passenger cars and light trucks. Projected ownership rates (numbers of vehicles per 1 000 inhabitants) are critically important to estimating future car and light-truck activity. Over the outlook period, ownership is expected to grow less than in the past, especially where vehicle ownership relative to incomes is already high (Figure 11.3). An ageing population also limits further growth. In contrast to past trends, passenger cars and light trucks lose modal shares to aviation. In 2020, cars and light trucks will account for about 81% of passenger-km in North America, 75% in Europe and 63% in the Pacific region.

Figure 11.3: **Passenger Vehicle Ownership vs. GDP Per Capita**



In all three regions, the oil-price hikes of the 1970s and 1980s helped trigger substantial efficiency improvements in new vehicles. Since the late 1980s, however, average new-vehicle fuel intensity has not improved much. The move towards larger and more powerful vehicles has balanced off potential gains from technical progress.[3] Resulting improvements in average fuel intensity of the vehicle stock have been relatively modest. In all regions, they have now come to an end, since new cars do not offer improved fuel intensity compared to older ones. In North America especially, light trucks will continue to gain fleet share relative to cars. Because their fuel intensity is about 40% higher, average fuel intensity per vehicle-km for cars and light trucks is expected to decline steadily.

Japan aims to improve fuel consumption per km in new cars by 17% by 2010 and the European Union by 25% by 2008. The average fuel efficiency of their fleets is assumed to follow this trend with a time lag. In North America, if there is no change in the corporate average fuel economy (CAFE) standards, only limited improvements in fuel intensity in cars and light trucks[4] are likely due to the fuel-price effect. On the basis of these diverging regional assumptions, cars and light trucks will contribute less to energy-demand growth in OECD Europe and Pacific, but significantly more in North America.[5]

Railways and buses. Bus and rail travel play a very minor role in energy consumption. Their importance in transport activity varies greatly among the regions. In North America, they take less than 5% of total passenger-km. In Western Europe, rail accounts for about 6% and bus travel for 10%. The shares in Japan are 24% and 6%. Rapidly expanding high-speed rail now accounts for 11% of rail passenger-km in Western Europe and 19% in Japan. Over the outlook period, railways and buses hold almost stable modal shares. Occupancy is probably the factor that has the most influence on their fuel intensity per passenger-km, which is on average significantly better than for cars or light trucks. Efficiency gains penetrate the vehicle stock slowly due to long vehicle life.

Aviation. Air travel has increased rapidly since 1970, by 5.3% annually on average across the OECD, doubling every 13 years. These trends persist in the Reference Scenario, with an annual average rise of 4%. The share of air travel in total passenger-km rises from 10-15% today to 23% in 2020. Some studies suggest faster growth, but the Reference Scenario assumes both increases in crude-oil prices and a relatively high price-elasticity of demand for air travel. Aviation fuel intensity has improved significantly in the past two decades, by 3% annually. More than half of that gain has come from load-factor improvements, the rest from technological advances and

3. IEA, 1997.
4. Cf. Figure 11.5.
5. Cf. Figure 11.8 at the end of this chapter.

increased aircraft size. The Reference Scenario projections assume little further load-factor progress but continued gains from technology and size. Including freight, aviation accounted for about 16% of fuel-demand growth between 1970 and 1997. Its share is expected to rise to 25% over the outlook period, or about 113 Mtoe for the OECD area.

Freight Transport

Freight accounts for one-third of transport-energy demand in the OECD area. Activity, expressed in tonne-km, has expanded by about 2% to 3% annually depending on the region since 1970. Growth in freight is slackening in North America and the Pacific, but not in Europe. The Reference Scenario expects activity to grow annually by 1.1% in OECD Pacific, 1.6% in North America and 2% in Europe over the projection period. Overall, product and transport chains are undergoing significant changes, due to structural and process changes within industry. Product volume is becoming more important than weight, and distances carried are increasing more than tonnes lifted. These structural changes are interacting with continuing shifts in freight modes as outlined below.

Road freight: Since the 1970s, the activity of trucks and vans in the OECD has increased on average by 3.7% annually and continuously gained freight market share. Road freight has benefited most from structural economic change. It comprises a large variety of transport services, ranging from small delivery vans and commercial vehicles (below 7 tonnes) in urban and short-trip use to heavy trucks (up to 40 tonnes and more) in long-haul use.[6] The projections show growth rates above the average for all freight activity. Trucks are expected to account for 51% of total freight tonne-km in North America and the OECD Pacific area and 83% in Europe.

Aggregate indicators do not readily reveal changes in the mix by size and class and in load factors. Yet these changes heavily affect trends in fuel intensity, more so than do improvements in technical efficiency. The on going liberalisation of trucking markets in Europe and Japan, and the increasing use of information technology to rationalise routes should lead to higher load factors and reduce empty running, at least for large trucks. These different influences have tended to offset themselves, resulting in broadly stable average fuel intensities in the past. The Reference Scenario assumes that they will remain stable or improve modestly. Between 1970 and 1997, road freight has generated around 40% of transport fuel-demand

6. In OECD Pacific and OECD North America, small commercial vehicles and vans are separated from the larger truck category.

growth in OECD Europe and North America, and about 26% in OECD Pacific. In Europe, the share of road freight in total transport fuel demand is projected to grow further. Across the OECD, road freight will add about 130 Mtoe to demand by 2020. In OECD Pacific and North America, where data sources separate out small vans and commercial trucks, these smaller vehicles account for almost half of the increase in fuel demand for road freight.

Rail freight and inland waterways: These modes together account for 8% to 15% of transport energy consumption depending on the region. They add little to the growth in energy demand over the projection period. Railways and, even more so, waterways have very low fuel intensities per tonne-km carried, compared with road transport or aviation. The rate of improvement in fuel intensity in these modes is slow due to low stock turnover.

These modes play different roles in each the three regions. In North America, rail shipping holds a 36% share in total freight and is projected to grow slightly faster than average freight volume. Since the mid-1980s, however, inland-waterway freight has fallen steeply; it now accounts for only 20% of total freight. The Reference Scenario projections assume a continued but slower decline. Rail freight is unimportant in Japan, accounting for only 5% of total freight, and this share is projected to remain stable. The share of inland and coastal waterway transport declines slowly from 44% in 1997 to 40% in 2020. In Western Europe, the contribution of the railways has declined continuously, from 33% of total freight in 1970 to 15% today. Old, slow rolling stock, inflexible service from state-owned national monopolies, competition for infrastructure with passenger transport and a lack of modern freight terminals have taken their toll. Combined road-rail services, by contrast, have expanded quickly. The outlook for rail freight is uncertain. Market liberalisation and substantial investment in infrastructure could boost its role. The Reference Scenario expects no further contraction, but rail freight nonetheless suffers losses in market share. Inland waterways should remain unimportant, at around 5% of total freight.

Air freight has expanded very fast in the recent past — at close to 10% a year in some places. It still accounts for under 2% of total freight in the OECD, but, with projected growth at 5.7% annually, it will more than double its market share to around 5% by 2020 and will account for 45% of the increase in aviation-fuel demand. The same fuel-price and price-elasticity considerations as for passenger air travel lie behind this projection. Airlines carry freight mostly in extra space on passenger planes;

dedicated freight planes make up only 20% of the aircraft fleet. This makes it hard to attribute energy consumption specifically to air freight. By the end of the outlook period the average aircraft will be four to six times as energy intensive per tonne-km as the average heavy truck.

Summary of Energy-Demand Projections in the Reference Scenario

Figure 11.4 and Table 11.1 pull together the main transport-energy trends, both in the past and as projected in the Reference Scenario, which takes account of the effect of currently enacted policies. Figure 11.9 (at the end of this chapter) gives a breakdown of increases in energy demand in the past and over the outlook period by transport mode. A few central findings stand out:

- *Projected energy demand growth* from transportation slows considerably in Europe and substantially in the OECD Pacific area. In North America, past trends continue.
- *Projected activity growth slows somewhat* — most in OECD Pacific, less in OECD Europe, least in North America and less for freight than for passenger travel. Europe's projected road-freight still grows significantly.
- *Without government policy intervention, gains from fuel-intensity improvements in passenger transport will not continue.* In OECD Pacific and OECD Europe, government policies foster continuing improvements, although they offset only a quarter of the fuel-demand increase from activity growth.
- *In freight, modal shifts will continue to raise average fuel demand per tonne-km.* The shares of road freight and, increasingly, aviation freight increase in most regions. Small commercial trucks and vans contribute about half to energy demand growth from road freight.
- *Aviation accounts for almost a quarter of the projected increase in fuel demand to 2020.* Fuel-intensity improvements in this mode offset only a quarter of the growth in energy demand from expanding activity.
- *CO_2 emissions from transportation will continue to grow rapidly* — by more than 60% until 2020 compared with 1990 in each region under the Reference-Scenario policy assumptions. As early as 2010, emissions increase 44% in North America and Europe and 48% in OECD Pacific.

Figure 11.4: **Transport-Energy Demand and CO_2 Emissions in the Reference Scenario**

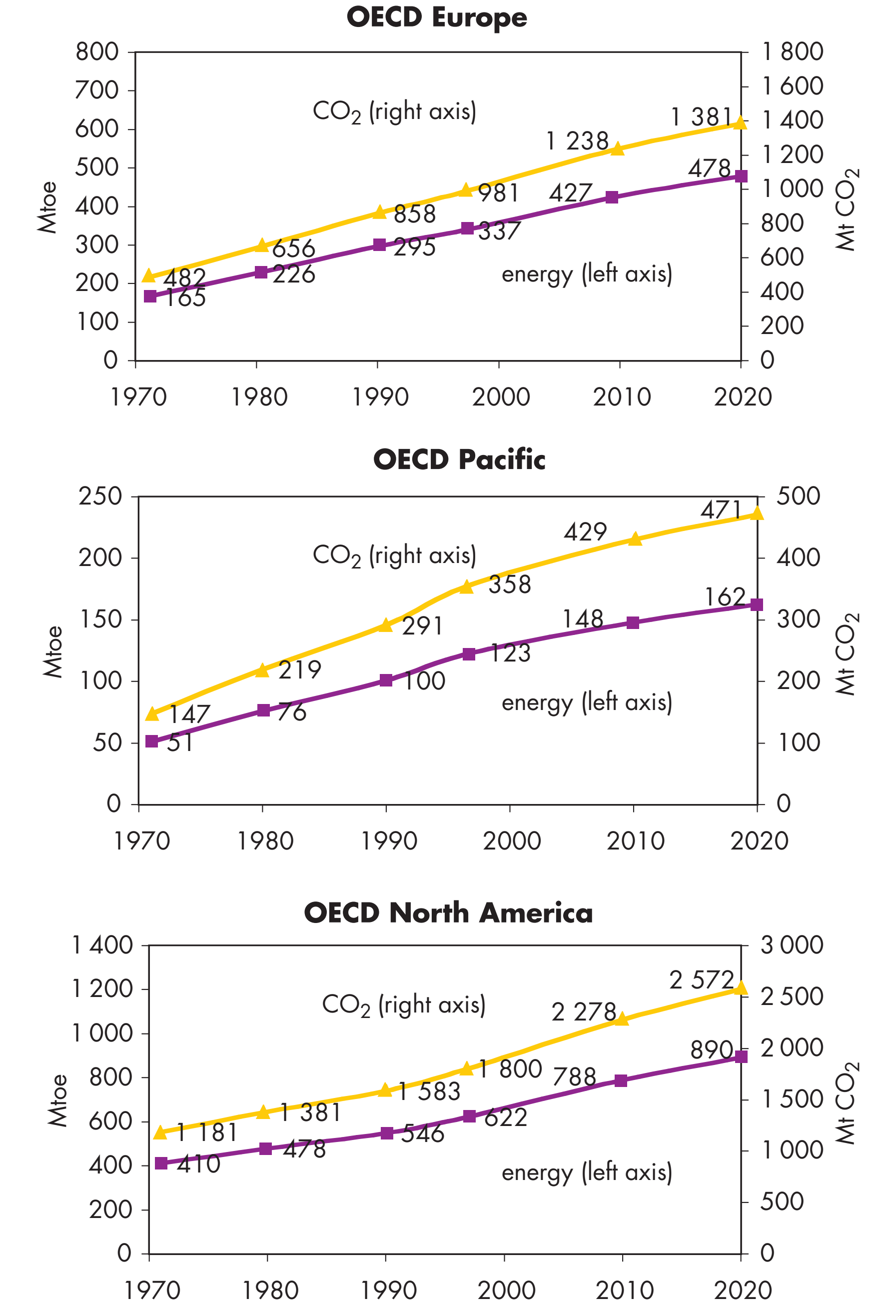


Table 11.1: **Transport-Energy Demand and CO_2 Emissions in the Reference Scenario**

	OECD Europe		**OECD Pacific**		**OECD North America**	
Annual growth rate (% per annum)	**1970-1997**	**1997-2020**	**1970-1997**	**1997-2020**	**1970-1997**	**1997-2020**
Passenger	2.5	1.1	4.0	1.1	1.3	1.4
Freight	3.1	2.1	2.7	1.4	2.6	1.8
Total	2.8	1.5	3.5	1.2	1.6	1.6
	2010	**2020**	**2010**	**2020**	**2010**	**2020**
Energy demand – Increase over 1997 levels*						
Mtoe	90	141	25	39	165	268
Relative change (%)	27	42	20	32	27	45
CO_2 emissions – Increase over 1990 levels						
Mt	381	523	139	180	695	990
Relative change (%)	44	61	48	62	44	63

*see Figure 11.8 (left and centre bars) for shares by mode.

The Alternative Case

Beyond the current policies already reflected in the Reference Scenario, what further measures could play a role and what impact could they have on energy demand and CO_2 emissions from transportation? This section focuses on additional government-policy measures consistent with the current policy debate, but not yet in place. It does not analyse all possible policies, or even the most promising, but rather crafts a cautious, schematic picture of a few that have at least some probability of enactment. It ignores single measures with small or locally confined effects, as well as general R&D support not connected to particular market-deployment measures. To allow for some lead-time in the policy process, it assumes that additional policy implementation starts in 2005. To make the analysis manageable, only Western Europe, Japan and OECD North America receive detailed study. Box 11.2 contains a list of the additional policies considered. The analysis groups the energy and CO_2 reduction measures in four different categories: improvements in fuel efficiency of cars and light trucks; the introduction of alternative fuels; policies to change transport demand and modal mix; and increased fuel taxation to reflect the carbon value determined in the CO_2 emission-trading case (see Chapter 10). Each category is treated separately before the total, bundled effects on energy demand and CO_2 emissions are considered in a "combined policy case" at the end of this section.

Improvements in Fuel Efficiency of Passenger Vehicles

Policies reflected in the Reference Scenario are designed to reduce automobile fuel intensity (energy consumption/vehicle km) in the coming decade by 24% in Europe and 17% in Japan. The Alternative Case assumes that, beyond 2010, a tightening of these policies will trigger further fuel-efficiency progress in new cars until 2020. While debate continues about which technologies could achieve such long-term targets, they do appear to be technically feasible at a reasonable additional cost.[7] Shifts to diesel cars and to smaller, lighter ones, as well as the introduction of vehicles with radically improved efficiency could contribute to these targets.

In this context, hybrid and fuel-cell vehicles have received particular attention because they already are or will soon be marketed on a small scale. Conventional, combustion-engine technologies still have a large potential

7. IEA (forthcoming), *How to Reduce Transport CO_2 Emissions: Policies and Measures for IEA Countries*, Paris.

Box 11.2: **Additional Policies in the Alternative Transportation Case**

All regions:

- Fuel tax increases equivalent to US$95 per tonne of carbon for all fuels.

North America:

- Stricter CAFE standards for cars and light trucks from 2005.
- Introduction of "low-carbon" fuels after 2010 with widened regulation of alternative fueled vehicle shares in fleets ("fleet mandates") and fuel tax incentives.

Western Europe:

- Further increased commitment until 2020 under the Voluntary Agreement of the European Association of Automobile Manufacturers (ACEA).
- Demand-restraint and demand-shift policies: urban car restraint; expansion of urban public transport; high-speed rail expansion; and electronic charging of trucks per tonne-km.

Japan:

- Sharpened requirements for car and light-truck fuel efficiency under the Top-Runner Programme until 2020.
- Demand-restraint and demand-shift policies: urban road pricing and other car restraint measures; improvement of public transport; mandatory city logistic schemes for small commercial vans and trucks; and expansion of high-speed rail service.

for fuel-efficiency improvements. Consequently, there is significant uncertainty about which technologies will succeed and how fast they will penetrate vehicle markets. It often takes between 10 and 20 years to move from prototype through small-scale production to actual market production in different vehicle classes. The more radical the changes involved, the longer this process is likely to take. Building new fuel-production capacity and infrastructure, if needed, could further delay the process.

The cost at which technologies can be developed is a vital factor in their success and their speed of market introduction. With increasing production volumes, experience effects become decisive in reducing costs. Such market dynamics are inherently difficult to foresee. Yet the time needed in expanding production and to reduce costs for such "outsider" technologies make it unlikely that they will play a decisive role in CO_2

reduction in the short to medium term. Beyond 2010, they could be part of the technology mix that achieves the fuel-intensity targets assumed below for 2020 under the additional-policy package. Box 11.3 gives a simple, quantitative example of a market-introduction scenario.

Under stricter requirements in Japan's Top-Runner Programme, average fuel economy is assumed to reach 17.2 km/l in 2020. In Europe, the Voluntary Agreement of ACEA is assumed to lead to a reduction in the sales-weighted average of CO_2 emissions from 186g of CO_2/km in 1995 to 120g CO_2/km in 2012 and 100g/km in 2020. In North America, CAFE standards are assumed to increase continuously after 2004, to attain 33 mpg for new cars and 24 mpg for light trucks in 2010, rising to 42 mpg and 30 mpg in 2020. By 2020, the average sales-weighted test-fuel intensity of new passenger vehicles is assumed to have improved by more than 30% in Japan and North America and by 46% in Western Europe compared with 1997 (Figure 11.5).

Several factors will delay or reduce the effect of improved fuel efficiency on actual energy consumption and CO_2 emissions:

- Stock turnover — new vehicles penetrate the fleet only gradually.
- The gap between test values and on-road performance — discrepancies between on-road performance and test cycle performance are likely to increase.
- The rebound effect — increased fuel efficiency and lower fuel costs per km can lead to more kilometres driven, increased fuel consumption and smaller CO_2 savings.

Assuming average fleet turnover rates of 10 to 15 years and factoring in the higher usage of new vehicles, average fleet performance in Europe will have improved by about 14% and about 9% in Japan by 2010. This impact is only 50-60% of the ultimate effect of current fuel-efficiency policies. The rest will take effect after 2010. Similarly, a part of the effect of the tightened policies assumed in this Alternative Case would show only after 2020.

Different elements contribute to the test/on-road gap[8], such as different mixes of driving patterns in real life compared with test cycles (such as urban *vs.* inter-city driving and average speeds), additional weight of the vehicle in use, varied vehicle equipment and ancillary electricity consumption from on-board devices, especially air conditioning. Increased

8. The gap is defined as (on-road fuel intensity — test fuel intensity) / test fuel intensity. Test fuel intensity depends on the test cycle used in each OECD region. It has been 18% and 21% for cars and light trucks in North America, and at 13% and 42% for cars in Western Europe and Japan, respectively. The corresponding estimates for 2020 are 25%, 22%, 22% and 47%.

Box 11.3: **The Role of Radically New, High-Efficiency Technologies — A Quantitative Example**

Assume that current small-scale production for a high-efficiency vehicle (about 55 mpg, 4.3 l/100km or 23 km/l) is scaled up to 470 000 vehicles annually in 2010 and 4.4 million in 2020. These figures correspond to shares of 4% and 34% in the North American new-car market for those years. Assuming that such vehicles are 30% more costly than their conventional counterparts at the start, larger incentives and "learning investments"[9] would be required to encourage acceptance by the market and eventually reduce costs. Assuming a cost reduction of 15% with each doubling of cumulative production, the high-efficiency vehicle would become competitive with its conventional counterparts around 2010.

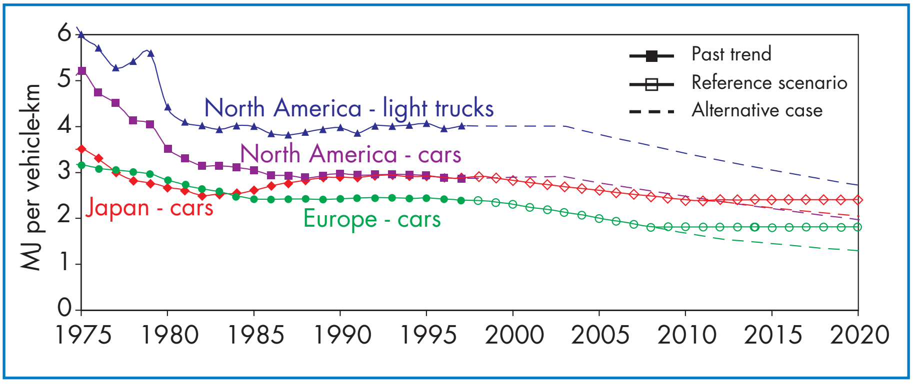
For simplicity, assume now that the efficiency of conventional cars does not improve substantially and that, over time, high-efficiency vehicles would become even more efficient (65 mpg, 3.6 l/100km or 28 km/l by 2020). The resulting overall improvement in average fuel intensity of new cars would be negligible in 2010 but would reach about 19% by 2020. Since the share of high-efficiency vehicles in new car sales increases to significant levels only in the later part of the projection period, their fleet penetration remains modest at less than 10%. As a result, fleet-fuel intensity in 2020 will have dropped by only 4%. This analysis suggests that radically new technologies thus are unlikely to gain major shares in new-vehicle sales by 2010 and major fleet shares by 2020. This implies that their importance to actual CO_2 reduction over the outlook period is very minor. They might, however, contribute meaningfully to enabling further tightening of fuel-efficiency regulations after 2010.

average speed, urban congestion and increased use of on-board electricity-consuming devices have caused gaps to widen, and they are likely to continue to do so. How much is hard to foresee. In 2010, more new-car air conditioning will probably cause the gap to widen in Europe. In Japan and North America, where air conditioning has already fully penetrated the fleet, other electricity-consuming equipment (especially IT devices) and

9. IEA, 2000.

increasing road congestion, as well as changes in driving patterns and average speeds, could have deteriorating influences. The increase in the gap through to 2020 is strongest in Europe. In Japan and North America the gap is also expected to increase, although at a lower rate.

Figure 11.5: **Fuel Intensity for New Passenger Vehicles**



Note: Data from different regions are not easily comparable due to different test cycles.

The rebound effect is usually limited. A 10% reduction in fuel cost per km is thought to lead to around 2% of additional driving, depending on the region. It could be stronger in Europe if future efficiency improvements coincide with a shift toward more diesel vehicles. Because diesel engines are 20% more fuel-efficient and diesel fuel is about 35% cheaper than gasoline, the per km fuel cost of cars would be drastically reduced, causing a higher rebound effect than without the shift.[10]

Table 11.2 summarises the effects on total transport-fuel consumption, compared with the Reference Scenario. The impact of the assumed new policies is strongest for North America, because all of it occurs in the Alternative Case rather than the Reference Scenario. For North America and Japan, energy demand and CO_2 emissions from freight transport are also reduced, because the fuel efficiency-policies also affect small commercial vans and trucks.

10. IEA, 1999b.

Table 11.2: **Passenger Vehicle Fuel Intensity Improvement: Transport-Energy Demand and Activity Change Compared with the Reference Scenario, 2020**
(Percentage change from Reference Scenario)

	Energy demand			Activity	
	Total	**Passenger**	**Freight**	**Passenger**	**Freight**
Western Europe	–4.1	–7.5	0	+2.4	0
Japan	–2.2	–2.8	–1.3	+0.3	0
North America	–8.3	–10.2	–5.0	+2.0	0

Using Alternative, "Low-Carbon" Fuels

For the short to medium term, few OECD countries are considering alternative fuels as an important option for mitigating energy-security concerns and greenhouse-gas emissions. Potential benefits for local air-quality, which have motivated government support for certain alternative fuels in the last two decades, are diminishing as emission standards tighten for conventional fuels and engines. Many alternative fuels do not offer significant GHG reductions, especially those derived from natural gas or LPG. Life-cycle emission reductions do not exceed 25% compared with current fuels and cannot justify the costly introduction and conversion of infrastructure and vehicles. Fuels like bio-diesel that *do* offer significant GHG reductions have very high production costs, but they also carry environmental disadvantages.[11]

In the longer term, fuels derived from cellulosic feedstocks (ethanol or methanol produced in advanced biological conversion processes) could bring life-cycle GHG-emission reductions of more than 80% compared with fossil fuels. They appear to have a strong cost-reduction potential, using advanced feedstock production and conversion technologies that could become available in ten years' time. A question — even in the longer term — is whether scarce biomass resources are best used for transportation fuels. Liquid-fuel production requires substantial energy input per output unit of useful energy, and biomass feedstock might find more cost-effective uses elsewhere.

11. IEA, 1999a.

Only in North America do alternative transport fuels play a significant role in government plans for long-term GHG-emission reductions and energy-supply security. Government-R&D funds and demonstration projects have been stepped up, with the aim of beginning commercial production of ethanol by 2010. Roughly 10% of gasoline now sold in North America is, in fact, "gasohol", a blend of 90% conventional gasoline and 10% corn-based ethanol by volume. In terms of energy content, the mix is 94% gasoline and 6% ethanol. "Flex-fuel" vehicles make up a significant share of current sales in North America, due to CAFE credits for this feature. While running mostly on gasoline, these cars could potentially use an ethanol-rich blend fuel. Both elements — low-percentage blending and "Flex-fuel" vehicles — can alleviate the chicken-and-egg, demand-side problem of introducing a new fuel.

On the supply side (i.e. the production of agricultural feedstocks and fuel), introducing a low-carbon fuel will depend heavily on government support, similar to that for introducing high-efficiency vehicles. Fuel taxation differentiated according to CO_2 emissions and fleet mandates for alternative-fuel use could stimulate production.[12] Otherwise, the high initial costs in the early stages of commercialisation will impede investment in production facilities. Market penetration will depend on many different factors, including, of course, the price of gasoline.

As an illustration, a market-expansion scenario for North America is assumed, where the low-carbon ethanol fuel starts production in 2010 and expands quickly to about 11 Mtoe (5.9 billion gallons) per year in 2015 and 27 Mtoe (14.2 billion gallons) in 2020. In energy terms, ethanol would replace 6% of gasoline use and about 3% of total transport energy use by 2020. This would correspond in 2020 to roughly a 100% penetration of gasohol as a gasoline substitute. Alternatively, 8% of the car and light-truck fleet could run on an ethanol-rich blend. Depending on the initial cost, assumed in this Case to be twice that of gasoline ($2/gallon of gasoline equivalent), and that costs fall by 7% each time cumulative production doubles, the cost by 2020 could be significantly lower than the comparable gasoline cost. The effect on CO_2 emissions would still be modest, about 90 Mt CO_2, or 4% of the CO_2 emissions from transport, but with a potential to grow after 2020. A strategy to introduce such a fuel can succeed only if costs can be reduced enough to phase out government support eventually.

12. Leiby and Rubin, 1998.

Policies for Demand Restraint and Modal Shift

Increases in travel and freight activity are the main factor driving growth in fuel demand and CO_2 emissions. Measures that aim to restrain transport volume and shift it to more environmentally benign modes are playing an increasingly important role in the policy plans of many OECD governments. Other concerns, such as congestion, urban access and living quality, diverse environmental objectives and the removal of economic distortions, including the charging of full infrastructure costs to each mode, often provide the key motivations behind such measures. Policies encompass pricing of different transport activities, transport supply through investments in infrastructure and rolling stock, regulation and restriction of traffic, and urban planning and land-use planning. They may apply locally, regionally or nationally.

The ongoing deregulation and liberalisation of public-transport services may interfere with such policies, in the absence of effective regulation. Packages of strong, complementary measures, which can effectively change the competitive situation between modes as well as consumer choices and behaviour, need to be sustained over long periods to achieve significant results.[13] They face significant political difficulties in implementation.

The demand policies variant of the Alternative Transportation Case is restricted to assessing what impact specified, assumed changes in transport activity and modal mix could have on energy demand and CO_2 emissions. The changes result from near and medium-term measures, which are driven mostly by policy objectives other than CO_2-emission reductions.[14] They reflect the limited, currently foreseeable level of policy intervention on transport activity and modal mix in most OECD Member countries. The results of this case suggest that they would not alter the transport-activity projections of the Reference Scenario substantially, but rather shift and limit growth in some areas.

Box 11.4 describes the assumed demand-side measures and their effects on transport in Western Europe and Japan. North America is not included in this part of the policy case, because demand-side policies do not appear as an important element there in the policy portfolio for CO_2 reductions.

Several difficulties concerning the quantitative assessment of transport-demand changes in response to demand-side policies explain the limited modelling effort possible in this context. The transfer of a package of measures that has proven successful in a certain local context to other cities

13. OECD/ECMT, 1995.
14. The measures resemble the "strand 1" and "strand 2" policies in OECD/ECMT (1995).

and regions is complex. The "upscaling" of the impact to a national level is therefore a simplification. For example, a possible modal shift depends strongly on the availability of alternative modes which varies greatly between regions and countries.

In addition, the overall response to certain measures is difficult to predict since factors such as technological innovations and organisational or behavioural changes can change the balance between modes. Kilometre-charges for trucks as contemplated in Europe may well lead to more use of combined rail but also increase load factors in trucks. An expansion of public transport infrastructure and services has frequently failed to attract customers, leading to lower average occupancy, economic losses to the operator and limited environmental benefits. On the other hand, expansion of attractive, high-speed rail services is likely to generate additional traffic beyond that shifted from other modes. Thus, measures that restrain demand for demand for certain transport modes must be backed-up with measures that promote the provision and use of alternative modes. At the same time, the different simultaneous responses make an assessment of their impact hard.

Moreover, our time frame to 2020 is too short for the full impact of the measures analysed here to show up. Infrastructure investments in alternative modes such as freight rail need to be sustained over long periods to show results. Also, changing land-use and urban planning policies will only show effects slowly[15]. In response to such changes, land-use patterns, including the location of jobs and residences will change. Such changes, some of which could already become relevant within our time frame, are not taken into account here. In the long run, the effects of a consistent demand-side policy package are likely to be more important than illustrated here.

A realistic assessment of the impact on energy demand of the assumed changes in the transportation system would benefit from more detailed analysis taking account of the widely varying energy intensities within each mode, which is usually characterised by its average fuel intensity. Substituting "average rail" for "average car", for example, does not yield a realistic estimate of feasible substitution. A distinction between short-distance urban and long-distance inter-city traffic in each mode would be necessary as a first step towards more realism in order to adequately capture, for example, the effects of substituting urban rail (tramway, metro) for urban car use.

15. A spatial model of transport and infrastructure would be needed for such a purpose, which is not feasible on an OECD-wide level.

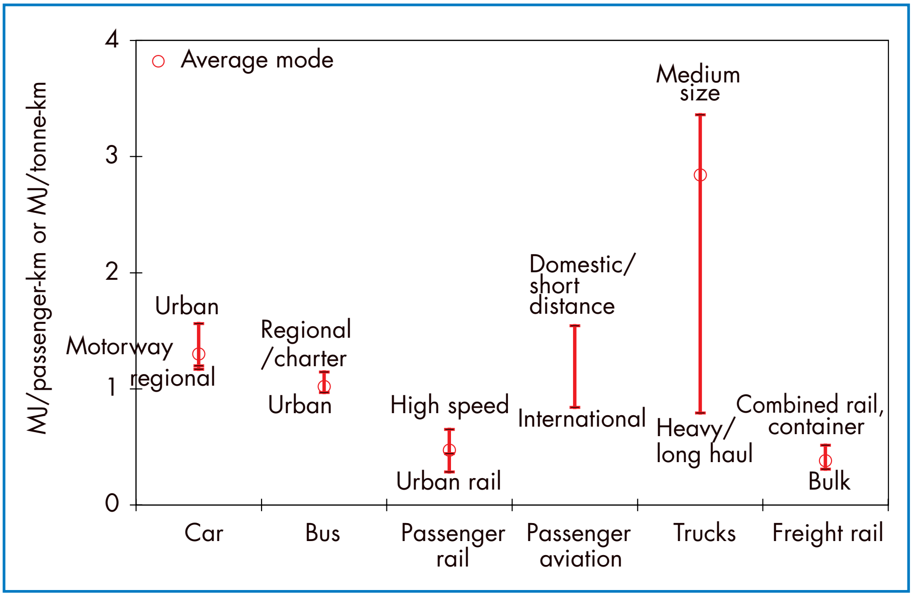
Box 11.4: **Assumed Demand-Side Measures and Effects**

Measures	Effects on Transport
Western Europe	
Urban car restraint: parking and access restrictions; traffic calming; and improvements in public and non-motorised transport	Urban car activity in the Reference Scenario is reduced by 7% in 2020: • 40% of the transport activity shifts to public modes (urban bus, urban rail). • The rest (60%) is suppressed or shifts to non-motorised modes, such as ride sharing.
High-speed rail services are expanded.	HSR expansion after 2010 is twice as fast as in the Reference Scenario: • 30% of additional high-speed rail activity shifts from domestic aviation. • 40% shifts from motorways. • The rest is real expanded capacity.
km charges are levied on heavy-truck activity; expansion of combined rail-transport infrastructure (terminals).	• Load-factor improvements in trucks by 6% in 2020 over the Reference Scenario. • 5% of long-haul truck ton-km shift to combined rail by 2020. • 3% of long-haul trucking is suppressed by 2020.
Japan	
Urban road pricing (applied to 30% of urban areas); other urban car restraint measures; and improvement of public modes.	Urban car activity in the Reference Scenario is reduced by 10% in 2020: • Of the 40% shifts to public modes (Urban bus and rail). • The rest (60%) is suppressed or shifts to non-motorised modes, such as ride sharing.
High-speed rail services are expanded.	HSR expansion after 2010 is twice as fast as in the Reference Scenario: • 30% of the additional high-speed rail activity shifts from domestic aviation. • 40% shifts from motorways. • The rest is real expanded capacity.
City logistics (mandatory trip bundling) for small commercial trucks (applied to 30% of urban areas).	In 2020, 6% of urban small van vehicle-km is bundled through city logistics systems and terminals and replaced by mid-sized, urban trucks on optimised routes.

In short, average fuel intensities yield only a rough indication of the energy implications of modal shifts. Figure 11.6 shows the ranges of fuel intensities used for calculating the energy benefits from modal shifts in Western Europe. These values vary considerably from city to city and from application to application. For Japan, similar ranges are applied in the calculation of energy savings.

Table 11.3 gives an approximate quantitative assessment, based on the assumptions in Box 11.4 and the fuel intensity ranges given in Figure 11.6 for Europe.

Figure 11.6: **Fuel Intensities in Western Europe, 2020**



Fuel Taxation

Fuel taxation plays an important role in all the policy variants analysed here. The price of gasoline at the pump can provide a signal to consumers to choose more efficient cars. Increases in taxation can help limit rebound effects. Differentiated fuel taxes are widely used to support or limit the use of specific fuels. Fuel-tax increases restrain transport activity and have implications for the relative competitive advantages of different modes.

Yet we should not overstate the role of taxation, especially as an isolated measure. The response to fuel-tax increases is very limited in the short term,

Table 11.3: **Demand Policies: Transport-Energy Demand and Activity Change Compared with the Reference Scenario, 2020**
(Percentage change from Reference Scenario)

	Energy demand			Activity	
	Total	**Passenger**	**Freight**	**Passenger**	**Freight**
Western Europe	–2.7	–1.2	–4.4	–0.4	–0.6
Japan	–4.2	–5.1	–3.1	–0.4	0

although somewhat greater in the long term. Moreover, considerable uncertainty surrounds long-term price elasticities as a measure of price responsiveness. The values vary over time and depend on the methodology used to calculate them, the transport mode and the region.

A fuel-demand change calculated from price changes and elasticities gives an aggregated picture of changes in transport activity, fuel intensity and structure in each transport mode. Fuel-taxation changes take effect simultaneously with others, such as regulatory changes, and work synergistically with them. In the future, it is likely that more selective pricing mechanisms, such as kilometre-charges and toll-rings around cities, will be deployed. Our calculations of the response to fuel-taxation changes in terms of energy-demand reduction (Table 11.4) are therefore very approximate.

The level of taxation assumed in this analysis is derived from the emission-trading case in Chapter 10. A tax of $95 (in 1990 US dollars) per tonne of carbon is added to final prices across all regions and transport fuels and phased in progressively between 2001 and 2010. The relative fuel-price change in each region depends on the carbon content of the fuel and its initial price level, including existing taxes. The total energy-demand reduction does not vary greatly across the regions. Higher relative fuel-price changes in North America are balanced somewhat by lower elasticities compared with the other regions. The overall reduction in energy demand calculated with this elasticity approach is around 4% across the OECD area.

Table 11.4: **The Effects of a Carbon Tax on Transport-Energy Demand and Activity Compared with the Reference Scenario, 2020** (per cent)

a) Relative long-term change due to a 10% fuel-price increase[1]		
	Energy demand	**Activity (passenger-km or ton-km)**
Passenger (cars, light trucks)	–3.5 to –5.5	–1.5 to –2.5
Freight (trucks)	–2.5 to –3.0	–0.05 to –1.5
Aviation	–4 to –7	–2 to –5

b) Relative change of fuel prices in 2010 due to a US$ 95/tC carbon tax			
	Gasoline	**Diesel**	**Kerosene**
Western Europe	+7	+12	+32
Japan	+10	+19	+32
North America	+15	+22	+32

c) Relative change in 2020 due to a US$ 95/tC carbon tax					
	Energy demand			**Activity**	
	Total	**Passenger**	**Freight**	**Passenger**	**Freight**
Western Europe	–3.8	–3.6	–4.1	–1.6	–1.1
Japan	–4.4	–4.8	–4.0	–2.1	–1.3
North America	–4.8	–5.0	–4.4	–2.6	–1.0

1. The activity elasticities are estimated from time-series data where possible. No cross-elasticities are used. Because the figures in the table are keyed to price increments of 10%, a value of –3% is equivalent to an elasticity of –0.3.

Combining the Different Policy Measures

There are important synergies among and some overlap between the different measures examined in the Alternative Case. This is particularly true for fuel taxation. Its effect on fuel intensity could overlap with fuel-consumption regulations, and transport-demand reductions. Modal shifts brought about by fuel-price changes could form part of demand-side policy packages. As a consequence of such overlaps, the combination of policy measures may well have — and is assumed here to have — a result *less than* the sum of the results of the policy measures considered separately.

Figures 11.7 and 11.8, and Table 11.5 present the combined results of the Alternative Transportation Case compared with the Reference Scenario and with the historical record for 1971-97:

Figure 11.7: **Energy Demand and CO_2 Emissions in the Alternative Case, Compared with the Reference Scenario**

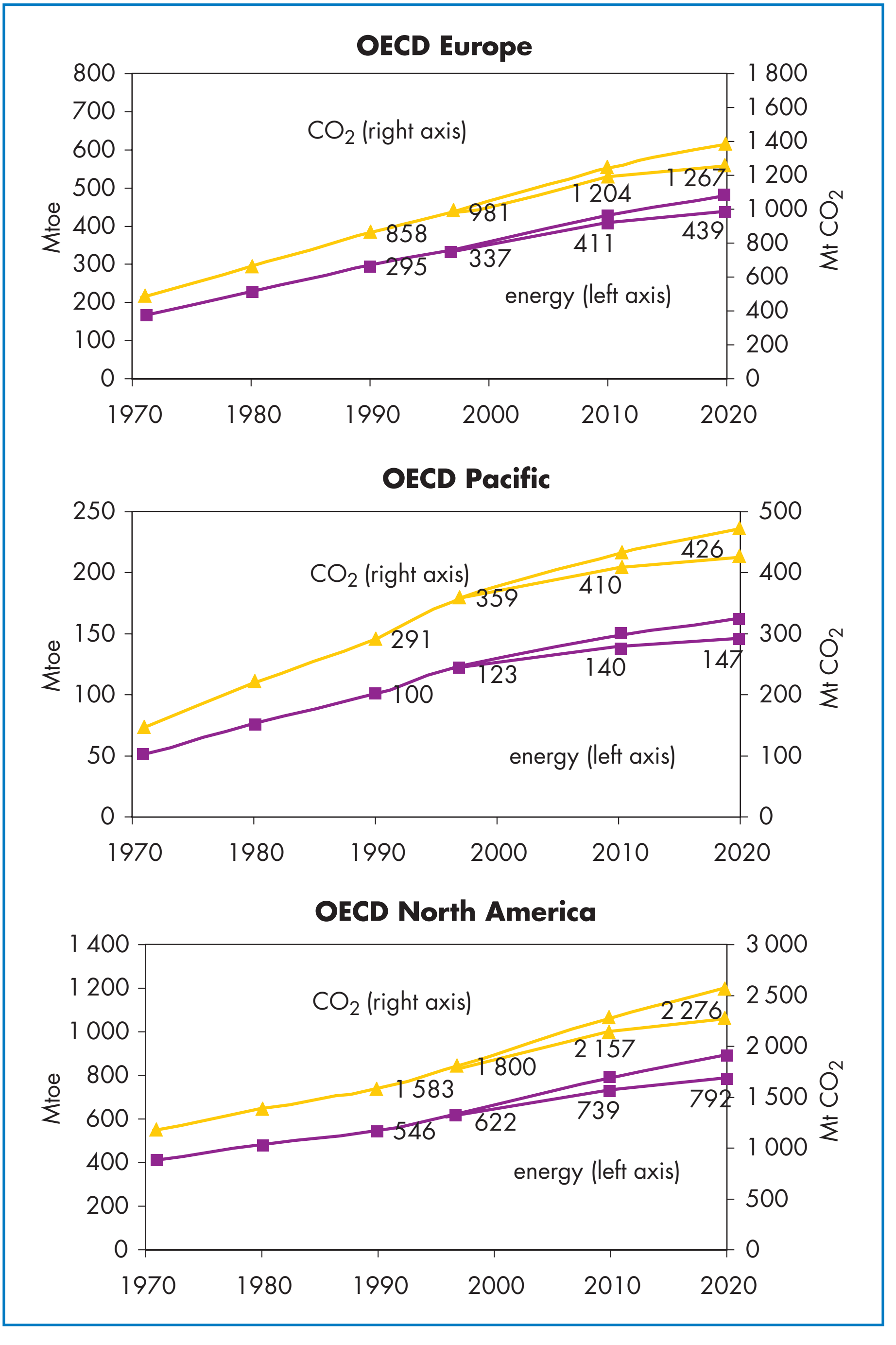
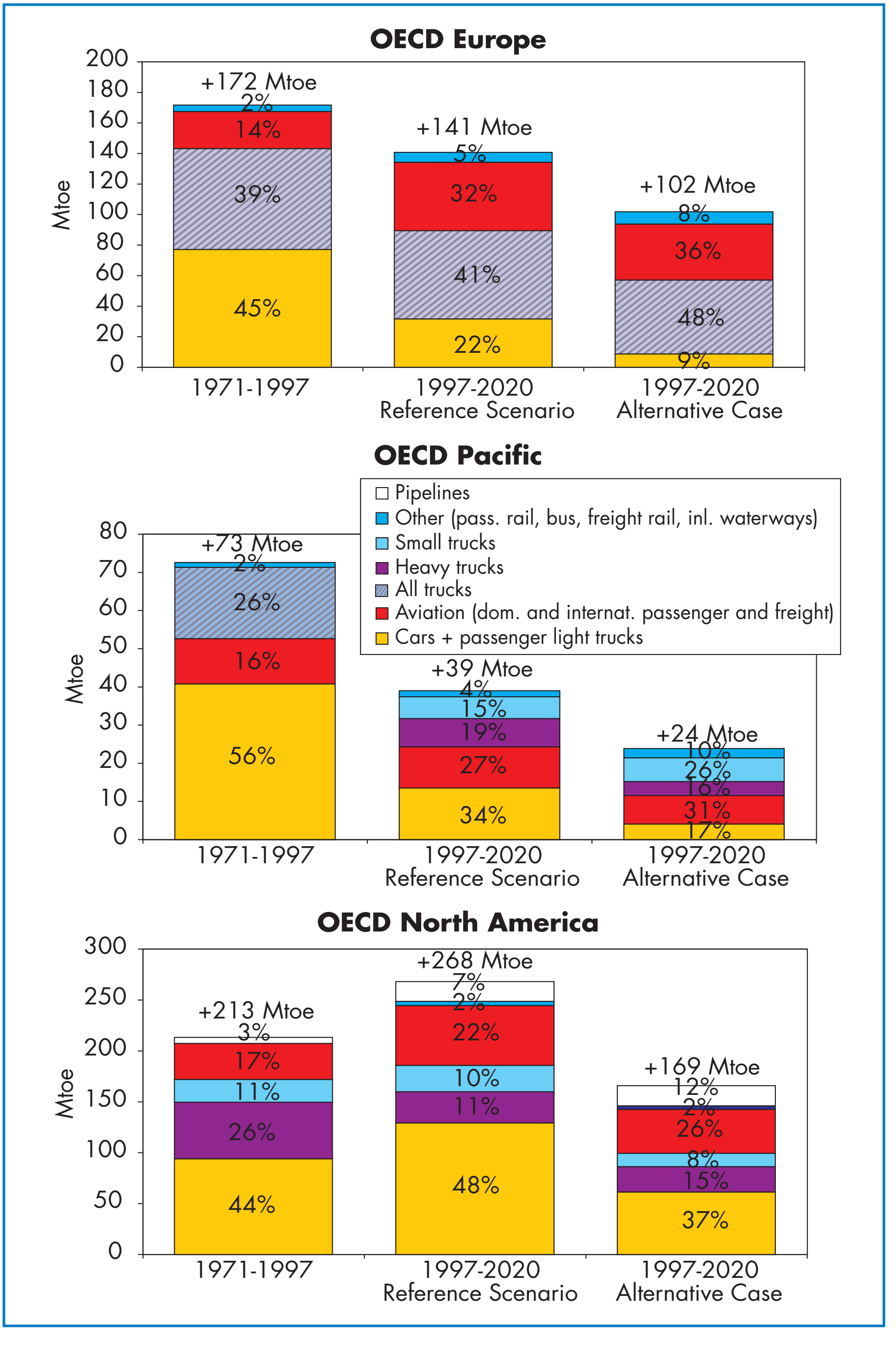


Figure 11.8: **Modal Allocation of Growth in Transport-Energy Demand in the Past, the Reference Scenario and the Alternative Case**



- In OECD Europe,[16] most of the reductions in energy demand and CO_2 emissions come from cars. Their energy-demand growth in 1997-2020, as projected in the Reference Scenario, would be almost completely contained. Some reductions also emerge in trucking and aviation, in response to the demand-side policies and the carbon tax. The most important feature of the Alternative Case is thus the continued improvement of car-fuel intensity by building on policies already in place. The fuel-price increases and demand side changes add to the effect, but do not drastically affect the other two growth sub-sectors, trucking and aviation.
- In the OECD Pacific[17] area, fuel-efficiency regulations for cars and small trucks also contribute most to the reductions. Demand policies supported by fuel-price increases have a less important but still sizeable effect on energy demand and CO_2 emissions.
- In OECD North America, the impact of the combined Alternative-Case policies relative to the Reference Scenario's projections exceeds that in the other regions, because the Reference Scenario includes no major policy efforts. The bulk of it again comes from fuel-intensity

Table 11.5: **Summary of Results for the Combined Policies of the Alternative Case**

	Europe		**Pacific**		**North America**	
	2010	**2020**	**2010**	**2020**	**2010**	**2020**
Energy demand change over 1997*						
Mtoe	74	102	17	23	117	169
Relative change (%)	22	30	13	19	19	27
CO_2 Emissions change over 1990						
Mt CO_2	347	410	119	135	574	693
Relative change (%)	40	48	41	46	36	44

* See Figure 11.8 for breakdown by mode.

