INTERNATIONAL ENERGY AGENCY

World Energy Outlook

2006

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six of the OECD's thirty member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

The IEA member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission takes part in the work of the IEA.

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.

The OECD member countries are: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The European Commission takes part in the work of the OECD.

The energy future which we are creating is unsustainable. If we continue as before, the energy supply to meet the needs of the world economy over the next twenty-five years is too vulnerable to failure arising from under-investment, environmental catastrophe or sudden supply interruption.

This has been the central message from the *World Energy Outlook* for the past several years; and in 2005 at Gleneagles and 2006 at St. Petersburg, G8 leaders endorsed that judgement, making a political commitment to change. They asked the IEA to map a new energy future.

This edition of the *Outlook* responds to that challenge. It starts, like previous editions, with a Reference Scenario projecting energy demand and supply if present policies were to continue. This is not to cast doubt on the will for change. Rather it serves as a point of departure for the analysis of how and how far that future can be altered and at what cost. It is a reminder of why that must happen: despite the shock of continuing high oil prices, the projected energy future has hardly changed.

The International Energy Agency has presented other options in the past – an Alternative Policy Scenario for the countries of the OECD in *WEO-2002* and a global Alternative Policy Scenario in *WEO-2004*, updated in *WEO-2005*. Their basis was what could be achieved by putting into effect those policies for change already under consideration by governments. Our dedicated team under Fatih Birol, to whom I again pay tribute, has carried this process much further in this *Outlook*, with the support of many distinguished contributors from outside the Agency and others within. The analysis of alternative policies and their effects in terms of energy security and carbon dioxide emissions makes up the entire second part of this book. It is a tool for change. For policy-makers, the Alternative Policy Scenario identifies the priority sectors for action and the key instruments. It measures both costs and cost-effectiveness. It shows what can be achieved, along the road to 2030, within ten years. Given the commitment of G8 leaders to act with resolve and urgency, this scenario might well have been renamed "Resolute Action".

What this scenario shows is that the world economy can flourish while using less energy. The perpetual rise in OECD oil imports can be halted by 2015. Carbon dioxide emissions can be cut by thousands of millions of tonnes by 2030. The investment cost is higher for consumers; but their extra cost is more than offset by savings in energy bills and in investment elsewhere. The challenge for governments is to persuade society that it wants this outcome sufficiently to give its backing to the necessary action, even where that means bearing a cost today for the benefit tomorrow.

It is possible to go further and faster by 2030, though the risks increase. We have illustrated how, to complement recent IEA studies on technology development and deployment.

No *Outlook* would be complete without a collection of additional insights into the most critical energy issues of the day. This year we have sought to explain how it is that higher energy prices are now going hand-in-hand with vigorous world economic growth and how oil and gas investment is shaping up in the years to 2010. We have looked in depth at two fuels which can help change the future: nuclear power, which can play a pivotal role if public acceptance is regained; and biofuels, which could supply a significant share of road transport fuels by 2030. We show how to ensure 1.3 billion people can have cleaner, more efficient cooking fuels by 2015 in order to contribute appropriately to the UN Millennium Development Goals. Finally, we present a snapshot of Brazil, the fifth-largest country in the world by land area and population, and one with a unique energy economy, of significance worldwide.

Projecting the future is a hazardous process, however sophisticated the selection of assumptions and the complexity of the energy model. The International Energy Agency does not hold out any of the scenarios depicted here as *forecasts* of the energy future. But they are reliable indications of what the future *could be* on the given assumptions. It will take courage to act, often in the face of political difficulty and controversy, to lead the world towards a more sustainable energy future. The objectives can be achieved, by practicable means and at a cost which does not outweigh the benefits. And those benefits are open to all, energy suppliers alongside energy consumers and, not least, those consumers in the countries most in need of economic development. They are vulnerable to what the French call *"l'énergie du désespoir"*, the overwhelming power of desperation. On the contrary, I confidently believe that there is *"de l'espoir dans l'énergie"*.

Claude Mandil
Executive Director

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The world is facing twin energy-related threats: that of not having adequate and secure supplies of energy at affordable prices and that of environmental harm caused by consuming too much of it. Soaring energy prices and recent geopolitical events have reminded us of the essential role affordable energy plays in economic growth and human development, and of the vulnerability of the global energy system to supply disruptions. Safeguarding energy supplies is once again at the top of the international policy agenda. Yet the current pattern of energy supply carries the threat of severe and irreversible environmental damage – including changes in global climate. Reconciling the goals of energy security and environmental protection requires strong and coordinated government action and public support.

The need to curb the growth in fossil-energy demand, to increase geographic and fuel-supply diversity and to mitigate climate-destabilising emissions is more urgent than ever. G8 leaders, meeting with the leaders of several major developing countries and heads of international organisations – including the International Energy Agency – at Gleneagles in July 2005 and in St. Petersburg in July 2006 called on the IEA to "advise on alternative energy scenarios and strategies aimed at a clean, clever and competitive energy future". This year's *Outlook* responds to that request. It confirms that fossil-fuel demand and trade flows, and greenhouse-gas emissions would follow their current unsustainable paths through to 2030 in the absence of new government action – the underlying premise of our Reference Scenario. It also demonstrates, in an Alternative Policy Scenario, that a package of policies and measures that countries around the world are considering would, if implemented, significantly reduce the rate of increase in demand and emissions. Importantly, the economic cost of these policies would be more than outweighed by the economic benefits that would come from using and producing energy more efficiently.