16. For Eastern Europe, not discussed in the text, the only policy measure included is one similar to the Voluntary Agreement.
17. For Australia and New Zealand, also not discussed, policy changes similar to those for North America (excluding alternative fuels) are assumed.

improvements in cars and light trucks. Using alternative fuels would compensate another 90 Mt CO_2 in 2020, but none in 2010. Assuming that this gain is attributed to transport, it would bring CO_2 emission growth by 2020 down to 38% (+603 Mt CO_2) over 1990 compared to 63% in the Reference Scenario.

Conclusions

- *The additional policies studied here can bring stabilisation of transport energy demand and CO_2 emissions after 2010 — but not before.* Until 2010, they have no significant effect, due to assumptions about their late introduction and gradual penetration. Energy demand and CO_2 emissions continue to grow rapidly and pose a real burden to the attainment of Kyoto targets.
- *Effective policies are available for containing passenger-vehicle energy demand.* If measures to hasten fuel-intensity improvements in cars and light trucks continue to be tightened, fuel-demand increases from this mode after 1997 can be held back at low levels until 2020. In the Alternative Case, such policies produce the biggest change compared to the Reference Scenario. High-efficiency hybrid and fuel-cell vehicles could potentially contribute to this development after 2010.
- *Road freight, in small and large trucks, provides a large share of the increase in transport energy demand under the combined policies in the Alternative Case.* Strong economic and regulatory measures beyond those assumed here might be necessary to contain its growth. Where fuel-intensity policies similar to those for cars are applied to small commercial trucks and vans, as in Japan and North America, their fuel-demand growth falls substantially.
- *Aviation-fuel demand growth is a major concern.* The fuel tax assumed here would not significantly affect it. A tougher burden could be needed and potentially justified by the greater climate impact from greenhouse gases emitted by aircraft[18].
- *Growth in passenger and freight-transport demand remains a long-term problem.* It is slowing, but it is not feasible to try to compensate for its effect on energy demand with fuel-intensity improvements alone. Nor would this approach be sufficient to achieve significant fuel-demand reductions in the longer term.

18. Due to the increased radiative forcing of GHGs emitted in the upper troposphere (IPCC 1999).

CHAPTER 12
THE ALTERNATIVE POWER GENERATION CASE

Introduction

Changes in OECD energy policy, technological developments and market economics over the next two decades may have a major impact on power-sector energy demand and CO_2 emissions. The trends they produce could differ markedly from the Reference-Scenario projections. This chapter analyses these trends and their implications for the three OECD regions.

The share of electricity in OECD energy demand is projected to increase over the next twenty years. The power sector already accounts for about a third of total CO_2 emissions, a share likely to grow even higher. Unlike the transport sector, where fuel substitution options are limited, the power sector can use a wide range of fuels. It offers great flexibility and numerous options to reduce greenhouse-gas emissions. The Reference Scenario projects total CO_2 emissions in the OECD to increase by 16% from their 1997 level in 2010 and by 25% in 2020. The corresponding figures for the power sector are much greater, at 21% in 2010 and 33% in 2020.

The Alternative Power-Generation Case examines four independent options for the future of the power sector in OECD countries. All four represent plausible alternatives to the Reference Scenario and offer opportunities for CO_2 emission reductions. They deal with:

- *Fossil fuels*. In the Reference Scenario, gas-fired combined-cycle gas turbine (CCGT) plants are the preferred option for new power generation for at least another decade, but some room remains for their further use, especially in the second half of the projection period. Deregulation and further improvements in the economics of gas-turbine technology could result in higher natural-gas use. Such improvements are also likely to lead to wider use of integrated gasification combined-cycle (IGCC) technology. The Alternative Case assumes higher efficiencies and lower capital costs compared with the Reference Scenario for CCGT and IGCC technologies.[1]

1. The assumptions used in the Alternative Case for all four options are described in the sections that examine the options.

- *Nuclear power* could decline less rapidly than in the Reference Scenario, if existing nuclear plants perform well in liberalised energy markets and operate longer. Concerns over climate change and energy security could also affect the future of nuclear power. The underlying assumption in the Alternative Case is that there are no nuclear plant retirements before 2020. Plant capacity factors are higher than in the Reference Scenario. The Alternative Case assumes that no additional plants over the Reference Scenario assumption are built.
- *Renewable energy* is currently a favourite option among OECD governments to reduce CO_2 emissions. The Alternative Case assumes a higher share of electricity from renewables. This would happen if government support grew stronger.
- *Combined heat and power* (CHP) could also find wider use with support from governments. The share of electricity from CHP plants is increased in the Alternative Case. Using natural gas and combustible renewables and waste (CRW) for fuel maximises the environmental advantages of CHP.

Table 12.1 summarises the main qualitative aspects of each of the four choices: their environmental performance, their economics and the barriers to their development.

Separate sections discuss each of the four options. To enable comparisons, electricity demand is held constant in all four cases. In reality, demand could differ slightly in each case because changes in the fuel mix would affect electricity prices. In the CHP option, electricity demand could be somewhat lower because on-site power generation reduces transmission losses. In any case, the differences are small and do not affect the results.

Fossil Fuels

Its high contribution to total emissions and relatively easy substitution possibilities make electricity generation a key sector for making emission reductions. A wide range of policies and measures aims at lowering the use of fossil fuels by promoting renewables. Other than supporting relevant research and development (R&D), few climate policies have specifically targeted improved efficiency of generation fired by fossil fuels as a means to reduce CO_2 emissions.[2]

CO_2 taxes or emission trading would increase incentives to improve generation efficiency. Neither has yet found wide enough application to

2. Measures to promote combined heat and power (CHP) represent one exception. The potential impact of these policies is discussed in a separate section.

Table 12.1: **Assessment of Four Options in the Alternative Power-Generation Case**

Option	CO_2 Emissions	Other Environmental Benefits	Cost Performance	Challenges and Barriers
Fossil Fuels: CCGT-Natural Gas	Low	No SO_2, low airborne emissions.	Cost effective.	Supply constraints could raise gas prices.
Fossil Fuels: IGCC-Coal	Lowest of all coal technologies; higher than gas-fired CCGT.	Low airborne emissions.	Current high cost. Cost reductions possible in the long term.	No supply constraints. Capital costs must be reduced.
Nuclear	Nil	No air pollutants (but solid waste).	Cost effective (existing plants).	Low public acceptability.
Renewables	Nil	No air pollutants (except biomass).	High cost. Requires government support.	High cost relative to fossil fuels. Supply constraints for some alternatives.
CHP	Low	Low emissions.	High cost. Requires government support.	High cost. Requires steady load of heat.

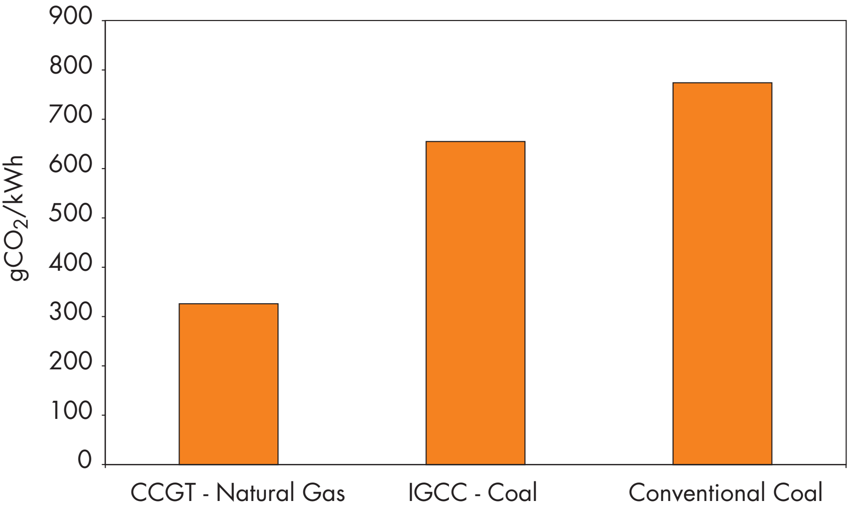
limit emissions from the electricity sector in OECD countries. Although some countries in Europe have introduced carbon taxes, they generally apply to sectors other than electricity generation, due to concerns about competitive distortions.[3]

3. IEA, 2000.

Compared with the Reference Scenario, the Alternative Case assumes reductions in capital costs and increased generation efficiency for certain technologies. Increasing competition in electricity markets combined with continuous research in turbine technology could result in lower costs and more efficiency improvements than in the Reference Scenario. Because oil use in OECD electricity generation is limited and because its importance will probably decline further, the analysis here focuses only on coal and gas.

CCGTs now have the lowest generating costs in many markets. Their high efficiency combined with the low carbon content of gas relative to coal allow them to produce electricity with less than half the carbon emissions of coal-fired plants (Figure 12.1). Uncertainty about future environmental requirements makes gas-based technologies low-risk options compared with other fossil fuels. The Alternative Case expects capital costs of CCGTs to be 10% lower in 2020 than the Reference Scenario assumes. Generation efficiency also improves faster, to 62%, two percentage points higher than in the Reference Scenario. The efficiency of CCGT plants has improved dramatically over the past few years, and advanced combined-cycle systems offering efficiencies of 60% could be on the market over the next few years. Thus, the small efficiency increase assumed in the Alternative Case is likely to take place over the outlook period.

Figure 12.1: **Alternative Power-Generation Case: CO_2 Emissions per Unit of Electricity Generated, for Various Fossil-Fuel Generation Alternatives in 2020**



The Reference Scenario projects that coal will remain important in OECD electricity generation throughout the outlook period. Coal-fired generation has by far the highest CO_2 emissions per unit of electricity output of all generating technologies. It also presents high environmental charges through the emissions of SO_2, NO_x, particulates and solid wastes. Tightening standards for these emissions could place coal-fired generation under significant pressure. On the other hand, the improved efficiency and environmental performance offered by new coal-fired technologies like IGCC will improve the competitiveness of coal-based generation. The Alternative Case takes up some IGCC improvements by assuming for 2020 lower capital costs, 10% below the Reference-Scenario projection, and higher generation efficiency, at 52% as against 50%. Further advances in turbine technology could accelerate improvements in IGCC efficiency.

To sum up so far, the Alternative-Case assumptions posit higher generation efficiency and lower capital costs than in the Reference Scenario for both coal and gas. They set the stage for the discussion below of results for fossil-fuel generation and related CO_2 emissions in the three OECD regions.

Box 12.1: **CO_2 Capture**

All power-generation alternatives fired by fossil fuels can in principle be combined with techniques that capture CO_2 from exhaust gases and store it in ocean depths or geological formations. Several options for capturing CO_2 already exist, but they all require extra energy, reducing the overall efficiency of generation, in a typical case, by ten percentage points. Losses and costs related to CO_2 capture can increase generation cost by at least 2 cents/kWh.[4]

The Alternative Case does not examine the impact of CO_2 capture. Nevertheless, various processes for CO_2 separation are currently under intensive research, and, with a breakthrough in cost reduction, CO_2 sequestration may be able to reduce emissions from power generation in many markets, especially with strict GHG regulations and/or tax schemes in place.

OECD Europe

Fossil fuels accounted for half of total electricity generation in 1997, of which coal took more than 60%. The role of natural gas has increased

4. IEA Greenhouse Gas Programme (www.ieagreen.org.uk).

significantly since 1990. The consequent reduction in the share of coal lowered emissions from power generation by 4% from 1990 to 1997. The smaller share of coal also helped keep total CO_2 emissions in OECD Europe at the same level in 1997 as in 1990. The Reference Scenario projects continued growth in the use of natural gas. Generation almost triples between 1997 and 2010 and goes up by another two thirds by 2020. Coal's share declines by six percentage points but coal consumption increases slightly in absolute terms.

In the Alternative Case, coal-fired generation falls by more than one-third over the projection period. Increased use of gas-fired generation results in almost a 3% reduction in power-sector emissions compared with the Reference Scenario in 2010 and about 12% in 2020. (Table 12.2). The difference in emissions between the two cases comes primarily from increased use of CCGTs. Towards 2020 new IGCC plants yield some additional reductions.

Table 12.2: **Electricity Generation and CO_2 Emissions for OECD Europe**

	1990	1997	2010		2020	
			Ref.	Alt.	Ref.	Alt.
Electricity Generation (TWh)						
Coal	1 007	908	1 020	958	1 110	665
Gas	163	363	1 046	1 107	1 738	2 184
Total	2 605	2 925	3 863	3 863	4 514	4 514
Shares of Total Generation (%)						
Coal	39	31	26	25	25	15
Gas	6	12	27	29	38	48
CO_2 Emissions (Mt)	1 281	1 233	1 534	1 492	1 680	1 480
CO_2 Emissions (1990=100)	100	96	120	116	131	116
Savings from Ref. Scenario (%)				2.7		12

OECD North America

Fossil fuels provided 64% of North America's power generation in 1997. Almost half of total electricity supply was from coal. The mix changed little between 1990 and 1997, with only a small increase in the share of natural gas. The Reference Scenario expects dependence on fossil fuels to increase to 71% of total generation in 2010 and 76% in 2020. Most of the new capacity is CCGT, which raises the gas share from 12% now to

23% by 2010 and to 27% in 2020. Yet coal continues to be the most used fuel throughout the outlook period, still accounting for more than 45% of electricity generated after 2010. The improved economics of CCGT plants in the Alternative Case do not push additional coal capacity out of the market in the short run, because most of new capacity up to 2010 in the Reference Scenario is already CCGT. The small increase in coal-fired generation in the Alternative Case between 1997 and 2010 is due primarily to the higher capacity factors for coal plants. After 2010 some new coal-based capacity develops in the Reference Scenario, while there is almost no expansion in the Alternative Case. Gas replaces about 10% of the Reference-Scenario coal generation by 2020 (Table 12.3).

The switch towards gas and the improved generation efficiency of both CCGT and IGCC plants assumed in the Alternative Case reduce emissions by 11% from the Reference Scenario in 2020. The modest emission savings by 2010 result primarily from only small increases in the capacity factor of gas-fired generation compared with the Reference Scenario.

Table 12.3: **Electricity Generation and CO_2 Emissions for OECD North America**

	1990	1997	2010		2020	
			Ref.	Alt.	Ref.	Alt.
Electricity Generation (TWh)						
Coal	1 783	2 076	2 348	2 306	2 701	2 452
Gas	392	531	1 212	1 254	1 564	1 813
Total	3 664	4 246	5 159	5 159	5 729	5 729
Shares of Total Generation (%)						
Coal	49	49	46	45	47	43
Gas	11	12	23	24	27	32
CO_2 Emissions (Mt)	2 005	2 331	2 818	2 783	3 127	2 794
CO_2 Emissions (1990=100)	100	116	141	139	156	139
Savings from Ref. Scenario (%)				1.3		11

OECD Pacific

Fossil fuels lost share in OECD Pacific power generation between 1990 and 1997, dropping from 66% to 62%. The key reason lay in the reduced use of oil in Japan's electricity sector, which led to a 25% plunge in oil-fired generation for the region. Gas-fired generation is expected to grow fast in the Reference Scenario, eventually catching up with coal in 2020.

As in the other two regions, the assumed improvements in CCGT technology in the Alternative Case do not yield much CO_2 savings up to 2010. Rather more occur by 2020, but less than in Europe and North America (Table 12.4). One reason is that power plants in the region are newer and generally more efficient than elsewhere in the OECD area. In addition, higher gas prices relative to coal make shifts from coal-fired generation to CCGT less attractive than in Europe and North America.

Table 12.4: **Electricity Generation and CO_2 Emissions for OECD Pacific**

	1990	**1997**	**2010**		**2020**	
			Ref.	**Alt.**	**Ref.**	**Alt.**
Electricity Generation (TWh)						
Coal	243	344	397	383	467	415
Gas	187	234	368	382	448	500
Total	1 037	1 249	1 533	1 533	1 745	1 745
Shares of Total Generation (%)						
Coal	23	28	26	25	27	24
Gas	18	19	24	25	26	29
CO_2 Emissions (Mt)	483	539	619	610	665	637
CO_2 Emissions (1990=100)	100	112	128	126	138	132
% Savings from Ref. Scenario				1.5		4

Summary of Changes in Generation Efficiency and Fuel Mix

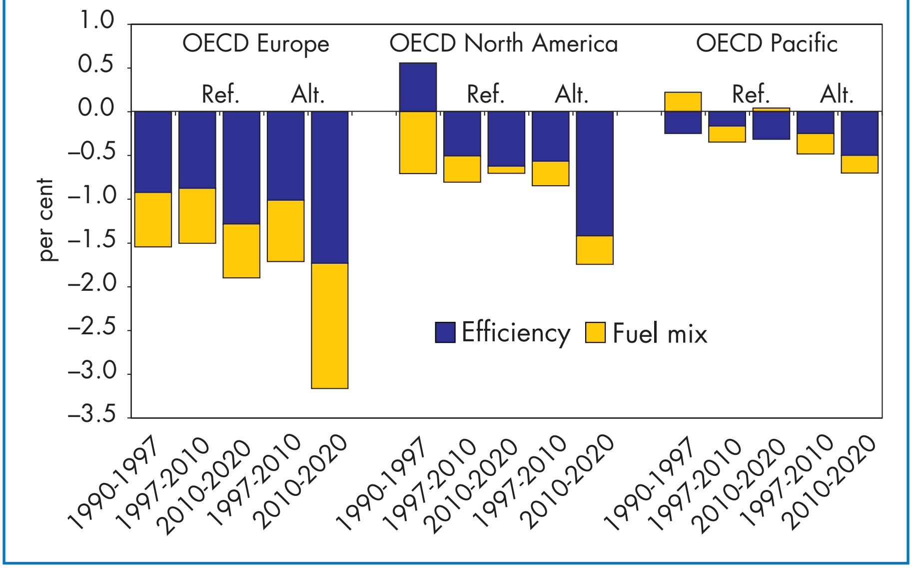
The assumed capital-cost reductions and improved generation efficiency for IGCC and CCGT lie behind the differences in projected emissions between the Alternative Case and the Reference Scenario. These technology improvements reduce emissions both through lowering fuel requirements (higher efficiency) and through shifting the fossil-fuel mix towards fuels with lower carbon content. Table 12.5 summarises the CO_2 emission reductions by region.

The changes in CO_2 emissions per kWh can be decomposed into impacts from efficiency improvements and from changes in the fuel mix. Figure 12.2 shows the results, expressed as annual percentage changes for both factors and for each of the OECD regions. For comparison, the same information is included for 1990-97.

Table 12.5: **CO_2 Emission Reductions in the Fossil-Fuel Option**

	2010		2020	
	% of Power Sector Emissions	% of Total CO_2 Emissions	% of Power Sector Emissions	% of Total CO_2 Emissions
Europe	2.7	0.9	12	4.1
North America	1.3	0.5	11	4.4
Pacific	1.5	0.5	4	1.6
OECD	1.7	0.7	10	3.9

Figure 12.2: **Changes in CO_2 per kWh Generated from Fossil Fuels**



For OECD Europe both factors significantly reduced emissions between 1990 and 1997, a development which continues in the Reference Scenario, with a stronger effect from efficiency improvements than from fuel switching.[5] The Alternative Case resembles the Reference Scenario up to 2010, but an accelerated shift towards gas, augmented by higher rates of

5. A switch from coal-fired generation to CCGT will yield emission reductions from both the reduced carbon content of the fuel and the increased efficiency of the CCGT plant.

efficiency improvement, leads to more than a 3% annual reduction in CO_2 emissions per kWh between 2010 and 2020, as against 1.9% in the Reference Scenario.

In North America the Reference Scenario expects small effects from fuel shifting, but efficiency improvements drive down emissions per unit of electricity generated by about 0.5% a year throughout the projection period. The Alternative Case produces an even stronger effect from improved generation efficiency after 2010, due to the higher efficiency of the new CCGT and IGCC capacity entering the market. In OECD Pacific, the higher generation efficiencies of currently installed plants leave less room for further improvements than in the two other regions. The higher price of gas relative to coal also limits the emission-reduction effect from fuel switching. This leads to relatively modest total reductions in CO_2 per kWh in the Alternative Case.

Implications

The projections presented for the Alternative Case show only small reductions by 2010 in all three OECD regions compared to the targets set in the Kyoto Protocol. With the fuel prices anticipated in this *Outlook*, the CCGT improvements assumed in the Alternative Case do not make the early retirement of existing coal capacity economically feasible.[6]

Power producers can also reduce CO_2 emissions without altering the composition of installed capacity. The lower operating cost of coal-fired plants often makes them more appropriate for base-load generation than natural gas. Changing this preference, *i.e.* shifting the operation of gas-fired plants towards base-load use, can result in lower emissions. In the Alternative Case, the reduced fuel cost from improved efficiency of the CCGT plants leads to a small increase in the capacity factor for gas-fired generation, but the overall effect on emissions is marginal. With changes in the relative fuel cost between coal and gas, *e.g.* by introducing a CO_2 tax, operating gas plants for base load will become more attractive and may have a considerable impact on emissions.

More use of natural gas in power generation will, however, drive up total gas demand and put pressure on prices. The difference in gas demand in 2010 is small for all three regions. By 2020 the impact on gas demand is

6. In Denmark, the government has introduced restrictions on investments in coal plants as a part of its climate-policy package. This policy may result in early phasing out of coal-fired capacity and thus entail stranded costs. See IEA (1998a).

more noticeable, especially in OECD Europe. (Table 12.6) Yet the deviations are still too small to suggest a big impact on prices.

Table 12.6: **Changes in Total Natural Gas Supply in the Alternative Case**

Changes in Gas Supply (%)	2010	2020
OECD Europe	+0.9	+9.1
OECD North America	–0.1	+3.4
OECD Pacific	+1.2	+5.3

With substantially higher demand for gas, supply may be tighter. Nearly all gas in OECD North America comes from within the region. As increased demand eats into these reserves, price increases are likely.[7] Rising prices will at some stage make imports of LNG competitive, with significant changes in LNG trade. OECD Pacific already imports LNG for electricity generation. In OECD Europe additional gas may also be supplied via pipeline. But as most of this supply would be from outside the region, increased dependence on natural gas can give rise to concerns over energy security.

Nuclear Power

The Reference Scenario projects OECD nuclear power to decline. Few new plants will come on line during the projection period, and nearly a third of existing plants could be retired. It is possible, however, that operators of some of the existing plants will seek extension of their operating licenses. The Alternative Case assumes continued improvement in the use of existing plants and that plant lifetimes of the good performers can be extended beyond 40 years. Competition, concern about climate change and energy security are the key factors behind these assumptions.[8]

Greater emphasis on energy security would tend to support nuclear power. Developments in energy markets could highlight nuclear's potential contribution to electricity supply and the fact that it is less affected by changes in fossil-fuel prices. Moreover, nuclear does not face fuel-supply shortages.

7. See Chapter 4 for a discussion of North American gas prospects.
8. See IEA (1998b).

Most OECD countries have introduced electricity-market competition or are doing so. This puts strong pressure on all generation plants, including nuclear ones, to improve technical performance. Competition will reinforce the trend toward improved nuclear-plant performance. Nuclear plants in OECD countries need to undergo periodic outages to load fresh fuel. The time needed for such fuel-loading operations and other maintenance has dropped steadily from over two months per year to under six weeks in most plants. Better procedures and preventive maintenance have also reduced plant downtime. As a result of these developments and operational improvements, plant utilisation rates have increased since 1990 from roughly 70% to 80%. The best plants today have lifetime average rates of over 90%. In the Reference Scenario, plant capacity factors[9] are assumed to increase over the next two decades: from 80% in 1997 to 85% in 2020 in OECD Europe, from 77% to 86% in North America; and from 83% to 85% in OECD Pacific[10]. The Alternative Case assumes that average nuclear-plant capacity factors are higher by two percentage points in 2020.

There is a strong motivation to extend plant lifetimes and output in competitive markets, to the extent possible within technical and safety constraints. Given both the investment and total generation costs of alternatives, keeping existing nuclear plants running or increasing their output can be more attractive than building new capacity of any type. This is already a nascent trend; some nuclear plant owners in Finland, Japan, the United Kingdom and the United States have already planned or obtained regulatory approval to operate beyond 40 years, up to 60 in some cases. In the Reference Scenario, a lifetime of 40 years is used as a general rule, although some of the existing nuclear plants are assumed to operate for longer and others are assumed to be retired early. The Alternative Case assumes that almost all plants will be able to continue operating beyond a 40-year lifetime.

Efforts to reduce CO_2 emissions, or further restrictions on conventional pollutants, could well lead to higher nuclear output and capacity than expected in the Reference Scenario. Because nuclear plants do not emit CO_2, they benefit when firm CO_2 limits are imposed. Several governments recognise the role of existing nuclear plants in climate-change policy. Government support tends to buttress trends towards improved technical performance.

9. Measured here as gross electricity generation over net capacity over a year (8 760 hours).
10. The increase is the highest in North America, where the capacity factor of US nuclear plants has increased significantly over the past few years.

If climate-change policy became more stringent, some OECD countries could develop new nuclear plants. Japan may add more new nuclear capacity than is assumed in the Reference Scenario as an important element in its climate-change policies.

Other factors could work against the construction of new nuclear plants. Given prevailing energy-market conditions, nuclear plants are seldom the least expensive option on the basis of total cost (cents/kWh). Their high capital costs are a major factor. Although the price of natural gas is assumed to increase over the outlook period, combined-cycle and coal-fired power generation remain strong competitors. Political restrictions in nuclear power in almost half of the OECD countries and concerns about nuclear-plant safety and waste disposal also limit new-construction opportunities. All these reasons explain why the Alternative Case assumes no *net* growth in nuclear plant capacity.

Nuclear technology is mature; the Alternative Case expects no major technological developments. Yet ongoing projects to develop new reactor concepts do have the potential to improve nuclear's competitiveness. Examples include the Generation IV initiative led by the United States, updated designs for high-temperature gas-cooled reactors, or more evolutionary design projects such as the European Pressurised Water Reactor and Candu-X reactor.

The Alternative Case assumes adequate supplies of nuclear fuel at reasonable prices. Since 1990, world consumption of uranium has exceeded production. In recent years, the annual deficit has been roughly 25 000 tonnes. Secondary sources have met the deficit: existing stockpiles of natural and enriched uranium as well as excess military uranium. Given extraction costs of US$ 40 or less per kilogramme of uranium and present rates of consumption, currently known reserves are adequate for at least 25 to 30 years. Although future uranium production is difficult to predict, prices will probably remain stable or decline over the outlook period.

The Results

Table 12.7 presents projections of nuclear generation in the Alternative Case. In OECD Europe and North America, nuclear generation is higher by 40% to 65% than in the Reference Scenario by 2020, because of increased capacity factors and plant lifetime extension. In the United States, where nuclear plants are, on average, the oldest in the OECD, extending plant lifetimes leads to much greater generation beyond 2010 compared with the Reference Scenario. In OECD Pacific (Japan), the difference is only 2% because Japanese nuclear plants are relatively young and no retirements are assumed in the Reference Scenario.

Table 12.7: **Nuclear Electricity Generation** (TWh)

	1997	2010 Ref.	2010 Alt.	2020 Ref.	2020 Alt.
OECD Europe	912	919	988	722	1 011
OECD North America	749	709	837	513	847
OECD Pacific	319	417	422	503	514

More generation from nuclear plants in the Alternative Case helps them to hold their share of total electricity generation better than the Reference Scenario projects. Across the OECD, nuclear power's share drops from about a quarter in 1997 to about a fifth in 2020, well above the 14% expected in the Reference Scenario. Among competing fuels, coal's portion decreases faster than in the Reference Scenario, from 40% to 33%, while that of gas grows more slowly, to 28% by 2020 rather than 31%. Table 12.8

Table 12.8: **Coal, Gas and Nuclear Shares in the Reference Scenario and in the Alternative Case** (Per cent of total electricity generation)

	1997	2010 Ref.	2010 Alt.	2020 Ref.	2020 Alt.
Coal					
OECD Europe	31	26	26	25	22
OECD North America	49	46	45	47	44
OECD Pacific	28	26	26	27	26
Gas					
OECD Europe	12	27	26	38	35
OECD North America	12	23	22	27	24
OECD Pacific	19	24	24	26	25
Nuclear					
OECD Europe	31	24	26	16	22
OECD North America	18	14	16	9	15
OECD Pacific	26	27	28	29	29

shows the changes in the shares of coal and gas in the OECD regions in the Alternative Case. The CO_2 emission reductions by region are presented in Table 12.9.

Table 12.9: **Carbon Dioxide Emission Reductions in the Nuclear Option**

	2010		2020	
	% of Power Sector Emissions	% of Total CO_2 Emissions	% of Power Sector Emissions	% of Total CO_2 Emissions
Europe	2	0.8	9	3.2
North America	3	1.1	6	2.7
Pacific	0.4	0.2	1	0.4
OECD	2	0.9	7	2.5

Implications

Life extension and improved performance of existing nuclear power plants can help reduce the growth in fossil-fuel use in OECD power generation and CO_2 emissions. If most nuclear plants operating today continue in operation to 2020, CO_2 emissions from electricity generation in the OECD are 7% lower than the Reference Scenario projects.

Renewables

OECD Member countries have a strong interest in promoting renewable energy and increasing its share in energy supply. Support for renewables emerged in the 1970s from supply-security concerns, to reduce import dependence and to diversify energy resources. In the two decades that followed, environmental issues gained ascendance. More recently, policymakers have begun to recognise that renewables provide a broad range of benefits, including environmental and security benefits, but also contributions to portfolio risk reductions, utility system efficiency and customer preferences. Support for renewables has grown even stronger since the Kyoto agreement. Many countries see them as part of national or international commitments to obtain emission reductions.

The common current definition of renewables excludes large-scale hydro. Hydropower is already a significant source of electricity in a number of OECD countries. It accounted for 15% of OECD electricity generation in 1997. Although some increases are expected, many of the best hydro-electric sites have already been exploited, and environmental concerns limit development. Thus the share of hydro in the Reference Scenario drops to 12% by 2020.[11]

Non-hydro renewable energy sources accounted for 2% of OECD electricity generation in 1997. The Reference Scenario projects this share to increase to 3% in 2010 and to 4% in 2020. Policies, programmes and incentives to support non-hydro renewables have been in place for several years. They have resulted in some increases, but the share of renewables in the electricity mix has remained low. More aggressive policies to increase the contribution of renewables substantially may be put into place during the projection period. The main policies are:

- Financial incentives, such as investment tax credits, production tax credits, subsidised loans and grants.
- Regulations and mandates, such as renewable portfolio standards and the obligation placed on utilities to purchase renewable energy.
- Green pricing, which offers the opportunity or obliges consumers to buy electricity from renewable energy sources at a premium price.

Many renewable-energy technologies are available to produce electricity in OECD countries. Their costs are generally high compared to conventional fuel sources, although some have shown sharp price declines in recent years. Over the projection period, these costs could decline further, but the costs of plants fired by gas and coal are also expected to decline. In general, electricity generation from renewables, will remain a relatively expensive option, but it could be cost-effective in some niche markets.

R&D has played an important role in the emergence of renewables. Available information on energy R&D spending by IEA governments indicates that the share of resources devoted to research on renewable energy technologies grew slightly in the 1990s, from 6.1% of the total in 1990 to 8.2% in 1998. In real terms, however, this was not a substantial increase in resources, which went from $549 million to $586 million (at 1998 prices and exchange rates). Considering that public budgets for energy R&D *decreased*, the increased funding that renewable technologies have obtained indicates a political commitment to expand their markets more aggressively. Favoured options in the allocation of funds are solar photovoltaic energy, biomass and wind.

11. Small-scale hydro is often included in policy packages to promote renewables. IEA data do not distinguish between small and large-scale applications and therefore small-scale hydro is excluded from the analysis.

The Alternative Case examines an accelerated path for renewables relative to the Reference Scenario. It examines the impact on CO_2 emissions if existing measures are strengthened and new policies adopted. The Reference Scenario expects an increased penetration of renewables and assumes a smooth continuation of existing policies to support them. The Alternative Case assumes that such policies are strengthened earlier and augmented with new ones.

OECD Europe

Electricity generation from renewables accounted for 1.8% of total output in OECD Europe in 1997. The region is currently the most rapidly expanding market for renewable energy sources, with an average growth rate in 1990-97 on the order of 15%, albeit from a small base. Wind power grew three times as fast.

Most European countries already have effective policies and programmes to promote the use of renewables, but a large potential remains unexploited. The Reference Scenario projects strong growth for renewables in electricity generation — by an average of 6.7% per year in 1997-2020, with their share reaching 5.2% of annual electricity generation by 2020.

Beside the country-level policies, the European Union has strategies to promote renewables. The European Commission's *White Paper on Renewable Energy Sources*[12] suggests a target of 12% for renewables in gross inland consumption (equivalent to TPES in this *Outlook*) by 2010, compared with less than 6% in 1995. In May 2000, the Commission adopted a proposal for a directive on the "Promotion of Electricity from Renewable Energy Sources in the Internal Electricity Market".[13] The proposal calls for a substantial increase in the share of renewables (including hydro) in gross electricity consumption, from 13.9% in 1997 to 22.1% in 2010, EU-wide. An indicative target is set for each EU Member state, although each has flexibility to set its own national targets. Excluding large hydro, the shares in electricity consumption are 3.2% in 1997 and 12.5% in 2010.[14]

Based on *WEO* estimates, meeting the proposed target requires electricity from renewable sources to increase by more than 20 TWh every year until 2010. This compares with annual increases of 5 TWh in 1992-99

12. European Commission, 1997a.
13. European Commission, 2000.
14. The analysis here focuses on OECD Europe. The European Union accounted for 82% of OECD Europe electricity generation and 93% of non-hydro renewable electricity in 1997.

and of 7 TWh in 1997-2010 projected in the Reference Scenario for OECD Europe. The Alternative Case assumes that the share of renewables roughly doubles relative to the Reference Scenario, reaching 7% in 2010 and 10% in 2020. Table 12.10 summarises the results.

Table 12.10: **Electricity Generation from Renewables in OECD Europe** (TWh)

	1990	1997	2010		2020	
			Ref.	Alt.	Ref.	Alt.
Geothermal	4	4	7	13	7	18
Wind	1	7	56	88	110	175
CRW	15	41	74	165	108	248
Solar/Tide/Other	1	1	4	5	8	11
% of Total	0.8	1.8	3.6	7.0	5.2	10.0

Note: Some waste in CRW may be of fossil origin but for statistical simplicity all CRW is considered as renewable. 1990 data for CRW may be somewhat underestimated.

More renewables in electricity generation would reduce the need for new fossil-fuel capacity. Consequently, the shares of coal and gas in 2020 are lower in the Alternative Case than in the Reference Scenario — by two percentage points for coal and at 35%, down from 38%, for gas. Significant reductions in CO_2 emissions also follow from the use of more renewables. The Alternative Case produces power sector emissions 5% lower than in the Reference Scenario in 2010 and 7% less in 2020.

Wind and CRW are the most likely sources. More extensive deployment of wind and biomass may induce further cost reductions, contributing to their competitiveness and market growth. To meet the Alternative-Case growth rate for renewables, the rate of annual capacity

Table 12.11: **Renewables Capacity in OECD Europe** (GW)

	1997	2010		2020	
		Ref.	Alt.	Ref.	Alt.
Geothermal	0.6	1	2	1	3
Wind	4.5	21	32	38	57
CRW	6	12	26	17	40
Solar/Tide/Other	0.5	1.6	2	4	5
Total	12	36	62	60	105

additions over the projection period must double. Table 12.11 shows the capacity projections.

OECD North America

Electricity from renewables provided 2.1% of total output in OECD North America in 1997. The United States accounts for more than 90%. In Canada, non-hydro renewables furnish about 1% of electricity generation, but Canada has one of the largest shares of hydro in its electricity mix among OECD countries.

Both countries support renewables with a growing number of incentives. Specific state policies in the US have played a particularly significant role. The recent past saw a pause, however, and the share of renewables in the electricity mix declined slightly over the last decade. Reasons included low fossil-fuel prices in North America — the lowest in the OECD — and uncertainty over the effects of electricity-industry reform.

Renewed state and federal interest in renewables has recently emerged, and it is likely to re-start renewables growth. The Reference Scenario expects their share of electricity output to increase to 2.4% in 2010 and to 3% in 2020. Policies and initiatives to foster that growth could potentially have a much larger impact than the Reference Scenario describes. The most important is the proposed "Federal Renewable Portfolio Standard" that would apply to all US electricity suppliers. It is included in the draft Comprehensive Electricity Competition Act. The proposal calls for non-hydro renewables (geothermal, wind, biomass and municipal solid waste, solar thermal and solar photovoltaic) to take 2.4% of electricity sales in 2000-04 and 7.5% by 2010-15. Most states are designing the details of their policies to support existing renewable projects and develop new ones.

Several other programmes promote individual renewable sources. The most ambitious is "Wind Powering America", a US Department of Energy (DOE) initiative, that could provide at least 5% of electricity from wind by 2020. "GeoPowering the West" is another US DOE programme to support the development of geothermal energy in western states.

The Alternative Case assumes that the share of renewables in electricity generation rises to 5% in 2010 and to 8.1% in 2020 (Table 12.12), a significant increase over the Reference Scenario. Generation from renewables doubles by 2010 and nearly triples by 2020. Compared with current levels, annual generation from renewable energy grows threefold by

2010 and fivefold by 2020. Table 12.13 shows the capacity requirements to meet this growth.

Table 12.12: **Electricity Generation from Renewables in OECD North America** (TWh)

	1990	1997	2010		2020	
			Ref.	Alt.	Ref.	Alt.
Geothermal	16	15	17	37	25	64
Wind	2	3	12	59	37	193
CRW	68	68	93	159	105	201
Solar/Tide/Other	1	1	2	3	3	6
% of Total*	2.4	2.1	2.4	5	3	8.1

* Per cent of total electricity generation.

Table 12.13: **Renewables Capacity in OECD North America** (GW)

	1997	2010		2020	
		Ref.	Alt.	Ref.	Alt.
Geothermal	3	3	6	4	10
Wind	1.7	6	20	12	60
CRW	13	16	27	18	34
Solar/Tide/Other	0.4	0.8	1.2	1.3	2
Total	18	25	55	35	106

The implied capacity additions in the Alternative Case are on the order of 3 GW per year to 2010 and 5 GW thereafter. Wind will probably provide most of the increases. Overall, wind accounts for more than a third of renewables capacity in 2010 and more than half in 2020.

The electricity mix in the Alternative Case is less dependent on coal and gas. In 2020, gas-fired generation is about 10% lower than the Reference Scenario projects and coal-fired generation is reduced by 6%. The share of gas declines by two percentage points, and coal's share is reduced by three percentage points. Emissions from power generation are 3% lower than in the Reference Scenario in 2010 and 6% lower in 2020.

OECD Pacific

Renewables generated 2.5% of electricity in OECD Pacific in 1997. The most widely used source, at 80%, is CRW. Geothermal takes second place, and the contribution of wind and solar is minimal. Japan has specific policy targets for renewable energy, most importantly for photovoltaics. Current capacity is small but increased from 55 MW in 1996 to 91 MW in 1997 and to 133 MW in 1998. Wind power is also gaining popularity in OECD Pacific countries.

In the Reference Scenario, renewables increase their share in the region to 3.1% of electricity supply in 2010 and to 4.1% in 2020. In the Alternative Case, the figures are 4% and 6.4%. The Alternative Case assumes higher growth for CRW, solar power and wind power. The projected renewables mix in electricity generation is shown in Table 12.14, and the corresponding capacity figures appear in Table 12.15.

Fossil-fuel-based electricity generation is only slightly affected in the Alternative Case. The shares of coal and gas in 2020 drop by one percentage

Table 12.14: **Electricity Generation from Renewables in OECD Pacific** (TWh)

	1990	1997	2010		2020	
			Ref.	Alt.	Ref.	Alt.
Geothermal	4	6	15	15	24	26
Wind	0	0	3	5	9	21
CRW	18	26	29	37	35	56
Solar/Tide/Other	0	0	1	4	4	9
% of Total*	2.1	2.5	3.1	4.0	4.1	6.4

* Per cent of total electricity generation.

Table 12.15: **Renewables Capacity in OECD Pacific** (GW)

	1997	2010		2020	
		Ref.	Alt.	Ref.	Alt.
Geothermal	1	2	2	3	4
Wind	0.0	1.0	1.7	2.9	7.0
CRW	6	7	9	7	11
Solar/Tide/Other	0.0	0.3	1.5	1.4	3.5
Total	7	10	14	15	25

point relative to the Reference Scenario. The assumed increases in renewables lead at first to only a small reduction in CO_2 emissions compared with the Reference Scenario, about 1% of power-sector emissions in 2010. A more substantial reduction of around 4% would emerge in 2020 if renewables do indeed take 6.4% of electricity supply by that year.

Implications

The chances are good that, with continued and even intensified government support, electricity generation from renewables will see strong expansion over the projection period — but from still very modest beginnings. Even if the Alternative-Case assumptions turn out to be correct, the results in terms of reduced CO_2 emissions by 2020 will be worthwhile but not large. The shares of coal and gas are reduced by two percentage points each by 2020 in the OECD as a whole. Yet renewables will still have much progress to make to erode the commanding shares of fossil fuels. Table 12.16 pulls together the emissions results for the entire OECD, expressing them as percentages by which emissions are lower in the Alternative Case than in the Reference Scenario.

Table 12.16: **CO_2 Emission Reductions from Increased Use of Renewables**

	2010		2020	
	% of Power Sector Emissions	% of Total CO_2 Emissions	% of Power Sector Emissions	% of Total CO_2 Emissions
Europe	5	1.6	7	2.3
North America	3	1.1	6	2.3
Pacific	1	0.5	4	1.4
OECD	3	1.2	6	2.2

Combined Heat and Power Plants (CHP)

Combined heat and power plants — also called cogeneration plants — produce both heat and electricity. They include large-scale utility plants that generate heat and power for sale to third parties and smaller-scale industrial or building installations, which generate for their own needs and may sell excess production. CHP plants make better use of input-fuel energy than do electricity-only plants, by converting a larger fraction of it to useful final energy. This can reduce fuel use and CO_2 emissions compared with electricity-only and heat-only plants. Thus CHP is often included in policy packages as a means to promote energy efficiency and to achieve emission reductions. CHP plants provided 10% of the OECD's electricity needs in 1997.

In the past, growth in CHP occurred because of both favourable economics and substantial government support. In recent years, that growth has stagnated in most countries. The liberalisation of electricity markets has had a negative impact on the economics of CHP plants. Many CHP plants in Europe have not been able to compete with low electricity prices. Having to pay for transmission has increased their costs. Loss of long-term electricity sales contracts also has created less favourable conditions. The uncertainty that arises from electricity-market liberalisation has tended to slow investment in new CHP.

Recent technological innovations may have a big impact on the future of CHP. Such innovations could increase the use of CHP through the commercialisation of micro-cogeneration systems for on-site generation in buildings. The small-scale cogeneration trend followed the appearance of very small, efficient gas engines and fuel cells. Natural gas will probably be the preferred fuel for new CHP plants, but biomass and wastes, already used in many cogeneration applications, may also be used.

CHP's relative advantages for CO_2 emissions depend on the technology and fuel that is used and on the fuels that are displaced. CHP systems offer efficiencies ranging from 70% to some 90%. If electricity generated in a gas-turbine CHP plant displaces that produced by a coal-fired station, emission reductions can be significant. If CHP substitutes for a modern CCGT plant with an efficiency near 60%, the benefits drop.

Small-scale cogeneration could have an increasing share in competitive electricity markets. The extent to which this happens will depend on the ability of small generating units to compete with central-station economies of scale plus transmission costs. In the Reference Scenario, CHP growth is limited and new technologies do not make significant inroads. Although there is some uncertainty over future electricity/heat demand and in particular on heat demand in some areas, it is generally agreed that CHP has the potential for further development, but this will depend largely on government policies that provide the right incentives.

The Alternative Case assumes higher shares of on-site generation in both industry and buildings, then examines the impact of the increased use of CHP on CO_2 emissions. Data problems make detailed quantitative analysis of CHP extremely difficult. The statistical information is often incomplete, and it is not always possible to compare published data because of differences in the definitions used by various sources. The IEA collects data on heat sold to third parties, and the heat that CHP units provide for consumption in place is not reported as part of the output of the CHP unit. Some countries estimate heat sold based on electricity generated by CHP units, but these estimates may not accurately reflect actual heat consumed. When reporting CHP capacity, some countries report units as "CHP" if they can co-generate heat and electricity, whether or not these units actually are used to generate heat in a given year. The analysis presented here looks at changes in annual levels rather than absolute values as indicators of future CHP growth.

OECD Europe

In OECD Europe, CHP plants accounted for 15% of electricity generation in 1997.[15] CHP penetration varies among countries. Poland, Denmark, Finland and the Netherlands have the highest levels. New CHP schemes in Europe are now limited, because of unfavourable economics or approaching saturation in some markets. The United Kingdom, where CHP capacity has been increasing, provides the only exception. It has a target of 5 GW of CHP by 2000 and a planned objective of 10 GW by 2010. By the end of 1998, capacity was close to the 2000 target, at about 4 GW.

In Europe, the most important initiative to promote CHP is a European Commission Communication, issued in 1997, that calls for doubling the share of electricity generation from CHP in the European Union from 9% in 1994 to 18% in 2010. The Communication emphasises that "while there is scope for action at the European level, the major responsibility for promoting CHP has to lie with the Member States."[16] Furthermore, the Commission's proposal for the revision of the Large Combustion Plant Directive requires all new large-combustion plants to consider using CHP and indeed to use it unless they can prove that it is not feasible. CHP is included in the Commission's Action Plan to improve energy efficiency.

The Alternative Case assumption is more conservative than the EU proposal. Electricity output from CHP plants in OECD Europe increases over the Reference Scenario by 7% of electricity generation in 2010 and

15. Poland alone accounted for one third of CHP-produced electricity in OECD Europe in 1997.
16. European Commission, 1997b, p. 13.

12% in 2020. Total CO_2 emissions are lower by 1% in 2010 and by 3.4% in 2020. Table 12.17 provides a summary of the results.

Table 12.17: **CHP in OECD Europe — The Alternative Case vs. the Reference Scenario** (per cent)

	2010	2020
Additional Electricity from CHP (relative to 1997)*	7	12
Additional Electricity from CHP (relative to Reference Scenario)*	7	12
CO_2 Emission Reductions	1.1	3.4

*Percentage point changes in electricity generation shares.

OECD North America

In North America, electricity from CHP plants provides 9% of total electricity output. The United States accounts for 98%. The US Public Utility Regulations Policy Act of 1978 (PURPA), designed to encourage the efficient use of fossil fuels in electricity generation, stimulated growth in cogeneration. One section of PURPA required utilities to buy electricity from independent power suppliers who generated electricity using renewable energy or used cogeneration to produce the electricity. Very few CHP projects have been developed under PURPA regulations since the early 1990s. In 1998 the US DOE issued the "CHP Challenge", an initiative that called for a doubling of CHP capacity by 2010. This would result in approximately 100 GW of CHP capacity in industry and buildings. Some estimates suggest that the remaining technical potential for CHP at existing industrial sites is more than 90 GW while the CHP potential for non-industrial applications lies in the range of 30-60 GW.[17]

In the Reference Scenario, the share of CHP electricity remains more or less at its current level over the entire projection period. As in OECD Europe, the Alternative Case uses assumptions lower than the officially proposed targets (in the "CHP Challenge"). It assumes that an additional 3% of electricity generation in 2010 and 5% in 2020 comes from CHP

17. United States Combined Heat & Power Association, 1999.

plants. Total CO_2 emissions are reduced by 0.6% in 2010 and by 1.6% in 2020 (Table 12.18).

Table 12.18: **CHP in OECD North America — The Alternative Case vs. the Reference Scenario** (per cent)

	2010	2020
Additional Electricity from CHP (relative to 1997)*	2	4
Additional Electricity from CHP (relative to Reference Scenario)*	3	5
CO_2 Emission Reductions	0.6	1.6

*Percentage point changes in electricity generation shares.

OECD Pacific

Current use of CHP in the OECD Pacific region is limited. No CHP data are available in the IEA statistics for Japan, but national sources indicate that cogeneration capacity was 3.9 GW in 1996. Australia produced 3% of its electricity and New Zealand 2% of its supply in CHP plants in 1997. In the absence of major government initiatives, future growth in CHP will remain low. Japan currently has its long-term energy strategy under review, with the outcome to become available early in 2001. CHP may receive increased attention, to obtain CO_2 emission reductions and to improve energy efficiency. Increased use of CHP in Australia could result from various initiatives to reduce GHG emissions. In the Reference

Table 12.19: **CHP in OECD Pacific — The Alternative Case vs. the Reference Scenario** (per cent)

	2010	2020
Additional Electricity from CHP (relative to 1997)*	4	6
Additional Electricity from CHP (relative to Reference Scenario)*	3	5
CO_2 Emission Reductions	1	2.3

*Percentage point changes in electricity generation shares.

Scenario, the share of electricity from CHP plants in the region increases by one percentage point. The Alternative Case raises that by three percentage points relative to the Reference Scenario in 2010 and by five in 2020. Table 12.19 shows the results.

Summary of Results and Conclusions

The Alternative Case shows that:

- Each option has implications for the regional electricity balances: the fossil-fuel and CHP options result in higher natural-gas use than the Reference Scenario projects; the nuclear and renewable options require less new gas and coal and so contribute to greater diversification of the electricity supply.
- High-efficiency fossil-fuel technologies, combined with low-carbon fuels, mainly natural gas, can moderate growth in CO_2 emissions — but strong price signals are needed to obtain larger reductions. While higher use of natural gas in CCGTs is desirable because of its environmental benefits, it could put pressure on gas supplies, lead to higher prices and increase gas-import dependence.
- Operating nuclear plants longer than expected can help restrain growth in fossil-fuel use and CO_2 emissions. Competitive markets could produce this result, and the only cost would be to refurbish older reactors.
- Renewables are an attractive option to reduce emissions, but at a cost, because they are generally more expensive than fossil fuels. Their development and their contribution to electricity supply will continue to depend on effective government policies and measures. Government support will be necessary to spur their markets. Along with the environmental benefits, this support could help reduce their costs in the long term. How much and how fast this could occur remains an uncertainty of this *Outlook*.
- CHP technologies reduce the environmental impact of burning fossil fuels, but government support will be necessary to achieve higher growth.
- Although the Alternative Case proposes paths considered plausible, each option raises some uncertainties. Nuclear power has to gain public acceptability; renewables are costly and may face physical constraints in some cases (such as wind and biomass); CHP is a costly option; and the fossil-fuel option raises concern over adequate gas supplies.

Table 12.20 summarises the results of the analysis for each option and for the three OECD regions. The CO_2 emissions reductions are not cumulative because of the independence of the assumptions.[18]

Table 12.20: **Summary Results of the Alternative Case**

Changes from Reference Scenario	**Europe 2010**	**Europe 2020**	**North America 2010**	**North America 2020**	**Pacific 2010**	**Pacific 2020**
More Natural Gas*	2	10	1	4	1	3
% CO_2 reduction (power sector only)	3	12	1	11	1	4
% CO_2 reduction (total emissions)	0.9	4.1	0.5	4.4	0.5	1.6
More Nuclear*	2	6	2	6	0.3	1
% CO_2 reduction (power sector only)	2	9	3	6	0.4	1
% CO_2 reduction (total emissions)	0.8	3.2	1.1	2.7	0.2	0.4
More Renewables*	3	5	3	5	1	2
% CO_2 reduction (power sector only)	5	7	3	6	1	4
% CO_2 reduction (total emissions)	1.6	2.3	1.1	2.3	0.5	1.4
More CHP Electricity*	7	12	3	5	3	5
% CO_2 reduction (total emissions)	1	3	0.6	1.6	1	2.3

*Percentage point changes in electricity generation shares.

There are many ways to reduce CO_2 emissions. The analysis presented above identifies four prominent ones. The results should not be seen as forecasts, but rather as orders of magnitude for possible emissions reductions in the electricity sector. Policymakers can use the results of this analysis to identify and select options to reduce GHG emissions that are best suited to their national circumstances.

18. For example, a higher share of nuclear and/or renewables would mean lower demand for new fossil-fuel capacity, which would reduce demand for natural gas and perhaps prevent natural-gas prices from rising to the levels assumed in the Reference Scenario. Such effects have not been modelled.

CHAPTER 13
INDIA: AN IN-DEPTH STUDY

Introduction

As India steadily gains importance on the world energy scene, this *Outlook* has for the first time separated India from the South Asia group for modelling and analysis.[1] Already a major energy importer, India will import even more over the outlook period. Even imports of coal, the nation's mainstay energy resource, will rise. The government is restructuring Indian energy markets to improve its economic performance and to bolster energy security and efficiency. Elimination of subsidies is a key issue, along with promoting gas supply and use.

India, already the world's fifth largest economy, will be among those growing fastest over the outlook period (Table 13.1). The population,

Table 13.1: **India's Significance in the World**

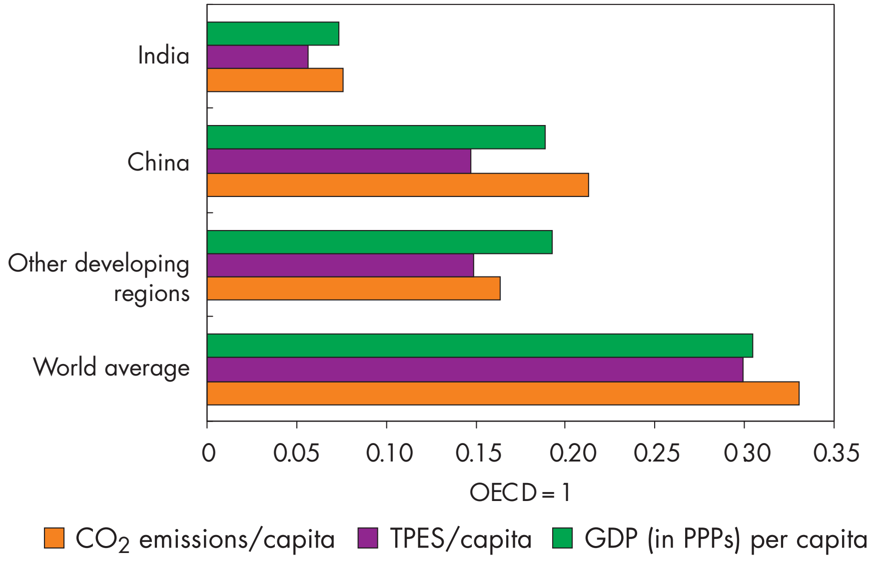
	1997 Share (%)	1997 Rank	2020 Share (%)	Increase* 1997-2020 Share (%)
GDP (US$ in PPPs)	4.0	5th	5.9	7.6
Population	16.6	2nd	17.0	18.3
TPES (excluding CRW)	3.1	7th	5.3	9.1
Coal	6.8	3rd	10.0	16.7
Oil	2.6	11th	4.6	8.1
Final electricity demand	3.0	8th	5.5	8.3
CRW	18.2	2nd	16.2	9.6
TPES (including CRW)	4.8	5th	6.3	11.9
CO_2 emissions	3.9	6th	6.2	10.1

* Percentage increase in India's share in world totals from 1997 to 2020.
Note: Due to its non-commercial nature and questions related to reliability of data, CRW is given separately.

1. This study has benefited from material provided by the Government of India (through the Ministry of Power), and Dr Sujata Gupta of the Tata Energy Research Institute. Their contributions are greatly appreciated.

which is growing faster than China's, passed one billion in 2000. Every year, it expands by roughly 16 million. India's per capita GDP is still low (Figure 13.1).

Figure 13.1: **India's Extremely Low Per Capita Indicators, 1997**



The *Outlook* projects growth in primary commercial energy demand at a higher rate than in any other region analysed. India's incremental demand accounts for 9% of the world total. Given the country's limited oil and gas resources, the consumption of coal is expected to grow, increasing India's share in world coal consumption to 10% by 2020. It imported two-thirds of its crude-oil requirements and absorbed close to 3% of world oil supply in 1999. Oil demand, currently rising at 6% to 8% a year, will reach close to 5 mb/d in 2020, equivalent to more than 60% of Saudi Arabia's oil production today. India will start importing liquefied natural gas soon. The *Outlook* sees it becoming a significant gas importer. India also heavily promotes renewable power for the electricity grid or in decentralised systems. Its installed renewable energy capacity ranks fourth in the world for wind power and third for photovoltaic electricity.

For commercial energy, India ranked seventh in the world in 1997, with 3.1% of world demand, up from around 1.3% in 1971. India accounts for nearly one-fifth of world consumption of CRW fuels. When these are included, India's current share of world primary-energy use rises to nearly 5%.

India suffers from serious local pollution, damaging the health of millions of people each year. With its size, fast growth in energy demand and the significance of coal in its fuel mix, India has also become an important influence on the global environment. Despite its extremely low per capita CO_2 emissions (Figure 13.1), India contributed 4% of the total world CO_2 emissions in 1997, about the same as Germany.

Major Issues and Uncertainties

Energy reforms have been somewhat slow or irregular in the past decade. They will be crucial for India's sustained economic growth and energy security. The development of energy markets and effective regulatory institutions will attract more international direct investment and build a more efficient energy economy. The *Outlook* assumes substantial progress on reforms.

Increasing reliance on imported energy will make India more vulnerable to price fluctuations or supply disruptions. The government acknowledges that assuring energy security is becoming an essential element of energy policy.[2] Whether implementation of measures already laid out (building strategic storage and enabling private investment in production and distribution of hydrocarbon products, for example) will be achieved is uncertain. So is the effect of efforts to promote effective diversification, efficiency and flexibility in the energy sector.

The mobilisation of investment remains a major source of uncertainty. The government has allocated a substantial and increasing share of its budget to the energy sector, but the requirements exceed what the public purse can provide. Private capital flows to India remain relatively small. The capability of the government to facilitate them will affect the energy mix.

Environmental conditions are uncertain. Reliance on coal could lead to increases in local pollution and CO_2 emissions beyond the projections.

Macroeconomic Background

GDP growth in India averaged 4.8% from 1971 to 1997. It accelerated in 1993, as market-oriented fiscal and structural reforms, begun in 1991, took hold. Growth averaged 7% in 1993-1997, followed by a

2. Ministry of Petroleum and Natural Gas, 2000.

slight slowdown in 1998 and 1999. Delays in implementing further reforms and a public deficit higher than planned somewhat constrained both private and public investment. Agricultural output dropped in 1998. Exports languished with inadequate industrial investment and sluggish external demand following the Asian economic crisis. The economy now seems to be regaining momentum as external demand recovers.

Like all oil-importing developing countries, India is very vulnerable to international oil-price fluctuations. Because the domestic prices of some oil products remain controlled, high oil prices in 2000 did not affect domestic prices proportionately. This limited or delayed their inflationary impact. High prices do increase the foreign-exchange cost of imported oil, however. They could add $6 billion to India's oil-import bill in 2000.[3] Energy price subsidies become more costly as oil prices go up, putting pressure on the government budget. High-cost oil imports have drained the Indian Oil Pool Account, which pays for the gap between subsidised domestic oil prices and international ones. These factors have aggravated fiscal and trade deficits and done damage to economic growth.

High population growth has dampened per capita income, which reached only $1 380 in 1997 (US$ 1990 in PPPs), substantially less than the developing-world average (Figure 13.1). Although it is the world's fifth-largest economy, India is below the top 100 countries in terms of per capita GDP. According to the World Bank,[4] India has the highest concentration of poverty, with more than 470 million people — about 45% of the population — living below the national poverty line. India accounts for 40% of the world's poor.

Table 13.2 reveals ongoing changes in India's economic structure, with the shares of both industry and services expanding rapidly as agriculture loses ground. Within industry, manufacturing accounted for 20% of GDP in 1997. This share, relatively low compared with other developing countries, has nevertheless grown steadily for decades. In the fast-growing services sector, information and communication technology has become an important factor and will continue. Despite its diminishing share of economic activity, agriculture still plays an important role as a main income source in rural areas, which contain three-quarters of the population and two-thirds of the labour force.[5]

3. IEA, 2000.
4. World Bank, *India Country Brief*, http://www.worldbank.or.jp/06group/RC_flame.htm.
5. According to the 1991 census.

Table 13.2: **India's Economic Structure** (Percentage shares in nominal GDP)

	1971	1997	1971-1997*
Agriculture	43	25	2.6
Industry	23	30	5.9
Services	34	45	6.1
GDP	100	100	4.8

* Average annual growth rates, in per cent.
Source: Indian Central Statistical Organisation (CSO).

Recent Energy-Sector Developments

Energy Demand[6]

Sustained growth in economic activity and incomes has generated substantial increases in Indian energy consumption (Table 13.3). Over the past three decades, these increases have been comparable to those of China and have surpassed those in the remaining regions of this *Outlook*, with the exception of East Asia. Nevertheless, per capita energy consumption is very low. At less than 0.3 toe in 1997, it was the lowest among all the developing regions.

Table 13.3: **Commercial Energy Profile**

	1971	1990	1997	1971-1990*	1990-1997*
TPES (Mtoe)	63	184	268	5.8	5.5
Coal (Mtoe)	38	106	153	5.6	5.4
Oil (Mtoe)	22	60	88	5.5	5.6
Gas (Mtoe)	0.6	10	18	16.0	8.4
Final electricity (Mtoe)	4	19	30	7.8	7.1
Industry (Mtoe)	19	65	83	6.8	3.6
Transport (Mtoe)	15	26	42	3.1	6.7
TPES/GDP (toe/US$ thousand)	0.16	0.20	0.20	1.2	0.0
TPES per capita (toe)	0.11	0.22	0.28	3.5	3.7
CO_2 emissions (Mt)	208	600	881	5.7	5.6

* Average annual growth rate, in per cent.

6. Unless otherwise stated, the figures discussed here refer only to demand for commercially traded energy and exclude the consumption of CRW fuels. The energy picture including these fuels is discussed later in the chapter.

India's energy intensity (primary energy consumption per unit of GDP) appears to have levelled off in the 1990s, after rising faster than in most countries over the preceding two decades. Although all the reasons are not yet clear[7], some of the apparent change may reflect an improvement in the efficiency of energy use, especially in the industry sector, related to recent changes in the industrial fuel mix. The share of coal in industry, relatively stable at around 60% for the two decades before 1990, dropped to around 50% by 1997. Price effects may have a role as well.

India's commercial fuel mix relies heavily on coal. In 1997, coal accounted for 57% of primary commercial energy demand, with oil at 33%. These figures have not changed much since 1971. The only significant development has been the growing importance of natural gas; its share rose from 1% in 1971 to 7% in 1997, reflecting gas discoveries and expanded gas production. These resources have been developed largely for use as petrochemical feedstocks and in fertiliser production, but some also go to generate power. Nuclear and hydropower together accounted for around 3% of primary commercial energy demand in 1997. The share of hydropower in the power generation mix has declined for the past 30 years.

For more than two decades, industry has been a major source of growth in final commercial energy demand, in line with its increasing share in the economy and reflecting a change in the composition of the industrial sector towards more energy-intensive industries. Energy demand for transport, slower growing than in industry and other sectors before 1990, accelerated in the 1990s and outpaced industrial demand growth by far. Transport also accounted for more than half of incremental oil demand between 1971 and 1997. The residential and services sectors now provide 15% of final commercial energy demand, which reflects both higher per capita incomes and increasing urbanisation. Energy consumption in agriculture, although a relatively small proportion of final demand, increased faster than in any other sub-sector in the 1990s. It has contributed to major advances in agricultural productivity.

Coal

Coal India Ltd. (CIL), a state-owned public firm, produces 87% of domestic coal. Singareni Collieries Co. Ltd. (SCCL), a joint undertaking

7. It is suggested that the interpretation of this trend requires "due care since the past trends in the consumption of commercial energy do not really represent the growth of demand for such energy but merely reflect the growth of its actual availability in view of the prevailing energy shortages." (GOI Planning Commission, 1999)

between the central government and Andhra Pradesh, accounts for another 10%. The fragile financial situations of both companies require restructuring. Political resistance, based mainly on fear of massive lay-offs, has delayed change in both companies. Many of the problems that the industry now faces arose from pricing policies that led to an inefficient allocation of resources. The coal industry could not generate adequate investment for expansion or quality improvements such as washeries. Low-quality, unwashed coal dominates domestic supply. Imports, to which Indian coal is losing market share, now satisfy demand for higher-quality coal grades.

These problems prompted the start of reform in 1993, but it progressed slowly. Since it regards full privatisation of the public coal companies as politically infeasible, the central government favours a gradual expansion of private activity through green-field projects. It first permitted private participation only in captive coal mining, which did not allow investors to sell surpluses on the market. Import restrictions were lifted and import duties reduced. In February 1997, the minister of coal announced a deregulation plan to open coal mining further to private investors, including foreign companies, and to end price and distribution controls by 2000.

Oil and Gas

Two public companies, the Oil and Natural Gas Corporation Ltd. (ONGC) and Oil India Ltd. (OIL), carry out most exploration and production activities. Several private companies also operate under production-sharing contracts. Pipeline gas transportation is the responsibility of the publicly-owned Gas Authority of India Ltd. (GAIL).

Reforms in the oil sector began to stimulate production in 1991 by opening onshore exploration and production to private and foreign firms through production-sharing contracts. The importing and marketing of LPG, kerosene, low-sulphur heavy fuel and lubricants were also opened to the private sector. In 1996, a second, three-stage phase of reform began, to allow gradual private participation, first in refining (1996-1998), then in upstream production (1998-2000) and finally in marketing (2000-2002). The second phase includes dismantling the Administered Pricing Mechanism (APM) and the implementation of a free, market-determined pricing mechanism (MDPM). In February 1997, the Government also endorsed a New Exploration Licensing Policy (NELP) to provide a framework to private company newcomers in oil exploration and to allow public companies to diversify and integrate vertically. It advertised the sale of 48 oil and gas blocks, 26 of them offshore, 10 onshore and 12 deep-sea.

Political resistance has slowed plans for a partial privatisation of public oil and gas companies such as IOC and GAIL. Opponents want to declare the oil and gas sector a strategic one and keep its public status. Nevertheless, private companies do play a growing role. Major oil companies such as Shell, Occidental, Amoco, Chevron and Enron have bid for exploration blocks. While state firms still control most retail gasoline sales, multinationals (Shell, Exxon and Caltex) hold over a third of the lubricants market. Foreign companies, including Gaz de France, British Gas, Enron and Totalfina, are looking at prospects for LNG imports, which could start in the next few years.

Electricity

In 1998, the State Electricity Boards (SEBs) owned 63.3% of generation capacity. The rest was owned by central public companies, such as National Thermal Power Corporation, and Independent Power Producers, which have only a marginal share. The central government has exclusive responsibility for high-voltage bulk inter-state transmission. Powergrid, a public company, is the central transmission utility. Transmission within states is in the hands of State Transmission Utilities. Most distribution rests with the SEBs.

India's power-sector reform began in 1991. It was based on the presumption that the entry of the private sector into generation would eventually facilitate the improvement of productivity in the financially troubled downstream activities handled by SEBs. Greenfield IPP projects were favoured over privatisation. Guidelines that were intended to facilitate private investment in generation were ordered. A slow and lengthy project-approval process, and the SEBs' inability to guarantee payment for electricity they would buy from IPPs, contributed to disappointing results in power-sector liberalisation. Foreign investors mostly held back, despite a clear initial demonstration of interest.

Almost a decade after the reform began, the regulatory institutions are now starting to emerge, with the establishment of a Central Electricity Regulatory Commission and State Electricity Regulatory Commissions in several states. Restructuring of the SEBs has also started, with states such as Orissa, Andhra Pradesh, Rajasthan, Haryana, Karnataka and Uttar Pradesh leading the way. Although these reforms may not accelerate changes in the power sector or greatly improve the quality of service in the short

Box 13.1: **Energy Pricing and Subsidies in the Indian Energy Sector**

The IEA conducted an in-depth study in 1999 on the effects of subsidy removal for selected developing countries.[8] Weighted average prices in the Indian energy sector in 1998 were around 14.2% below a reference value (full supply costs or international prices adjusted for transport costs and margins). Estimates of energy savings from removing subsidies amount to 14% for the portion of primary energy supply taken into account in the study, which is equivalent to 7.2% of total primary energy supply. The reduction in CO_2 emissions in India would be some 14%. The fiscal savings would amount to 356.2 billion Rupees ($8.6 billion). If all subsidies were paid out of central-government expenditure (which is not the case), they would equal about 15% of central-government outlays.

The highest subsidy (52.6%) applies to kerosene used for cooking. LPG also enjoys heavy subsidies (31.6%). Coal, the most important product in overall energy use, sells at prices around 13.1% below the reference value for steam coal and 42.3% for coking coal.[9] The welfare (or efficiency) loss is estimated at 60.6 billion Rupees (about $1.5 billion), or roughly 0.3% of GDP. It is highest in the electricity sector. Energy subsidies in India tend to be regressive and do not necessarily fulfil the social targets claimed to justify them.

The government is aware of the need to reduce subsidies and has started reforms in all sectors, but at different speeds. These reforms go in the right direction, but vested interests often endanger their implementation. Consumers are becoming sensitive to the low quality of services they receive, and some price increases would probably prove acceptable, if service quality improves.

Subsidy elimination would reduce energy consumption, with potential positive effects for both energy security and CO_2 emissions. The 33 Mtoe of energy thus saved would come mostly from a reduction in steam-coal consumption by industry and in kerosene consumption by households, representing respectively 21.3% and 13.3% of the total reductions.

8. IEA, 1999.
9. These estimates might have to be adjusted in the light of new information about transportation costs.

term, they do provide a new environment, and a real power market will probably emerge in India in the medium to long term.

Prices

The fixing of energy prices for social and political reasons has led to economic inefficiencies throughout the Indian energy sector. Although energy subsidies are declining, they remain significant and still impose heavy costs on the Indian economy (see Box 13.1). Despite the end of subsidies on several products, such as light and heavy oils, most fuels still have administered prices. Many of them are subsidised and some are taxed within a system of cross-subsidies that seldom balances. State intervention affects energy prices through channels such as capital ownership in energy companies and railway freight rates that artificially lower the transport cost of coal over long distances.

Assumptions

The *Outlook* assumes that India's GDP will almost triple through 2020, with an average annual growth rate of 4.9% (Table 13.4). This assumption is based on the broadening and deepening of the economic reform programme in general and energy-sector reforms in particular. The prospects for continued reform represent one of the key uncertainties surrounding the projections. Population growth is likely to continue at an average annual rate of 1.2%. These assumptions would lead to a rise in real per capita income of 3.6% per year, to $3 118 in 2020 (in PPP terms), more than twice that of 1997. Continued structural changes could have important consequences for the energy outlook. GDP growth, led by investment in energy-intensive industry and infrastructure, could bring higher energy intensity, but a greater role for services and less energy-intensive industry could have an opposite effect.

Given a continuing process of reform, the *Outlook* also assumes that energy prices will increasingly reflect the economic costs of supply.

Table 13.4: **Assumptions for the Reference-Scenario Projection**

	1971	1997	2010	2020	1997-2020*
GDP (US$ 1990 in PPPs)	391	1 328	2 550	3 950	4.9
Population (million)	560	962	1 148	1 267	1.2

* Annual average growth rate, in per cent.

Specifically, the pre-tax prices of oil products and coal will follow international spot-market prices. An LNG price similar to that for Asian-Pacific markets is assumed, although India's proximity to the Middle East and possible imports by pipeline could lead to a lower value.

Results of the Projections

Overview

Projected primary commercial energy demand (Figure 13.2) grows at an average annual rate of 4.4%, reaching 716 Mtoe in 2020. Coal and oil continue to dominate the primary fuel structure, supplying more than 80% of commercial primary energy demand in 2020. Natural gas will be the fastest-growing commercial fuel, at 8.3% per annum. Figure 13.3 shows each fuel's contribution to the increase of total primary energy supply for the past 26 years and for the outlook period. It makes four points:

- Incremental total demand for the next 23 years will be almost twice that of the past 26.
- Incremental oil and gas demand will be much larger than in the past.
- Although coal's growth is slower than that of other fuels and its share declines, it will remain the largest contributor to the demand increase in absolute terms.
- Contributions from hydro and nuclear power will be limited.

Figure 13.2: **Total Primary Energy Supply**

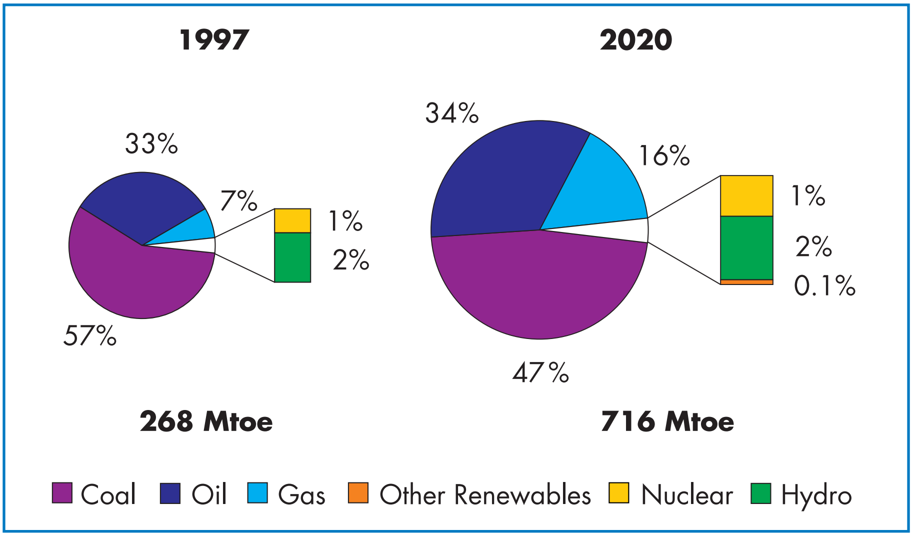
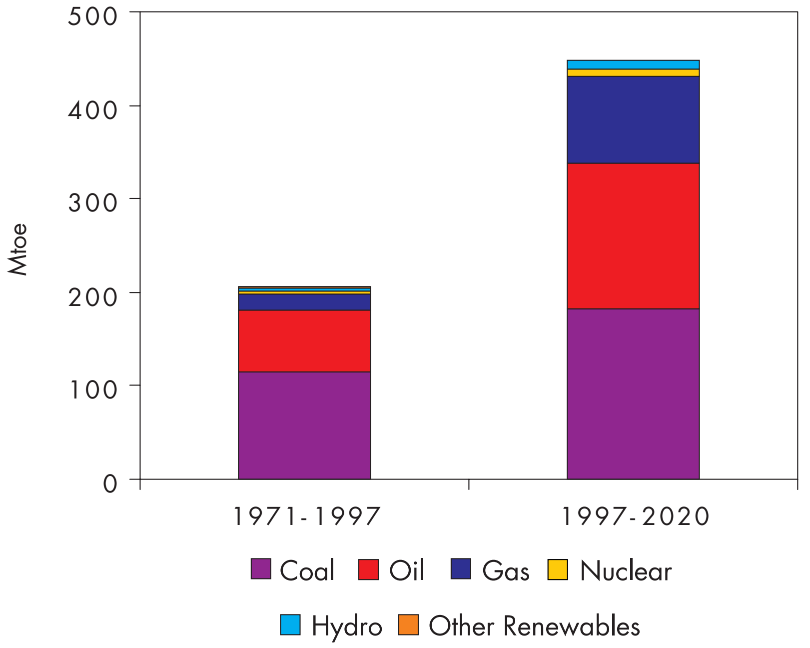


Figure 13.3: **Incremental Primary Energy Demand by Fuel**



Final commercial energy consumption will almost triple, with annual average growth of 4.6%. The share of coal falls relative to gas, oil and electricity. The transport sector will be the main source of the projected increase in oil demand. Electricity demand will increase by 5.4% per year, faster than the assumed GDP growth rate. Its current 19% share of total final consumption will increase to 22% in 2020. In 1997, industry generated about 46% of electricity demand and agriculture 27%.

Sectoral Demand Trends

Industry is a major consumer of commercial energy in India, accounting for just over half of final energy demand in 1997. Projected industrial energy demand rises by a factor of 2.5, to reach 212 Mtoe by 2020. With growth somewhat slower than that of total final energy demand and GDP, industry's share of total final energy demand will fall to around 47% from 51% in 1997. Industrial energy-demand growth will moderate to the extent that structural change favours less energy-intensive activities.

This is a likely development as the economy reaps the benefits of international trade liberalisation and pursues its comparative advantage in labour-intensive manufacturing. On the other hand, demand for energy-intensive building materials such as cement and steel may also grow as the country upgrades its basic infrastructure and buildings.

The changes in industrial fuel mix, which may partially account for the recently observed stabilisation of energy-intensity growth, are projected to continue. The share of coal in total industrial demand is projected to erode further to 33% in 2020, well down from 51% currently and 60% in the 1970s and 1980s. Oil use also drops relative to other fuels. Gas use will expand from its present 11% to 27% in 2020, largely in response to expansion in the output of chemicals and building materials. Expansion in a broad range of industries will underpin a rising share for electricity.

Iron and steel's energy consumption accounts for almost 15% of consumption in the whole of industry. Growth in steel output has averaged around 7% per year since 1980, which is somewhat faster than the growth in GDP. Apparent per-capita steel consumption remains low by international standards. So there is considerable potential for it to increase as economic growth brings increased demand for infrastructure, buildings and steel-intensive commodities such as motor vehicles. Projected energy demand in this sub-sector rises at about 4% a year over the outlook period, close to the industry average and rather slower than GDP growth. This reflects large expected energy-efficiency gains from the use of imported coal and the phasing out of open-hearth furnaces. Coal will continue as the dominant fuel, but electricity demand will increase faster as electric-arc furnace technology penetrates the industry.

The chemicals industry, with 25% of industrial energy demand, includes primarily fertilisers and petrochemicals, especially the former. Energy-intensity trends in fertiliser production largely determine those in the industry as a whole. Despite increased consumption, average fertiliser use per hectare of arable land remains low by international standards. Nitrogenous fertilisers account for most output. Given expected agricultural needs, demand for fertilisers will continue to grow strongly. Domestic production will meet most of this growth and so will require capacity expansion. Energy demand in the entire chemicals industry should grow at about 6% per annum over the outlook period, faster than in iron and steel and the average for all industry. Gas will continue to be by far the fastest-growing fuel and will account for more than half of energy demand in the industry. Energy intensity could improve with expanded gas-based production.

Other industries, which provide the remaining 60% of industrial energy demand, include a wide variety of manufacturing activities. Some are energy-intensive, such as aluminium and other non-ferrous metals. Some, like textiles, have mixed energy characteristics. Many others are not energy-intensive. Aluminium production has grown more slowly than GDP in recent years, due to resource constraints and lower investment in aluminium-consuming sectors. Current efforts include boosting production and increased use of less energy-intensive technology. India is the world's third largest producer of cement, but its current per-capita consumption remains extremely low, at 57 kg compared with 465 kg in OECD countries. Coal accounts for more than 60% of the cement industry's energy input, with little change expected. The *Outlook* assumes that production in this broad range of industries will continue to grow fast, but that its share will decrease rapidly, improving overall energy intensity despite the heavy weight of coal in the aluminium and cement industries. As a result, energy demand will grow at only about 3% per annum over the outlook period. Coal's expected share will decrease to around 44% in 2020 from 63% in 1997, while electricity's will grow to 38% from 24%.

The transport sector's recently accelerated growth is projected to continue over the outlook period. Energy consumption will more than triple as it rises by 5.3% a year, faster than GDP growth and substantially faster than the rise in final energy consumption. About two-thirds of India's incremental oil demand will come from this sector. Energy demand for road transport is projected to grow by 5.5% a year.

The main sources of this growth are an expected increase in vehicle ownership and continued modal shifts. Higher household incomes drive the growth of motor-vehicle sales. Rising passenger-vehicle ownership — it was only 4.5 per 1000 people in 1996[10] — will contribute significantly to this projection. The modal shift involves a turn from rail to road. The railways' share of transport energy consumption fell to only 6% in 1997 from almost 60% in 1971. Road vehicles now account for 80% of all passenger kilometres and 60% of freight transport. Road transport is considerably more energy intensive than rail, so the continued shift will add significantly to the growth of energy consumption.

Despite recent price increases to bring domestic prices in line with international reference prices, diesel remains less than half as expensive as gasoline, providing a strong incentive to purchase diesel vehicles.[11] The

10. International Road Federation, 2000.

11. This issue of "*dieselisation*" of the Indian energy sector is discussed in detail in IEA (1998), p. 333.

combination of cheap diesel fuel, high rail-freight tariffs, which subsidise passenger fares, and the railways' inability to meet demand for some types of freight movement have led to more road freight in trucks fuelled by diesel oil.

Higher per-capita incomes, combined with the increased availability of motor vehicles, mean substantial potential for growth in passenger activity. On the other hand, it is highly uncertain whether recent passenger growth will continue throughout the outlook period. Insufficient infrastructure could entail serious constraints on it, if uncertain government plans to invest in roads do not come to fruition, particularly in rural but also in urban areas.

Despite the decreasing relative position of the railways, they have seen considerable growth in both passenger and freight traffic. Passenger kilometres tripled from 118 billion in 1970 to 380 billion in 1997 and freight tonne-kilometres increased from 127 billion to 287 billion.[12] Nevertheless, railway energy consumption plunged dramatically, to 2.5 Mtoe in 1997 from 8.7 Mtoe in 1971. This was due to a major reduction in energy intensity, mostly resulting from a shift away from coal to diesel and electricity (Figure 13.4). Coal use has been almost phased out, and more diesel-fuelled traction will fill most of the gap, because rail electrification has heavy capital requirements and is cost effective only at high traffic densities. Because coal use is already very low, the decreasing trend in overall railway energy consumption is expected to turn upward, although additional reductions in energy intensity could come through improved management and technical improvements.

Despite agriculture's declining share of overall economic activity, its energy consumption has grown twice as fast as total final demand since 1990, at some 9% per year. Total cropped area steadily increased from 165.8 million hectares in 1970/71 to 188.2 million hectares in 1994/95,[13] while the gross irrigated area increased from 31.1 million hectares to 70.6 million. The *Outlook* projection shows continued relatively fast growth of agricultural energy consumption at almost 5% a year, slightly higher than total final consumption. The government's *Ninth Five-Year* Plan targets 4.5% annual growth in agriculture during 1997-2002. This could involve continuing expansion of the area under crops and in the proportion of land under irrigation. Coupled with more multiple cropping, it could bring

12. Ministry of Railways, *Annual Report and Accounts.*
13. Tata Energy Research Institute, 1999.

increases in energy consumption. More agricultural mechanisation, for both land preparation (tractors) and lift irrigation (pumpsets) would do the same. Extensive pumpset electrification, coupled with heavily subsidised electricity prices, has led to a rapid increase in the demand for electricity in agricultural energy consumption.[14] Future policy on agricultural electricity prices remains uncertain. Agriculture accounts for more than a quarter of total electricity use, and the phasing out of subsidies could reduce that share's growth.

The residential/commercial sector, mainly its residential component, accounted for 14% of final commercial energy consumption in 1997. Growth since 1971 has been over 5% per year, much higher than the increase in per-capita GDP, mainly because of switching from non-commercial to commercial energy. Household income, demographic trends and urbanisation, together with an accelerated shift away from non-commercial fuels in urban areas, are the major determinant of the amount of energy consumed and fuel choices over the projection period. The sector's electricity demand is projected to triple. A rapid increase in electrical-appliance ownership and the continuing electrification of rural areas will contribute significantly, and will be moderated only by increases in equipment efficiency. Uncertainty remains about the level of electrification in rural households. The grid has been extended to almost 90% of India's villages, but the 1991 census revealed that less than one-third of rural households are actually connected to it.[15]

CRW

Given the predominance of traditional-fuel use by households, it is important to look at the sector's demand for CRW fuels, mainly biomass, with a clear distinction between them and commercial energy.[16] Households consume far more CRW fuels than commercial energy. Its estimated share in the residential subsector is close to 90%. Households account for more than half of India's final energy demand when CRW fuels are included. To put it differently, CRW, when included, accounts for 54% of India's final energy consumption and 42% of primary energy use. These

14. Substantial energy is also provided by draught animals, the numbers of which continue to increase. There is large potential for their replacement by mechanised power.
15. Rajsekhar, B. and A. Gupta, 1998.
16. Although some portion of CRW, especially much of biomass in urban areas, is also traded on a commercial basis, this *Outlook* treats all CRW as "non-commercial", for consistency with common terminology.

Table 13.5: **Final CRW Use in Selected Non-OECD Countries, 1997**

	Total CRW in TFC (Mtoe)	Share of CRW in TFC (%)	Per capita CRW use (kgoe)	Per capita commercial energy use (kgoe)	Urban population (% of total)
India	193	54	200	168	27
China	208	25	169	497	32*
Thailand	12	22	200	699	21
Brazil	34	25	210	644	80

*Urban population ratio for China does not include Hong Kong.

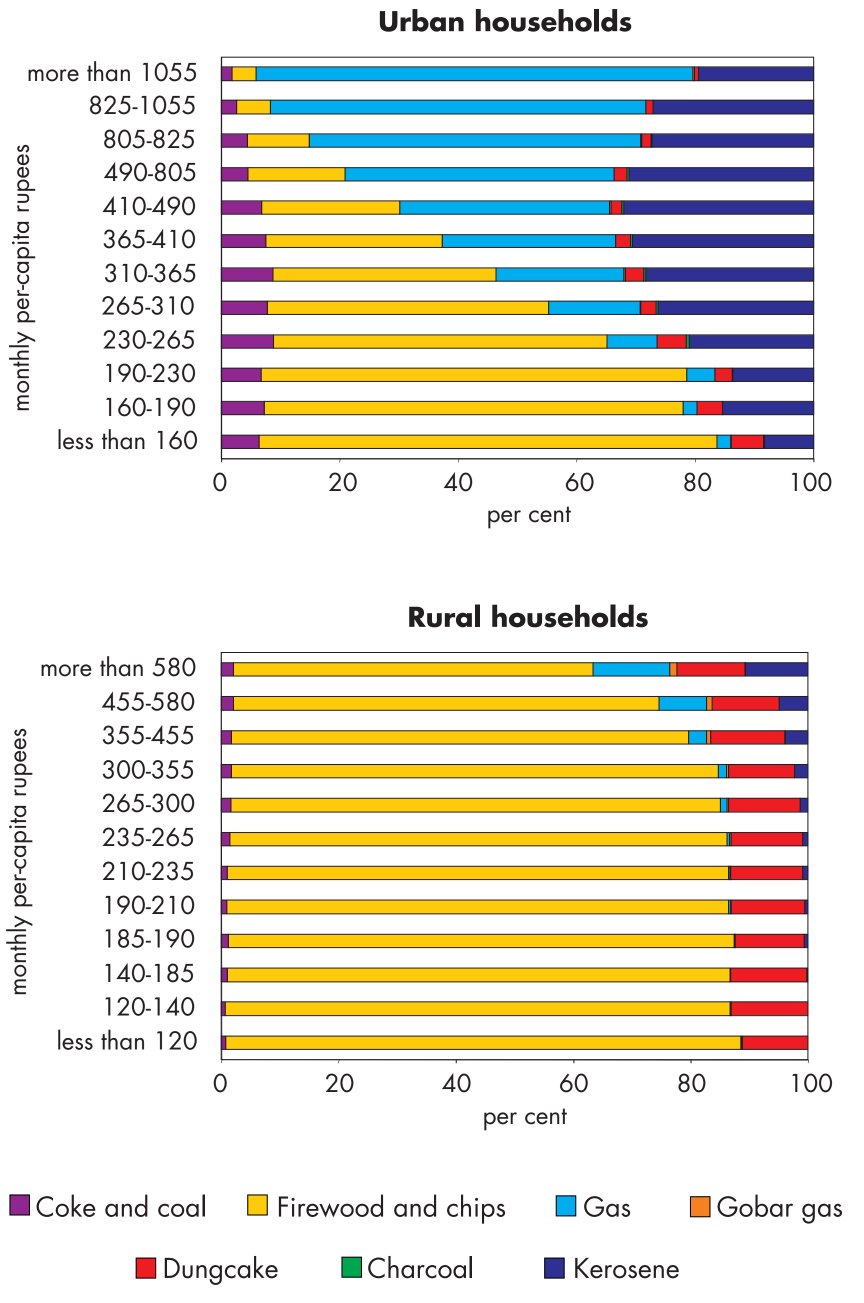
shares are much higher than those of China (Table 13.5) and East Asia and closer to those found in Africa (59% of TFC and 49% of TPES). India accounts for about one-fifth of world CRW energy uses.