Fossil energy will remain dominant to 2030

Global primary energy demand in the Reference Scenario is projected to increase by just over one-half between now and 2030 – an average annual rate of 1.6%. Demand grows by more than one-quarter in the period to 2015 alone. Over 70% of the increase in demand over the projection period comes from developing countries, with China alone accounting for 30%. Their economies and population grow much faster than in the OECD, shifting the centre of gravity of global energy demand. Almost half of the increase in global primary energy use goes to generating electricity and one-fifth to meeting transport needs – almost entirely in the form of oil-based fuels.

Globally, fossil fuels will remain the dominant source of energy to 2030 in both scenarios. In the Reference Scenario, they account for 83% of the overall increase in energy demand between 2004 and 2030. As a result, their share of world demand edges up, from 80% to 81%. The share of oil drops, though oil remains the largest single fuel in the global energy mix in 2030. Global oil demand reaches 99 million barrels per day in 2015 and 116 mb/d in 2030 – up from 84 mb/d in 2005. In contrast to *WEO-2005*, coal sees the biggest increase in demand in absolute terms, driven mainly by power generation. China and India account for almost four-fifths of the incremental demand for coal. It remains the second-largest primary fuel, its share in global demand increasing slightly. The share of natural gas also rises, even though gas use grows less quickly than projected in the last *Outlook*, due to higher prices. Hydropower's share of primary energy use rises slightly, while that of nuclear power falls. The share of biomass falls marginally, as developing countries increasingly switch to using modern commercial energy, offsetting the growing use of biomass as feedstock for biofuels production and for power and heat generation. Non-hydro renewables – including wind, solar and geothermal – grow quickest, but from a small base.

We have revised upwards our assumptions for oil prices in this *Outlook*, in the expectation that crude oil and refined-product markets remain tight. Market fundamentals point to a modest easing of prices as new capacity comes on stream and demand growth slows. But new geopolitical tensions or, worse, a major supply disruption could drive prices even higher. We assume the average IEA crude oil import price falls back to $47 per barrel in real terms in the early part of the next decade and then rises steadily through to 2030. Natural gas prices are assumed broadly to follow the trend in oil prices, because of the continuing widespread use of oil-price indexation in long-term gas supply contracts and because of inter-fuel competition. Coal prices are assumed to change proportionately less over time, but follow the direction of oil and gas prices.

The threat to the world's energy security is real and growing

Rising oil and gas demand, if unchecked, would accentuate the consuming countries' vulnerability to a severe supply disruption and resulting price shock. OECD and developing Asian countries become increasingly dependent on imports as their indigenous production fails to keep pace with demand. Non-OPEC production of conventional crude oil and natural gas liquids is set to peak within a decade. By 2030, the OECD as a whole imports two-thirds of its oil needs in the Reference Scenario, compared with 56% today. Much of the additional imports come from the Middle East, along vulnerable maritime routes. The concentration of oil production in a small group of countries with large reserves – notably Middle East OPEC members and Russia – will increase their market dominance and their ability to impose higher prices. An increasing share of gas demand is also expected to be met by imports, via pipeline or in the form of liquefied natural gas from increasingly distant suppliers.

The growing insensitivity of oil demand to price accentuates the potential impact on international oil prices of a supply disruption. The share of transport demand – which is price-inelastic relative to other energy services – in global oil consumption is projected to rise in the Reference Scenario. As a result, oil demand becomes less and less responsive to movements in international crude oil prices. The corollary of this is that prices would fluctuate more than in the past in response to future short-term shifts in demand and supply. The cushioning effect of subsidies to oil consumers on demand contributes to the insensitivity of global oil demand to changes in international prices. Current subsidies on oil products in non-OECD countries are estimated at over $90 billion annually. Subsidies on all forms of final energy outside the OECD amount to over $250 billion per year – equal to all the investment needed in the power sector each year, on average, in those countries.

Oil prices still matter to the economic health of the global economy. Although most oil-importing economies around the world have continued to grow strongly since 2002, they would have grown even more rapidly had the price of oil and other forms of energy not increased. In many importing countries, increases in the value of exports of non-energy commodities, the prices of which have also risen, have offset at least part of the impact of higher energy prices. The eventual impact of higher energy prices on macroeconomic prospects remains uncertain, partly because the effects of recent price increases have not fully worked their way through the economic system. There are growing signs of inflationary pressures, leading to higher interest rates. Most OECD countries have experienced a worsening of their current account balances, most obviously the United States. The recycling of petro-dollars may have helped to mitigate the increase in long-term interest rates, delaying the adverse impact on real incomes and output of higher energy prices. The longer prices remain at current levels or the more they rise, the greater the threat to economic growth in importing countries. An oil-price shock caused by a sudden and severe supply disruption would be particularly damaging – for heavily indebted poor countries most of all.