A large part of CRW energy is consumed in rural households.[17] This involves heavy use of animal waste, some 20% to 30% of the biomass total, and very limited use of charcoal. This probably occurs because India has relatively less wood than do China and East Asia. Agricultural residues make up another 20% to 30%. Data for India show an impressive increase in household consumption of LPG and kerosene in the last 20 years (13% and 6% per annum respectively). But surveys suggest that urban households absorbed most of this increase, with little or no effect on rural areas. According to some estimates, the share of biomass in rural energy consumption has remained relatively unchanged, while the total use of biomass has increased with rural population growth, alternative fuels being unavailable. Gradual changes have occurred in the shares of the different biomass fuels, with shifts from dung and agricultural residues to wood, and from collected wood (twigs) to marketed wood (logs).[18]

Survey data also show that biomass, principally in the form of firewood, satisfies a substantial proportion of urban energy demand. Evidence indicates that at all income levels the share of biomass in household energy use falls over time, at different rates according to urban or rural location. The first commercial substitute for biomass in low-income

17. CRW consumption in urban households and in the industrial sector is also quite significant, at 6%-8% and about 11% of total biomass consumption, respectively.
18. Natarajan, 1998.

Figure 13.4: **Household Fuel Use across Income Classes**



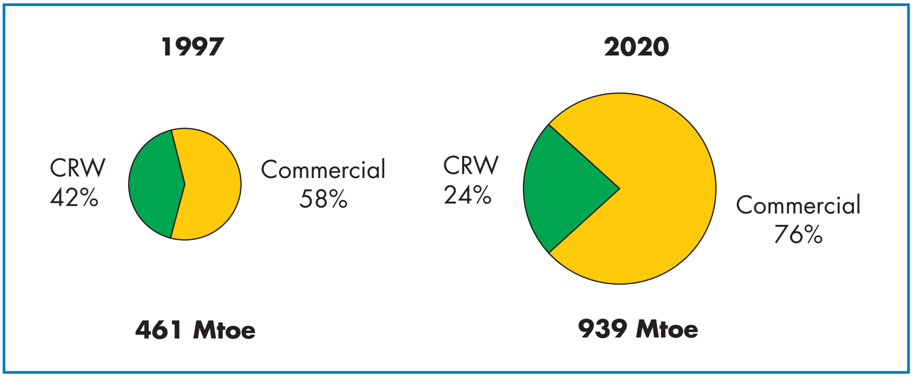
Source: National Sample Survey Organisation (1997).

urban households is kerosene, which remains heavily subsidised as a way to promote development. LPG, and then electricity, follow as income rises.

The outstanding energy characteristic of rural households, however, is their reliance on traditional fuels even at upper income levels (Figure 13.4). For rural energy demand over the outlook period, one of the most important factors will be the sustainability of current biomass consumption. Fuelwood resources are becoming increasingly scarce. In some areas this presents a problem of crisis proportions.

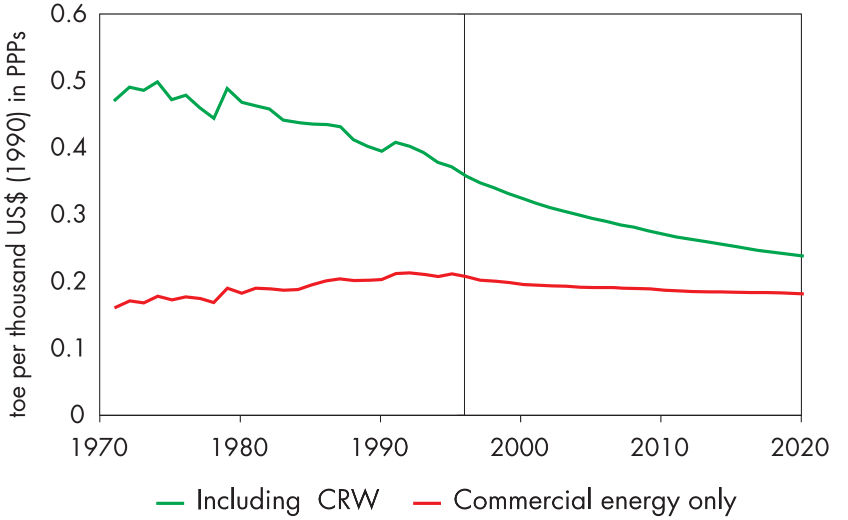
The *Outlook* expects that per capita CRW use will slowly decline. The total amount will continue to increase slowly, mostly in rural areas, from 193 Mtoe now to 223 Mtoe in 2020, rising with population growth but not as fast. This represents average annual growth of 0.6%, as against 4.6% for commercial primary energy fuels. As a result, the share of CRW in total primary demand will decline to 24% in 2020 from 42% in 1997 (Figure 13.5).

Figure 13.5: **Share of CRW in Total Primary Energy Supply**



Given the importance of CRW in India, the inclusion of this energy source in the analysis can greatly affect the inferences that can be drawn. For example, energy intensity including CRW stands at a very high level and is declining quite rapidly. This contrasts with the relatively flat path of commercial-energy intensity. Figure 13.6 shows this clearly. CRW fuels are generally used very inefficiently and their substitution by commercial fuels will result in an overall efficiency gain. The bulk of the incremental increase in total primary energy demand will come from commercial energy rather than CRW.

Figure 13.6: **Primary Energy Intensity Including and Excluding CRW**



Supply Prospects

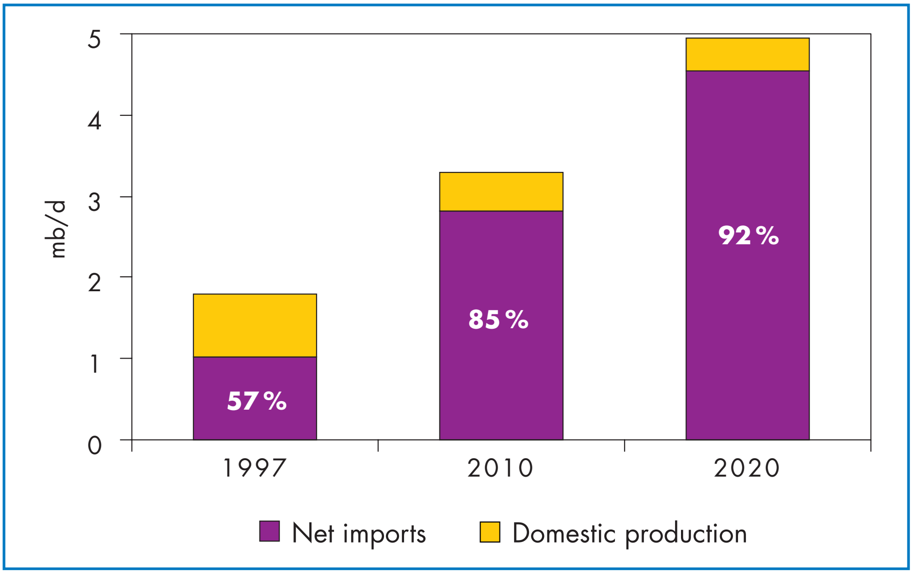
Oil

In 1999, India produced 0.75 mb/d of oil while demand for petroleum products was equivalent to more than 2 mb/d of crude oil. India's oil fields lie in the Bombay High, Upper Assam, Cambay, Krisha-Godawari and Cauvery basins. Output from the offshore Bombay High field, which accounts for roughly half of production, has declined slowly in recent years, a trend that will continue. A gas re-injection and reservoir-pressure maintenance program has been under study for years, but has not progressed very far. Although production from private and joint-venture fields has grown, it is not expected to reverse continued gradual declines in production. Improved Bombay High output could potentially stabilise supply for a few years at best. India needed net imports of about 1.3 mb/d in 1999 to satisfy more than half of its oil demand.

Imports are shifting from oil products to crude oil as a result of growth in Indian refinery capacity. The government has pursued a target of 90% self-sufficiency in middle distillates, with product imports limited mostly to kerosene and LPG after 1999. India imports most of its oil from Middle-

East OPEC. Given its dramatically increasing reliance on imported oil (Figure 13.7), dependence on OPEC oil is bound to grow significantly.

Figure 13.7: **Oil Balance in India**



Gas

Projected increases in gas demand over the outlook period will necessitate large imports and an end to self-sufficiency in gas. Natural-gas production reached 21 bcm in 1999. Gas reserves are mainly in the Bombay High Fields. Production rises steadily, helped by better exploitation of associated gas. Further exploration and production from sedimentary Basins are likely to bring out additional gas. The government also expects to tap coal-bed methane in the longer term. Other options include facilities to handle LNG imports and pipelines from gas-producing countries. These will require substantial investment. In a recent policy paper,[19] the government identifies natural gas as the preferred future fuel and discusses measures necessary to increase supply capacity, including both pipelines and LNG terminals. A number of terminals have been announced and are at various stages of development. The pace of both market reforms and the realisation of LNG projects present key uncertainties for the gas projections in this *Outlook*.

19. Ministry of Petroleum and Natural Gas, 2000.

The list of planned capacities (Table 13.6 gives a partial list) indicates that by 2010 India could join the world's big importers of LNG. If there are no imports through pipelines, LNG could supply almost half of projected demand, but many obstacles remain. On the demand side, recipients are limited largely to power plants, which face delays in project clearance, slow development of regulatory mechanisms and inadequate capacity of potential power customers to pay. On the supply side, many LNG terminals have yet to find supply arrangements in an international gas market prone to changes in contractual agreements. Operators also must find financing for both the terminals and LNG transportation.

Table 13.6: **Some Announced LNG Projects***

Location	Operator	(Mt)	Origin of envisaged supply	Demand source	Starting date
Dabhol (Maharashtra)	Enron	4.7	Oman, Abu Dhabi, Malaysia	Power plants: 2.2 Mt, Industry: 2.5 Mt	2001
Dahej (Gujarat), Cochin (Kerala)	Petronet LNG, Gaz de France	7.5	Qatar	Dahej 5 Mt, Cochin 2.5 Mt	2003
Ennore (Tamil Nadu)	DBEC Consortium	2.6	Qatar	Power plants: 1.7 Mt, Industry: 0.9 Mt	2003
Pipavav (Gujarat)	GPLCL, British Gas	2.65-5.3	Yemen	Pipavav-Hazira pipeline planned	2003
Trombay (Maharashtra)	Indigas, Totalfina	3	To be decided	Power plants: 0.8 Mt, Industry: 2.2 Mt	2003

* Based on various sources including: The Institute of Energy Economics, 1999; USDOE, 2000; and TERI, 1999.

Possible gas suppliers through international pipelines are Bangladesh, Oman, Iran, and Central Asia. On the whole, however, pipeline projects are less feasible than LNG projects, at least in the mid-term. Challenges include slow and uncertain gas-field development plans, political sensitivities and financial and technical difficulties.

Coal

Production increased from about 73 million tonnes in 1971 to almost 300 million tonnes in 1999. Although some coal exports go to Bangladesh and Nepal, India is a net importer — 15 million tonnes in 1997, mostly coking coal from Australia. In order to meet a projected 120% increase in coal demand, imports, largely of steam coal, will have to rise. Both coking and steam coal have ready sources in Indonesia, South Africa and Australia.

Substantial proven reserves in India are estimated at 72.7 billion tonnes, of which three-quarters occur in Bihar, Madhya, Pradesh and West Bengal.[20] Indian coal is high in ash and of low calorific value with lower sulphur content. Domestic coal needs washing to make it suitable for coke ovens. Extraction productivity is low, with mechanisation limited largely to coal cutting. Loading is done predominantly by hand. Average production costs, low by international standards, have been kept stable in real terms by lower costs in new developments. Costs will rise as stripping ratios increase. Reserves mainly lie far from major consuming centres. About three-quarters of coal production moves to power plants by rail, on either Indian Railways or dedicated lines; the rest goes either by truck or in coastal vessels. This places a considerable burden on the rail system. Projected coal increases in consumption will entail substantial investment in transport capacity.

Power Generation

Electricity generation amounted to 463 TWh in 1997, with installed capacity of utilities and captive power producers at 103 GW. Electricity output has grown fast, at an average of 7% per year over the past decade. Coal fuels nearly three-quarters of power-plant output. Chronic electricity shortages occur as demand outpaces power availability, due chiefly to shortfalls in new capacity and transmission lines, and to power theft. Plant load factors are often low, due to the advanced age of generating units, lack of appropriate coal quality, equipment deficiencies and insufficient maintenance. The lack of a national grid aggravates power shortages. Some states have low-cost surplus power during off-peak periods, while others have to operate very expensive coal-fired units to deal with shortages. The development of a national power grid, first approved in 1981, would help.

The poor performance of the utilities is due largely to low tariffs, which the state governments set at an estimated 20% below generation cost on average. Revenue collection is poor, and the utilities face increasing costs. Despite several tariff increases, the gap between unit production cost and

20. GOI Planning Commission, 1999.

average tariff has widened, raising the pressure to reform the power sector and facilitate investment.

The *Outlook* projects strong growth in electricity use, although at a slower pace than in the past. Generation will rise threefold, at an average annual rate of 5.2%, while installed capacity will increase at only 4.9%. Lower capacity needs follow from assumed improvements in plant performance and the introduction of new, more reliable generating units. The sector will remain dependent on coal, although coal's share in generation will probably drop to two-thirds by 2020 (Table 13.7). The share of gas-fired generation will increase from 6% to 15%. New power projects based mainly on imported LNG could develop where coal is expensive to transport, but this would require tariff reform to cover the cost of the LNG. Oil-fired generation is marginal and will diminish further. Several projects under development, however, would be oil-fired initially and would eventually switch to gas when it becomes available. The 1998 modifications to the liquid-fuel policy are unlikely to have a significant impact on oil-fired capacity.

Table 13.7: **India's Electricity Generation and Capacity**

	1997		2020	
	GW	TWh	GW	TWh
Total	**103**	**463**	**309**	**1 483**
Coal	66	339	193	1 008
Oil	3	12	6	32
Gas	9	28	47	216
Nuclear	2	10	6	39
Hydro	22	75	50	171
Other Renewables	1	0	6	18

IEA data indicate that transmission and distribution losses drain off about 18% of total electricity generation, with considerable interstate variation. Losses in some states are double the national average.[21] The average is 6% in OECD countries. Pilfering and insufficient investment in transmission and distribution largely explain why losses are so high. These difficulties are likely to ease over the projection period, assuming that the

21. TERI (1999).

necessary reforms take place and adequate investment in occurs in transmission and distribution.

The capacity required to meet projected demand will cost an estimated \$230 billion, or 1.1 % of GDP per year over the projection period. The projected growth implies capacity additions of 9 GW of new capacity each year. Chances of reaching these goals depend on the pace of reform, a major uncertainty. The projections may prove too optimistic if policies prove not to be effective.

India was the first developing country to produce electricity from nuclear power, at the 2x160 MW Tarapur plant in Maharashtra in 1969. It had 10 grid-connected reactors totaling two GW at the end of 1997. Two new units, rated at 220 MW each, were connected to the grid in the first half of 2000. Four others are under construction, with two close to completion in mid-2000. The performance of Indian reactors has been rather poor, but capacity factors have recently increased. Data for 1999 suggest a capacity factor of 76%.[22] Official plans call for 20 GW of installed capacity by 2020, but internal financial resources are limited and obtaining external funds, including private ones, seems unlikely. In April 2000, a parliamentary committee criticized the plan as too ambitious. The *Outlook* assumes a more modest increase in nuclear capacity, to 6 GW by 2020.

Hydropower, the second-largest source of electricity, accounted for 16% of output and 21% of installed capacity in 1997. Hydro potential is estimated at 84 GW at a 60% load factor, most of it in the North and Northeast. Only 15% has been developed, and another 7% is under development. Hydropower has moved very slowly compared to thermal power. Capacity has hardly doubled since 1980, while thermal capacity has nearly quadrupled. Hydro's share in the power-plant mix has declined, with negative implications for peak-load supply availability. The decline will probably continue, to 11% by 2020. Large new hydro plants often encounter difficulties for environmental, social and financial reasons.

Other renewable energy for power generation is receiving increased attention (Table 13.8).[23] It is already used to provide electricity in rural areas, particularly where early connection to the grid is not envisaged. It is also being promoted to diversify energy supplies.

22. Calculated using electricity generation data for 1999 from the Commissariat a l'Energie Atomique, 2000.

23. In 2000, the government declared an ambitious target of 10% of total power capacity to come from renewable energy by 2012.

Table 13.8: **India's Installed Renewable Capacity and Potential**

Source	Capacity in 1999 (MW)	Potential (GW)
Biomass and Waste	49	17
Wind	1 080	45
Small Hydro (<25 MW)	271	10
Solar	42	n.a.
Ocean	0	50

Sources: Council of Power Utilities (1997), TERI (1999), MNES (2000).

Installed wind-power capacity is among the highest in the world. It increased rapidly in the 1990s, boosted by both subsidies and financial incentives. Its projected rise to four GW by 2020 will require stronger policies for the use of renewable energy. One such initiative is a proposal to introduce a fossil-fuel levy to fund renewables development.[24] India's solar potential is also large and is being progressively tapped both for heating and for photovoltaic power. A 140 MW Integrated Solar Combined Cycle power plant is under construction in Rajasthan.

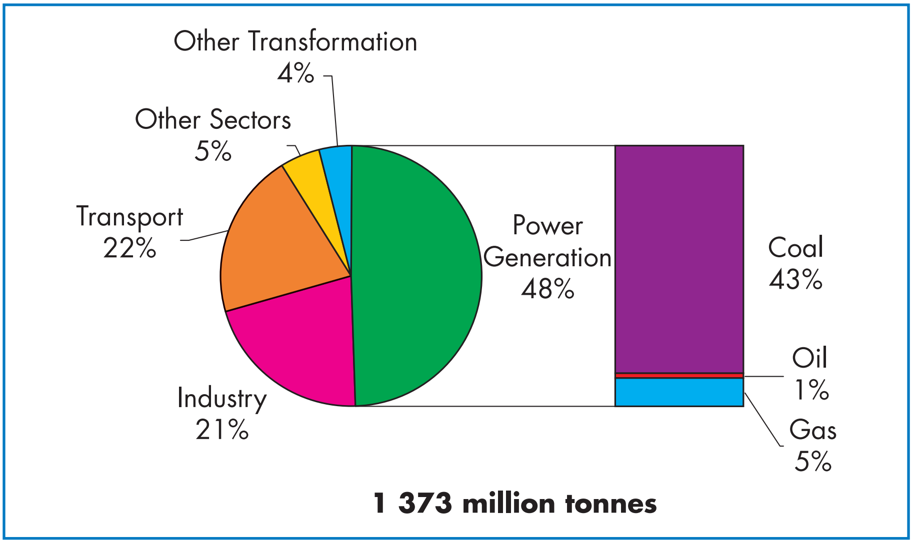
Environmental Issues

Local pollution, especially in India's large and medium-sized cities, has reached alarming levels. Energy consumption is a main contributor, chiefly from a large and fast-growing fleet of small vehicles with two-stroke engines. The widespread use of diesel fuel also plays a role. About 80% of road vehicles in India run on diesel, compared to 15% in China and 31% in Malaysia. Coal power plants contribute heavily to air pollution. Biomass-fuelled cooking ovens generate indoor pollution that adds to ambient air degradation.

Globally, India is one of the lowest CO_2 emitters per capita (0.9 tonnes of CO_2 per capita, one-twelfth the OECD average). Yet the energy sector's carbon intensity is high and total emissions rank among the world highest, due to high coal intensity and the vast population. Projected CO_2 emissions will reach 2.25 billion tonnes in 2020, up from 881 million tonnes in 1997. For perspective, the incremental increase of 1 373 million tonnes much exceeds Japan's current total emissions, and the 2020 total is twice as high. Figure 13.8 shows where the incremental emissions will come from. About

24. *Financial Times*, 28 April 2000, "*Renewable Energy Report*".

Figure 13.8: **Incremental CO_2 Emissions by Sector, 1997-2020**
(Million tonnes of CO_2)



half will come from power generation, where coal will dominate. An increased share of gas in power generation, if sufficient investment comes forth, could lead to fewer emissions.

CHAPTER 14
ASSESSMENT OF PAST *WEO* PROJECTIONS

This chapter assesses the projections of the IEA's *World Energy Outlook* over the past eight years.[1] It tests the accuracy of the underlying assumptions for economic growth and crude-oil prices, and of the resulting projections of OECD primary energy demand and world oil demand. OECD energy demand was chosen for this analysis because the World Energy Model on which the *WEO* is based provides more detailed models for the OECD regions. In addition, data for these regions are of relatively high quality. Oil is the most important fuel in most countries, and world oil demand data are also relatively reliable. The analysis includes comparisons of the *WEO* projections with the work of others, to identify and analyse common themes and important differences.

Projections and the World Energy Model

Projections help policymakers make informed decisions, given certain assumptions. In addition to the key postulates about economic growth and crude-oil prices that are the main drivers of the IEA model, the energy-demand projections in past *WEO's* have assumed in the "base case", that policies will not change over the outlook period. Only policies already in place influenced the projection results.

The projections flow from the IEA's World Energy Model (WEM).[2] Annual modifications to the WEM capture data revisions and update the assumptions. Lags in data collection and analysis entail a three-year gap between the last year of final energy data and the publication date of each *Outlook*. These lags result from the complexity of compiling multi-country energy data, often themselves derived through different methodologies. While the WEM captures the forces affecting energy markets, adjustment factors are imposed to complement the projections. *WEO* projections

1. This chapter is based on a presentation by the IEA at the Energy Modelling Forum (EMF), organised by EMF, IEA and the International Institute for Applied Systems Analysis (IIASA) at Stanford University, California in June 2000. It has benefited from the comments of many of the Forum's participants.
2. Appendix 1 provides an overview of the World Energy Model.

reflect the best judgements of IEA analysts, who draw on broad discussions with energy experts.

Evaluation of Projections

This analysis looks at the accuracy of the *WEO* projections and assumptions *ex post*, in order to detect the sources of inaccuracies or weaknesses in model construction and to identify circumstances that can lead to projection errors. Reliable projections depend primarily on reliable data. A careful evaluation of the data used in each *Outlook* accompanies the discussion of trends in *WEO* projections. The IEA energy database has undergone modifications over the past decade, in country coverage and product specification. To disregard these changes would make comparisons meaningless.

Reliable projections also depend on how well the model replicates the functioning of energy markets. The *WEO* projections reflect the most likely steady-state scenarios under given sets of economic and energy assumptions, which are themselves subject to uncertainties which could affect future energy demand. Modellers need a discussion of these "surprise events" to ascertain the robustness of the model's predictions. Some of the major uncertainties include economic instability in the FSU, economic growth and recovery in Asia and the evolution of oil prices.

Brief Description of Past *WEOs*

The *World Energy Outlook* appeared annually from 1993 to 1996 and biennially since then.[3] When the 1993 *Outlook* was published, the Gulf War price shock had dissipated. The long-term view held that the price of crude oil would rise steadily to US$30 (in constant 1993 prices) in 2010. Most of the uncertainties in the 1993 projections concerned economic growth. Instability in the countries of the Former Soviet Union made forecasts for the region very difficult. In Central and Eastern Europe (CEE), although progress toward market economies seemed likely, the paths to that goal also remained difficult to predict. China, too, presented much uncertainty, although continued robust growth was expected.

3. The IEA published an energy outlook for internal use in 1982. That *Outlook* projected world oil demand in 2000 at between 58 mb/d and 74 mb/d. Given the high oil-prices in the early 1980s and expectations of even higher prices, it comes as no surprise that low oil prices towards the end of the period yielded a world oil demand in 2000 of 76.2 mb/d (estimate from IEA's *Oil Market Report,* June 2000), *i.e.* close to the high end of the 1982 projection.

The 1994 *Outlook* updated the 1993 base case with modelling refinements and detailed analyses of the OECD Pacific region, East Asia, China and CEE. The prolonged recession in the OECD area in the early 1990s, especially in Japan, led to a downward revision from the 1993 *Outlook* in expected GDP growth and energy demand in the OECD.

The 1995 and 1996 *Outlooks* presented two scenarios to capture uncertainty about the sustainability of rapidly rising energy demand and falling oil prices.[4] The *Capacity Constraints* case assumed that growth in energy demand would not be satisfied at current price levels, and the *Energy Savings* case assumed that energy-efficiency improvements would dampen energy demand. Both assumed the same rate of economic growth over the outlook period but differed in their judgements of growth in energy demand.

The *Capacity Constraints* case predicted that low prices would not encourage enough investment in energy production and transportation to meet increased demand, even though the marginal cost of production in some areas like Venezuela was less than the current price. It expected rising oil prices to dampen demand. Because their underlying assumptions fall more into line with those of other projections analysed here, only the projections from the *Capacity Constraints* case are used in the comparisons in this chapter.

The *Energy Savings* case assumed that changes in behaviour such as the use of more efficient household appliances and motor vehicles, would ease pressure on energy prices and reduce demand. The resultant increase in energy efficiency would more than compensate for any increase in demand that resulted from lower prices. This case was modelled by imposing efficiency improvements sufficient to hold the oil price stable over the outlook period.

The 1998 *WEO* considered just one scenario: *Business As Usual*. It focused on energy demand by fuel type and by energy-related service: electrical services, mobility, stationary services and fuels used in power generation. It also analysed non-commercial biomass energy use, separately and for the first time, in its energy outlook for developing countries.

Exogenous Variables in the *WEO*

The *WEO*'s long-term oil-price assumptions have changed significantly since 1993, reflecting current events and technological advances, including progress in oil exploration and production. GDP assumptions for the OECD have not changed significantly since 1993, but

4. The 1995 *Outlook* also carried out detailed analyses for Mexico, Brazil and South Asia, and the 1996 *Outlook* projected energy demand in the FSU as a group.

those for world GDP growth have risen. The oil-price assumptions largely *overestimated* the rise in oil prices, while the GDP assumptions largely *underestimated* economic growth over the past decade.

GDP Assumptions

GDP growth is the principal determinant of the energy-demand projections in the *World Energy Outlook*. The IEA bases the GDP assumptions largely on OECD and IMF forecasts, with some adjustments. Beyond the first two or three years of the *WEO* projection period, growth is set at a long-term average annual rate. If the actual GDP growth rate for a specific year is significantly above or below this trend rate, the projection for that year will be affected accordingly. Thus, business cycles can act as a source of projection errors in energy demand. Growth assumptions that over- or underestimate actual growth in the short term can lead to large errors in projections of energy demand. The three-year lag in final energy data used for each *Outlook* may compound this problem.

Table 14.1 compares GDP growth assumptions with the most recent estimates for economic growth over the time period analysed in each *WEO*. For example, the *WEO96* GDP growth assumption for the OECD, 2.7%, covered the time period from 1993 to 2000. The latest estimate for GDP growth over this period is 2.7%, reflecting the accuracy of the 1996 *Outlook*. The 1994 *WEO* adopted short-term growth assumptions lower than in subsequent *WEOs* (except for the identical OECD assumption in 1998) because the OECD and much of the world were just emerging from a severe recession in 1990 and 1991. A one-tenth percentage point decrease

Table 14.1: **GDP Growth-Rate Assumptions *vs.* Latest Estimates**
(Average annual growth rates, in per cent)

	OECD		World	
	WEO assumption	Estimated* growth	*WEO* assumption	Estimated* growth
WEO93 (1991-2010)	2.4	n.a	3	n.a.
WEO94 (1991-2000)	2.3	2.4	2.6	3.3
WEO95 (1992-2000)	2.6	2.5	3	3.4
WEO96 (1993-2000)	2.7	2.7	3.2	3.6
WEO98 (1995-2000)	2.6	2.8	3.6	3.5

* Using the most recent GDP figures from OECD and IMF.

in expected GDP growth in the 1994 *Outlook* as compared with 1993 translated into an OECD energy-demand projection for 2000 one per cent, or about 50 Mtoe, lower than the 1993 projection. Stronger economic growth in OECD countries in 1994 and 1995 was reflected in the GDP growth assumptions in the 1995 and 1996 *Outlooks*. The 1998 *WEO* assumed a low OECD growth rate, reflecting widespread expectations at the time.

Assumptions for world economic growth have risen since 1994. In 1994 through 1996, there were expectations for recovery in the FSU and in Central and Eastern Europe. The latest estimate for world GDP growth over the periods covered by the 1995 and 1996 *Outlooks* indicates that world growth was significantly underestimated. The 1998 *Outlook* anticipated lower growth in China but strong world growth over the projection period, predicated on an economic resurgence in the Asian region.

Oil-Price Assumptions

Assumptions for long-term oil prices have declined considerably since the early 1990s (Table 14.2), partly because of expectations regarding the backstop technology cost. Assumptions for the long-term oil price were gradually adjusted downward from *Outlook* to *Outlook*.

Table 14.2: **Assumptions for IEA Crude Oil-Import Price, 2000 and 2005**
(US$ 1990 per barrel)

	2000	2005
WEO93	25	28
WEO94	21	26
WEO95	21	26
WEO96	16	23
WEO98	17	17

The 1993 and 1994 *Outlooks* assumed that the IEA import price of crude oil would rise steadily in real terms up to 2005, from about $17 to $28.[5] They mirrored the sentiments of most energy experts and other

5. The 1982 *WEO* had assumed that the crude oil price would be between $40 and $65 (in 1990 US dollars) in 2000.

energy outlooks at the time. This forecast rested largely on the belief that investment in energy production and transportation would not be sufficient to meet the expected increase in energy demand, and it reflected concern about the resource base, given prevailing prices.

Falling oil prices in the first half of the 1990s changed many expectations. The 1995 *WEO* still foresaw prices rising steadily over the projection period, but the 1996 *Outlook*, held them flat until 2000, with a steady climb thereafter. It predicated the flat real price on the possibility that an increase in non-OPEC supply would moderate the call on OPEC. Significant downward pressure on the oil price would occur if Iraq returned to the market, in the absence of offsetting reductions by other OPEC producers.

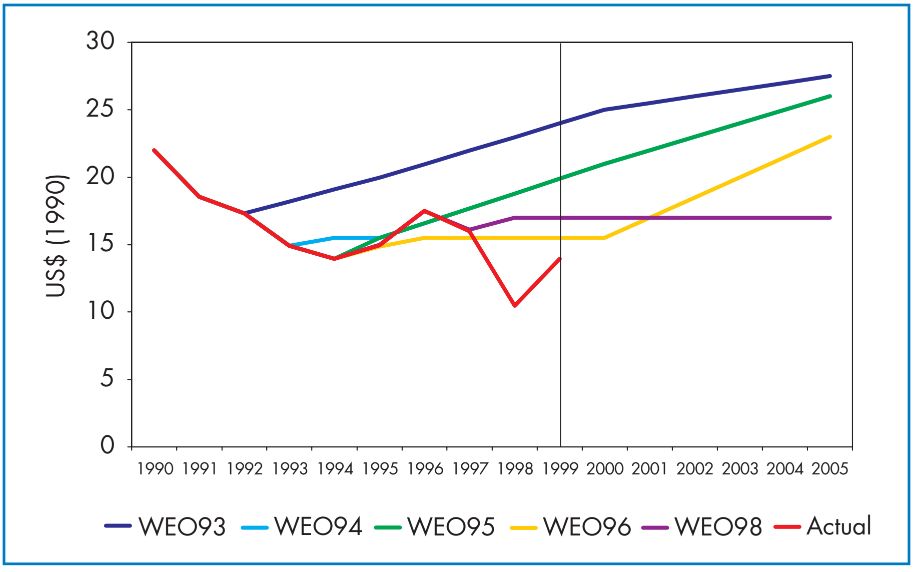
The 1998 *WEO* extended the assumption of flat oil prices until at least 2010, when the price projection rose to reflect an expected transition from conventional to "non-conventional" oil as the source of marginal supply. The financial crisis in Asia created uncertainty about growth prospects in the region, and the 1998 *Outlook* was unable to take fully into account its dampening effect on oil demand.

As illustrated in Figure 14.1, previous *Outlooks* have tended to overestimate the actual price of crude oil, except for 1996, when exceptional circumstances led to a brief rise. Following the period of high prices in the aftermath of the Gulf War, prices fell steadily from 1991 to 1994. Nevertheless, most energy forecasters continued to project rising long-term oil prices until flat short-term price projections became the norm in 1996.

A number of circumstances can explain the era of low prices, unexpected by most energy analysts. The two most important were the unwillingness of producers to restrain supply and large investments in non-OPEC capacity. These two conditions, combined with technical advances in bringing on new reserves and increased competition from other fuels, kept oil prices down.

Large swings in crude-oil prices after 1995 caught many oil analysts offguard. Among other events, the delay in Iraqi oil sales in 1996 and the Asian crisis that began in 1997 aggravated volatility. The price surge in 1996, from $18.80 in January to $25.40 in December (WTI crude price), resulted from a combination of factors. First, an expected increase in non-OPEC supply did not occur. Second, considerable de-stocking at US refineries in 1995 left a lean stock situation in 1996. Third, the cold winter of 1995-96 and an increase in Asian refining capacity added to demand pressure. All these events reinforced the highest-profile cause, the delay in Iraqi oil sales. Combined with low stocks, it caused backwardation in

Figure 14.1: **Oil-Price Assumptions**



futures markets, with prices for forward contracts significantly below those for immediate physical delivery. The substantial decline in crude-oil prices that followed in 1998 came from weak demand in Asia and oversupply, brought on by Iraqi re-emergence and an OPEC quota increase in November 1997.

Evaluation of Projections

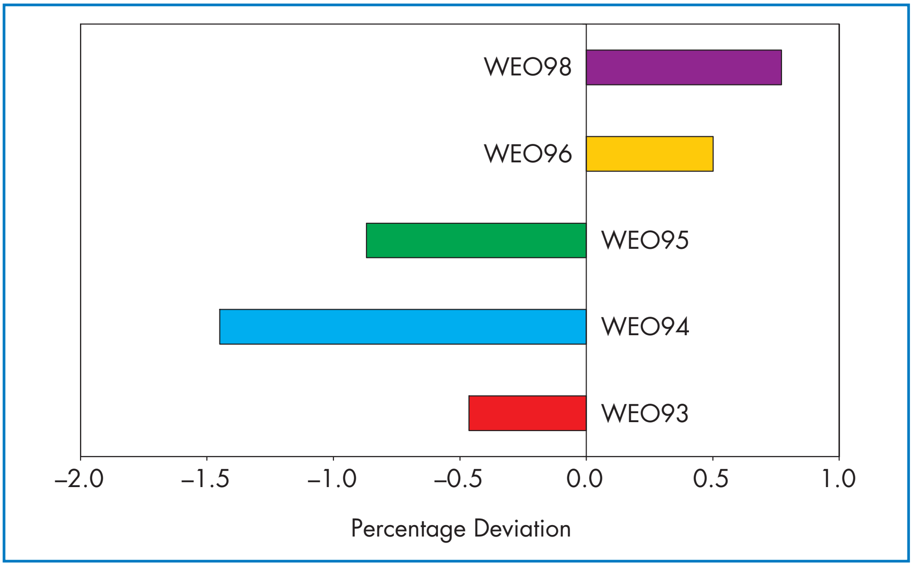
This section evaluates the previous *WEO* projections for OECD energy demand and world oil demand. Two caveats are in order. First, the assumption of unchanged policies underlying most cases in the *WEO* may be an important reason why energy projections differ from actual energy demand. Past projections have assumed that no new government policies are adopted over the outlook period, on the reasonable premise that the direction of such future policies is simply unknowable at the time the projections are prepared. Second, the projections may appear to have predicted energy demand accurately, but errors in some countries/regions may have been compensated by errors in others.

OECD Energy Demand[6]

Figure 14.2 shows the deviation of past *WEO* projections of OECD energy demand in 2000 from the *current* data from IEA statistics. For example, the 1996 *WEO* overestimated demand in 2000 by 0.5%. Figure 14.2 shows that *WEO* projections have differed from OECD energy-demand data for 2000 by less than 1.5%. The 1993 *WEO* projection showed the least deviation from current data; it underestimated demand in 2000 by less than 0.5%.

The low GDP growth assumption in the 1994 *Outlook* underestimated the strength of economic recovery in the OECD, especially in Japan, and thus led to an underestimation of energy demand in 2000. In the 1998 *WEO*, projected OECD energy demand was some 0.8% higher than current data indicate. This may be attributed to higher-than-average energy intensity improvements in the United States over the past several years.[7]

Figure 14.2: ***WEO*** **Deviations from Current Data for OECD Energy Demand in 2000**



6. The countries included in the OECD regional groupings have changed over the past decade as new countries have joined the IEA. Certain countries have changed groupings; Mexico was included in OECD North America in the 1995 and 1996 *Outlooks*, but has subsequently been moved to the Latin America regional grouping. Korea, although a member of the OECD, is included in the East Asian group of countries. Finally, the Czech Republic and Hungary were not included in OECD Europe until the 1998 *Outlook*. The analysis takes account of these changes in regional aggregation.
7. See Chapter 4 for a discussion of these energy-intensity improvements.

Table 14.3: **OECD Energy Demand: Per Cent Errors, 1993 to 1998**
(Projections vs. actual levels)

	1993	1994	1995	1996	1997	1998	Average absolute per cent error
WEO93	0.3	0.1	–0.4	–1.7	–0.9	–0.4	0.6
WEO94		–0.4	–1.0	–2.5	–1.7	–1.3	1.4
WEO95			–0.5	–1.9	–1.1	–0.6	1.1
WEO96				–1.5	–0.5	0.3	0.7
WEO98						0.6	0.6
Average absolute per cent error	0.3	0.3	0.7	1.9	1.0	0.6	0.9

Note: Errors are defined as: [(projected value — actual value)/projected value]*100.

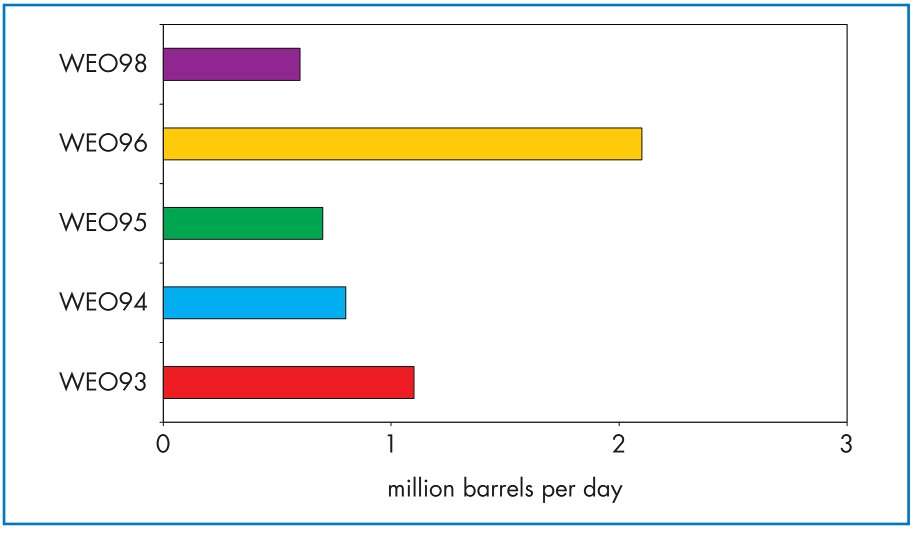
Table 14.3 looks at percentage deviations of OECD energy demand projections from 1993 to 1998. The *WEO* generally underestimated growth in the demand for energy. The greatest projection errors appear for 1996 and 1997, when economic growth in the United States and Japan greatly exceeded expectations. The average error for 1998 was quite low, given the number of *WEOs* included. In a comparison of the individual *Outlooks*, those of both 1993 and 1998 had the lowest average errors across the years they covered, and the 1996 *Outlook* also performed quite well. The accuracy of the 1993 *Outlook* is quite remarkable, given the number of projections included.

The seeming accuracy of the projections disguises many changes that have occurred in OECD energy demand, in the fuel mix and in demand among different regions. For example, the early *Outlooks* underestimated the increase in gas's share of electricity generation in OECD Europe. The 1993 *WEO* expected it to rise to 19% in 2000, but the latest available estimate is closer to 21%. Policies liberalising the gas market in Europe were not reflected in the data that the earlier *Outlooks* used.

World Oil-Demand Projections

WEO expectations for world oil demand in 2000 came relatively close to the current estimate, within 2.1 mb/d (Figure 14.3). The 1993 *WEO* projected world oil demand to reach 77.3 mb/d in 2000; current estimates place it at about 76.2 mb/d, only some 1.1 mb/d less than the 1993 projection. The 1994 and 1995 *Outlooks* had expectations about future oil demand even closer to the current estimate, and the 1998 *WEO* projection for 2000 was only 0.6 mb/d higher.

Figure 14.3: ***WEO*** **Deviations from Estimated World-Oil Demand in 2000**



* Latest estimate of 76.2 mb/d is from the IEA's *Oil Market Report,* June 2000.

As the figure indicates, the 1996 *WEO* projection exceeded the current estimate of world oil demand in 2000 by some 2.1 mb/d. It expected demand to grow somewhat faster than over the previous two decades. The 1996 *WEO* predicted that strong economic growth in the OECD would fuel rapid growth in transport demand, while robust GDP growth, urbanisation and the rising need for mobility would push up oil demand in developing countries. Limited alternatives to oil also pointed to a rapid rise in demand in the FSU, the CEE countries and other areas outside the OECD. As matters turned out, the 1996 *WEO* overestimated oil demand in 2000 in Asia, excluding China, by some 2.3 mb/d, largely because of the unanticipated economic collapse in that region. Expected demand in the FSU and CEE was roughly 2 mb/d higher than current estimates. While projections of oil demand in China and the OECD area actually fell below the current estimates, they could not balance the overestimates for Asia and the FSU/CEE.

One of the main developments in the world oil market over the past decade has been an unexpected increase in oil supplies from outside OPEC. The 1994 *WEO* expected OECD oil production to decline relative to OPEC and the rest of the world, based on the economics of oil production and exploration in the OECD area. Instead, non-OPEC and especially OECD supplies came into the market at prices much lower than those assumed. The latest estimates place the OECD's share in total world oil supply at over 28%, roughly equivalent to that in 1990.

Box 14.1: **Oil Demand and Mobility**

The growth in oil demand over the last decade has resulted largely from increasing demand for mobility. Particularly in OECD countries, the transport sector has accounted for most of the increase in oil demand. Demand responds, albeit modestly, to changes in end-user prices (including tax). High taxes on petroleum products mean that oil-price fluctuations have relatively little effect on demand, except in low-tax countries or for low-taxed products such as heavy fuel oil. In contrast, the past 25 years have revealed a clear, direct relationship between GDP and the growth in demand for mobility services (see Figure 2.3 in Chapter 2). World transport demand has followed economic output; it was largely unaffected by the 1973 and 1979 oil-price shocks. This relationship is expected to persist.

Comparisons with Other Energy Outlooks

This section compares the *WEO* with energy outlooks from the US Department of Energy (DOE), the European Commission, the Petroleum Industry Research Associates (PIRA) Energy Group and other private organisations.[8] All the comparisons use reference or base-case scenarios. Despite broad similarities between these outlooks, they show some notable differences.

GDP Assumptions

In general, every outlook assumed that economic growth in the OECD would slow from its historical average annual rate of some 2.9%

8. The projections from private organisations are derived from data provided by the International Energy Workshop Poll and the Energy Modelling Forum and can be found in the IPCC Scenario Database (CGER-NIES).

from 1971 to 1991. The assumptions ranged between 2.3% and 2.7% per year, on average, in the 1990s (Table 14.4). The *WEO* assumptions occupied the high end of the range, because in 1995 and 1996 they excluded slow GDP growth in the recession years of the early 1990s. The latest estimate for average annual growth in the OECD area from 1990 to 2000 is 2.5%.[9] Thus, nearly all the outlooks reviewed appear to have underestimated GDP growth in the OECD.

Table 14.4: **Comparison of GDP-Growth Assumptions, 1990 to 2000***
(Annual average growth rate, in per cent)

Year of Outlook:	**1992**	**1993**	**1994**	**1995**	**1996**	**1998**
OECD GDP-Growth Assumptions GDP growth from 1990-2000 is estimated to be 2.5% (OECD, 2000).						
DGE	2.3	-	-	-	2.3	-
*WEO**	-	-	2.3	2.6	2.7	2.2
DOE	-	2.5	2.2	2.3	2.2	2.0
PIRA	-	2.2	2.3	2.2	2.0	2.1
World GDP-Growth Assumptions GDP growth from 1990-2000 is estimated to be 3.2% (IMF, 2000).						
DGE	2.7	-	-	-	2.8	-
*WEO**	-	-	2.6	3.0	3.2	3.0
DOE	-	2.5	2.4	2.3	2.2	2.1
PIRA	-	3.5	3.5	3.6	3.5	3.0

* *WEO*94: 1991-2000; *WEO*95: 1992-2000; *WEO*96: 1993-2000.
Source: European Commission (1992 and 1996), DOE/EIA (1992-1998), PIRA Energy Group (1993-1998).

The *Outlooks* displayed much more disparity in their assumption for world economic growth (Table 14.4). The DOE's reference-case assumptions were consistently lower than those of the IEA and PIRA, perhaps because the DOE assumed much longer recovery periods in the aftermath of financial crises in Mexico and Asia and held less optimistic views on short-term world economic growth.

9. OECD, 2000.

Oil-Price Assumptions

Table 14.5 compares assumptions about the likely path of crude-oil prices.[10] Two trends are evident. First, the *WEO* assumptions lie at the high end of the range of projections. Second, all of the oil-price projections declined over the six years studied. In the early to mid-1990s, the major

Table 14.5: **Comparison of Crude Oil-Price Assumptions***
(US$ 1990 per barrel)

		2000	2010
1993	DRI	23	32
	Global2100	31	37
	OWEM	18	22
	WEO93	25	28
	PIRA93	18	19**
	DOE93	22	28
1994	GRI	20	25
	LYNCH	16	18
	WEO94	21	26
	PIRA94	19	19**
	DOE94	19	26
1995	OWEM	14	18
	WEO95	21	26
	PIRA95	14	15**
	DOE95	16	22
1996	EC	19	26
	WEO96	16	23
	PIRA96	15	14**
1997	DOE97	16	18
1998	*WEO98*	17	17
	PIRA98	14	15**

Notes: * PIRA projections are for WTI Cushing. ** 2005.
Sources: DRI (1993), Manne and Schrattenholzer, GLOBAL2100 (1993), OWEM (1993, 1995), Gas Research Institute (1993), Lynch (1994), European Commission (1996), Conventional Wisdom Scenario. For WEO, DOE and PIRA, see Table 14.4.

10. The projections included in Table 14.5 are all in the public domain.

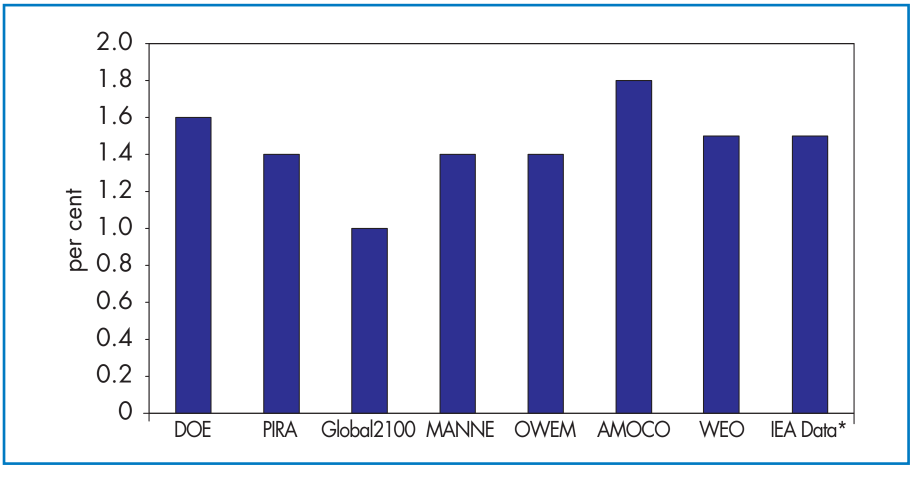
differences turned on expectations about the potential for oil from low-cost sources to be brought to market.

In its 1993 projection, PIRA expected the oil price in 2000 to be lower than did the IEA.[11] The PIRA view at the time was that OPEC had too much spare capacity. The IEA adhered to this view but was more willing to believe that producers could curtail supply over the long-term. In PIRA's view, the economic downturn in Europe and Japan, and the continuing decline in the FSU, would weaken energy demand and keep prices low. In its 1993 projection, the DOE saw the US import price rising to almost $22 (US$ 1990) by 2000, more in line with the IEA and DRI.

Projections of OECD Energy Demand

Figure 14.4 compares 1993 projections for annual average growth in OECD energy demand from 1990 to 2000. Except for Amoco and DOE, and the IEA, which was quite accurate in its projected growth rate for OECD demand, the projections underestimated this growth. Because of different assumptions about GDP growth, the pace of technological development and different country groupings among forecasts, few other generalisations are possible.

Figure 14.4: **Comparison of 1993 Projections of Average Annual Growth in OECD Total Primary Energy Demand, 1990 to 2000**



*1990-1999 is based on IEA statistics; 2000 is based on preliminary data.
Source: See Tables 14.4 and 14.5 and Amoco (1993), Manne (1993).

11. Although the WTI and the IEA import cost differ on an annual basis, the spread between their actual values has never exceeded $3 in nominal terms in the 1990s.

World Oil-Demand Projections

Table 14.6 compares projections for average annual growth in world oil demand. The long-term projections are generally higher than the short-term ones. Except for 1996, the *WEO* figures appear to have been very accurate; the latest estimate for average annual oil-demand growth from 1990 to 2000 is 1.5%. The European Commission underestimated world oil demand in 2000, while PIRA tended to overestimate it. In its 1995 and

Table 14.6: **Comparison of World Oil-Demand Projections**
(Average annual growth rate, in per cent)

		1990-2000	2000-2010
1992	IIASA/GEECP	0.3	0.2
1993	DRI	1.3	2.2
	OWEM	0.8	1.2
	GLOBAL2100	0.7	0.7
	WEO93	1.5	1.8
	PIRA93	1.6	-
	DOE93	1.5	1.2
1994	LYNCH	1.8	2.0
	WEO94	1.5	2.0
	PIRA94	1.7	-
	DOE94	1.6	1.1
1995	OWEM	1.3	1.3
	EC	0.4	1.0
	WEO95	1.5	2.1
	PIRA95	1.9	-
	DOE95	1.5	1.5
1996	*WEO96*	1.7	2.1
	PIRA96	1.9	-
	DOE96	1.5	1.8
1998	*WEO98*	1.5	2.2
	PIRA98	1.5	2.1
	DOE98	1.6	2.2
2000	**Latest OMR Estimate**	**1.5**	**-**

Sources: See Tables 14.4 and 14.5. IIASA/GEECP model found in Sinyak (1992).

1996 *Outlooks*, PIRA expected a large inflow of oil from non-OPEC sources and oversupply from OPEC. Compared with PIRA and the IEA, the DOE expected lower growth in world oil demand in its outlooks from 1993 to 1996. After the 1996 oil price increase, its 1998 expectations about growth in world oil demand rose somewhat.

What Have We Learned?

WEO projections appear to have performed quite well over the past eight years. The accuracy of the projections for OECD energy demand has improved, which is what one would expect if the accuracy of the underlying model has improved. Nevertheless, the WEM has not faced a test of serious adversity, mainly because the world economy grew steadily throughout the 1990s.

Projections of world-oil demand came remarkably close to current estimates, a result of the linear relationship between transport demand and GDP and the dampening effect of high energy taxes in many countries. Tax regimes, particularly in OECD countries, tend to be predictable. Because changes in end-user prices have much more effect on energy demand than do crude-oil price changes, high, fixed tax components in final prices have prevented oil-price fluctuations from having much impact on demand.

Long-term oil-price assumptions have fallen considerably since the early 1990s. Large and somewhat unexpected non-OPEC supply growth was probably a major determinant of the declining trend in oil prices. Rising energy demand and flat energy prices were the most persistent characteristics of the energy market in the 1990s.

Oil-price assumptions clearly have much less influence on energy demand than GDP assumptions. GDP growth is the major determinant of growth in energy demand. This highlights a need for more careful attention to non-OECD demand, characterised by less mature economies with more uncertain growth rates, higher energy intensity and a lesser role for energy taxes. In particular, a more detailed description of the energy-demand trends in these countries, or one at least as detailed as data constraints will allow, would help to increase the accuracy of the *WEO* projections for world-energy and oil demand.

PART D

TABLES FOR REFERENCE-SCENARIO PROJECTIONS AND APPENDICES

Part D provides detailed tables of the *WEO's* economic and population assumptions and of the projections for energy demand, power generation and energy-related CO_2 emissions. Tables are provided for the world, for each of the *WEO* regions and for regional aggregates. Three appendices are also contained in Part D. Appendix 1 presents an overview of the World Energy Model. Appendix 2 compares the *WEO 2000* projections with other studies. Definitions and conversion factors are provided in Appendix 3. The bibliography and a glossary conclude Part D.

General Note to the Tables

The analysis of energy demand is based on data up to 1997, published in mid-1999 in *Energy Balances of OECD Countries* and *Energy Balances of Non-OECD Countries*.

The tables in this section present detailed projections of energy demand, electricity generation and capacity, and CO_2 emissions for the following regions:

- World
- OECD
- OECD North America
- OECD Europe
- OECD Pacific
- Transition Economies (including Russia)
- Russia
- Developing Countries
- China
- South Asia (including India)
- India
- East Asia
- Latin America (including Brazil)
- Brazil
- Africa
- Middle East

CO_2 emissions of Annex B countries are shown separately. The regions, fuels and sectors shown in the tables are defined in Appendix 3.

Both in the text of this book and in the tables, rounding may cause some discrepancy between the total and the sum of the individual components.

Economic Growth Assumptions
(average annual growth rates, in per cent)

	1971-1997	1997-2020
North America	2.7	2.1
Europe	2.4	2.1
Pacific	3.4	1.7
OECD	**2.7**	**2**
Russia	–5.7*	2.9
Rest of Transition Economies	–5.3	3.2
Transition Economies	**–5.3***	**3.1**
China	8.3	5.2
East Asia	6.9	4.2
India	4.8	4.9
South Asia	4.8	4.7
Brazil	4.2	2.5
Latin America	3.5	3.2
Africa	3	2.9
Middle East	3.4	3.2
Developing Countries	**5.3**	**4.3**
World	**3.4**	**3.1**

* 1992-1997.
Source: OECD, World Bank and IMF.

Population Growth Assumptions
(average annual growth rates, in per cent)

	1971-1997	1997-2020
North America	1	0.7
Europe	0.5	0.2
Pacific	0.8	0.1
OECD	**0.7**	**0.3**
Russia	0.4	–0.2
Rest of Transition Economies	0.5	0.7
Transition Economies	**0.6**	**0**
China	1.5	0.7
East Asia	2	1.1
India	2.1	1.2
South Asia	2.2	1.4
Brazil	2	1.1
Latin America	2.1	1.3
Africa	2.7	2.1
Middle East	3.3	2.6
Developing Countries	**2**	**1.3**
World	**1.7**	**1.1**

Source: United Nations, OECD.

Reference Scenario: World

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**5012**	**8743**	**11390**	**13710**	**100**	**100**	**100**	**100**	**2.2**	**2.1**	**2.0**
Coal	1446	2255	2820	3350	29	26	25	24	1.7	1.7	1.7
Oil	2461	3541	4589	5494	49	41	40	40	1.4	2.0	1.9
of which International Marine Bunkers	*118*	*132*	*159*	*181*	*2*	*2*	*1*	*1*	*0.4*	*1.4*	*1.4*
Gas	900	1911	2724	3551	18	22	24	26	2.9	2.8	2.7
Nuclear	29	624	690	617	1	7	6	5	12.5	0.8	0.0
Hydro	104	221	287	336	2	3	3	2	2.9	2.1	1.8
Other Renewables	72	189	279	361	1	2	2	3	3.8	3.0	2.8
Power Generation	**1199**	**3150**	**4275**	**5201**	**100**	**100**	**100**	**100**	**3.8**	**2.4**	**2.2**
Coal	587	1374	1864	2305	49	44	44	44	3.3	2.4	2.3
Oil	268	279	316	328	22	9	7	6	0.1	1.0	0.7
Gas	206	556	966	1409	17	18	23	27	3.9	4.3	4.1
Nuclear	29	624	690	617	2	20	16	12	12.5	0.8	0.0
Hydro	104	221	287	336	9	7	7	6	2.9	2.1	1.8
Other Renewables	5	97	152	206	0	3	4	4	11.9	3.5	3.3
Own Use & Losses	**587**	**1084**	**1398**	**1715**					**2.4**	**2.0**	**2.0**
of which Electricity	*75*	*213*	*300*	*385*					*4.1*	*2.7*	*2.6*
Total Final Consumption	**3627**	**5808**	**7525**	**9117**	**100**	**100**	**100**	**100**	**1.8**	**2.0**	**2.0**
Coal	620	635	693	757	17	11	9	8	0.1	0.7	0.8
Oil	1888	2823	3708	4493	52	49	49	49	1.6	2.1	2.0
Gas	608	1044	1338	1606	17	18	18	18	2.1	1.9	1.9
Electricity	377	987	1423	1846	10	17	19	20	3.8	2.9	2.8
Heat	68	232	244	273	2	4	3	3	4.8	0.4	0.7
Renewables	66	87	118	142	2	1	2	2	1.0	2.4	2.2

Industry	**1378**	**2048**	**2590**	**3080**	**100**	**100**	**100**	**100**	**1.5**	**1.8**	**1.8**
Coal	273	469	535	599	20	23	21	19	2.1	1.0	1.1
Oil	486	551	654	736	35	27	25	24	0.5	1.3	1.3
Gas	339	470	638	782	25	23	25	25	1.3	2.4	2.2
Electricity	196	423	604	781	14	21	23	25	3.0	2.8	2.7
Heat	48	98	110	121	3	5	4	4	2.8	0.9	0.9
Renewables	36	38	50	62	3	2	2	2	0.1	2.2	2.2
Transportation	**846**	**1646**	**2291**	**2870**	**100**	**100**	**100**	**100**	**2.6**	**2.6**	**2.4**
Oil	792	1577	2206	2769	94	96	96	96	2.7	2.6	2.5
Other fuels	55	69	85	101	6	4	4	4	0.9	1.6	1.7
Other Sectors	**1278**	**1899**	**2380**	**2862**	**100**	**100**	**100**	**100**	**1.5**	**1.8**	**1.8**
Coal	315	138	131	130	25	7	5	5	–3.1	–0.4	–0.2
Oil	490	501	608	709	38	26	26	25	0.1	1.5	1.5
Gas	252	533	647	760	20	28	27	27	2.9	1.5	1.6
Electricity	171	545	795	1034	13	29	33	36	4.6	2.9	2.8
Heat	21	134	134	152	2	7	6	5	7.5	0.0	0.5
Renewables	30	48	66	77	2	3	3	3	1.8	2.5	2.1
Non-Energy Use	**125**	**215**	**264**	**304**					**2.1**	**1.6**	**1.5**

OECD CRW (included above)	73	151	208	247	1	2	2	2	2.8	2.5	2.2
Non-OECD CRW (NOT included above)	637	911	1034	1128	11	9	8	8	1.4	1.0	0.9
Total Primary Energy Supply (including CRW)	**5650**	**9654**	**12424**	**14838**	**100**	**100**	**100**	**100**	**2.1**	**2.0**	**1.9**

Reference Scenario: World

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**5224**	**13949**	**19989**	**25881**	**100**	**100**	**100**	**100**	**3.8**	**2.8**	**2.7**
Coal	2103	5337	7467	9763	40	38	37	38	3.6	2.6	2.7
Oil	1095	1282	1442	1498	21	9	7	6	0.6	0.9	0.7
Gas	692	2159	4698	7745	13	15	24	30	4.5	6.2	5.7
Nuclear	111	2393	2647	2369	2	17	13	9	12.5	0.8	0.0
Hydro	1208	2566	3341	3904	23	18	17	15	2.9	2.1	1.8
Other Renewables	14	211	395	603	0	2	2	2	10.9	4.9	4.7
Capacity (GW)	**n.a.**	**3221**	**4386**	**5515**	**n.a.**	**100**	**100**	**100**	**n.a.**	**2.4**	**2.4**
Coal	n.a.	1030	1311	1677	n.a.	32	30	30	n.a.	1.9	2.1
Oil	n.a.	410	466	474	n.a.	13	11	9	n.a.	1.0	0.6
Gas	n.a.	643	1226	1822	n.a.	20	28	33	n.a.	5.1	4.6
Nuclear	n.a.	352	366	323	n.a.	11	8	6	n.a.	0.3	–0.4
Hydro	n.a.	738	926	1078	n.a.	23	21	20	n.a.	1.8	1.7
Other Renewables	n.a.	48	91	142	n.a.	1	2	3	n.a.	5.0	4.8

Reference Scenario: World

	CO₂ Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**14753**	**22984**	**30083**	**36680**	**100**	**100**	**100**	**100**	**1.7**	**2.1**	**2.1**
change since 1990 (%)		*8.1*	*41.5*	*72.6*							
Coal	5651	8758	10993	13082	38	38	37	36	1.7	1.8	1.8
Oil	7008	9806	12798	15398	48	43	43	42	1.3	2.1	2.0
of which International Marine Bunkers	*379*	*422*	*509*	*578*	3	2	2	2	0.4	1.4	1.4
Gas	2094	4419	6292	8200	14	19	21	22	2.9	2.8	2.7
Power Generation	**3885**	**7663**	**10671**	**13479**	**100**	**100**	**100**	**100**	**2.6**	**2.6**	**2.5**
Coal	2490	5481	7415	9148	64	72	69	68	3.1	2.4	2.3
Oil	857	883	999	1039	22	12	9	8	0.1	1.0	0.7
Gas	539	1299	2257	3292	14	17	21	24	3.4	4.3	4.1
Own Use & Losses	**1346**	**2154**	**2740**	**3330**	**100**	**100**	**100**	**100**	**1.8**	**1.9**	**1.9**
Total Final Consumption	**9142**	**12745**	**16163**	**19293**	**100**	**100**	**100**	**100**	**1.3**	**1.8**	**1.8**
Coal	2497	2794	3059	3354	27	22	19	17	0.4	0.7	0.8
Oil	5291	7559	10052	12285	58	59	62	64	1.4	2.2	2.1
Gas	1354	2392	3053	3654	15	19	19	19	2.2	1.9	1.9
Industry	**3226**	**4337**	**5237**	**6035**	**100**	**100**	**100**	**100**	**1.1**	**1.5**	**1.4**
Coal	1141	2139	2434	2728	35	49	46	45	2.4	1.0	1.1
Oil	1361	1147	1387	1578	42	26	26	26	–0.7	1.5	1.4
Gas	725	1050	1416	1729	22	24	27	29	1.4	2.3	2.2
Transportation	**2469**	**4776**	**6661**	**8353**	**100**	**100**	**100**	**100**	**2.6**	**2.6**	**2.5**
Oil	2322	4654	6515	8186	94	97	98	98	2.7	2.6	2.5
Other Fuels	147	123	146	167	6	3	2	2	–0.7	1.3	1.3
Other Sectors	**3303**	**3270**	**3818**	**4379**	**100**	**100**	**100**	**100**	**0.0**	**1.2**	**1.3**
Coal	1230	537	508	508	37	16	13	12	–3.1	–0.4	–0.2
Oil	1486	1488	1799	2096	45	46	47	48	0.0	1.5	1.5
Gas	588	1246	1511	1774	18	38	40	41	2.9	1.5	1.6
Non-Energy Use	**144**	**361**	**447**	**526**	**100**	**100**	**100**	**100**	**3.6**	**1.7**	**1.7**

Reference Scenario: OECD

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**3310**	**4750**	**5532**	**5895**	**100**	**100**	**100**	**100**	**1.4**	**1.2**	**0.9**
Coal	802	1013	1060	1091	24	21	19	19	0.9	0.3	0.3
Oil	1691	1935	2222	2367	51	41	40	40	0.5	1.1	0.9
Gas	645	999	1349	1549	19	21	24	26	1.7	2.3	1.9
Nuclear	27	516	533	453	1	11	10	8	12.0	0.2	–0.6
Hydro	74	112	119	124	2	2	2	2	1.6	0.5	0.5
Other Renewables	72	174	248	309	2	4	4	5	3.5	2.8	2.5
Power Generation	**799**	**1852**	**2229**	**2373**	**100**	**100**	**100**	**100**	**3.3**	**1.4**	**1.1**
Coal	398	796	888	942	50	43	40	40	2.7	0.8	0.7
Oil	180	102	84	59	23	6	4	3	–2.2	–1.5	–2.3
Gas	115	244	483	640	14	13	22	27	2.9	5.4	4.3
Nuclear	27	516	533	453	3	28	24	19	12.0	0.2	–0.6
Hydro	74	112	119	124	9	6	5	5	1.6	0.5	0.5
Other Renewables	5	82	121	155	1	4	5	7	11.2	3.1	2.8
Own Use & Losses	**333**	**401**	**468**	**509**					**0.7**	**1.2**	**1.0**
of which Electricity	*51*	*105*	*132*	*149*					*2.8*	*1.7*	*1.5*
Total Final Consumption	**2521**	**3267**	**3805**	**4116**	**100**	**100**	**100**	**100**	**1.0**	**1.2**	**1.0**
Coal	296	133	98	82	12	4	3	2	–3.0	–2.3	–2.1
Oil	1405	1713	1981	2130	56	52	52	52	0.8	1.1	1.0
Gas	463	669	769	809	18	20	20	20	1.4	1.1	0.8
Electricity	273	619	781	887	11	19	21	22	3.2	1.8	1.6
Heat	17	46	58	68	1	1	2	2	3.8	1.9	1.7
Renewables	66	86	117	141	3	3	3	3	1.0	2.4	2.2

Industry	**947**	**970**	**1051**	**1088**	**100**	**100**	**100**	**100**	**0.1**	**0.6**	**0.5**
Coal	177	107	82	68	19	11	8	6	–1.9	–2.0	–2.0
Oil	367	297	301	300	39	31	29	28	–0.8	0.1	0.0
Gas	221	270	305	309	23	28	29	28	0.8	0.9	0.6
Electricity	135	243	294	327	14	25	28	30	2.3	1.5	1.3
Heat	11	15	19	22	1	2	2	2	1.2	1.9	1.8
Renewables	36	38	50	62	4	4	5	6	0.1	2.2	2.2
Transportation	**626**	**1083**	**1362**	**1530**	**100**	**100**	**100**	**100**	**2.1**	**1.8**	**1.5**
Oil	598	1049	1315	1471	96	97	97	96	2.2	1.8	1.5
Other fuels	28	34	48	59	4	3	3	4	0.8	2.6	2.5
Other Sectors	**863**	**1089**	**1252**	**1351**	**100**	**100**	**100**	**100**	**0.9**	**1.1**	**0.9**
Coal	111	25	16	14	13	2	1	1	–5.5	–3.4	–2.5
Oil	357	242	227	214	41	22	18	16	–1.5	–0.5	–0.5
Gas	225	376	431	458	26	35	34	34	2.0	1.1	0.9
Electricity	134	368	474	544	16	34	38	40	4.0	2.0	1.7
Heat	6	31	39	45	1	3	3	3	6.3	1.9	1.7
Renewables	30	47	65	76	3	4	5	6	1.8	2.5	2.1
Non-Energy Use	**86**	**126**	**140**	**147**					**1.5**	**0.8**	**0.7**

CRW (included above)	73	151	208	247	2	3	4	4	2.8	2.5	2.2
Total Primary Energy Supply (including CRW)	**3310**	**4750**	**5532**	**5895**	**100**	**100**	**100**	**100**	**1.4**	**1.2**	**0.9**

Reference Scenario: OECD

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**3768**	**8420**	**10555**	**11988**	**100**	**100**	**100**	**100**	**3.1**	**1.8**	**1.5**
Coal	1506	3328	3765	4278	40	40	36	36	3.1	1.0	1.1
Oil	800	513	422	302	21	6	4	3	–1.7	–1.5	–2.3
Gas	491	1128	2626	3750	13	13	25	31	3.3	6.7	5.4
Nuclear	104	1980	2044	1738	3	24	19	14	12.0	0.2	–0.6
Hydro	857	1299	1387	1447	23	15	13	12	1.6	0.5	0.5
Other Renewables	11	172	312	474	0	2	3	4	11.0	4.7	4.5
Capacity (GW)	**n.a.**	**1871**	**2283**	**2530**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.5**	**1.3**
Coal	n.a.	595	594	663	n.a.	32	26	26	n.a.	0.0	0.5
Oil	n.a.	177	165	118	n.a.	9	7	5	n.a.	–0.6	–1.7
Gas	n.a.	381	747	958	n.a.	20	33	38	n.a.	5.3	4.1
Nuclear	n.a.	286	277	232	n.a.	15	12	9	n.a.	–0.2	–0.9
Hydro	n.a.	395	428	447	n.a.	21	19	18	n.a.	0.6	0.5
of which Pumped Storage	*n.a.*	*79*	*85*	*89*	*n.a.*	*4*	*4*	*4*	*n.a.*	*0.6*	*0.5*
Other Renewables	n.a.	37	71	111	n.a.	2	3	4	n.a.	5.1	4.8

Reference Scenario: OECD

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**9350**	**11467**	**13289**	**14298**	**100**	**100**	**100**	**100**	**0.8**	**1.1**	**1.0**
change since 1990 (%)		*7.8*	*24.9*	*34.4*							
Coal	3129	3952	4150	4283	33	34	31	30	0.9	0.4	0.4
Oil	4716	5195	6005	6416	50	45	45	45	0.4	1.1	0.9
Gas	1505	2320	3134	3600	16	20	24	25	1.7	2.3	1.9
Power Generation	**2642**	**4103**	**4971**	**5473**	**100**	**100**	**100**	**100**	**1.7**	**1.5**	**1.3**
Coal	1742	3208	3576	3790	66	78	72	69	2.4	0.8	0.7
Oil	574	325	267	189	22	8	5	3	–2.2	–1.5	–2.3
Gas	325	570	1128	1494	12	14	23	27	2.2	5.4	4.3
Own Use & Losses	**694**	**734**	**856**	**922**	**100**	**100**	**100**	**100**	**0.2**	**1.2**	**1.0**
Total Final Consumption	**6015**	**6630**	**7461**	**7904**	**100**	**100**	**100**	**100**	**0.4**	**0.9**	**0.8**
Coal	1180	600	448	377	20	9	6	5	–2.6	–2.2	–2.0
Oil	3812	4482	5234	5656	63	68	70	72	0.6	1.2	1.0
Gas	1023	1548	1779	1871	17	23	24	24	1.6	1.1	0.8
Industry	**2104**	**1644**	**1611**	**1553**	**100**	**100**	**100**	**100**	**–0.9**	**–0.2**	**–0.2**
Coal	711	494	378	315	34	30	23	20	–1.4	–2.0	–1.9
Oil	936	534	538	534	44	32	33	34	–2.1	0.1	0.0
Gas	457	615	694	703	22	37	43	45	1.1	0.9	0.6
Transportation	**1810**	**3139**	**3945**	**4424**	**100**	**100**	**100**	**100**	**2.1**	**1.8**	**1.5**
Oil	1748	3083	3866	4324	97	98	98	98	2.2	1.8	1.5
Other Fuels	63	56	80	100	3	2	2	2	–0.5	2.8	2.6
Other Sectors	**2048**	**1705**	**1750**	**1765**	**100**	**100**	**100**	**100**	**–0.7**	**0.2**	**0.2**
Coal	436	101	65	56	21	6	4	3	–5.5	–3.4	–2.5
Oil	1087	726	680	640	53	43	39	36	–1.5	–0.5	–0.5
Gas	525	878	1006	1069	26	52	57	61	2.0	1.0	0.9
Non-Energy Use	**53**	**142**	**155**	**162**	**100**	**100**	**100**	**100**	**3.9**	**0.7**	**0.6**

Reference Scenario: OECD North America

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**1736**	**2400**	**2783**	**2957**	**100**	**100**	**100**	**100**	**1.3**	**1.1**	**0.9**
Coal	295	541	599	647	17	23	22	22	2.4	0.8	0.8
Oil	801	935	1107	1207	46	39	40	41	0.6	1.3	1.1
Gas	548	579	721	778	32	24	26	26	0.2	1.7	1.3
Nuclear	12	195	185	134	1	8	7	5	11.4	–0.4	–1.6
Hydro	37	59	57	59	2	2	2	2	1.8	–0.2	0.0
Other Renewables	43	91	115	132	2	4	4	4	2.9	1.8	1.6
Power Generation	**394**	**958**	**1126**	**1182**	**100**	**100**	**100**	**100**	**3.5**	**1.3**	**0.9**
Coal	192	496	559	611	49	52	50	52	3.7	0.9	0.9
Oil	58	21	18	17	15	2	2	1	–3.8	–1.4	–1.1
Gas	95	130	237	282	24	14	21	24	1.2	4.7	3.4
Nuclear	12	195	185	134	3	20	16	11	11.4	–0.4	–1.6
Hydro	37	59	57	59	9	6	5	5	1.8	–0.2	0.0
Other Renewables	1	57	71	80	0	6	6	7	18.1	1.7	1.5
Own Use & Losses	**153**	**184**	**203**	**211**					**0.7**	**0.8**	**0.6**
of which Electricity	*25*	*52*	*63*	*70*					*2.9*	*1.5*	*1.3*
Total Final Consumption	**1354**	**1633**	**1908**	**2067**	**100**	**100**	**100**	**100**	**0.7**	**1.2**	**1.0**
Coal	83	29	25	22	6	2	1	1	–4.0	–1.1	–1.3
Oil	709	859	1027	1126	52	53	54	54	0.7	1.4	1.2
Gas	379	389	423	437	28	24	22	21	0.1	0.6	0.5
Electricity	140	313	380	422	10	19	20	20	3.1	1.5	1.3
Heat	0	8	10	11	0	1	1	1	–	1.2	1.1
Renewables	42	34	42	50	3	2	2	2	–0.9	1.7	1.7

Industry	**444**	**429**	**466**	**482**	**100**	**100**	**100**	**100**	**–0.1**	**0.6**	**0.5**
Coal	66	27	25	23	15	6	5	5	–3.4	–0.6	–0.7
Oil	114	115	120	123	26	27	26	25	0.0	0.4	0.3
Gas	176	152	157	153	40	35	34	32	–0.6	0.3	0.0
Electricity	58	111	131	144	13	26	28	30	2.6	1.3	1.1
Heat	0	6	7	8	0	1	2	2	–	1.3	1.1
Renewables	31	19	25	31	7	4	5	6	–1.8	2.2	2.1
Transportation	**410**	**622**	**788**	**890**	**100**	**100**	**100**	**100**	**1.6**	**1.8**	**1.6**
Oil	392	597	752	846	96	96	96	95	1.6	1.8	1.5
Other fuels	18	25	35	44	4	4	4	5	1.3	2.7	2.5
Other Sectors	**458**	**508**	**574**	**610**	**100**	**100**	**100**	**100**	**0.4**	**0.9**	**0.8**
Coal	18	2	1	0	4	0	0	0	–8.1	–6.0	–9.0
Oil	161	74	74	72	35	15	13	12	–2.9	0.0	–0.1
Gas	186	215	233	242	41	42	41	40	0.6	0.6	0.5
Electricity	82	202	249	277	18	40	43	45	3.5	1.6	1.4
Heat	0	2	3	3	0	0	0	0	–	1.0	0.8
Renewables	11	13	15	16	3	3	3	3	0.5	0.8	0.8
Non-Energy Use	**43**	**73**	**81**	**85**					**2.1**	**0.8**	**0.7**

CRW (included above)	43	78	99	107	2	3	4	4	2.4	1.8	1.4
Total Primary Energy Supply (including CRW)	**1736**	**2400**	**2783**	**2957**	**100**	**100**	**100**	**100**	**1.3**	**1.1**	**0.9**

Reference Scenario: OECD North America

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**1925**	**4246**	**5159**	**5729**	**100**	**100**	**100**	**100**	**3.1**	**1.5**	**1.3**
Coal	805	2076	2348	2701	42	49	46	47	3.7	1.0	1.2
Oil	242	122	102	95	13	3	2	2	–2.6	–1.4	–1.1
Gas	407	531	1212	1564	21	12	23	27	1.0	6.6	4.8
Nuclear	45	749	709	513	2	18	14	9	11.4	–0.4	–1.6
Hydro	426	681	665	687	22	16	13	12	1.8	–0.2	0.0
Other Renewables	1	87	124	170	0	2	2	3	19.5	2.8	2.9
Capacity (GW)	**n.a.**	**904**	**1073**	**1168**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.3**	**1.1**
Coal	n.a.	345	348	397	n.a.	38	32	34	n.a.	0.1	0.6
Oil	n.a.	39	36	34	n.a.	4	3	3	n.a.	–0.6	–0.7
Gas	n.a.	224	396	457	n.a.	25	37	39	n.a.	4.5	3.2
Nuclear	n.a.	112	95	68	n.a.	12	9	6	n.a.	–1.2	–2.1
Hydro	n.a.	166	172	177	n.a.	18	16	15	n.a.	0.3	0.3
of which Pumped Storage	*n.a.*	*20*	*20*	*20*	*n.a.*	*2*	*2*	*2*	*n.a.*	*0.2*	*0.1*
Other Renewables	n.a.	18	25	35	n.a.	2	2	3	n.a.	2.4	2.8

Reference Scenario: OECD North America

	CO$_2$ Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO$_2$ Emissions	**4664**	**5948**	**6995**	**7606**	**100**	**100**	**100**	**100**	**0.9**	**1.3**	**1.1**
change since 1990 (%)		*12.2*	*32.0*	*43.5*							
Coal	1147	2113	2347	2540	25	36	34	33	2.4	0.8	0.8
Oil	2236	2486	2967	3250	48	42	42	43	0.4	1.4	1.2
Gas	1281	1350	1681	1816	27	23	24	24	0.2	1.7	1.3
Power Generation	**1347**	**2331**	**2818**	**3127**	**100**	**100**	**100**	**100**	**2.1**	**1.5**	**1.3**
Coal	881	1958	2207	2414	65	84	78	77	3.1	0.9	0.9
Oil	187	69	58	54	14	3	2	2	–3.8	–1.4	–1.1
Gas	280	304	554	660	21	13	20	21	0.3	4.7	3.4
Own Use & Losses	**345**	**354**	**378**	**383**	**100**	**100**	**100**	**100**	**0.1**	**0.5**	**0.3**
Total Final Consumption	**2972**	**3263**	**3799**	**4095**	**100**	**100**	**100**	**100**	**0.4**	**1.2**	**1.0**
Coal	242	130	117	104	8	4	3	3	–2.4	–0.8	–0.9
Oil	1901	2225	2695	2973	64	68	71	73	0.6	1.5	1.3
Gas	829	907	987	1018	28	28	26	25	0.3	0.6	0.5
Industry	**794**	**646**	**658**	**643**	**100**	**100**	**100**	**100**	**–0.8**	**0.1**	**0.0**
Coal	173	121	112	102	22	19	17	16	–1.3	–0.6	–0.7
Oil	266	173	181	185	34	27	28	29	–1.6	0.4	0.3
Gas	355	352	365	355	45	54	55	55	0.0	0.3	0.0
Transportation	**1181**	**1800**	**2278**	**2572**	**100**	**100**	**100**	**100**	**1.6**	**1.8**	**1.6**
Oil	1140	1747	2200	2475	97	97	97	96	1.7	1.8	1.5
Other Fuels	41	54	77	97	3	3	3	4	1.0	2.9	2.6
Other Sectors	**990**	**732**	**769**	**781**	**100**	**100**	**100**	**100**	**–1.2**	**0.4**	**0.3**
Coal	69	8	3	1	7	1	0	0	–8.1	–6.0	–9.0
Oil	488	222	221	215	49	30	29	28	–3.0	0.0	–0.1
Gas	434	502	545	565	44	69	71	72	0.6	0.6	0.5
Non-Energy Use	**7**	**85**	**94**	**99**	**100**	**100**	**100**	**100**	**10.2**	**0.8**	**0.7**

Reference Scenario: OECD Europe

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**1246**	**1716**	**2019**	**2144**	**100**	**100**	**100**	**100**	**1.2**	**1.3**	**1.0**
Coal	428	342	327	301	34	20	16	14	–0.9	–0.3	–0.6
Oil	661	686	776	815	53	40	38	38	0.1	1.0	0.7
Gas	92	344	522	650	7	20	26	30	5.2	3.3	2.8
Nuclear	13	238	239	188	1	14	12	9	11.7	0.1	–1.0
Hydro	28	42	50	52	2	2	2	2	1.6	1.3	1.0
Other Renewables	24	64	104	137	2	4	5	6	3.9	3.9	3.4
Power Generation	**315**	**637**	**783**	**827**	**100**	**100**	**100**	**100**	**2.8**	**1.6**	**1.1**
Coal	180	227	245	233	57	36	31	28	0.9	0.6	0.1
Oil	72	43	35	22	23	7	4	3	–2.0	–1.6	–2.8
Gas	18	72	181	282	6	11	23	34	5.5	7.4	6.1
Nuclear	13	238	239	188	4	37	31	23	11.7	0.1	–1.0
Hydro	28	42	50	52	9	7	6	6	1.6	1.3	1.0
Other Renewables	3	16	33	50	1	3	4	6	6.2	5.8	5.0
Own Use & Losses	**143**	**155**	**205**	**236**					**0.3**	**2.2**	**1.9**
of which Electricity	*21*	*40*	*52*	*60*					*2.5*	*2.1*	*1.8*
Total Final Consumption	**926**	**1214**	**1414**	**1528**	**100**	**100**	**100**	**100**	**1.0**	**1.2**	**1.0**
Coal	187	77	49	37	20	6	3	2	–3.3	–3.5	–3.2
Oil	526	598	667	700	57	49	47	46	0.5	0.8	0.7
Gas	77	246	304	328	8	20	22	21	4.6	1.6	1.3
Electricity	99	212	284	333	11	17	20	22	3.0	2.3	2.0
Heat	17	37	46	53	2	3	3	3	3.0	1.8	1.6
Renewables	20	43	64	77	2	4	5	5	3.0	3.0	2.6

Industry	**373**	**377**	**406**	**419**	**100**	**100**	**100**	**100**	**0.0**	**0.6**	**0.5**
Coal	90	54	34	23	24	14	8	6	–1.9	–3.7	–3.6
Oil	173	110	104	100	46	29	26	24	–1.7	–0.4	–0.4
Gas	41	101	127	134	11	27	31	32	3.5	1.8	1.2
Electricity	55	90	113	127	15	24	28	30	1.9	1.8	1.5
Heat	11	9	10	11	3	2	3	3	–0.9	1.1	1.1
Renewables	4	13	18	23	1	3	4	5	5.0	2.5	2.5
Transportation	**165**	**337**	**427**	**478**	**100**	**100**	**100**	**100**	**2.8**	**1.8**	**1.5**
Oil	157	331	417	465	95	98	98	97	2.9	1.8	1.5
Other fuels	8	6	9	12	5	2	2	3	–0.9	3.0	2.9
Other Sectors	**354**	**462**	**536**	**584**	**100**	**100**	**100**	**100**	**1.0**	**1.2**	**1.0**
Coal	90	22	14	13	26	5	3	2	–5.3	–3.4	–2.4
Oil	164	120	101	88	46	26	19	15	–1.2	–1.3	–1.4
Gas	35	145	176	193	10	31	33	33	5.6	1.5	1.3
Electricity	41	116	162	194	12	25	30	33	4.1	2.6	2.2
Heat	6	28	36	42	2	6	7	7	5.9	2.0	1.8
Renewables	16	30	46	55	5	7	9	9	2.4	3.3	2.6
Non-Energy Use	**34**	**38**	**45**	**48**					**0.4**	**1.3**	**1.0**
CRW (included above)	22	59	93	121	2	3	5	6	4.0	3.6	3.2
Total Primary Energy Supply (including CRW)	**1246**	**1716**	**2019**	**2144**	**100**	**100**	**100**	**100**	**1.2**	**1.3**	**1.0**

Reference Scenario: OECD Europe

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**1392**	**2925**	**3863**	**4514**	**100**	**100**	**100**	**100**	**2.9**	**2.2**	**1.9**
Coal	618	908	1020	1110	44	31	26	25	1.5	0.9	0.9
Oil	316	201	163	104	23	7	4	2	–1.7	–1.6	–2.8
Gas	76	363	1046	1738	5	12	27	38	6.2	8.5	7.0
Nuclear	51	912	919	722	4	31	24	16	11.7	0.1	–1.0
Hydro	322	488	576	607	23	17	15	13	1.6	1.3	1.0
Other Renewables	9	53	140	233	1	2	4	5	7.0	7.8	6.7
Capacity (GW)	**n.a.**	**678**	**859**	**967**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.8**	**1.6**
Coal	n.a.	195	183	191	n.a.	29	21	20	n.a.	–0.5	–0.1
Oil	n.a.	76	68	35	n.a.	11	8	4	n.a.	–0.8	–3.3
Gas	n.a.	93	258	386	n.a.	14	30	40	n.a.	8.2	6.4
Nuclear	n.a.	131	125	97	n.a.	19	15	10	n.a.	–0.3	–1.3
Hydro	n.a.	171	189	197	n.a.	25	22	20	n.a.	0.8	0.6
of which Pumped Storage	*n.a.*	*35*	*36*	*36*	*n.a.*	*5*	*4*	*4*	*n.a.*	*0.2*	*0.1*
Other Renewables	n.a.	12	36	60	n.a.	2	4	6	n.a.	8.7	7.2

Reference Scenario: OECD Europe

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**3753**	**4007**	**4612**	**4915**	**100**	**100**	**100**	**100**	**0.3**	**1.1**	**0.9**
change since 1990 (%)		*0.4*	*15.6*	*23.2*							
Coal	1678	1340	1275	1170	45	33	28	24	–0.9	–0.4	–0.6
Oil	1863	1875	2131	2242	50	47	46	46	0.0	1.0	0.8
Gas	212	793	1205	1504	6	20	26	31	5.2	3.3	2.8
Power Generation	**1012**	**1233**	**1534**	**1680**	**100**	**100**	**100**	**100**	**0.8**	**1.7**	**1.4**
Coal	739	928	1000	952	73	75	65	57	0.9	0.6	0.1
Oil	231	137	111	71	23	11	7	4	–2.0	–1.6	–2.8
Gas	42	168	423	657	4	14	28	39	5.5	7.4	6.1
Own Use & Losses	**280**	**268**	**374**	**434**	**100**	**100**	**100**	**100**	**–0.2**	**2.6**	**2.1**
Total Final Consumption	**2461**	**2507**	**2703**	**2801**	**100**	**100**	**100**	**100**	**0.1**	**0.6**	**0.5**
Coal	813	342	214	161	33	14	8	6	–3.3	–3.5	–3.2
Oil	1471	1601	1792	1888	60	64	66	67	0.3	0.9	0.7
Gas	177	564	697	752	7	23	26	27	4.6	1.6	1.3
Industry	**999**	**694**	**645**	**605**	**100**	**100**	**100**	**100**	**–1.4**	**–0.6**	**–0.6**
Coal	427	250	154	108	43	36	24	18	–2.0	–3.7	–3.6
Oil	476	218	206	198	48	31	32	33	–3.0	–0.4	–0.4
Gas	95	225	284	300	10	32	44	49	3.4	1.8	1.2
Transportation	**482**	**981**	**1238**	**1381**	**100**	**100**	**100**	**100**	**2.8**	**1.8**	**1.5**
Oil	463	980	1237	1379	96	100	100	100	2.9	1.8	1.5
Other Fuels	19	1	1	1	4	0	0	0	–10.3	0.7	0.7
Other Sectors	**942**	**790**	**773**	**766**	**100**	**100**	**100**	**100**	**–0.7**	**–0.2**	**–0.1**
Coal	356	88	56	50	38	11	7	7	–5.2	–3.4	–2.4
Oil	504	364	305	265	54	46	39	35	–1.2	–1.3	–1.4
Gas	81	338	412	451	9	43	53	59	5.6	1.5	1.3
Non-Energy Use	**38**	**42**	**47**	**50**	**100**	**100**	**100**	**100**	**0.4**	**0.8**	**0.7**

Reference Scenario: OECD Pacific

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**329**	**633**	**730**	**794**	**100**	**100**	**100**	**100**	**2.6**	**1.1**	**1.0**
Coal	78	130	134	144	24	21	18	18	2.0	0.2	0.4
Oil	229	313	339	346	70	50	46	44	1.2	0.6	0.4
Gas	5	77	107	121	2	12	15	15	10.9	2.6	2.0
Nuclear	2	83	109	131	1	13	15	16	15.2	2.1	2.0
Hydro	9	11	13	13	3	2	2	2	0.7	0.9	0.7
Other Renewables	5	19	29	40	1	3	4	5	5.5	3.4	3.3
Power Generation	**90**	**258**	**320**	**364**	**100**	**100**	**100**	**100**	**4.1**	**1.7**	**1.5**
Coal	26	74	85	98	29	29	27	27	4.0	1.1	1.2
Oil	49	38	31	21	55	15	10	6	–1.0	–1.5	–2.6
Gas	2	42	65	76	2	16	20	21	13.3	3.4	2.6
Nuclear	2	83	109	131	2	32	34	36	15.2	2.1	2.0
Hydro	9	11	13	13	10	4	4	4	0.7	0.9	0.7
Other Renewables	1	9	17	26	1	4	5	7	8.6	4.8	4.5
Own Use & Losses	**37**	**63**	**61**	**62**					**2.1**	**–0.2**	**0.0**
of which Electricity	*5*	*13*	*16*	*18*					*4.1*	*1.6*	*1.5*
Total Final Consumption	**241**	**420**	**483**	**521**	**100**	**100**	**100**	**100**	**2.2**	**1.1**	**0.9**
Coal	25	27	25	23	10	6	5	4	0.3	–0.7	–0.6
Oil	170	256	287	304	71	61	59	58	1.6	0.9	0.8
Gas	8	34	42	45	3	8	9	9	5.9	1.6	1.2
Electricity	34	94	116	132	14	22	24	25	4.0	1.6	1.5
Heat	0	0	2	4	0	0	0	1	–	13.1	9.7
Renewables	4	9	11	13	1	2	2	3	3.7	1.7	1.7

Industry	**130**	**164**	**179**	**188**	**100**	**100**	**100**	**100**	**0.9**	**0.7**	**0.6**
Coal	22	25	23	22	17	16	13	12	0.7	–0.7	–0.7
Oil	81	73	77	77	62	45	43	41	–0.4	0.4	0.2
Gas	3	17	20	22	2	11	11	12	6.8	1.3	1.0
Electricity	23	43	50	56	18	26	28	30	2.4	1.3	1.2
Heat	0	0	2	3	0	0	1	2	–	–	–
Renewables	2	6	7	8	1	3	4	4	5.1	1.7	1.8
Transportation	**51**	**123**	**148**	**162**	**100**	**100**	**100**	**100**	**3.5**	**1.4**	**1.2**
Oil	49	121	145	159	97	98	98	98	3.5	1.4	1.2
Other fuels	2	2	3	3	3	2	2	2	1.2	0.9	1.0
Other Sectors	**51**	**119**	**143**	**158**	**100**	**100**	**100**	**100**	**3.3**	**1.4**	**1.2**
Coal	3	1	1	1	6	1	1	1	–3.2	0.4	0.3
Oil	31	48	52	54	62	40	37	34	1.6	0.7	0.6
Gas	4	16	21	23	9	14	15	15	5.1	2.0	1.5
Electricity	10	50	63	73	20	42	44	47	6.2	1.9	1.7
Heat	0	0	1	1	0	0	0	0	–	1.5	1.3
Renewables	2	4	4	5	4	3	3	3	2.3	1.7	1.4
Non-Energy Use	**9**	**14**	**13**	**13**					**1.8**	**–0.5**	**–0.3**

CRW (included above)	9	13	16	19	3	2	2	2	1.5	1.2	1.5
Total Primary Energy Supply (including CRW)	**329**	**633**	**730**	**794**	**100**	**100**	**100**	**100**	**2.6**	**1.1**	**1.0**

Reference Scenario: OECD Pacific

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**451**	**1249**	**1533**	**1745**	**100**	**100**	**100**	**100**	**4.0**	**1.6**	**1.5**
Coal	84	344	397	467	19	28	26	27	5.6	1.1	1.3
Oil	242	190	157	103	54	15	10	6	–0.9	–1.5	–2.6
Gas	7	234	368	448	2	19	24	26	14.3	3.5	2.9
Nuclear	8	319	417	503	2	26	27	29	15.2	2.1	2.0
Hydro	109	130	146	153	24	10	10	9	0.7	0.9	0.7
Other Renewables	2	32	48	71	0	3	3	4	12.4	3.1	3.6
Capacity (GW)	**n.a.**	**289**	**351**	**395**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.5**	**1.4**
Coal	n.a.	55	64	75	n.a.	19	18	19	n.a.	1.1	1.3
Oil	n.a.	62	60	49	n.a.	21	17	13	n.a.	–0.2	–1.0
Gas	n.a.	64	93	115	n.a.	22	27	29	n.a.	2.9	2.5
Nuclear	n.a.	44	57	67	n.a.	15	16	17	n.a.	2.0	1.9
Hydro	n.a.	57	67	73	n.a.	20	19	18	n.a.	1.2	1.1
of which Pumped Storage	*n.a.*	*24*	*28*	*32*	*n.a.*	*8*	*8*	*8*	*n.a.*	*1.4*	*1.4*
Other Renewables	n.a.	7	10	16	n.a.	2	3	4	n.a.	3.0	3.7

Reference Scenario: OECD Pacific

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**933**	**1512**	**1682**	**1777**	**100**	**100**	**100**	**100**	**1.9**	**0.8**	**0.7**
change since 1990 (%)		*12.0*	*24.6*	*31.6*							
Coal	304	500	528	573	33	33	31	32	1.9	0.4	0.6
Oil	617	835	906	924	66	55	54	52	1.2	0.6	0.4
Gas	12	177	247	280	1	12	15	16	10.9	2.6	2.0
Power Generation	**283**	**539**	**619**	**665**	**100**	**100**	**100**	**100**	**2.5**	**1.1**	**0.9**
Coal	122	322	369	424	43	60	60	64	3.8	1.1	1.2
Oil	157	119	99	65	55	22	16	10	–1.0	–1.5	–2.6
Gas	4	98	151	177	1	18	24	27	13.3	3.4	2.6
Own Use & Losses	**69**	**113**	**104**	**105**	**100**	**100**	**100**	**100**	**1.9**	**–0.6**	**–0.3**
Total Final Consumption	**582**	**860**	**959**	**1007**	**100**	**100**	**100**	**100**	**1.5**	**0.8**	**0.7**
Coal	125	128	117	111	21	15	12	11	0.1	–0.7	–0.6
Oil	440	655	746	795	76	76	78	79	1.5	1.0	0.8
Gas	17	77	95	102	3	9	10	10	5.9	1.6	1.2
Industry	**311**	**304**	**307**	**304**	**100**	**100**	**100**	**100**	**–0.1**	**0.1**	**0.0**
Coal	111	123	112	105	36	40	36	34	0.4	–0.7	–0.7
Oil	193	143	150	151	62	47	49	50	–1.2	0.4	0.2
Gas	7	39	46	48	2	13	15	16	6.6	1.3	1.0
Transportation	**147**	**358**	**429**	**471**	**100**	**100**	**100**	**100**	**3.5**	**1.4**	**1.2**
Oil	144	357	428	470	98	100	100	100	3.5	1.4	1.2
Other Fuels	3	1	1	1	2	0	0	0	–4.1	0.7	0.6
Other Sectors	**116**	**183**	**208**	**218**	**100**	**100**	**100**	**100**	**1.8**	**1.0**	**0.8**
Coal	11	5	5	6	10	3	3	3	–2.8	0.4	0.3
Oil	94	141	154	160	82	77	74	73	1.5	0.7	0.6
Gas	10	38	49	53	9	20	23	24	5.1	2.0	1.5
Non-Energy Use	**8**	**15**	**14**	**14**	**100**	**100**	**100**	**100**	**2.4**	**–0.5**	**–0.3**

Reference Scenario: Transition Economies

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**864**	**1001**	**1192**	**1440**	**100**	**100**	**100**	**100**	**0.6**	**1.4**	**1.6**
Coal	337	203	242	284	39	20	20	20	–1.9	1.4	1.5
Oil	312	228	284	363	36	23	24	25	–1.2	1.7	2.0
Gas	202	484	572	714	23	48	48	50	3.4	1.3	1.7
Nuclear	2	63	65	47	0	6	5	3	15.2	0.2	–1.3
Hydro	13	23	28	31	1	2	2	2	2.2	1.5	1.3
Other Renewables	0	0	1	1	0	0	0	0	–	26.0	15.8
Power Generation	**265**	**395**	**458**	**538**	**100**	**100**	**100**	**100**	**1.5**	**1.2**	**1.4**
Coal	122	98	136	157	46	25	30	29	–0.8	2.5	2.1
Oil	47	22	19	14	18	6	4	3	–2.9	–1.4	–1.9
Gas	82	188	211	287	31	48	46	53	3.3	0.9	1.9
Nuclear	2	63	65	47	1	16	14	9	15.2	0.2	–1.3
Hydro	13	23	28	31	5	6	6	6	2.2	1.5	1.3
Other Renewables	0	0	1	1	0	0	0	0	–	28.4	17.3
Own Use & Losses	**148**	**244**	**276**	**327**					**1.9**	**0.9**	**1.3**
of which Electricity	*15*	*34*	*37*	*46*					*3.1*	*0.7*	*1.3*
Total Final Consumption	**579**	**649**	**765**	**950**	**100**	**100**	**100**	**100**	**0.4**	**1.3**	**1.7**
Coal	117	53	55	66	20	8	7	7	–3.0	0.3	1.0
Oil	233	151	199	265	40	23	26	28	–1.7	2.2	2.5
Gas	116	193	241	290	20	30	32	31	2.0	1.7	1.8
Electricity	62	90	124	179	11	14	16	19	1.4	2.6	3.0
Heat	51	163	146	150	9	25	19	16	4.6	–0.9	–0.3
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**278**	**234**	**288**	**343**	**100**	**100**	**100**	**100**	**–0.6**	**1.6**	**1.7**
Coal	46	30	32	40	16	13	11	12	–1.6	0.6	1.2
Oil	60	27	34	40	22	12	12	12	–3.0	1.7	1.7
Gas	92	72	100	114	33	31	35	33	–0.9	2.5	2.0
Electricity	44	40	57	83	16	17	20	24	–0.3	2.8	3.3
Heat	37	66	65	67	13	28	23	19	2.3	0.0	0.1
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**101**	**87**	**125**	**177**	**100**	**100**	**100**	**100**	**–0.5**	**2.8**	**3.1**
Oil	86	64	99	146	86	73	79	83	–1.2	3.4	3.7
Other fuels	14	24	27	30	14	27	21	17	2.0	1.0	1.1
Other Sectors	**175**	**311**	**332**	**406**	**100**	**100**	**100**	**100**	**2.2**	**0.5**	**1.2**
Coal	60	20	20	24	34	7	6	6	–4.1	–0.2	0.7
Oil	63	46	49	58	36	15	15	14	–1.2	0.5	1.0
Gas	24	105	123	156	14	34	37	38	5.8	1.3	1.7
Electricity	14	42	59	85	8	14	18	21	4.4	2.6	3.1
Heat	14	97	80	84	8	31	24	21	7.7	–1.5	–0.6
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**25**	**16**	**20**	**23**					**–1.8**	**1.6**	**1.7**

CRW (NOT included above)	21	25	24	25	2	2	2	2	0.7	–0.3	–0.1
Total Primary Energy Supply (including CRW)	**885**	**1026**	**1216**	**1465**	**100**	**100**	**100**	**100**	**0.6**	**1.3**	**1.6**

Reference Scenario: Transition Economies

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**881**	**1440**	**1883**	**2615**	**100**	**100**	**100**	**100**	**1.9**	**2.1**	**2.6**
Coal	395	317	461	590	45	22	24	23	–0.8	2.9	2.7
Oil	154	98	84	68	17	7	4	3	–1.7	–1.2	–1.6
Gas	176	508	755	1407	20	35	40	54	4.2	3.1	4.5
Nuclear	6	241	248	182	1	17	13	7	15.2	0.2	–1.2
Hydro	150	268	327	360	17	19	17	14	2.2	1.5	1.3
Other Renewables	0	6	8	9	0	0	0	0	–	1.7	1.5
Capacity (GW)	**n.a.**	**398**	**444**	**559**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.9**	**1.5**
Coal	n.a.	110	110	125	n.a.	28	25	22	n.a.	0.0	0.6
Oil	n.a.	40	37	32	n.a.	10	8	6	n.a.	–0.5	–0.9
Gas	n.a.	118	161	267	n.a.	30	36	48	n.a.	2.4	3.6
Nuclear	n.a.	42	40	28	n.a.	10	9	5	n.a.	–0.2	–1.7
Hydro	n.a.	87	94	103	n.a.	22	21	19	n.a.	0.6	0.7
Other Renewables	n.a.	2	2	2	n.a.	0	0	0	n.a.	1.8	1.6

Reference Scenario: Transition Economies

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**2721**	**2566**	**3091**	**3814**	**100**	**100**	**100**	**100**	**–0.2**	**1.4**	**1.7**
change since 1990 (%)		*–36.9*	*–24.0*	*–6.2*							
Coal	1325	795	962	1131	49	31	31	30	–1.9	1.5	1.5
Oil	931	652	810	1035	34	25	26	27	–1.4	1.7	2.0
Gas	464	1119	1319	1648	17	44	43	43	3.4	1.3	1.7
Power Generation	**830**	**908**	**1102**	**1354**	**100**	**100**	**100**	**100**	**0.3**	**1.5**	**1.7**
Coal	489	400	552	639	59	44	50	47	–0.8	2.5	2.1
Oil	151	69	58	44	18	8	5	3	–2.9	–1.4	–2.0
Gas	191	439	492	670	23	48	45	50	3.3	0.9	1.9
Own Use & Losses	**404**	**533**	**603**	**713**	**100**	**100**	**100**	**100**	**1.1**	**1.0**	**1.3**
Total Final Consumption	**1486**	**1125**	**1387**	**1747**	**100**	**100**	**100**	**100**	**–1.1**	**1.6**	**1.9**
Coal	471	271	289	351	32	24	21	20	–2.1	0.5	1.1
Oil	750	417	553	740	50	37	40	42	–2.2	2.2	2.5
Gas	265	437	545	656	18	39	39	38	1.9	1.7	1.8
Industry	**647**	**409**	**507**	**602**	**100**	**100**	**100**	**100**	**–1.7**	**1.7**	**1.7**
Coal	194	178	199	246	30	44	39	41	–0.3	0.8	1.4
Oil	246	75	94	110	38	18	18	18	–4.4	1.7	1.7
Gas	207	156	215	246	32	38	42	41	–1.1	2.5	2.0
Transportation	**295**	**228**	**336**	**481**	**100**	**100**	**100**	**100**	**–1.0**	**3.0**	**3.3**
Oil	257	189	292	433	87	83	87	90	–1.2	3.4	3.7
Other Fuels	38	39	44	48	13	17	13	10	0.1	0.9	0.9
Other Sectors	**479**	**463**	**514**	**631**	**100**	**100**	**100**	**100**	**–0.1**	**0.8**	**1.4**
Coal	234	81	78	94	49	17	15	15	–4.0	–0.2	0.7
Oil	189	138	147	173	39	30	29	27	–1.2	0.5	1.0
Gas	56	244	289	364	12	53	56	58	5.8	1.3	1.7
Non-Energy Use	**65**	**25**	**30**	**34**	**100**	**100**	**100**	**100**	**–3.6**	**1.2**	**1.2**

Reference Scenario: Russia

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**n.a.**	**575**	**660**	**802**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.1**	**1.5**
Coal	n.a.	97	105	112	n.a.	17	16	14	n.a.	0.6	0.6
Oil	n.a.	127	163	218	n.a.	22	25	27	n.a.	1.9	2.4
Gas	n.a.	310	343	422	n.a.	54	52	53	n.a.	0.8	1.4
Nuclear	n.a.	29	34	33	n.a.	5	5	4	n.a.	1.4	0.6
Hydro	n.a.	13	15	17	n.a.	2	2	2	n.a.	0.8	1.0
Other Renewables	n.a.	0	1	1	n.a.	0	0	0	n.a.	29.1	17.3
Power Generation	**n.a.**	**235**	**253**	**291**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.5**	**0.9**
Coal	n.a.	42	53	53	n.a.	18	21	18	n.a.	1.9	1.0
Oil	n.a.	5	5	4	n.a.	2	2	1	n.a.	–0.6	–0.8
Gas	n.a.	147	145	183	n.a.	62	57	63	n.a.	–0.1	1.0
Nuclear	n.a.	29	34	33	n.a.	12	14	11	n.a.	1.4	0.6
Hydro	n.a.	13	15	17	n.a.	6	6	6	n.a.	0.8	1.0
Other Renewables	n.a.	0	1	1	n.a.	0	0	0	n.a.	27.3	16.7
Own Use & Losses	**n.a.**	**159**	**173**	**202**					**n.a.**	**0.6**	**1.0**
of which Electricity	*n.a.*	*20*	*20*	*23*					*n.a.*	*0.6*	*0.8*
Total Final Consumption	**n.a.**	**379**	**433**	**545**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.0**	**1.6**
Coal	n.a.	27	27	33	n.a.	7	6	6	n.a.	0.0	0.8
Oil	n.a.	81	110	153	n.a.	21	25	28	n.a.	2.3	2.8
Gas	n.a.	91	117	146	n.a.	24	27	27	n.a.	1.9	2.1
Electricity	n.a.	50	67	99	n.a.	13	15	18	n.a.	2.2	3.0
Heat	n.a.	129	112	114	n.a.	34	26	21	n.a.	–1.0	–0.5
Renewables	n.a.	0	0	0	n.a.	0	0	0	n.a.	–	–

Industry	**n.a.**	**134**	**159**	**191**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.3**	**1.5**
Coal	n.a.	12	12	15	n.a.	9	8	8	n.a.	0.2	1.1
Oil	n.a.	14	17	20	n.a.	10	10	10	n.a.	1.6	1.7
Gas	n.a.	34	48	58	n.a.	26	30	30	n.a.	2.6	2.3
Electricity	n.a.	23	30	46	n.a.	17	19	24	n.a.	2.1	3.1
Heat	n.a.	52	52	52	n.a.	38	32	27	n.a.	0.0	0.0
Renewables	n.a.	0	0	0	n.a.	0	0	0	–	–	–
Transportation	**n.a.**	**52**	**74**	**106**	**n.a.**	**100**	**100**	**100**	**n.a.**	**2.7**	**3.1**
Oil	n.a.	32	52	81	n.a.	62	70	76	n.a.	3.7	4.1
Other fuels	n.a.	20	22	25	n.a.	38	30	24	n.a.	0.8	0.9
Other Sectors	**n.a.**	**181**	**187**	**232**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.3**	**1.1**
Coal	n.a.	13	13	15	n.a.	7	7	7	n.a.	–0.2	0.7
Oil	n.a.	26	30	38	n.a.	15	16	16	n.a.	1.1	1.5
Gas	n.a.	42	52	71	n.a.	23	28	30	n.a.	1.6	2.3
Electricity	n.a.	22	31	46	n.a.	12	17	20	n.a.	2.7	3.2
Heat	n.a.	77	61	63	n.a.	43	32	27	n.a.	–1.8	–0.9
Renewables	n.a.	0	0	0	n.a.	0	0	0	n.a.	–	–
Non-Energy Use	**n.a.**	**11**	**13**	**16**					**n.a.**	**1.5**	**1.6**

CRW (NOT included above)	n.a.	17	16	16	n.a.	3	2	2	n.a.	–0.4	–0.2
Total Primary Energy Supply (including CRW)	**n.a**	**592**	**676**	**818**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.0**	**1.4**

Reference Scenario: Russia

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**n.a.**	**833**	**1027**	**1443**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.6**	**2.4**
Coal	n.a.	140	185	198	n.a.	17	18	14	n.a.	2.2	1.5
Oil	n.a.	44	41	37	n.a.	5	4	3	n.a.	–0.6	–0.8
Gas	n.a.	377	487	874	n.a.	45	47	61	n.a.	2.0	3.7
Nuclear	n.a.	109	132	128	n.a.	13	13	9	n.a.	1.5	0.7
Hydro	n.a.	157	175	197	n.a.	19	17	14	n.a.	0.8	1.0
Other Renewables	n.a.	6	8	9	n.a.	1	1	1	n.a.	1.6	1.4
Capacity (GW)	**n.a.**	**214**	**229**	**289**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.5**	**1.3**
Coal	n.a.	45	41	44	n.a.	21	18	15	n.a.	–0.7	–0.1
Oil	n.a.	17	16	14	n.a.	8	7	5	n.a.	–0.6	–0.8
Gas	n.a.	86	102	156	n.a.	40	44	54	n.a.	1.3	2.6
Nuclear	n.a.	20	22	19	n.a.	9	9	7	n.a.	0.6	–0.1
Hydro	n.a.	44	47	53	n.a.	20	20	18	n.a.	0.5	0.8
Other Renewables	n.a.	2	2	2	n.a.	1	1	1	n.a.	1.5	1.4

Reference Scenario: Russia

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**n.a.**	**1456**	**1670**	**2041**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.1**	**1.5**
change since 1990 (%)		*–38.2*	*–29.1*	*–13.4*							
Coal	n.a.	381	419	450	n.a.	26	25	22	n.a.	0.7	0.7
Oil	n.a.	359	461	619	n.a.	25	28	30	n.a.	1.9	2.4
Gas	n.a.	715	789	972	n.a.	49	47	48	n.a.	0.8	1.3
Power Generation	**n.a.**	**528**	**571**	**657**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.6**	**1.0**
Coal	n.a.	171	219	217	n.a.	32	38	33	n.a.	1.9	1.0
Oil	n.a.	14	13	12	n.a.	3	2	2	n.a.	–0.6	–0.8
Gas	n.a.	343	338	429	n.a.	65	59	65	n.a.	–0.1	1.0
Own Use & Losses	**n.a.**	**373**	**408**	**477**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.7**	**1.1**
Total Final Consumption	**n.a.**	**555**	**691**	**907**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.7**	**2.2**
Coal	n.a.	131	131	158	n.a.	24	19	17	n.a.	0.0	0.8
Oil	n.a.	220	300	421	n.a.	40	43	46	n.a.	2.4	2.9
Gas	n.a.	204	261	328	n.a.	37	38	36	n.a.	1.9	2.1
Industry	**n.a.**	**179**	**217**	**264**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.5**	**1.7**
Coal	n.a.	70	71	89	n.a.	39	33	34	n.a.	0.2	1.1
Oil	n.a.	37	45	55	n.a.	21	21	21	n.a.	1.6	1.7
Gas	n.a.	72	101	121	n.a.	40	46	46	n.a.	2.6	2.3
Transportation	**n.a.**	**131**	**193**	**284**	**n.a.**	**100**	**100**	**100**	**n.a.**	**3.0**	**3.4**
Oil	n.a.	96	154	241	n.a.	73	80	85	n.a.	3.7	4.1
Other Fuels	n.a.	35	39	43	n.a.	27	20	15	n.a.	0.9	0.9
Other Sectors	**n.a.**	**228**	**262**	**337**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.1**	**1.7**
Coal	n.a.	52	50	60	n.a.	23	19	18	n.a.	–0.2	0.7
Oil	n.a.	79	90	112	n.a.	34	35	33	n.a.	1.1	1.5
Gas	n.a.	98	121	165	n.a.	43	46	49	n.a.	1.6	2.3
Non-Energy Use	**n.a.**	**17**	**19**	**22**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.9**	**1.1**

Reference Scenario: Developing Countries

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**719**	**2859**	**4507**	**6194**	**100**	**100**	**100**	**100**	**5.5**	**3.6**	**3.4**
Coal	308	1039	1518	1975	43	36	34	32	4.8	3.0	2.8
Oil	339	1246	1923	2583	47	44	43	42	5.1	3.4	3.2
Gas	54	428	803	1288	7	15	18	21	8.3	5.0	4.9
Nuclear	0	45	92	117	0	2	2	2	20.7	5.7	4.3
Hydro	17	86	140	180	2	3	3	3	6.4	3.8	3.3
Other Renewables	0	15	30	50	0	1	1	1	–	5.3	5.3
Power Generation	**135**	**903**	**1588**	**2290**	**100**	**100**	**100**	**100**	**7.6**	**4.4**	**4.1**
Coal	67	479	840	1206	49	53	53	53	7.9	4.4	4.1
Oil	41	154	213	255	31	17	13	11	5.2	2.5	2.2
Gas	10	124	273	483	7	14	17	21	10.3	6.2	6.1
Nuclear	0	45	92	117	0	5	6	5	20.7	5.7	4.3
Hydro	17	86	140	180	13	10	9	8	6.4	3.8	3.3
Other Renewables	0	15	30	50	0	2	2	2	–	5.4	5.3
Own Use & Losses	**106**	**439**	**654**	**879**					**5.6**	**3.1**	**3.1**
of which Electricity	*8*	*74*	*131*	*190*					*8.8*	*4.5*	*4.2*
Total Final Consumption	**528**	**1892**	**2955**	**4051**	**100**	**100**	**100**	**100**	**5.0**	**3.5**	**3.4**
Coal	208	449	540	609	39	24	18	15	3.0	1.4	1.3
Oil	249	959	1528	2099	47	51	52	52	5.3	3.6	3.5
Gas	29	182	328	507	5	10	11	13	7.3	4.6	4.5
Electricity	41	278	518	780	8	15	18	19	7.6	4.9	4.6
Heat	0	24	40	55	0	1	1	1	–	4.0	3.7
Renewables	0	1	1	1	0	0	0	0	–	2.4	2.0

Industry	**153**	**843**	**1251**	**1648**	**100**	**100**	**100**	**100**	**6.8**	**3.1**	**3.0**
Coal	51	332	420	491	33	39	34	30	7.5	1.8	1.7
Oil	59	227	320	397	38	27	26	24	5.3	2.7	2.5
Gas	26	128	233	359	17	15	19	22	6.3	4.7	4.6
Electricity	17	139	253	370	11	17	20	22	8.4	4.7	4.3
Heat	0	17	25	32	0	2	2	2	–	2.8	2.7
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**120**	**476**	**803**	**1164**	**100**	**100**	**100**	**100**	**5.4**	**4.1**	**4.0**
Oil	107	465	793	1152	90	98	99	99	5.8	4.2	4.0
Other fuels	13	11	11	11	10	2	1	1	–0.5	–0.4	0.0
Other Sectors	**240**	**499**	**796**	**1105**	**100**	**100**	**100**	**100**	**2.9**	**3.7**	**3.5**
Coal	144	92	95	93	60	18	12	8	–1.7	0.2	0.0
Oil	70	213	331	437	29	43	42	40	4.4	3.5	3.2
Gas	3	53	93	146	1	11	12	13	12.1	4.4	4.5
Electricity	24	135	262	405	10	27	33	37	6.9	5.2	4.9
Heat	0	6	15	23	0	1	2	2	–	6.7	5.8
Renewables	0	1	1	1	0	0	0	0	–	2.4	2.0
Non-Energy Use	**14**	**74**	**105**	**134**					**6.6**	**2.7**	**2.6**

CRW (NOT included above)	616	886	1010	1103	46	24	18	15	1.4	1.0	1.0
Total Primary Energy Supply (including CRW)	**1336**	**3745**	**5517**	**7297**	**100**	**100**	**100**	**100**	**4.0**	**3.0**	**2.9**

Reference Scenario: Developing Countries

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**575**	**4090**	**7551**	**11278**	**100**	**100**	**100**	**100**	**7.8**	**4.8**	**4.5**
Coal	203	1692	3241	4895	35	41	43	43	8.5	5.1	4.7
Oil	141	672	936	1129	25	16	12	10	6.2	2.6	2.3
Gas	26	522	1318	2588	5	13	17	23	12.2	7.4	7.2
Nuclear	1	172	354	450	0	4	5	4	20.7	5.7	4.3
Hydro	200	998	1627	2097	35	24	22	19	6.4	3.8	3.3
Other Renewables	3	33	75	119	1	1	1	1	9.8	6.5	5.7
Capacity (GW)	**n.a.**	**952**	**1659**	**2427**	**n.a.**	**100**	**100**	**100**	**n.a.**	**4.4**	**4.2**
Coal	n.a.	325	606	888	n.a.	34	37	37	n.a.	4.9	4.5
Oil	n.a.	193	264	324	n.a.	20	16	13	n.a.	2.4	2.3
Gas	n.a.	144	318	596	n.a.	15	19	25	n.a.	6.3	6.4
Nuclear	n.a.	24	49	62	n.a.	3	3	3	n.a.	5.5	4.2
Hydro	n.a.	256	404	527	n.a.	27	24	22	n.a.	3.6	3.2
Other Renewables	n.a.	9	18	29	n.a.	1	1	1	n.a.	5.4	5.1

Reference Scenario: Developing Countries

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**2303**	**8528**	**13195**	**17990**	**100**	**100**	**100**	**100**	**5.2**	**3.4**	**3.3**
change since 1990 (%)		*38.2*	*113.8*	*191.5*							
Coal	1197	4012	5881	7668	52	47	45	43	4.8	3.0	2.9
Oil	982	3537	5474	7370	43	41	41	41	5.1	3.4	3.2
Gas	125	980	1839	2952	5	11	14	16	8.3	5.0	4.9
Power Generation	**414**	**2651**	**4598**	**6652**	**100**	**100**	**100**	**100**	**7.4**	**4.3**	**4.1**
Coal	259	1873	3288	4719	63	71	71	71	7.9	4.4	4.1
Oil	132	488	674	806	32	18	15	12	5.2	2.5	2.2
Gas	23	291	637	1128	5	11	14	17	10.3	6.2	6.1
Own Use & Losses	**248**	**887**	**1281**	**1696**	**100**	**100**	**100**	**100**	**5.0**	**2.9**	**2.9**
Total Final Consumption	**1641**	**4990**	**7316**	**9642**	**100**	**100**	**100**	**100**	**4.4**	**3.0**	**2.9**
Coal	846	1923	2322	2626	52	39	32	27	3.2	1.5	1.4
Oil	730	2660	4265	5889	44	53	58	61	5.1	3.7	3.5
Gas	66	407	729	1127	4	8	10	12	7.2	4.6	4.5
Industry	**475**	**2284**	**3119**	**3881**	**100**	**100**	**100**	**100**	**6.2**	**2.4**	**2.3**
Coal	236	1466	1857	2167	50	64	60	56	7.3	1.8	1.7
Oil	179	538	755	934	38	24	24	24	4.3	2.6	2.4
Gas	60	279	507	780	13	12	16	20	6.1	4.7	4.6
Transportation	**364**	**1410**	**2380**	**3448**	**100**	**100**	**100**	**100**	**5.3**	**4.1**	**4.0**
Oil	317	1381	2357	3429	87	98	99	99	5.8	4.2	4.0
Other Fuels	47	29	23	19	13	2	1	1	–1.9	–1.8	–1.7
Other Sectors	**776**	**1102**	**1554**	**1983**	**100**	**100**	**100**	**100**	**1.4**	**2.7**	**2.6**
Coal	560	355	365	358	72	32	24	18	–1.7	0.2	0.0
Oil	210	624	972	1283	27	57	63	65	4.3	3.5	3.2
Gas	6	123	216	341	1	11	14	17	12.1	4.4	4.5
Non-Energy Use	**26**	**194**	**263**	**330**	**100**	**100**	**100**	**100**	**8.0**	**2.4**	**2.3**

Reference Scenario: China

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**239**	**905**	**1426**	**1937**	**100**	**100**	**100**	**100**	**5.2**	**3.6**	**3.4**
Coal	190	662	940	1192	80	73	66	62	4.9	2.7	2.6
Oil	43	201	371	541	18	22	26	28	6.1	4.8	4.4
Gas	3	21	56	111	1	2	4	6	7.6	7.8	7.5
Nuclear	0	4	22	37	0	0	2	2	–	14.4	10.5
Hydro	3	17	35	53	1	2	2	3	7.5	5.8	5.1
Other Renewables	0	0	2	3	0	0	0	0	–	–	–
Power Generation	**37**	**303**	**564**	**819**	**100**	**100**	**100**	**100**	**8.4**	**4.9**	**4.4**
Coal	30	264	466	661	82	87	83	81	8.7	4.5	4.1
Oil	4	16	28	39	11	5	5	5	5.4	4.3	3.8
Gas	0	2	12	27	0	1	2	3	–	15.0	12.1
Nuclear	0	4	22	37	0	1	4	5	–	14.4	10.5
Hydro	3	17	35	53	7	6	6	7	7.5	5.8	5.1
Other Renewables	0	0	2	3	0	0	0	0	–	–	–
Own Use & Losses	**32**	**111**	**169**	**227**					**4.9**	**3.3**	**3.1**
of which Electricity	*2*	*25*	*49*	*75*					*9.9*	*5.5*	*4.9*
Total Final Consumption	**184**	**613**	**937**	**1259**	**100**	**100**	**100**	**100**	**4.7**	**3.3**	**3.2**
Coal	135	334	398	446	74	54	43	35	3.5	1.4	1.3
Oil	37	166	307	449	20	27	33	36	6.0	4.9	4.4
Gas	1	16	37	70	1	3	4	6	9.7	6.6	6.6
Electricity	10	75	158	243	6	12	17	19	8.0	5.9	5.2
Heat	0	22	37	51	0	4	4	4	–	4.0	3.6
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**12**	**347**	**499**	**638**	**100**	**100**	**100**	**100**	**13.8**	**2.8**	**2.7**
Coal	3	227	290	341	24	65	58	54	18.2	1.9	1.8
Oil	8	42	62	77	63	12	13	12	6.8	3.2	2.7
Gas	1	13	29	52	12	4	6	8	8.8	6.6	6.3
Electricity	0	49	92	136	1	14	18	21	24.2	5.1	4.6
Heat	0	17	25	32	0	5	5	5	–	2.8	2.7
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**6**	**77**	**140**	**213**	**100**	**100**	**100**	**100**	**10.6**	**4.7**	**4.5**
Oil	6	70	134	207	100	90	96	97	10.1	5.1	4.8
Other fuels	0	8	6	6	0	10	4	3	–	–1.4	–0.8
Other Sectors	**163**	**155**	**250**	**347**	**100**	**100**	**100**	**100**	**–0.2**	**3.7**	**3.6**
Coal	132	87	90	88	81	56	36	25	–1.6	0.2	0.0
Oil	21	34	77	118	13	22	31	34	1.9	6.4	5.5
Gas	0	3	8	18	0	2	3	5	21.6	6.9	7.8
Electricity	10	25	64	105	6	16	25	30	3.6	7.3	6.3
Heat	0	5	12	19	0	3	5	5	–	7.0	6.0
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**2**	**33**	**47**	**61**					**10.5**	**2.7**	**2.7**

CRW (NOT included above)	169	208	217	221	41	19	13	10	0.8	0.3	0.2
Total Primary Energy Supply (including CRW)	**408**	**1113**	**1643**	**2158**	**100**	**100**	**100**	**100**	**3.9**	**3.0**	**2.9**

Reference Scenario: China

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**144**	**1163**	**2408**	**3691**	**100**	**100**	**100**	**100**	**8.4**	**5.8**	**5.1**
Coal	99	863	1711	2568	69	74	71	70	8.7	5.4	4.9
Oil	15	83	145	197	10	7	6	5	6.9	4.3	3.8
Gas	0	7	57	149	0	1	2	4	n.a.	18.0	14.5
Nuclear	0	14	83	143	0	1	3	4	n.a.	14.4	10.5
Hydro	30	196	406	622	21	17	17	17	7.5	5.8	5.1
Other Renewables	0	0	7	12	0	0	0	0	–	–	–
Capacity (GW)	**n.a.**	**263**	**510**	**763**	**n.a.**	**100**	**100**	**100**	**n.a.**	**5.2**	**4.7**
Coal	n.a.	177	337	489	n.a.	67	66	64	n.a.	5.1	4.5
Oil	n.a.	20	33	45	n.a.	8	6	6	n.a.	3.9	3.6
Gas	n.a.	4	15	34	n.a.	2	3	4	n.a.	10.0	9.5
Nuclear	n.a.	2	11	20	n.a.	1	2	3	n.a.	13.9	10.2
Hydro	n.a.	60	112	171	n.a.	23	22	22	n.a.	4.9	4.7
Other Renewables	n.a.	0	3	4	n.a.	0	1	1	n.a.	14.7	10.4

Reference Scenario: China

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**872**	**3162**	**4822**	**6426**	**100**	**100**	**100**	**100**	**5.1**	**3.3**	**3.1**
change since 1990 (%)		*31.8*	*101.1*	*168.0*							
Coal	739	2548	3638	4624	85	81	75	72	4.9	2.8	2.6
Oil	126	567	1060	1555	14	18	22	24	6.0	4.9	4.5
Gas	7	46	124	247	1	1	3	4	7.4	7.9	7.5
Power Generation	**132**	**1090**	**1941**	**2770**	**100**	**100**	**100**	**100**	**8.5**	**4.5**	**4.1**
Coal	118	1035	1825	2587	90	95	94	93	8.7	4.5	4.1
Oil	13	51	89	121	10	5	5	4	5.3	4.3	3.8
Gas	0	4	27	62	0	0	1	2	–	15.0	12.1
Own Use & Losses	**104**	**212**	**304**	**395**	**100**	**100**	**100**	**100**	**2.8**	**2.8**	**2.8**
Total Final Consumption	**637**	**1860**	**2577**	**3261**	**100**	**100**	**100**	**100**	**4.2**	**2.5**	**2.5**
Coal	526	1374	1647	1851	83	74	64	57	3.8	1.4	1.3
Oil	107	452	851	1259	17	24	33	39	5.7	5.0	4.6
Gas	3	34	79	151	1	2	3	5	9.4	6.6	6.7
Industry	**40**	**1067**	**1412**	**1705**	**100**	**100**	**100**	**100**	**13.5**	**2.2**	**2.1**
Coal	13	956	1226	1441	33	90	87	85	17.9	1.9	1.8
Oil	23	84	125	155	58	8	9	9	5.1	3.2	2.7
Gas	3	27	61	109	8	3	4	6	8.4	6.6	6.3
Transportation	**16**	**232**	**416**	**628**	**100**	**100**	**100**	**100**	**10.7**	**4.6**	**4.4**
Oil	16	208	398	615	100	90	96	98	10.3	5.1	4.8
Other Fuels	0	24	17	13	0	10	4	2	–	–2.5	–2.5
Other Sectors	**578**	**446**	**592**	**729**	**100**	**100**	**100**	**100**	**–1.0**	**2.2**	**2.2**
Coal	513	336	346	338	89	75	58	46	–1.6	0.2	0.0
Oil	65	102	228	348	11	23	39	48	1.7	6.4	5.5
Gas	0	8	18	42	0	2	3	6	21.7	6.9	7.8
Non-Energy Use	**3**	**116**	**157**	**199**	**100**	**100**	**100**	**100**	**15.5**	**2.3**	**2.4**

Reference Scenario: South Asia

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**72**	**315**	**564**	**843**	**100**	**100**	**100**	**100**	**5.8**	**4.6**	**4.4**
Coal	39	155	252	344	53	49	45	41	5.5	3.8	3.5
Oil	27	111	203	304	38	35	36	36	5.6	4.8	4.5
Gas	3	37	87	163	5	12	15	19	9.8	6.8	6.6
Nuclear	0	3	6	11	0	1	1	1	8.4	6.6	6.3
Hydro	3	9	14	19	4	3	3	2	4.4	3.9	3.4
Other Renewables	0	0	1	1	0	0	0	0	–	47.5	26.9
Power Generation	**17**	**135**	**246**	**363**	**100**	**100**	**100**	**100**	**8.4**	**4.7**	**4.4**
Coal	10	103	182	260	62	76	74	72	9.2	4.5	4.1
Oil	2	9	15	19	11	6	6	5	6.2	4.4	3.6
Gas	1	12	28	52	8	9	11	14	9.2	6.3	6.4
Nuclear	0	3	6	11	2	2	3	3	8.4	6.6	6.3
Hydro	3	9	14	19	17	6	6	5	4.4	3.9	3.4
Other Renewables	0	0	1	1	0	0	0	0	–	47.5	26.9
Own Use & Losses	**11**	**29**	**52**	**78**					**3.8**	**4.5**	**4.3**
of which Electricity	*2*	*12*	*21*	*31*					*8.1*	*4.7*	*4.3*
Total Final Consumption	**51**	**197**	**358**	**548**	**100**	**100**	**100**	**100**	**5.3**	**4.7**	**4.6**
Coal	21	44	59	71	42	22	16	13	2.8	2.2	2.1
Oil	23	96	177	269	45	49	49	49	5.7	4.8	4.6
Gas	2	21	50	93	4	11	14	17	9.8	6.8	6.6
Electricity	5	35	72	115	10	18	20	21	7.8	5.7	5.3
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**21**	**97**	**166**	**247**	**100**	**100**	**100**	**100**	**6.0**	**4.2**	**4.1**
Coal	11	44	59	71	53	45	35	29	5.3	2.2	2.1
Oil	5	20	35	49	23	21	21	20	5.6	4.3	3.9
Gas	2	17	41	78	8	18	25	32	9.1	7.0	6.8
Electricity	3	16	31	49	15	16	19	20	6.1	5.4	5.1
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**17**	**52**	**105**	**170**	**100**	**100**	**100**	**100**	**4.4**	**5.5**	**5.3**
Oil	9	51	104	169	52	99	99	100	7.0	5.6	5.3
Other fuels	8	1	1	1	48	1	1	0	–9.3	1.3	0.8
Other Sectors	**10**	**43**	**81**	**124**	**100**	**100**	**100**	**100**	**5.6**	**5.0**	**4.7**
Coal	2	0	0	0	18	0	0	0	–12.7	–0.6	–0.4
Oil	7	20	31	42	66	46	39	34	4.2	3.6	3.4
Gas	0	4	9	15	1	10	11	12	15.0	6.2	5.9
Electricity	2	19	40	66	15	44	50	53	10.1	6.1	5.6
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**2**	**5**	**6**	**7**					**3.1**	**2.4**	**2.1**

CRW (NOT included above)	149	242	275	294	67	43	33	26	1.9	1.0	0.9
Total Primary Energy Supply (including CRW)	**221**	**556**	**838**	**1136**	**100**	**100**	**100**	**100**	**3.6**	**3.2**	**3.2**

Reference Scenario: South Asia

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**76**	**541**	**1081**	**1695**	**100**	**100**	**100**	**100**	**7.8**	**5.5**	**5.1**
Coal	32	339	673	1034	42	63	62	61	9.5	5.4	5.0
Oil	6	38	67	86	7	7	6	5	7.7	4.5	3.7
Gas	4	52	140	295	5	10	13	17	10.3	7.9	7.8
Nuclear	1	10	24	43	2	2	2	3	8.4	6.6	6.3
Hydro	33	101	166	218	43	19	15	13	4.4	3.9	3.4
Other Renewables	0	0	11	20	0	0	1	1	–	49.8	29.1
Capacity (GW)	**n.a.**	**123**	**235**	**360**	**n.a.**	**100**	**100**	**100**	**n.a.**	**5.1**	**4.8**
Coal	n.a.	66	130	198	n.a.	54	55	55	n.a.	5.3	4.9
Oil	n.a.	11	18	24	n.a.	9	8	7	n.a.	4.1	3.5
Gas	n.a.	14	32	62	n.a.	11	14	17	n.a.	6.5	6.7
Nuclear	n.a.	2	4	7	n.a.	2	2	2	n.a.	4.7	5.2
Hydro	n.a.	28	47	62	n.a.	23	20	17	n.a.	3.9	3.4
Other Renewables	n.a.	1	4	7	n.a.	1	2	2	n.a.	10.1	8.2

Reference Scenario: South Asia

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**233**	**1001**	**1760**	**2588**	**100**	**100**	**100**	**100**	**5.8**	**4.4**	**4.2**
change since 1990 (%)		*46.9*	*158.2*	*279.8*							
Coal	150	603	979	1337	64	60	56	52	5.5	3.8	3.5
Oil	76	314	582	878	32	31	33	34	5.6	4.9	4.6
Gas	7	85	199	373	3	8	11	14	9.9	6.8	6.7
Power Generation	**49**	**457**	**823**	**1197**	**100**	**100**	**100**	**100**	**9.0**	**4.6**	**4.3**
Coal	40	401	710	1014	82	88	86	85	9.2	4.5	4.1
Oil	6	27	48	62	12	6	6	5	6.2	4.4	3.6
Gas	3	29	65	121	6	6	8	10	9.2	6.3	6.4
Own Use & Losses	**18**	**27**	**54**	**90**	**100**	**100**	**100**	**100**	**1.6**	**5.5**	**5.4**
Total Final Consumption	**166**	**517**	**883**	**1301**	**100**	**100**	**100**	**100**	**4.5**	**4.2**	**4.1**
Coal	99	199	265	319	60	39	30	25	2.7	2.2	2.1
Oil	63	270	504	771	38	52	57	59	5.8	4.9	4.7
Gas	4	48	114	211	2	9	13	16	10.0	6.9	6.7
Industry	**78**	**288**	**446**	**619**	**100**	**100**	**100**	**100**	**5.2**	**3.4**	**3.4**
Coal	61	199	265	319	79	69	59	52	4.6	2.2	2.1
Oil	13	51	88	123	17	18	20	20	5.4	4.3	4.0
Gas	4	38	93	176	5	13	21	28	9.3	7.0	6.9
Transportation	**57**	**156**	**317**	**514**	**100**	**100**	**100**	**100**	**3.9**	**5.6**	**5.3**
Oil	27	156	317	514	46	100	100	100	7.0	5.6	5.3
Other Fuels	31	0	0	0	54	0	0	0	–18.9	–17.1	–11.1
Other Sectors	**28**	**68**	**113**	**160**	**100**	**100**	**100**	**100**	**3.5**	**4.0**	**3.8**
Coal	7	0	0	0	26	0	0	0	–12.3	–0.6	–0.5
Oil	20	58	92	124	73	86	81	78	4.1	3.6	3.4
Gas	0	10	21	35	1	14	19	22	15.0	6.2	5.9
Non-Energy Use	**3**	**6**	**8**	**9**	**100**	**100**	**100**	**100**	**2.7**	**2.5**	**2.2**

Reference Scenario: India

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**63**	**268**	**478**	**716**	**100**	**100**	**100**	**100**	**5.7**	**4.5**	**4.4**
Coal	38	153	246	336	60	57	52	47	5.5	3.7	3.5
Oil	22	88	162	243	35	33	34	34	5.5	4.8	4.5
Gas	1	18	52	111	1	7	11	16	13.9	8.6	8.3
Nuclear	0	3	6	10	0	1	1	1	8.6	6.3	6.1
Hydro	2	6	11	15	4	2	2	2	3.8	4.3	3.7
Other Renewables	0	0	0	1	0	0	0	0	–	42.6	24.8
Power Generation	**15**	**121**	**219**	**324**	**100**	**100**	**100**	**100**	**8.4**	**4.7**	**4.4**
Coal	10	103	179	254	69	85	82	79	9.3	4.3	4.0
Oil	2	3	6	6	10	2	3	2	1.9	6.2	4.2
Gas	0	6	17	37	2	5	8	11	12.4	8.3	8.2
Nuclear	0	3	6	10	2	2	3	3	8.6	6.3	6.1
Hydro	2	6	11	15	16	5	5	5	3.8	4.3	3.7
Other Renewables	0	0	0	1	0	0	0	0	–	42.6	24.8
Own Use & Losses	**10**	**26**	**46**	**69**					**3.5**	**4.5**	**4.4**
of which Electricity	*1*	*10*	*18*	*27*					*8.2*	*4.7*	*4.4*
Total Final Consumption	**43**	**162**	**294**	**451**	**100**	**100**	**100**	**100**	**5.2**	**4.7**	**4.6**
Coal	21	43	57	69	47	26	19	15	2.8	2.3	2.1
Oil	18	80	146	221	42	49	50	49	5.8	4.8	4.5
Gas	0	9	28	60	0	6	10	13	16.0	8.8	8.4
Electricity	4	30	62	101	10	19	21	22	7.6	5.8	5.4
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**19**	**83**	**142**	**212**	**100**	**100**	**100**	**100**	**5.9**	**4.2**	**4.1**
Coal	11	43	57	69	58	51	40	33	5.4	2.3	2.1
Oil	5	18	31	42	24	22	22	20	5.4	4.2	3.8
Gas	0	9	27	57	1	11	19	27	16.2	8.8	8.4
Electricity	3	14	27	43	16	16	19	20	6.0	5.4	5.1
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**15**	**42**	**83**	**135**	**100**	**100**	**100**	**100**	**4.0**	**5.5**	**5.3**
Oil	7	41	82	134	46	98	99	99	7.1	5.5	5.3
Other fuels	8	1	1	1	54	2	1	1	–9.4	1.4	0.8
Other Sectors	**8**	**33**	**64**	**98**	**100**	**100**	**100**	**100**	**5.6**	**5.1**	**4.8**
Coal	2	0	0	0	22	0	0	0	–13.2	–0.9	–0.7
Oil	5	17	28	39	61	51	44	39	4.9	4.0	3.7
Gas	0	0	1	2	0	1	2	3	12.8	8.2	8.2
Electricity	1	16	34	57	16	48	54	58	10.1	6.2	5.8
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**2**	**4**	**5**	**6**					**2.8**	**2.0**	**1.7**

CRW (NOT included above)	121	193	213	223	66	42	31	24	1.8	0.8	0.6
Total Primary Energy Supply (including CRW)	**184**	**461**	**691**	**939**	**100**	**100**	**100**	**100**	**3.6**	**3.2**	**3.1**

Reference Scenario: India

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**66**	**463**	**935**	**1483**	**100**	**100**	**100**	**100**	**7.8**	**5.6**	**5.2**
Coal	32	339	657	1008	48	73	70	68	9.5	5.2	4.9
Oil	5	12	27	32	7	3	3	2	3.7	6.4	4.3
Gas	0	28	91	216	0	6	10	15	18.9	9.6	9.4
Nuclear	1	10	22	39	2	2	2	3	8.6	6.3	6.1
Hydro	28	75	129	171	42	16	14	12	3.8	4.3	3.7
Other Renewables	0	0	9	18	0	0	1	1	–	48.0	28.3
Capacity (GW)	**n.a.**	**103**	**199**	**309**	**n.a.**	**100**	**100**	**100**	**n.a.**	**5.2**	**4.9**
Coal	n.a.	66	127	193	n.a.	64	64	63	n.a.	5.1	4.8
Oil	n.a.	3	5	6	n.a.	3	3	2	n.a.	6.0	4.0
Gas	n.a.	9	22	47	n.a.	9	11	15	n.a.	7.0	7.4
Nuclear	n.a.	2	4	6	n.a.	2	2	2	n.a.	4.6	5.1
Hydro	n.a.	22	38	50	n.a.	21	19	16	n.a.	4.3	3.7
Other Renewables	n.a.	1	3	6	n.a.	1	2	2	n.a.	9.9	8.2

Reference Scenario: India

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**208**	**881**	**1533**	**2254**	**100**	**100**	**100**	**100**	**5.7**	**4.4**	**4.2**
change since 1990 (%)		*46.8*	*155.6*	*275.8*							
Coal	147	595	956	1305	71	68	62	58	5.5	3.7	3.5
Oil	60	245	457	692	29	28	30	31	5.6	4.9	4.6
Gas	1	41	121	257	1	5	8	11	13.8	8.6	8.3
Power Generation	**46**	**423**	**752**	**1097**	**100**	**100**	**100**	**100**	**8.9**	**4.5**	**4.2**
Coal	40	400	695	989	88	95	92	90	9.3	4.3	4.0
Oil	5	8	18	21	11	2	2	2	1.9	6.2	4.2
Gas	1	14	40	87	1	3	5	8	12.4	8.3	8.2
Own Use & Losses	**16**	**23**	**48**	**81**	**100**	**100**	**100**	**100**	**1.4**	**5.7**	**5.6**
Total Final Consumption	**146**	**435**	**733**	**1077**	**100**	**100**	**100**	**100**	**4.3**	**4.1**	**4.0**
Coal	97	192	258	312	66	44	35	29	2.7	2.3	2.1
Oil	49	221	411	629	34	51	56	58	6.0	4.9	4.6
Gas	0	22	65	136	0	5	9	13	15.9	8.8	8.4
Industry	**71**	**255**	**393**	**544**	**100**	**100**	**100**	**100**	**5.1**	**3.4**	**3.3**
Coal	59	192	258	312	83	75	66	57	4.7	2.3	2.1
Oil	12	43	74	101	16	17	19	19	5.2	4.2	3.8
Gas	0	21	62	130	1	8	16	24	16.1	8.8	8.4
Transportation	**52**	**124**	**250**	**407**	**100**	**100**	**100**	**100**	**3.5**	**5.5**	**5.3**
Oil	21	124	250	407	40	100	100	100	7.2	5.5	5.3
Other Fuels	31	0	0	0	60	0	0	0	–19.5	–25.0	–25.0
Other Sectors	**22**	**50**	**85**	**119**	**100**	**100**	**100**	**100**	**3.3**	**4.0**	**3.8**
Coal	7	0	0	0	32	0	0	0	–12.7	–0.9	–0.7
Oil	15	49	82	113	68	98	97	95	4.8	4.0	3.7
Gas	0	1	3	6	0	2	3	5	12.8	8.2	8.2
Non-Energy Use	**2**	**5**	**6**	**7**	**100**	**100**	**100**	**100**	**2.6**	**2.0**	**1.7**

Reference Scenario: East Asia

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**96**	**550**	**908**	**1279**	**100**	**100**	**100**	**100**	**7.0**	**3.9**	**3.7**
Coal	34	101	154	222	36	18	17	17	4.2	3.3	3.5
Oil	58	315	498	665	60	57	55	52	6.8	3.6	3.3
Gas	1	88	176	286	2	16	19	22	17.0	5.4	5.2
Nuclear	0	30	52	57	0	5	6	4	–	4.4	2.9
Hydro	2	7	12	16	2	1	1	1	4.6	4.3	3.8
Other Renewables	0	9	17	33	0	2	2	3	–	5.7	6.0
Power Generation	**15**	**167**	**291**	**432**	**100**	**100**	**100**	**100**	**9.8**	**4.4**	**4.2**
Coal	3	47	94	157	18	28	32	36	11.5	5.5	5.4
Oil	10	38	45	47	65	23	16	11	5.5	1.3	0.9
Gas	0	37	71	122	2	22	24	28	20.6	5.1	5.3
Nuclear	0	30	52	57	0	18	18	13	–	4.4	2.9
Hydro	2	7	12	16	14	4	4	4	4.6	4.3	3.8
Other Renewables	0	9	17	33	0	5	6	8	–	5.7	6.1
Own Use & Losses	**10**	**82**	**131**	**180**					**8.5**	**3.6**	**3.4**
of which Electricity	*1*	*10*	*18*	*26*					*9.6*	*4.4*	*4.2*
Total Final Consumption	**77**	**366**	**606**	**850**	**100**	**100**	**100**	**100**	**6.2**	**3.9**	**3.7**
Coal	29	41	46	49	38	11	8	6	1.4	0.8	0.8
Oil	42	244	407	564	54	67	67	66	7.0	4.0	3.7
Gas	1	25	51	80	1	7	8	9	13.2	5.7	5.2
Electricity	5	55	99	153	7	15	16	18	9.4	4.7	4.5
Heat	0	1	3	4	0	0	0	1	–	5.5	4.9
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**39**	**162**	**241**	**322**	**100**	**100**	**100**	**100**	**5.7**	**3.1**	**3.0**
Coal	23	40	45	49	58	25	19	15	2.2	0.9	0.9
Oil	13	78	111	141	33	48	46	44	7.2	2.8	2.6
Gas	1	16	36	58	2	10	15	18	12.6	6.4	5.8
Electricity	3	28	50	74	7	17	21	23	9.3	4.4	4.3
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**18**	**110**	**202**	**299**	**100**	**100**	**100**	**100**	**7.1**	**4.8**	**4.5**
Oil	18	110	201	299	99	100	100	100	7.2	4.8	4.5
Other fuels	0	0	0	0	1	0	0	0	2.1	2.2	2.2
Other Sectors	**19**	**86**	**148**	**209**	**100**	**100**	**100**	**100**	**6.0**	**4.3**	**3.9**
Coal	6	2	1	1	34	2	1	0	–5.4	–2.8	–2.5
Oil	10	48	80	104	52	56	54	50	6.3	4.0	3.4
Gas	0	9	15	22	1	10	10	10	14.7	4.2	3.9
Electricity	2	26	49	78	13	31	33	37	9.5	4.9	4.8
Heat	0	1	3	4	0	2	2	2	–	5.5	4.9
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**1**	**8**	**15**	**20**					**7.1**	**4.3**	**3.9**

CRW (NOT included above)	103	115	129	140	52	17	12	10	0.4	0.8	0.9
Total Primary Energy Supply (including CRW)	**198**	**665**	**1037**	**1419**	**100**	**100**	**100**	**100**	**4.8**	**3.5**	**3.4**

Reference Scenario: East Asia

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**72**	**757**	**1361**	**2081**	**100**	**100**	**100**	**100**	**9.5**	**4.6**	**4.5**
Coal	10	221	445	744	14	29	33	36	12.6	5.5	5.4
Oil	38	171	201	210	52	23	15	10	6.0	1.3	0.9
Gas	0	160	356	682	0	21	26	33	30.0	6.3	6.5
Nuclear	0	113	198	217	0	15	15	10	–	4.4	2.9
Hydro	24	78	136	183	34	10	10	9	4.6	4.3	3.8
Other Renewables	0	13	25	44	0	2	2	2	–	5.2	5.6
Capacity (GW)	**n.a.**	**179**	**300**	**443**	**n.a.**	**100**	**100**	**100**	**n.a.**	**4.1**	**4.0**
Coal	n.a.	33	72	115	n.a.	19	24	26	n.a.	6.1	5.6
Oil	n.a.	48	58	62	n.a.	27	19	14	n.a.	1.5	1.1
Gas	n.a.	48	95	170	n.a.	27	32	38	n.a.	5.3	5.6
Nuclear	n.a.	15	27	29	n.a.	9	9	7	n.a.	4.3	2.8
Hydro	n.a.	30	44	59	n.a.	17	15	13	n.a.	2.9	2.9
Other Renewables	n.a.	3	5	8	n.a.	2	2	2	n.a.	2.9	4.2

Reference Scenario: East Asia

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**307**	**1455**	**2365**	**3347**	**100**	**100**	**100**	**100**	**6.2**	**3.8**	**3.7**
change since 1990 (%)		*64.0*	*166.6*	*277.2*							
Coal	134	391	601	869	44	27	25	26	4.2	3.4	3.5
Oil	170	863	1367	1830	55	59	58	55	6.5	3.6	3.3
Gas	3	201	397	647	1	14	17	19	17.1	5.4	5.2
Power Generation	**42**	**393**	**680**	**1056**	**100**	**100**	**100**	**100**	**9.0**	**4.3**	**4.4**
Coal	11	184	371	620	25	47	55	59	11.6	5.5	5.4
Oil	31	122	144	150	73	31	21	14	5.4	1.3	0.9
Gas	1	87	165	286	2	22	24	27	20.6	5.1	5.3
Own Use & Losses	**20**	**164**	**263**	**359**	**100**	**100**	**100**	**100**	**8.5**	**3.7**	**3.5**
Total Final Consumption	**246**	**898**	**1421**	**1931**	**100**	**100**	**100**	**100**	**5.1**	**3.6**	**3.4**
Coal	120	198	220	238	49	22	15	12	2.0	0.8	0.8
Oil	124	648	1095	1528	50	72	77	79	6.6	4.1	3.8
Gas	2	53	106	165	1	6	7	9	13.1	5.6	5.1
Industry	**134**	**394**	**530**	**658**	**100**	**100**	**100**	**100**	**4.2**	**2.3**	**2.3**
Coal	94	192	216	234	70	49	41	36	2.8	0.9	0.9
Oil	39	170	243	309	29	43	46	47	5.9	2.8	2.6
Gas	2	32	71	115	1	8	13	17	12.3	6.4	5.8
Transportation	**54**	**326**	**600**	**890**	**100**	**100**	**100**	**100**	**7.1**	**4.8**	**4.5**
Oil	54	326	600	890	99	100	100	100	7.2	4.8	4.5
Other Fuels	1	0	0	0	1	0	0	0	–9.1	–2.2	–1.2
Other Sectors	**55**	**169**	**276**	**362**	**100**	**100**	**100**	**100**	**4.4**	**3.8**	**3.4**
Coal	25	6	4	3	45	3	1	1	–5.4	–2.8	–2.5
Oil	30	142	237	308	54	84	86	85	6.2	4.0	3.4
Gas	1	21	35	50	1	12	13	14	14.7	4.2	3.9
Non-Energy Use	**2**	**9**	**15**	**21**	**100**	**100**	**100**	**100**	**5.9**	**4.3**	**3.9**

Reference Scenario: Latin America

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**181**	**495**	**758**	**1004**	**100**	**100**	**100**	**100**	**3.9**	**3.3**	**3.1**
Coal	8	27	42	56	4	6	6	6	4.8	3.3	3.1
Oil	138	301	426	537	76	61	56	53	3.0	2.7	2.5
Gas	28	108	205	313	15	22	27	31	5.4	5.0	4.7
Nuclear	0	6	8	7	0	1	1	1	–	2.5	1.0
Hydro	7	47	69	81	4	9	9	8	7.3	3.1	2.5
Other Renewables	0	6	8	10	0	1	1	1	–	2.1	2.1
Power Generation	**33**	**126**	**220**	**315**	**100**	**100**	**100**	**100**	**5.4**	**4.4**	**4.0**
Coal	2	10	19	29	5	8	9	9	7.0	5.4	5.0
Oil	17	36	54	69	52	29	24	22	3.0	3.0	2.8
Gas	7	22	63	118	20	18	28	38	4.9	8.2	7.5
Nuclear	0	6	8	7	0	4	4	2	–	2.5	1.0
Hydro	7	47	69	81	23	37	32	26	7.3	3.1	2.5
Other Renewables	0	6	8	10	0	5	4	3	–	2.1	2.1
Own Use & Losses	**39**	**92**	**125**	**155**					**3.4**	**2.4**	**2.3**
of which Electricity	*2*	*15*	*24*	*31*					*7.5*	*3.5*	*3.3*
Total Final Consumption	**124**	**351**	**539**	**710**	**100**	**100**	**100**	**100**	**4.1**	**3.4**	**3.1**
Coal	4	11	14	16	3	3	3	2	4.1	1.9	1.7
Oil	96	229	334	427	77	65	62	60	3.4	2.9	2.7
Gas	12	51	88	122	10	15	16	17	5.7	4.3	3.9
Electricity	12	59	103	145	10	17	19	20	6.4	4.3	3.9
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**43**	**127**	**190**	**241**	**100**	**100**	**100**	**100**	**4.2**	**3.2**	**2.8**
Coal	3	11	14	16	8	8	7	7	4.5	2.0	1.8
Oil	24	47	58	65	55	37	30	27	2.7	1.7	1.4
Gas	10	41	69	93	23	32	36	38	5.5	4.1	3.6
Electricity	6	29	50	68	14	23	26	28	6.2	4.3	3.8
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**51**	**132**	**206**	**278**	**100**	**100**	**100**	**100**	**3.8**	**3.5**	**3.3**
Oil	50	131	205	276	99	99	99	99	3.7	3.5	3.3
Other fuels	0	1	2	2	1	1	1	1	6.1	1.0	1.2
Other Sectors	**26**	**81**	**128**	**173**	**100**	**100**	**100**	**100**	**4.4**	**3.6**	**3.3**
Coal	0	0	0	0	1	0	0	0	0.1	0.2	0.1
Oil	18	41	57	68	69	51	44	39	3.2	2.5	2.2
Gas	2	9	18	28	8	11	14	16	5.7	5.3	4.9
Electricity	6	30	53	77	22	37	41	44	6.6	4.4	4.1
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**4**	**11**	**15**	**18**					**3.5**	**2.3**	**2.2**

CRW (NOT included above)	71	88	95	100	28	15	11	9	0.9	0.5	0.5
Total Primary Energy Supply (including CRW)	**252**	**583**	**853**	**1104**	**100**	**100**	**100**	**100**	**3.3**	**3.0**	**2.8**

Reference Scenario: Latin America

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**165**	**863**	**1468**	**2041**	**100**	**100**	**100**	**100**	**6.6**	**4.2**	**3.8**
Coal	5	39	80	127	3	5	5	6	8.2	5.6	5.2
Oil	53	156	230	295	32	18	16	14	4.2	3.0	2.8
Gas	17	85	294	608	10	10	20	30	6.5	10.0	8.9
Nuclear	0	22	30	27	0	2	2	1	–	2.5	1.0
Hydro	87	541	807	947	53	63	55	46	7.3	3.1	2.5
Other Renewables	3	20	28	36	2	2	2	2	7.7	2.7	2.7
Capacity (GW)	**n.a.**	**195**	**324**	**448**	**n.a.**	**100**	**100**	**100**	**n.a.**	**4.0**	**3.7**
Coal	n.a.	8	14	21	n.a.	4	4	5	n.a.	4.4	4.4
Oil	n.a.	45	66	83	n.a.	23	20	19	n.a.	2.9	2.7
Gas	n.a.	23	69	137	n.a.	12	21	31	n.a.	8.7	8.0
Nuclear	n.a.	3	4	4	n.a.	1	1	1	n.a.	2.8	1.2
Hydro	n.a.	111	166	195	n.a.	57	51	43	n.a.	3.1	2.5
Other Renewables	n.a.	4	6	8	n.a.	2	2	2	n.a.	2.7	2.8

Reference Scenario: Latin America

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**495**	**1225**	**1871**	**2499**	**100**	**100**	**100**	**100**	**3.5**	**3.3**	**3.1**
change since 1990 (%)		*29.6*	*98.0*	*164.4*							
Coal	32	106	165	220	6	9	9	9	4.7	3.5	3.2
Oil	399	870	1234	1557	81	71	66	62	3.0	2.7	2.6
Gas	64	249	471	721	13	20	25	29	5.3	5.0	4.7
Power Generation	**76**	**206**	**393**	**614**	**100**	**100**	**100**	**100**	**3.9**	**5.1**	**4.9**
Coal	7	38	76	118	9	19	19	19	6.9	5.4	5.0
Oil	54	115	170	219	71	56	43	36	3.0	3.0	2.8
Gas	15	52	146	276	20	25	37	45	4.9	8.2	7.5
Own Use & Losses	**87**	**189**	**244**	**294**	**100**	**100**	**100**	**100**	**3.0**	**2.0**	**1.9**
Total Final Consumption	**332**	**830**	**1234**	**1591**	**100**	**100**	**100**	**100**	**3.6**	**3.1**	**2.9**
Coal	22	69	91	104	7	8	7	7	4.6	2.1	1.8
Oil	283	645	944	1211	85	78	77	76	3.2	3.0	2.8
Gas	28	115	199	276	8	14	16	17	5.6	4.3	3.9
Industry	**115**	**274**	**385**	**468**	**100**	**100**	**100**	**100**	**3.4**	**2.6**	**2.4**
Coal	20	68	89	103	17	25	23	22	4.8	2.2	1.8
Oil	72	115	142	158	63	42	37	34	1.8	1.6	1.4
Gas	23	91	153	207	20	33	40	44	5.4	4.1	3.6
Transportation	**149**	**389**	**609**	**822**	**100**	**100**	**100**	**100**	**3.8**	**3.5**	**3.3**
Oil	148	387	606	818	99	99	99	100	3.8	3.5	3.3
Other Fuels	1	3	3	4	1	1	1	0	4.9	1.7	1.6
Other Sectors	**59**	**140**	**204**	**259**	**100**	**100**	**100**	**100**	**3.4**	**3.0**	**2.7**
Coal	1	1	1	1	2	1	0	0	0.1	0.2	0.1
Oil	53	117	161	193	90	84	79	74	3.1	2.5	2.2
Gas	5	22	43	65	9	16	21	25	5.7	5.3	4.9
Non-Energy Use	**9**	**27**	**35**	**42**	**100**	**100**	**100**	**100**	**4.1**	**2.2**	**2.0**

Reference Scenario: Brazil

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**35**	**132**	**201**	**250**	**100**	**100**	**100**	**100**	**5.2**	**3.3**	**2.8**
Coal	2	12	17	20	7	9	9	8	6.5	2.6	2.1
Oil	29	86	124	148	82	65	61	59	4.3	2.9	2.4
Gas	0	5	16	32	0	4	8	13	15.5	8.7	8.2
Nuclear	0	1	3	3	0	1	1	1	–	10.4	5.8
Hydro	4	24	38	44	11	18	19	17	7.4	3.7	2.6
Other Renewables	0	0	0	0	0	0	0	0	–	–	–
Power Generation	**6**	**29**	**53**	**71**	**100**	**100**	**100**	**100**	**6.4**	**4.7**	**4.0**
Coal	1	2	3	3	10	5	5	5	3.9	4.1	3.4
Oil	2	3	4	6	26	9	8	8	2.0	4.4	3.7
Gas	0	0	4	16	0	1	8	22	–	24.7	19.6
Nuclear	0	1	3	3	0	3	6	4	–	10.4	5.8
Hydro	4	24	38	44	64	82	72	61	7.4	3.7	2.6
Other Renewables	0	0	0	0	0	0	0	0	–	–	–
Own Use & Losses	**5**	**27**	**36**	**41**					**6.4**	**2.2**	**1.9**
of which Electricity	*1*	*5*	*8*	*10*					*8.0*	*3.6*	*2.9*
Total Final Consumption	**28**	**105**	**161**	**195**	**100**	**100**	**100**	**100**	**5.2**	**3.3**	**2.7**
Coal	1	5	6	7	2	4	4	4	8.7	2.4	1.9
Oil	24	72	105	126	85	69	66	64	4.3	2.9	2.4
Gas	0	4	10	14	1	4	6	7	12.8	7.3	5.9
Electricity	4	25	39	48	13	23	24	25	7.6	3.7	3.0
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**9**	**39**	**59**	**72**	**100**	**100**	**100**	**100**	**5.7**	**3.3**	**2.7**
Coal	0	4	6	7	5	11	10	10	9.2	2.6	2.0
Oil	7	19	26	30	73	49	44	42	4.1	2.4	2.0
Gas	0	4	9	13	0	9	15	19	18.7	7.3	5.9
Electricity	2	12	18	21	21	30	30	30	7.2	3.3	2.7
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**13**	**38**	**59**	**72**	**100**	**100**	**100**	**100**	**4.1**	**3.3**	**2.8**
Oil	13	38	59	72	100	100	100	100	4.1	3.3	2.8
Other fuels	0	0	0	0	0	0	0	0	2.9	0.0	0.0
Other Sectors	**5**	**25**	**38**	**47**	**100**	**100**	**100**	**100**	**6.7**	**3.5**	**2.8**
Coal	0	0	0	0	0	0	0	0	–	–	–
Oil	3	12	16	19	61	47	43	41	5.7	2.7	2.2
Gas	0	0	1	1	3	1	2	2	2.6	7.4	6.7
Electricity	2	13	21	26	37	52	56	57	8.1	4.0	3.2
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**1**	**4**	**5**	**5**					**4.5**	**1.4**	**0.9**

CRW (NOT included above)	35	40	46	49	50	24	19	16	0.5	1.0	0.8
Total Primary Energy Supply (including CRW)	**70**	**172**	**248**	**299**	**100**	**100**	**100**	**100**	**3.5**	**2.8**	**2.4**

Reference Scenario: Brazil

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**51**	**307**	**516**	**637**	**100**	**100**	**100**	**100**	**7.2**	**4.1**	**3.2**
Coal	2	5	9	12	4	2	2	2	4.1	4.2	3.5
Oil	5	10	17	22	9	3	3	4	2.8	4.4	3.7
Gas	0	1	20	69	0	0	4	11	–	24.9	19.7
Nuclear	0	3	11	11	0	1	2	2	–	10.4	5.8
Hydro	43	279	445	507	85	91	86	80	7.4	3.7	2.6
Other Renewables	1	9	12	16	2	3	2	2	8.9	2.7	2.5
Capacity (GW)	**n.a.**	**63**	**104**	**127**	**n.a.**	**100**	**100**	**100**	**n.a.**	**3.9**	**3.1**
Coal	n.a.	2	2	2	n.a.	3	2	2	n.a.	1.7	1.3
Oil	n.a.	4	5	6	n.a.	6	5	5	n.a.	2.7	2.1
Gas	n.a.	0	4	13	n.a.	1	4	10	n.a.	22.2	17.6
Nuclear	n.a.	1	2	2	n.a.	1	2	1	n.a.	8.8	4.9
Hydro	n.a.	55	88	100	n.a.	87	84	79	n.a.	3.7	2.6
Other Renewables	n.a.	2	3	4	n.a.	3	3	3	n.a.	2.5	2.4

Reference Scenario: Brazil

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**97**	**301**	**453**	**570**	**100**	**100**	**100**	**100**	**4.4**	**3.2**	**2.8**
change since 1990 (%)		*37.6*	*107.1*	*160.4*							
Coal	9	47	66	77	9	16	15	14	6.5	2.7	2.2
Oil	88	242	351	420	90	81	78	74	4.0	2.9	2.4
Gas	0	12	35	73	0	4	8	13	15.6	8.8	8.2
Power Generation	**7**	**15**	**34**	**68**	**100**	**100**	**100**	**100**	**2.8**	**6.8**	**6.9**
Coal	2	6	10	13	32	41	29	19	3.8	4.1	3.4
Oil	5	8	14	18	68	55	40	27	1.9	4.4	3.7
Gas	0	1	10	36	0	4	30	54	–	24.7	19.6
Own Use & Losses	**12**	**35**	**47**	**54**	**100**	**100**	**100**	**100**	**4.4**	**2.1**	**1.9**
Total Final Consumption	**78**	**251**	**372**	**448**	**100**	**100**	**100**	**100**	**4.6**	**3.1**	**2.5**
Coal	6	42	57	66	7	17	15	15	8.0	2.5	2.0
Oil	72	201	293	351	92	80	79	78	4.0	3.0	2.5
Gas	0	8	21	32	0	3	6	7	12.7	7.3	5.9
Industry	**27**	**91**	**133**	**161**	**100**	**100**	**100**	**100**	**4.8**	**3.0**	**2.5**
Coal	5	41	57	65	20	45	43	40	8.1	2.6	2.0
Oil	21	42	57	67	80	46	43	42	2.7	2.4	2.0
Gas	0	8	19	29	0	9	15	18	19.2	7.3	5.9
Transportation	**40**	**115**	**176**	**216**	**100**	**100**	**100**	**100**	**4.2**	**3.3**	**2.8**
Oil	40	115	176	216	100	100	100	100	4.2	3.3	2.8
Other Fuels	0	0	0	0	0	0	0	0	2.5	0.0	0.0
Other Sectors	**8**	**33**	**48**	**56**	**100**	**100**	**100**	**100**	**5.6**	**2.8**	**2.3**
Coal	0	0	0	0	0	0	0	0	–	–	–
Oil	8	33	46	54	96	98	97	96	5.7	2.7	2.2
Gas	0	1	1	3	4	2	3	4	2.6	7.4	6.7
Non-Energy Use	**4**	**12**	**14**	**14**	**100**	**100**	**100**	**100**	**4.5**	**1.3**	**0.8**

Reference Scenario: Africa

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**76**	**241**	**349**	**457**	**100**	**100**	**100**	**100**	**4.6**	**2.9**	**2.8**
Coal	36	87	116	143	48	36	33	31	3.5	2.2	2.2
Oil	35	104	147	192	46	43	42	42	4.3	2.7	2.7
Gas	3	41	73	108	3	17	21	24	11.4	4.5	4.3
Nuclear	0	3	3	3	0	1	1	1	–	0.2	0.1
Hydro	2	5	7	8	3	2	2	2	4.1	1.9	1.7
Other Renewables	0	0	2	3	0	0	1	1	–	11.5	8.5
Power Generation	**27**	**89**	**134**	**178**	**100**	**100**	**100**	**100**	**4.8**	**3.2**	**3.0**
Coal	21	50	67	82	81	56	50	46	3.3	2.3	2.2
Oil	3	14	18	22	11	16	14	12	6.4	1.9	1.8
Gas	0	16	37	60	1	18	27	34	15.5	6.5	5.9
Nuclear	0	3	3	3	0	4	3	2	–	0.2	0.1
Hydro	2	5	7	8	7	6	5	4	4.1	1.9	1.7
Other Renewables	0	0	2	3	0	0	1	2	–	11.5	8.5
Own Use & Losses	**1**	**43**	**63**	**84**					**17.2**	**2.9**	**2.9**
of which Electricity	*1*	*7*	*10*	*13*					*7.3*	*3.0*	*3.0*
Total Final Consumption	**56**	**142**	**205**	**269**	**100**	**100**	**100**	**100**	**3.6**	**2.8**	**2.8**
Coal	18	18	22	25	32	13	11	9	0.0	1.3	1.3
Oil	31	84	122	160	54	59	59	59	4.0	2.9	2.8
Gas	1	12	18	24	1	9	9	9	12.6	2.9	2.8
Electricity	7	27	43	61	12	19	21	23	5.4	3.6	3.5
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–

Industry	**21**	**47**	**64**	**80**	**100**	**100**	**100**	**100**	**3.0**	**2.4**	**2.4**
Coal	10	10	12	13	47	22	19	17	0.1	1.2	1.1
Oil	6	14	19	22	30	29	29	28	2.9	2.3	2.1
Gas	0	9	13	16	2	19	20	20	11.9	2.8	2.7
Electricity	4	14	20	28	20	29	32	35	4.5	3.2	3.2
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**20**	**44**	**61**	**79**	**100**	**100**	**100**	**100**	**3.1**	**2.6**	**2.6**
Oil	16	43	60	78	80	97	98	98	3.9	2.6	2.6
Other fuels	4	1	1	2	20	3	2	2	–4.7	1.4	1.3
Other Sectors	**13**	**41**	**66**	**94**	**100**	**100**	**100**	**100**	**4.5**	**3.7**	**3.6**
Coal	4	3	4	4	27	7	5	4	–0.6	1.2	1.1
Oil	7	22	36	51	54	53	54	55	4.5	3.9	3.7
Gas	0	3	5	6	1	7	7	7	14.0	3.5	3.5
Electricity	2	13	22	32	18	32	33	34	6.8	4.0	3.9
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Non-Energy Use	**2**	**11**	**14**	**17**					**6.7**	**1.8**	**1.9**

CRW (NOT included above)	125	231	294	347	62	49	46	43	2.4	1.9	1.8
Total Primary Energy Supply (including CRW)	**200**	**473**	**643**	**803**	**100**	**100**	**100**	**100**	**3.4**	**2.4**	**2.3**

Reference Scenario: Africa

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**90**	**399**	**619**	**864**	**100**	**100**	**100**	**100**	**5.9**	**3.4**	**3.4**
Coal	56	204	281	349	62	51	45	40	5.1	2.5	2.4
Oil	10	60	78	95	12	15	13	11	6.9	2.0	2.0
Gas	1	59	164	308	1	15	26	36	16.9	8.2	7.5
Nuclear	0	13	13	13	0	3	2	2	–	0.2	0.1
Hydro	22	63	80	93	25	16	13	11	4.1	1.9	1.7
Other Renewables	0	0	4	6	0	0	1	1	–	18.1	11.7
Capacity (GW)	**n.a.**	**97**	**142**	**192**	**n.a.**	**100**	**100**	**100**	**n.a.**	**3.0**	**3.0**
Coal	n.a.	37	46	54	n.a.	38	33	28	n.a.	1.7	1.6
Oil	n.a.	23	30	36	n.a.	24	21	19	n.a.	2.0	2.0
Gas	n.a.	14	36	68	n.a.	14	26	36	n.a.	7.7	7.2
Nuclear	n.a.	2	2	2	n.a.	2	1	1	n.a.	0.0	0.0
Hydro	n.a.	20	26	30	n.a.	21	18	16	n.a.	1.9	1.7
Other Renewables	n.a.	0	1	2	n.a.	0	1	1	n.a.	8.5	6.6

Reference Scenario: Africa

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**249**	**729**	**1039**	**1348**	**100**	**100**	**100**	**100**	**4.2**	**2.8**	**2.7**
change since 1990 (%)		*19.3*	*70.0*	*120.4*							
Coal	140	338	449	549	56	46	43	41	3.5	2.2	2.1
Oil	103	297	422	549	41	41	41	41	4.2	2.7	2.7
Gas	6	94	168	249	2	13	16	18	11.3	4.6	4.3
Power Generation	**93**	**277**	**405**	**527**	**100**	**100**	**100**	**100**	**4.3**	**3.0**	**2.8**
Coal	83	194	261	318	89	70	65	60	3.3	2.3	2.2
Oil	9	46	58	69	10	16	14	13	6.4	1.9	1.8
Gas	1	38	86	139	1	14	21	26	15.5	6.5	5.9
Own Use & Losses	**–14**	**107**	**154**	**204**	**100**	**100**	**100**	**100**	**–**	**2.8**	**2.8**
Total Final Consumption	**170**	**345**	**480**	**616**	**100**	**100**	**100**	**100**	**2.8**	**2.6**	**2.5**
Coal	77	78	93	105	46	23	19	17	0.0	1.3	1.3
Oil	91	240	348	459	54	70	73	75	3.8	2.9	2.9
Gas	1	27	39	51	1	8	8	8	12.3	2.9	2.8
Industry	**68**	**106**	**136**	**160**	**100**	**100**	**100**	**100**	**1.7**	**1.9**	**1.8**
Coal	46	47	55	61	68	44	40	38	0.1	1.2	1.1
Oil	20	40	54	65	30	38	40	41	2.7	2.3	2.1
Gas	1	19	27	34	2	18	20	21	11.5	2.8	2.7
Transportation	**61**	**127**	**177**	**230**	**100**	**100**	**100**	**100**	**2.8**	**2.6**	**2.6**
Oil	47	125	175	228	77	99	99	99	3.9	2.6	2.6
Other Fuels	14	2	2	2	23	1	1	1	–8.0	0.8	0.8
Other Sectors	**35**	**83**	**131**	**180**	**100**	**100**	**100**	**100**	**3.4**	**3.5**	**3.4**
Coal	14	12	14	15	39	14	11	9	–0.6	1.2	1.1
Oil	21	65	106	150	60	78	81	83	4.4	3.9	3.7
Gas	0	7	11	15	1	8	8	8	14.1	3.5	3.5
Non-Energy Use	**6**	**29**	**37**	**45**	**100**	**100**	**100**	**100**	**6.6**	**1.8**	**1.9**

Reference Scenario: Middle East

	Energy Demand (Mtoe)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total Primary Energy Supply	**55**	**354**	**502**	**675**	**100**	**100**	**100**	**100**	**7.4**	**2.7**	**2.8**
Coal	0	7	13	18	1	2	3	3	11.6	5.2	4.4
Oil	38	214	278	344	70	60	55	51	6.8	2.0	2.1
Gas	16	132	207	307	29	37	41	46	8.5	3.5	3.8
Nuclear	0	0	2	2	0	0	0	0	–	–	–
Hydro	0	2	3	3	1	0	1	0	6.4	4.5	2.5
Other Renewables	0	1	1	1	0	0	0	0	–	2.8	2.3
Power Generation	**8**	**82**	**132**	**183**	**100**	**100**	**100**	**100**	**9.6**	**3.7**	**3.6**
Coal	0	5	11	16	0	7	9	9	–	5.7	4.7
Oil	6	40	53	59	80	49	40	32	7.6	2.1	1.7
Gas	1	34	63	104	16	42	48	57	13.7	4.8	4.9
Nuclear	0	0	2	2	0	0	1	1	–	–	–
Hydro	0	2	3	3	4	2	2	2	6.4	4.5	2.5
Other Renewables	0	0	0	0	0	0	0	0	–	54.1	31.1
Own Use & Losses	**15**	**81**	**114**	**156**					**6.8**	**2.7**	**2.9**
of which Electricity	*0*	*6*	*10*	*14*					*11.5*	*4.1*	*4.0*
Total Final Consumption	**35**	**223**	**309**	**414**	**100**	**100**	**100**	**100**	**7.4**	**2.5**	**2.7**
Coal	0	1	1	1	1	0	0	0	2.9	2.0	2.5
Oil	21	140	181	230	60	63	59	56	7.6	2.0	2.2
Gas	12	56	83	118	34	25	27	29	6.2	3.0	3.3
Electricity	2	26	43	64	6	12	14	15	10.3	4.1	4.0
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	1	1	1	0	0	0	0	–	2.5	2.1

Industry	**16**	**64**	**91**	**120**	**100**	**100**	**100**	**100**	**5.4**	**2.7**	**2.8**
Coal	0	1	1	1	2	1	1	1	2.9	2.0	2.5
Oil	4	27	35	42	23	42	38	35	7.8	2.1	2.0
Gas	12	32	45	61	71	50	50	51	3.9	2.7	2.8
Electricity	1	5	10	16	4	7	11	13	7.9	6.1	5.5
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	0	0	0	0	0	0	0	–	–	–
Transportation	**9**	**61**	**89**	**124**	**100**	**100**	**100**	**100**	**7.8**	**2.9**	**3.1**
Oil	9	61	89	124	100	100	100	100	7.8	2.9	3.1
Other fuels	0	0	0	0	0	0	0	0	–	5.0	5.3
Other Sectors	**8**	**93**	**121**	**159**	**100**	**100**	**100**	**100**	**9.7**	**2.1**	**2.4**
Coal	0	0	0	0	0	0	0	0	–	–	–
Oil	7	47	50	54	83	50	41	34	7.6	0.5	0.6
Gas	0	24	38	57	0	26	31	36	–	3.5	3.8
Electricity	1	21	33	48	17	23	27	30	11.0	3.6	3.6
Heat	0	0	0	0	0	0	0	0	–	–	–
Renewables	0	1	1	1	0	1	1	1	–	2.5	2.1
Non-Energy Use	**1**	**6**	**8**	**11**					**5.7**	**2.8**	**2.8**

CRW (NOT included above)	1	1	1	2	1	0	0	0	1.2	2.0	2.0
Total Primary Energy Supply (including CRW)	**56**	**355**	**503**	**676**	**100**	**100**	**100**	**100**	**7.4**	**2.7**	**2.8**

Reference Scenario: Middle East

	Levels				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Electricity Generation (TWh)	**28**	**366**	**614**	**907**	**100**	**100**	**100**	**100**	**10.4**	**4.1**	**4.0**
Coal	0	25	51	73	0	7	8	8	–	5.8	4.8
Oil	20	163	216	246	71	45	35	27	8.5	2.2	1.8
Gas	4	159	307	547	15	43	50	60	15.1	5.2	5.5
Nuclear	0	0	7	7	0	0	1	1	–	–	–
Hydro	4	19	34	34	14	5	5	4	6.4	4.5	2.5
Other Renewables	0	0	0	1	0	0	0	0	–	54.6	31.3
Capacity (GW)	**n.a.**	**95**	**149**	**220**	**n.a.**	**100**	**100**	**100**	**n.a.**	**3.5**	**3.7**
Coal	n.a.	4	8	11	n.a.	4	5	5	n.a.	5.8	4.8
Oil	n.a.	45	59	73	n.a.	48	39	33	n.a.	2.1	2.1
Gas	n.a.	40	71	125	n.a.	42	48	57	n.a.	4.5	5.0
Nuclear	n.a.	0	1	1	n.a.	0	1	0	n.a.	–	–
Hydro	n.a.	6	10	10	n.a.	6	7	5	n.a.	4.5	2.5
Other Renewables	n.a.	0	0	0	n.a.	0	0	0	n.a.	13.1	10.1

Reference Scenario: Middle East

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**146**	**956**	**1338**	**1783**	**100**	**100**	**100**	**100**	**7.5**	**2.6**	**2.7**
change since 1990 (%)		*47.5*	*106.4*	*175.2*							
Coal	1	25	49	68	1	3	4	4	11.5	5.2	4.4
Oil	108	625	809	1000	74	65	60	56	7.0	2.0	2.1
Gas	37	305	480	714	25	32	36	40	8.5	3.5	3.8
Power Generation	**22**	**227**	**356**	**488**	**100**	**100**	**100**	**100**	**9.4**	**3.5**	**3.4**
Coal	0	21	43	61	0	9	12	13	–	5.7	4.7
Oil	19	126	164	184	87	55	46	38	7.5	2.1	1.7
Gas	3	80	148	243	13	35	42	50	13.7	4.8	4.9
Own Use & Losses	**34**	**189**	**262**	**354**	**100**	**100**	**100**	**100**	**6.8**	**2.5**	**2.8**
Total Final Consumption	**90**	**539**	**720**	**942**	**100**	**100**	**100**	**100**	**7.1**	**2.2**	**2.5**
Coal	2	5	6	9	2	1	1	1	4.7	2.0	2.5
Oil	62	405	523	661	68	75	73	70	7.5	2.0	2.2
Gas	27	130	191	272	30	24	27	29	6.2	3.0	3.3
Industry	**40**	**156**	**211**	**271**	**100**	**100**	**100**	**100**	**5.3**	**2.3**	**2.4**
Coal	2	5	6	9	4	3	3	3	4.7	2.0	2.5
Oil	12	78	102	123	29	50	48	45	7.6	2.1	2.0
Gas	27	73	102	139	67	47	48	51	3.9	2.7	2.8
Transportation	**25**	**179**	**261**	**364**	**100**	**100**	**100**	**100**	**7.8**	**2.9**	**3.1**
Oil	25	179	261	364	100	100	100	100	7.8	2.9	3.1
Other Fuels	0	0	0	0	0	0	0	0	–	–	–
Other Sectors	**21**	**197**	**237**	**293**	**100**	**100**	**100**	**100**	**9.0**	**1.4**	**1.7**
Coal	0	0	0	0	0	0	0	0	–	–	–
Oil	21	140	149	160	100	71	63	55	7.6	0.5	0.6
Gas	0	57	89	133	0	29	37	45	–	3.5	3.8
Non-Energy Use	**4**	**7**	**10**	**14**	**100**	**100**	**100**	**100**	**2.6**	**2.8**	**2.8**

Reference Scenario: Annex B

	CO_2 Emissions (Mt)				Shares (%)				Growth Rates (% per annum)		
	1971	1997	2010	2020	1971	1997	2010	2020	1971-1997	1997-2010	1997-2020
Total CO_2 Emissions	**n.a.**	**13385**	**15537**	**17024**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.2**	**1.1**
change since 1990 (%)		*–4.1*	*11.4*	*22.0*							
Coal	n.a.	4520	4812	5056	n.a.	34	31	30	n.a.	0.5	0.5
Oil	n.a.	5621	6535	7083	n.a.	42	42	42	n.a.	1.2	1.0
Gas	n.a.	3243	4191	4885	n.a.	24	27	29	n.a.	2.0	1.8
Power Generation	**n.a.**	**4763**	**5732**	**6395**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.4**	**1.3**
Coal	n.a.	3467	3928	4200	n.a.	73	69	66	n.a.	1.0	0.8
Oil	n.a.	357	297	213	n.a.	7	5	3	n.a.	–1.4	–2.2
Gas	n.a.	939	1507	1983	n.a.	20	26	31	n.a.	3.7	3.3
Own Use & Losses	**n.a.**	**1206**	**1385**	**1540**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.1**	**1.1**
Total Final Consumption	**n.a.**	**7416**	**8420**	**9089**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.0**	**0.9**
Coal	n.a.	794	648	615	n.a.	11	8	7	n.a.	–1.6	–1.1
Oil	n.a.	4738	5569	6095	n.a.	64	66	67	n.a.	1.3	1.1
Gas	n.a.	1883	2203	2379	n.a.	25	26	26	n.a.	1.2	1.0
Industry	**n.a.**	**1943**	**1975**	**1969**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.1**	**0.1**
Coal	n.a.	613	506	471	n.a.	32	26	24	n.a.	–1.5	–1.1
Oil	n.a.	582	594	595	n.a.	30	30	30	n.a.	0.2	0.1
Gas	n.a.	748	874	903	n.a.	38	44	46	n.a.	1.2	0.8
Transportation	**n.a.**	**3287**	**4159**	**4728**	**n.a.**	**100**	**100**	**100**	**n.a.**	**1.8**	**1.6**
Oil	n.a.	3196	4041	4585	n.a.	97	97	97	n.a.	1.8	1.6
Other Fuels	n.a.	90	119	143	n.a.	3	3	3	n.a.	2.1	2.0
Other Sectors	**n.a.**	**2022**	**2107**	**2203**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.3**	**0.4**
Coal	n.a.	165	125	128	n.a.	8	6	6	n.a.	–2.1	–1.1
Oil	n.a.	810	770	740	n.a.	40	37	34	n.a.	–0.4	–0.4
Gas	n.a.	1047	1212	1335	n.a.	52	58	61	n.a.	1.1	1.1
Non-Energy Use	**n.a.**	**164**	**179**	**189**	**n.a.**	**100**	**100**	**100**	**n.a.**	**0.7**	**0.6**

APPENDIX 1
WORLD ENERGY MODEL DESCRIPTION

Objectives

Since 1993, the IEA has provided long-term energy projections using a world energy model (WEM). The WEM used to produce this *Outlook* is the sixth version of the model. The WEM is a tool to analyse:

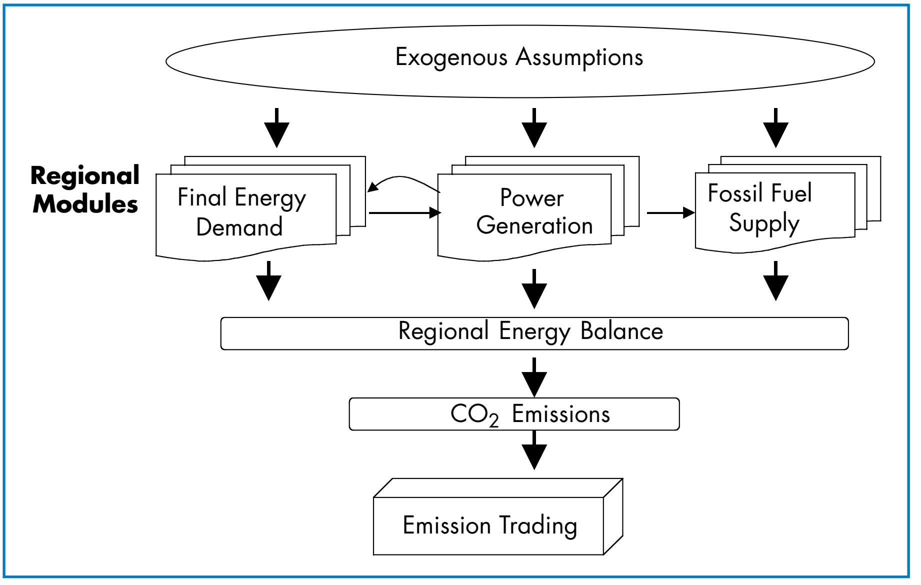
- *Global energy prospects:* trends in demand, supply availability and constraints, international trade and energy balances by sector and by fuel to 2020.
- *Environmental impact of energy use:* CO_2 emissions from fuel combustion are derived from the detailed projections of energy consumption, while emission trading among Annex B countries is simulated to arrive at a optimal price for tradable permits.
- *Effects of policy actions or technological changes:* scenarios to analyse the impact of policy actions and developments in technologies, such as in: electricity generation, transportation and fossil fuel supply, and in the overall energy supply/demand balance.

Model Structure

The WEM is a mathematical model made up of four main sub-models: final demand, power generation and other transformation, fossil fuel supply and emission trading. Figure A1.1 provides a simplified overview of the structure of the model.

The main exogenous assumptions are GDP, population, international fossil fuel prices and technological developments. The level of electricity consumption and electricity prices link the final energy demand and power generation modules. Primary demand for fossil fuels serves as input for the supply modules. Energy balances are calculated using the outputs of the three modules for each region. CO_2 emissions can then be derived using implied carbon factors. The emission trading module uses marginal abatement cost curves, obtained by an iterative process of running the WEM with different carbon values.

Figure A1.1: **World Energy Model Overview**



Geographic Breakdown

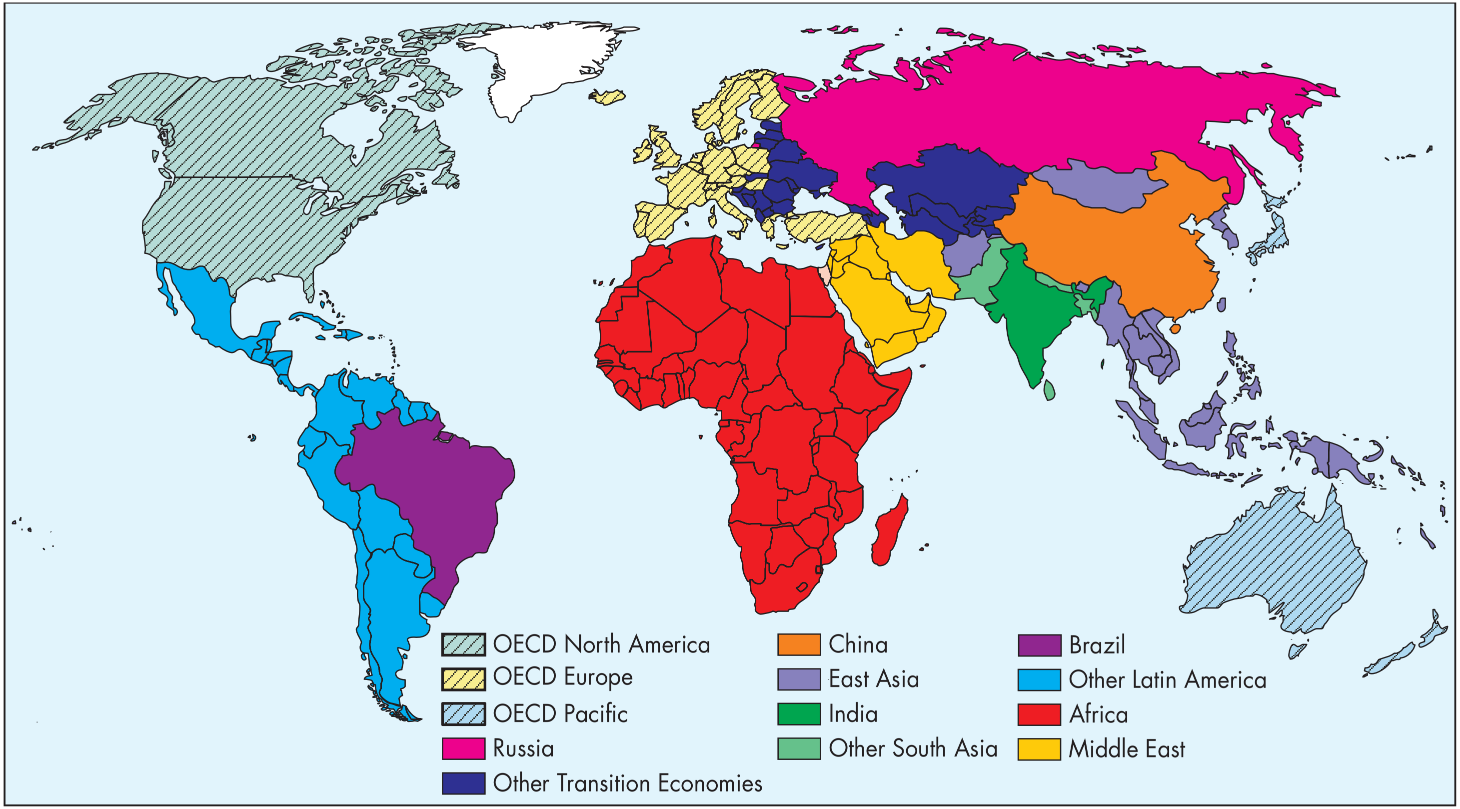
Figure A1.2 presents the regional structure of the WEM. The number of regions/countries included has increased since the 1998 *WEO*. The WEM now contains more detailed, separate treatment of four countries: China, Russia, India and Brazil.

Technical Aspects

The development and running of the WEM requires access to historical data on economic and energy variables. Most of the data is provided by the Energy Statistics Division of the IEA. Some of the principal sources of information are shown in Table A1.1.

The parameters of each module equation are estimated econometrically, usually using data for the period 1971-1997. To take into account expected structural, policy or technological changes, adjustments of these parameters are sometimes made, using both econometric and calibration techniques. In regions such as the transition economies, where reliable data are only available from 1992, it is not possible to use econometric estimation. The results are prepared using assumptions based on cross-country analyses or expert judgement.

Figure A1.2: **WEM Regions**



Note: The depiction of boundaries shown on this map is not warranted to be error free and does not necessarily imply acceptance by the IEA.

Table A1.1: **Primary Data Sources**

Variables	Sources
Energy	IEA; Nuclear Energy Agency; International Atomic Energy Agency
Macro-economic activity and demography	OECD; The World Bank; United Nations; International Monetary Fund; International Road Federation; International Iron and Steel Institute
Oil and gas resources	United States Geological Survey (USGS); Cedigaz; Petroconsultants
Technology	IEA; Nuclear Energy Agency; Coal Industry Advisory Board; IEA Coal Research; Utility Data Institute; Ministry of International Trade and Industry (Japan); US Energy Information Administration; Commissariat à l'Energie Atomique

Simulations are carried out on an annual basis. Modules can be isolated and simulations run separately. This is particularly useful in the adjustment process and in the sensitivity analyses of specific areas.

The WEM makes use of various software: specific database management tools, econometric software and simulation programmes.

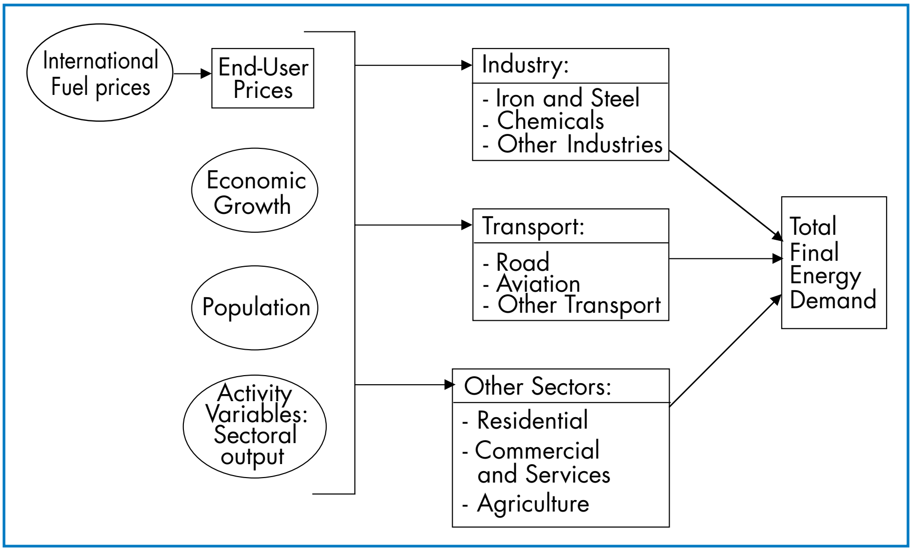
Description of the Modules

Final Energy Demand

The final energy demand module is based on the sectoral breakdown shown in Figure A1.3. In some cases non-OECD regions are modelled in a less detailed manner than OECD countries. This is often due to a lack of information. The industry sector is not broken into sub-sectors for some countries. The residential, commercial and services sectors are also sometimes merged. In the standard model, nine sectors are modelled.

Total final energy demand is the sum of energy consumption of each sector. In each sector six types of energy are identified: coal, oil, gas, electricity, heat and renewables. Within each sector, whether substitution

Figure A1.3: **Structure of the Final Energy Demand Module**



between fuels is considered or not, fuel consumption is estimated in a more or less aggregate way. If aggregated, the consumption is split between fuels mainly by relative fuel prices as well as other market determinants, such as capital stock turnover. If fuels are estimated separately, total final consumption is calculated as the sum of each component. In most of the equations, energy demand is a function of the following explanatory variables:

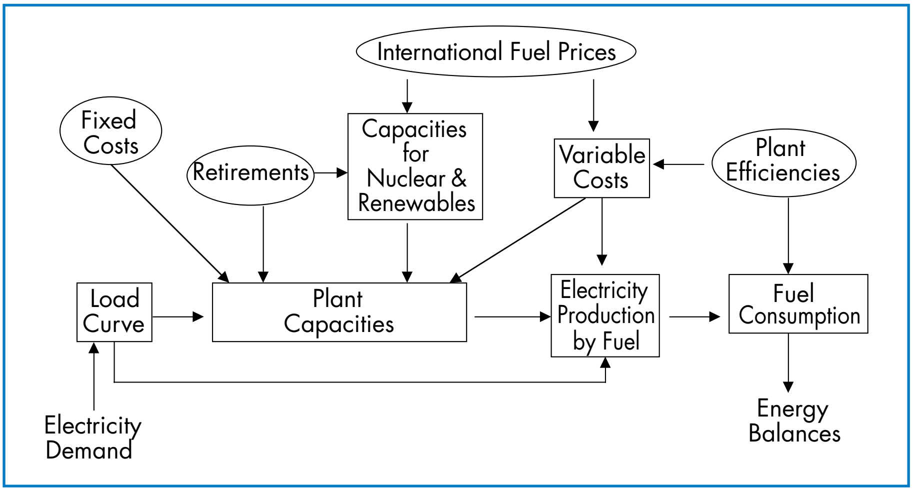
- *Economic activity:* This is represented in general by GDP or GDP per capita. In several sectors, a specific activity variable is used. For example, in the steel industry, final energy demand is a function of steel production. In the transport sector, vehicle stock, passenger-kilometres or tonne-kilometres are used.
- *Price:* End-user prices are calculated from the exogenous international energy prices. They take into account both variable and fixed taxes, and also transformations and distribution costs. For each sector, a representative price (usually a weighted average) is derived. This takes account of the product mix in final consumption and differences between countries. This representative price is then used as an explanatory variable directly, lagged or as a moving average.
- *Other variables:* Other variables are used to take into account structural and technological changes, or saturation effects.

Power Generation

The purpose of the power generation module is to calculate the following:

- Amount of any new generating capacity needed.
- Type of any new plant to be built.
- Amount of electricity generated by each type of plant.
- Fuels consumed to generate the previously determined level of electricity demand.
- System marginal cost of generation.

Figure A1.4: **Power Generation Module**



The structure of the power generation module is described in Figure A1.4. Peak load is calculated using the demand for electricity together with an assumed load curve. The need for new generating capacity is calculated by adding a minimum reserve plant margin to peak load and comparing that with the capacity of existing plants less plant retirements using assumed plant lives. An allowance is made for assumed plant availability. If new capacity is needed, the choice is made on the basis of levelised cost. The levelised generating cost (expressed as monetary value per kWh) combines capital, operating and fuel costs over the whole operating life of a plant using a given discount rate and plant utilisation rate. The model uses 11 different technological types of plant:

- Steam boiler
- Combined cycle gas turbine (CCGT)

- Open cycle gas turbine (GT)
- Integrated gasification combined cycle (IGCC)
- Nuclear
- Biomass
- Geothermal
- Wind
- Hydro (conventional)
- Hydro (pumped storage)
- Solar

Where possible, the CHP option is considered for fossil fuels and biomass plants.

Capacities for nuclear and renewables plants are calculated mainly from exogenous assumptions, but are influenced by international fossil fuels prices to take account of price incentives to develop such plants.

Fossil fuel prices are used to load plants in ascending order of fuel and operating cost, allowing for assumed plant availability. Once the mix of generation plants has been determined, the fuel requirements are then deduced by plant type using an assumed efficiency.

The marginal generating cost of the system is calculated, and this cost is then fed back to the demand model to determine the electricity price.

CO_2 Emissions

For each region, sector and fuel, CO_2 emissions are calculated by multiplying energy demand by an implied carbon emission factor. Implied emission factors for coal, oil and gas differ between sectors and regions, reflecting the product mix. They have been calculated from 1997 IEA data.[1]

Fossil Fuel Supply

Oil module

The purpose of this module is to determine the level of oil production in each region. Production is split into three categories:

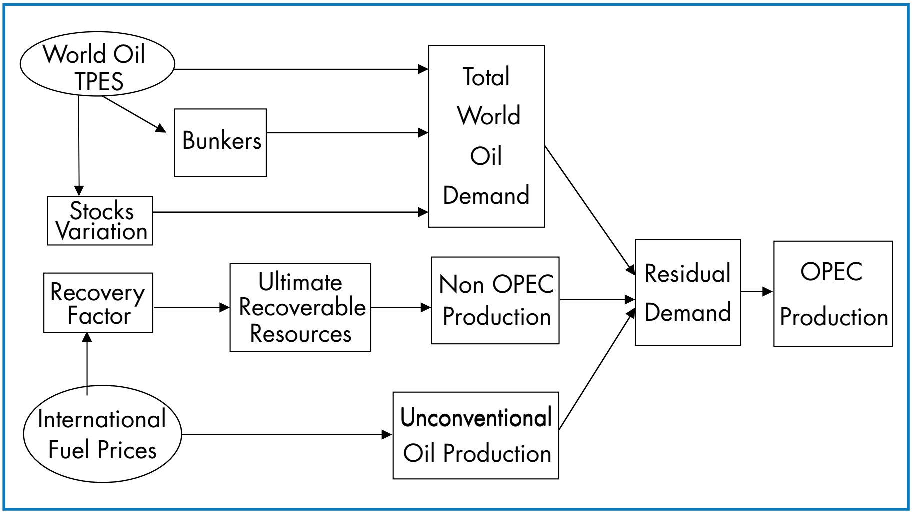
- Non-OPEC
- OPEC
- Unconventional oil production

OPEC conventional oil production is assumed to fill the gap between non-OPEC and unconventional production and total world oil demand

1. IEA, 1999.

(Figure A1.5). Total oil demand is the sum of regional oil demand, world bunkers and stock variation.

Figure A1.5: **Structure of Oil Supply Sub-Module**



The derivation of conventional and unconventional non-OPEC production uses a combination of two different approaches. A short-term approach estimates production profiles based on a field-by-field analysis. A long-term approach involves the determination of production according to the level of ultimate recoverable resources and a depletion rate estimated using historical data. Ultimate recoverable resources depend on a recovery factor. This recovery factor reflects reserve growth, which results from improvements in drilling, exploration and production technologies. The trend in the recovery rate is, in turn, a function of the oil price and a technological improvement factor.

Gas module

The gas sub-module is similarly based on a resources approach. However, there are some important differences with the oil sub-module. In particular, three regional gas markets — America, Europe and Africa, and Asia — are considered, whereas oil is modelled as a single international market. Two country types are modelled: net importers and net exporters. Once gas production from each net importer region is estimated, taking into account ultimate recoverable resources and a depletion rate, the remaining regional demand is allocated to the net exporter regions with exogenous assumptions on their respective shares.

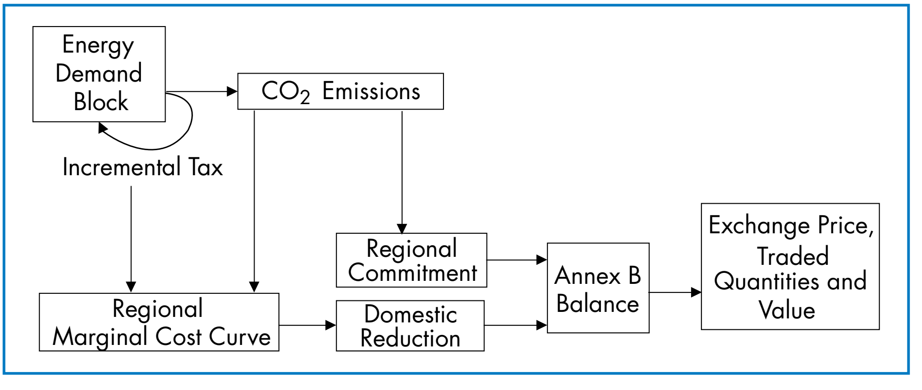
Coal module

Sufficient reserves of coal exist to meet world demand and coal reserves are generally much more evenly distributed throughout the world than oil and gas reserves. Because of the wide diversity of existing and potential coal suppliers, security of coal supply is not an issue. The current WEM does not, therefore, model coal supply explicitly but information on coal production prospects is provided in the regional chapters.

Emission Trading

Running the emission trading module involves a two-step process. First, marginal abatement cost curves for each of the five trading regions[2] are calculated for each given set of energy balances. Second, trade in emission permits among the five Annex B regions is determined, establishing a market-clearing price for each permit on the basis of the marginal abatement cost curves (Figure A1.6).

Figure A1.6: **Emission Trading Module**



Marginal abatement cost curves are obtained through an iterative process. They are calculated by introducing different carbon tax rates in the regional final energy modules. With each iteration, the regional modules yield different levels of carbon dioxide emissions compared with the

2. OECD North America, OECD Europe (excluding Turkey), OECD Pacific, Russia and Ukraine/Eastern Europe.

reference case. The results are then used to estimate econometrically a continuous marginal abatement cost curve.

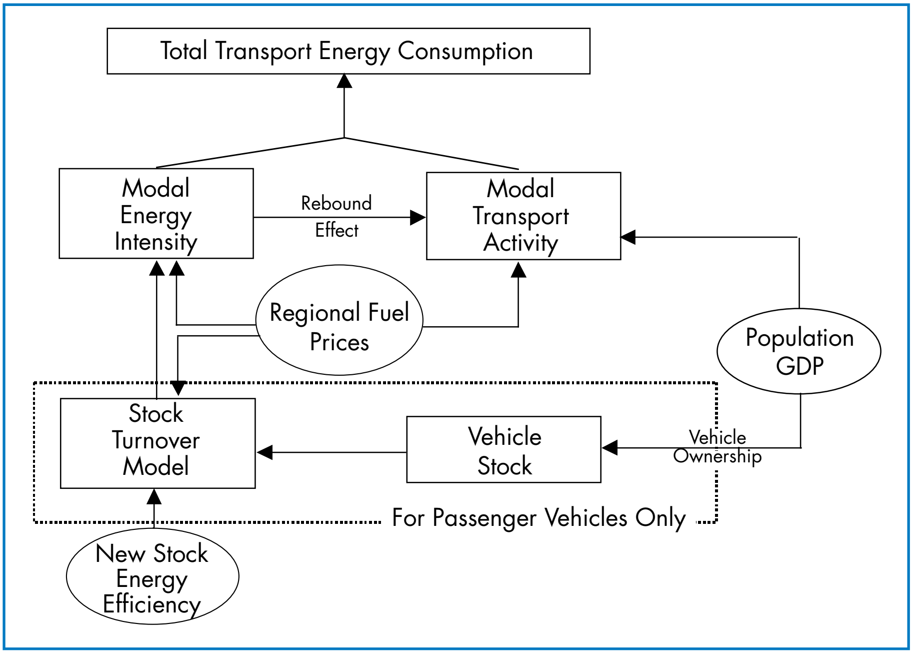
Trading itself can be seen as a process of finding the market-clearing price, at which the trading system is in equilibrium. Equilibrium is the point at which the sum of all the emissions reductions equals the sum of the Kyoto commitments. Thus, every region reduces its emissions up to the point where its marginal abatement cost equals the permit price.

In the second step, the difference between each region's commitment and the initial reduction is assessed. This defines the scope for exports and imports of permits. Total exports must equal total imports, as the sum of excess demands will sum to zero. Monetary transfers, GDP impacts, and the calculations of gains from trade are then calculated arithmetically.

Modelling Transportation for the Alternative Transportation Case

The simulations of alternative transportation policies described in Chapter 11 require a more disaggregated framework than that provided by the standard WEM. Therefore, a more detailed bottom-up model was developed (Figure A1.7). To maintain consistency between this approach

Figure A1.7: **Structure of the Transportation Model**



and the aggregated approach of the WEM, the reference case for the transportation model was calibrated so as to achieve a maximum difference of ±2% on total transport final consumption with the WEM results.

For every region, activity levels for each mode of transport are a function of population, GDP and price. The elasticity of transport activity to the fuel cost per km is applied to all modes except passenger and freight rail and inland waterways. In the case of passenger vehicles, this elasticity is also used to determine the rebound effect of increased transport demand resulting from improved fuel intensity. Additional assumptions to reflect passenger vehicle ownership saturation are also made.

Modal energy intensity is projected taking into account changes in energy efficiency and fuel prices. For cars and light trucks, stock turnover is explicitly modelled in order to allow for the effects of fuel efficiency regulation of new cars on fleet energy intensity. Fuel efficiency regulation for new cars and light trucks as well as (additional) fuel taxation can be directly modelled.

APPENDIX 2
COMPARISON OF *WEO 2000* PROJECTIONS WITH OTHER STUDIES

Comparison of Energy Projections with Other Studies

This appendix compares the *WEO*'s energy demand projections in the Reference Scenario with those of other recent modelling efforts, notably the *International Energy Outlook (IEO) 2000* of the US Department of Energy[1] and the projections generated by the POLES model, published in *European Union Outlook to 2020* and elsewhere.[2] Table A2.1 provides a general comparison of the *WEO 2000* results with the *IEO* and the POLES exercises.

All three projections have a medium to long-term perspective.[3] They are based on global energy models with regional breakdowns, analyse both supply and demand and thus ensure consistency between regional and world energy balances. *IEO* does not, however, provide a complete analysis of final consumption. Population growth assumptions are the same for *IEO* and *WEO*, and slightly higher for POLES. World GDP-growth assumptions vary more, ranging from 2.8% to 3.5% per annum, due mainly to differences in the growth-rate assumptions for the transition economies,[4] Latin America and South and East Asia.

Oil-price fluctuations in recent years have highlighted the uncertainty surrounding future trends. It is therefore not surprising that the models show a wide range of price assumptions. In the *IEO*, the international oil price grows slowly over its projection period, to reach $22/bbl (in 1998 dollars) by 2020. This differs significantly from POLES and *WEO*, which both assume more rapid price increases, especially in the second half of the projection period. By 2020, the oil price goes up to $30/bbl for POLES and to $27/bbl for *WEO* (both in 1998 dollars). As a result of similar energy-consumption patterns, differences in energy intensities mainly reflect the

1. DOE/EIA (2000).
2. EC (1999) and Criqui and Kouvaritakis (2000).
3. The time horizon is 2020 for *WEO* and *IEO* and 2030 for POLES.
4. Uncertainties concerning Russian GDP are discussed in Chapter 7.

Table A2.1: **Key Assumptions and Projections for the World in Different Studies** (Average annual growth rates, in per cent)

	***WEO 2000* Reference Scenario 1997-2020**	**IEO 2000 Reference Case 1997-2020**	**POLES Reference Case 2000-2020**
GDP	3.1	2.8	3.5
Population	1.1	1.1	1.3
Oil price in 2020 (in 1998 US$)	27	22	30
TPES	2.0	2.1	2.3
Coal	1.7	1.6	3.2
Oil	1.9	1.9	1.7
Gas	2.7	3.2	2.8
Nuclear	0.0	–0.3	0.7
Renewables	2.3	1.9	1.1
Hydro	1.8	n.a.	2.1
Other	2.8	n.a.	0.7
TFC	2.0	n.a.	2.0
Electricity consumption	2.8	2.5	3.7
Transportation	2.4	2.5	2.0
CO_2 emissions	2.1	2.1	2.6

"n.a." = not available.

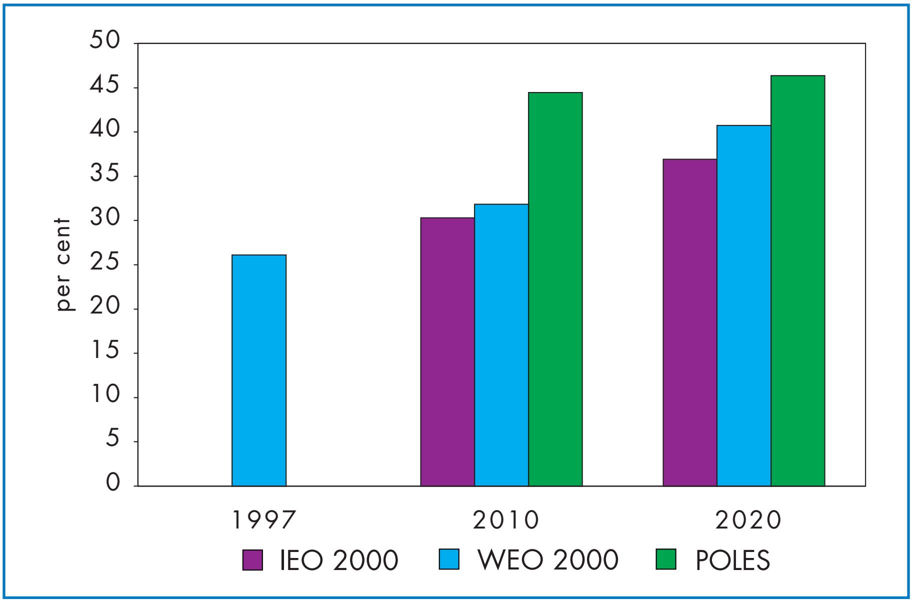
different GDP-growth assumptions. Primary intensity falls by 1.1% per year on average for *WEO*, compared with 1.2% for POLES and 0.7% for *IEO*.

The growth rates for total primary energy supply are similar, between 2% and 2.3% per year. Yet this apparent consensus masks important differences in the fuel mix. Nuclear power shows the biggest range of variation. It increases in POLES by 0.7% per year, but stagnates in *WEO* and declines marginally in *IEO*. The projected rate of growth in coal consumption in POLES is nearly twice as high as in *IEO* and *WEO*. All three sets of projections show rapid growth for natural gas, ranging from 2.7% to 3.2% per year. *WEO* has the highest growth for renewables. For oil, the three sets of projections are closest, with growth varying between 1.7% and 1.9%.

Total final consumption growth rates are the same in POLES and *WEO*, although some differences exist in the fuel mix or in the sectoral breakdowns. For both electricity and transport, *WEO* ranks between *IEO* and POLES. All three studies project strong growth in electricity consumption, entailing an increase in the share of electricity in the global energy mix. Final consumption in the transport sector increases more rapidly than total energy consumption in *WEO* and *IEO*. It increases more slowly in POLES.

For oil production, all three models project increasing reliance on OPEC supply, especially from the Gulf countries (Figure A2.1). In *WEO*, the share of OPEC Middle East in total world production increases faster than in *IEO*, from 26% in 1997 to 41% in 2020. In POLES, it rises still more sharply until 2010, to 44%, then levels off at 46 % in 2020.

Figure A2.1: **Comparison of Middle East OPEC Shares in World Oil Production**



OECD North America

Table A2.2 compares the projections for North America. All three studies adopt similar assumptions for GDP and population. *IEO*, for example, assumes average GDP growth of 2.3% compared to *WEO*'s 2.1%. *WEO* assumes higher natural-gas prices.

Table A2.2: **Comparison of Projections for OECD North America, 1997-2020**
(Average annual growth rates, in per cent)

	WEO 2000	**IEO 2000**	**POLES***
GDP (assumption)	2.1	2.3	2.2
Population (assumption)	0.7	0.8	0.6
TPES	0.9	1.1	0.7
Coal	0.8	0.9	2.4
Oil	1.1	1.3	0.1
Gas	1.3	1.6	0
Nuclear	–1.6	–1.6	0.4
Hydro & other renewables	1.1	1.1	1.1
Electricity consumption	1.3	1.2	2.2
Transportation	1.6	1.8	0.4
CO_2 emissions	1.1	1.3	0.9

* Growth rates from 2000 to 2020.

The 0.9% average rate of TPES growth over the projection period in the *WEO* falls between those of *IEO* (1.1%) and POLES (0.7%). The differences in demand growth rates reflect those in oil and gas price trends. The *WEO* and *IEO* projections are relatively close, but the discrepancy between them and POLES is more important. POLES projects much higher coal and nuclear demand at the expense of oil and gas. *IEO* projects a slightly faster increase in primary supply of gas, oil and coal than *WEO*, and the same rate of decline in nuclear power. The *WEO* projects a marginally higher expansion in electricity demand (1.3% per annum) than *IEO* (1.2%). POLES projects a slower rise in transportation demand but faster growth in electricity.

OECD Europe

The same three studies were compared for OECD Europe.[5] Again, assumptions for population and GDP are very similar (Table A2.3). Because in all three models energy demand derives mainly from economic

5. Some differences in regional definition do exist. For both *IEO* and POLES, "Europe" does not include Poland, the Czech Republic and Hungary. *IEO* puts Turkey in the Middle East, although both POLES and this *WEO* include it in Europe. The different treatments of Turkey and Poland may partly explain the differences in energy consumption levels and trends.

growth, the projections for TPES are also very close. Differences are more significant in the fuel mixes and sector contributions. Coal consumption varies the most. The projected growth of 2.2% per year contrasts sharply with the decreases projected by both this *Outlook* and *IEO*.

Table A2.3: **Comparison of Projections for OECD Europe, 1997-2020**
(Average annual growth rates, in per cent)

	WEO 2000	**IEO 2000**	**POLES***
GDP (assumption)	2.1	2.3	2.2
Population (assumption)	0.2	0	0.3
TPES	1.0	0.9	0.9
Coal	–0.6	–1.1	2.2
Oil	0.7	0.4	0.5
Gas	2.8	2.9	1.3
Nuclear	–1.0	–0.8	–0.2
Hydro & other renewables	2.6	1.9	1.5
Electricity consumption	2.0	1.7	2.0
Transportation	1.5	1.0	1.1
CO_2 emissions	0.9	0.8	1.1

* Growth rates from 2000 to 2020.

The gas-consumption growth rates in both the *IEO* and *WEO* are also much higher than in POLES. All three models project nuclear power to decline, POLES the least and *WEO* the most. The stronger decline of nuclear power in *WEO* arises partly from taking into account the recent German decision on closing nuclear plants. All three studies see hydro and other renewables growing substantially. They all project electricity demand to expand more slowly than GDP, confirming and agreeing on saturation effects and efficiency gains.

A significant difference concerns transport energy demand. *IEO* and POLES expect it to rise much more slowly than does this *Outlook*. This may result from the different regional definitions. Poland, the Czech Republic, Hungary and Turkey are all likely to increase their car-ownership by enough to affect oil consumption in transport at the aggregate regional level. Projections of CO_2 emissions result from fuel-mix projections. Despite the maintenance of much more nuclear capacity in POLES, more coal consumption and relatively less gas use lead to a higher emission trend. *IEO*'s emission projections come close to the *WEO*'s, although they do not include some countries (*e.g.* Turkey) with high expected emissions growth.

OECD Pacific

For the OECD Pacific region, projections from the Asia Pacific Energy Research Centre (APERC) were added to the comparison. Table A2.4 summarises the key assumptions and results for each. The *WEO* projections fall generally within the range of the other projections and are similar. *WEO* and *IEO* are the closest. The two most striking differences lie in *IEO*'s lower assumed level of nuclear power in primary supply and *WEO*'s lower projected growth of gas in total primary consumption than in the POLES and APERC models.

Table A2.4: **Comparison of Projections for OECD Pacific, 1997-2020**
(Average annual growth rates, in per cent)

	WEO 2000	**IEO 2000**	**POLES***	**APERC****
GDP (assumption)	1.7	1.5	2.1	n.a.
Population (assumption)	0.1	0.2	0.2	n.a.
TPES	1.0	0.9	1.2	1.9
Coal	0.4	0.6	2.2	2.5
Oil	0.4	0.6	0.3	0.8
Gas	2.0	2.0	3.8	4.1
Nuclear	2.0	0.7	1.6	2.3
Hydro & other renewables	2.8	1.2	1.3	n.a.
Electricity consumption	1.5	1.5	2	2.6
Transportation	1.2	0.9	0.9	1.7
CO_2 emissions	0.7	0.8	1.2	1.7

*Growth rates from 2000 to 2020. **Growth rates from 1995 to 2010. "n.a." = not available.

Comparison of Global Emissions Projections with Other Studies

Table A2.5 compares the *WEO 2000* emission projections with the *IEO* and POLES studies. The results among the three studies are very similar. The POLES reference-case results are somewhat higher, due mainly to an assumption of higher economic growth. The slightly lower GDP growth assumptions of *IEO 2000* produce CO_2 emissions similar to the *WEO*'s because the US Department of Energy projects a more carbon-intensive energy mix. Other than the *IEO 2000* and POLES models, which have projections for North America and Europe, the main source used in the following comparison is the Asia Pacific Energy Research Centre (APERC, 1998).

Table A2.5: **Comparison of Global CO_2 Emissions Forecasts***
(Million tonnes of CO_2)

	WEO 2000	**IEO 2000**	**POLES**
1990	21 254	21 399	21 498
2010	30 084	29 868	30 023
2020	36 680	36 700	39 204
Emission growth, 1990-2020 (per cent)	73	72	82

*Including international marine bunkers.

On a more disaggregated level, the *WEO* results can be compared with those of *IEO 2000*, the POLES model and the model used by the APERC for the three OECD regions — North America, Europe and Pacific.[6] Table A2.6 shows that for all three regions the *WEO* projects *lower* CO_2 emissions than do the others. The difference is particularly significant for OECD Pacific, comparing the WEO with APERC's projections, mainly because the latter, formulated before the 1997 financial crisis, assume a higher rate of GDP growth.

Table A2.6: **Comparison of Growth of Regional CO_2 Emissions**
(Average annual growth rates, in per cent)

	OECD North America	**OECD Europe**	**OECD Pacific**
WEO 2000	1.1	0.9	0.7
Other Models	1.3*	1.1**	1.7***

* IEO 2000, the average annual growth rate covers 1997-2020. ** POLES 2000, the average annual growth rate covers 2000-2020. *** APERC, the average annual growth rate covers 1995-2010.

6. A model for the EU area with greater detail than the POLES model is the PRIMES model contained in EU (1999), p. 217. It was not used here, however, because its results cover only the EU 15, thus making a meaningful comparison impossible.

Box A2.1: **The IPCC Emission Scenarios**

The Intergovernmental Panel on Climate Change (IPCC) was assembled to synthesise and assess the scientific, technical and socio-economic information pertaining to climate change and the measures designed to contain it. Its set of long-term GHG emission scenarios, released in 1992 became a widely-used reference. A new set of scenarios that will provide input into the third IPCC Assessment Report is now available as the result of a global modelling effort.[7] Six teams in the United States, Europe and Japan provided results of 40 different scenarios, grouped in four "families" distinguished by their assumptions for economic and demographic growth, their degree of convergence between regions and their reflection on new technologies. Each scenario runs over a hundred-year period until 2100.

Clearly, these long-term GHG emissions scenarios are very different from the medium-term energy projections contained in the *WEO* Reference Scenario. Projections for annual global CO_2 emissions from fossil fuels vary substantially (Table 2.7). This array of possible emission paths compares to CO_2 emissions of 22 Gt in 1990 and a projection of 36.7 Gt for 2020 in this *Outlook*'s Reference Scenario.

Two scenario "families" are described by the IPCC: the "A family", which focuses on economic indicators, and the "B family", which considers the extent of future globalisation. Within this broad grouping, the A1 scenarios assume an affluent world with rapid demographic transition, robust productivity and economic growth in all regions, a considerable catch-up by developing countries and diffusion of more efficient technologies consistent with high productivity growth (IPCC, 2000, p. 187). The B2 scenarios assume a slowdown of globalisation and convergence, increasing importance of regional and local decision-making and a relatively high concern for environmental sustainability (primarily at the local level). The B2 scenarios can be considered "middle of the road", between the unfavourable economic and environmental developments of the A2 scenarios and the aggressive global co-ordination to combat climate change and other environmental problems in the B1 scenarios. All the scenarios reveal their most salient features only over the full 100-year timeframe.

Inside the A1 group, the A1C scenario assumes widespread adoption of "clean-coal" technologies and good environmental

7. Intergovernmental Panel on Climate Change (IPCC), 2000.

performance except for CO_2 emissions. The A1T scenario, which for 2020 predicts the same global CO_2 emissions as the *WEO* Reference Scenario, assumes a "non-fossil" long-term future with rapid development of solar and nuclear technologies on the supply side and mini-turbines and fuel cells used in energy end-use applications (IPCC, 2000, p. 188). This does not contradict the medium-term "fossil-fuel future" projected in the *WEO*. Most non-fossil technologies in the A1T scenario are assumed to come into widespread use only after 2020.

Table A2.7: ***WEO 2000*** **in Comparison with Three IPCC Scenarios, 2020**

	WEO 2000 Reference Scenario	A1C AIM	IPCC* A1T MESSAGE	B2 IMAGE
Population (billion)	7.4	7.6	7.6	7.9
GDP (trillion US$ 1990)	67.3	67.2	67.2	48.9**
Fossil-Fuel CO_2 Emissions (10^9 tonnes)	36.7	52.4	36.7	31.1

* The three reported IPCC scenarios were generated by the Asian Pacific Integrated Model (AIM) of the NIE, Japan, the Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE) of IIASA, Austria, and the Integrated Model to Assess the Greenhouse Effect (IMAGE) of RIVM, the Netherlands. **Estimated from original data ($42.1 trillion) converted at market exchange rates. Source: IPCC (2000).

APPENDIX 3
DEFINITIONS

This appendix provides general information on the fuel, sectoral and regional definitions used throughout *WEO 2000*. Readers interested in obtaining more detailed information on definitions and conversion factors should consult the annual IEA publications: *Energy Balances of OECD Countries, Energy Balances of Non-OECD Countries, Coal Information, Oil Information* and *Gas Information*.

Coal

Coal includes all coal, both primary (including hard coal and lignite) and derived fuels (including patent fuel, coke oven coke, gas coke, coke oven gas and blast furnace gas). Peat is also included in this category.

Oil

Oil includes crude oil, natural gas liquids, refinery feedstocks and additives, other hydrocarbons and petroleum products (refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes, petroleum coke and other petroleum products).

Gas

Gas includes natural gas (both associated and non-associated gas but excluding natural gas liquids) and gas works gas.

Nuclear

Nuclear data in primary energy demand refer to the primary heat equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33%.

Hydro

Hydro data in primary energy demand refer to the energy content of the electricity produced in hydro power plants assuming 100% efficiency.

Combustible Renewables and Waste

Combustible Renewables and Waste (CRW) comprises solid biomass and animal products, gas/liquids from biomass, industrial waste and municipal waste.

Other Renewables

Other Renewables include geothermal, solar, wind, tidal, and wave energy for electricity generation. Direct use of geothermal and solar heat is also included in this category. Unless the actual efficiency of the geothermal process is known, the quantity of geothermal energy entering electricity generation is inferred from the electricity production at geothermal plants, assuming an average thermal efficiency of 10%. For solar, wind, tidal and wave energy, the quantities entering electricity generation are equal to the electrical energy generated (i.e. 100% efficiencies).

For OECD countries, *Other Renewables* includes *Combustible Renewables and Waste*. *CRW* are indicated separately for non-OECD regions, except for electricity output in TWh, which includes *CRW* for all regions.

Heat

Heat includes the quantity of heat produced for sale. The large majority of the heat included in this category comes from the combustion of fuels, although some small amounts are produced from electrically powered heat pumps and boilers.

Total Primary Energy Supply

Total Primary Energy Supply (TPES) is equivalent to primary energy demand. This represents inland demand only and, except for world energy demand, excludes international marine bunkers.

International Marine Bunkers

International Marine Bunkers cover those quantities delivered to sea-going ships of all flags, including warships. Consumption by ships engaged in transport in inland and coastal waters is not included.

Power Generation

Power Generation refers to *fuel use* in electricity and combined heat and power (CHP) plants. Both public and autoproducer plants are included.

Total Final Consumption

Total Final Consumption (TFC) is the sum of consumption by the different end-use sectors. *TFC* is broken down into energy demand in the following sectors: industry, transport, other (includes agriculture, residential, commercial and public services) and non-energy use. Industry includes manufacturing, construction and mining industries. In final consumption, petrochemical feedstocks appear under *industry use.* Other non-energy uses are shown under *non-energy use.*

Own Use and Losses

Own Use and Losses covers own use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes transfers, statistical differences, heat plants, gas works, petroleum refineries, coal transformation, liquefaction, own use and distribution losses.

Electricity Generation

Electricity Generation shows the total amount of TWh generated by power plants. It includes own use and transmission and distribution losses.

Regional Definitions

OECD Europe

OECD Europe comprises the following countries: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

OECD North America

OECD North America consists of Canada and the United States of America.

OECD Pacific

OECD Pacific includes Australia, Japan and New Zealand.

Transition Economies

The transition economies include the following countries: Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Federal Republic of Yugoslavia, Former Yugoslav Republic of Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovak Republic, Slovenia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

For statistical reasons, this region also includes Cyprus, Gibraltar and Malta.

China

China refers to the People's Republic of China, including Hong Kong.

East Asia

East Asia includes the following countries: Afghanistan, Bhutan, Brunei, Chinese Taipei, Fiji, French Polynesia, Indonesia, Kiribati, Democratic People's Republic of Korea, Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Thailand, Vietnam and Vanuatu.

South Asia

South Asia includes Bangladesh, India, Nepal, Pakistan and Sri Lanka.

Latin America

Latin America includes the following countries: Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Mexico, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Anguilla, Saint Lucia, St. Vincent-Grenadines, Surinam, Trinidad and Tobago, Uruguay and Venezuela.

Africa

Africa comprises Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Congo, Democratic Republic of Congo, Cote d' Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Middle East

The Middle East region is defined as Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates and Yemen. It includes the neutral zone.

∴

In addition to the WEO regions, the following groupings are also referred to in the text.

European Union

Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden and United Kingdom.

Organisation for Petroleum Exporting Countries

Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Asia-Pacific Economic Co-operation

Australia, Brunei Darussalam, Canada, Chile, China, Indonesia, Japan, Korea, Malaysia, Mexico, New Zealand, Papua New Guinea, Peru, Philippines, Russia, Singapore, Chinese Taipei, Thailand, United States of America, Vietnam.

Annex B Countries

Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom, United States of America.

LIST OF ABBREVIATIONS AND ACRONYMS

In this book, acronyms are frequently substituted for a number of terms used within the International Energy Agency. This glossary provides a quick and central reference for many of the abbreviations used.

bbl	barrel
bcm	billion cubic metres
boe	barrel of oil equivalent
CAFE	corporate average fuel economy
cap	capita
CCGT	combined cycle gas turbine
CEE	Central and Eastern Europe
CHP	combined heat and power
CIF	cost, insurance and freight
cmd	cubic metres per day
CNPC	China National Petroleum Corporation
CO_2	carbon dioxide
CRW	combustible renewables and waste
EAF	electric arc furnace
EC	European Commission
EU	European Union
FDI	foreign direct investment
FSU	former Soviet Union
GCC	Gulf Co-operation Council
GDP	gross domestic product
GHG	greenhouse gas
GW	gigawatt
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IMF	International Monetary Fund
IPP	Independent Power Producers
ICT	information and communication technology
kb/d	thousand barrels per day
kg	kilogramme
kgoe	kilogrammes of oil equivalent

km	kilometre
kW	kilowatt
kWh	kilowatt-hour
LNG	liquefied natural gas
LPG	liquefied petroleum gas
mb/d	million barrels per day
M$	million US dollars
MBtu	million British thermal units
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt-hour
NCV	net calorific value
NEM	National Electricity Market, Australia
NGL	natural gas liquid
NO_x	nitrogen oxides
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation for Petroleum Exporting Countries
PPP	purchasing power parity
Sinopec	China Petroleum Corporation
SO_2	sulphur dioxide
SOE	state owned enterprise
tcf	trillion cubic feet
tce	tonnes of coal equivalent
tcm	trillion cubic metres
TFC	total final consumption of energy
toe	tonnes of oil equivalent
tonne	metric ton
TPES	total primary energy supply
TW	terawatt
TWh	terawatt-hour
UAE	United Arab Emirates
UES	United Energy Systems (Russian utility)
UN	United Nations
WEO	World Energy Outlook
WTO	World Trade Organisation

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