Will the investment come?

Meeting the world's growing hunger for energy requires massive investment in energy-supply infrastructure. The Reference Scenario projections in this *Outlook* call for cumulative investment of just over $20 trillion (in year-2005 dollars) over 2005-2030. This is around $3 trillion higher than in *WEO-2005*, mainly because of recent sharp increases in unit capital costs, especially in the oil and gas industry. The power sector accounts for 56% of total investment – or around two-thirds if investment in the supply chain to meet the fuel needs of power stations is included. Oil investment – three-quarters of which goes to the upstream – amounts to over $4 trillion in total over 2005-2030. Upstream investment needs are more sensitive to changes in decline rates at producing fields than to the rate of growth of demand for oil. More than half of all the energy investment needed worldwide is in developing countries, where demand and production increase most quickly. China alone needs to invest about $3.7 trillion – 18% of the world total.

There is no guarantee that all of the investment needed will be forthcoming. Government policies, geopolitical factors, unexpected changes in unit costs and prices, and new technology could all affect the opportunities and incentives for private and publicly-owned companies to invest in different parts of the various energy-supply chains. The investment decisions of the major oil- and gas-producing countries are of crucial importance, as they will increasingly affect the volume and cost of imports in the consuming countries. There are doubts, for example, about whether investment in Russia's gas industry will be sufficient even to maintain current export levels to Europe and to start exporting to Asia.

The ability and willingness of major oil and gas producers to step up investment in order to meet rising global demand are particularly uncertain. Capital spending by the world's leading oil and gas companies increased sharply in nominal terms over the course of the first half of the current decade and, according to company plans, will rise further to 2010. But the impact on new capacity of higher spending is being blunted by rising costs. Expressed in cost inflation-adjusted terms, investment in 2005 was only 5% above that in 2000. Planned upstream investment to 2010 is expected to boost slightly global spare crude oil production capacity. But capacity additions could be smaller on account of shortages of skilled personnel and equipment, regulatory delays, cost inflation, higher decline rates at existing fields and geopolitics. Increased capital spending on refining is expected to raise throughput capacity by almost 8 mb/d by 2010. Beyond the current decade, higher investment in real terms will be needed to maintain growth in upstream and downstream capacity. In a Deferred Investment Case, lower OPEC crude oil production, partially offset by increased non-OPEC production, pushes oil prices up by one-third, trimming global oil demand by 7 mb/d, or 6%, in 2030 relative to the Reference Scenario.

On current energy trends, carbon-dioxide emissions will accelerate

Global energy-related carbon-dioxide (CO_2) emissions increase by 55% between 2004 and 2030, or 1.7% per year, in the Reference Scenario. They reach 40 gigatonnes in 2030, an increase of 14 Gt over the 2004 level. Power generation contributes half of the increase in global emissions over the projection period. Coal overtook oil in 2003 as the leading contributor to global energy-related CO_2 emissions and consolidates this position through to 2030. Emissions are projected to grow slightly faster than primary energy demand – reversing the trend of the last two-and-a-half decades – because the average carbon content of primary energy consumption increases.

Developing countries account for over three-quarters of the increase in global CO_2 emissions between 2004 and 2030 in this scenario. They overtake the OECD as the biggest emitter by soon after 2010. The share of developing countries in world emissions rises from 39% in 2004 to over one-half by 2030. This increase is faster than that of their share in energy demand, because their incremental energy use is more carbon-intensive than that of the OECD and transition economies. In general, the developing countries use proportionately more coal and less gas. China alone is responsible for about 39% of the rise in global emissions. China's emissions more than double between 2004 and 2030, driven by strong economic growth and heavy reliance on coal in power generation and industry. China overtakes the United States as the world's biggest emitter before 2010. Other Asian countries, notably India, also contribute heavily to the increase in global emissions. The per-capita emissions of non-OECD countries nonetheless remain well below those of the OECD.

Prompt government action can alter energy and emission trends

The Reference Scenario trends described above are not set in stone. Indeed, governments may well take stronger action to steer the energy system onto a more sustainable path. In the Alternative Policy Scenario, the policies and measures that governments are currently considering aimed at enhancing energy security and mitigating CO_2 emissions are assumed to be implemented. This would result in significantly slower growth in fossil-fuel demand, in oil and gas imports and in emissions. These interventions include efforts to improve efficiency in energy production and use, to increase reliance on non-fossil fuels and to sustain the domestic supply of oil and gas within net energy-importing countries.

World primary energy demand in 2030 is about 10% lower in the Alternative Policy Scenario than in the Reference Scenario – roughly equivalent to China's entire energy consumption today. Global demand grows, by 37% between 2004 and 2030, but more slowly: 1.2% annually against 1.6% in the Reference Scenario. The biggest energy savings in both absolute and percentage terms come from coal. The impact on energy demand of new policies is less marked in the first decade of the *Outlook* period, but far from negligible. The difference in global energy demand between the two scenarios in 2015 is about 4%.

In stark contrast with the Reference Scenario, OECD oil imports level off by around 2015 and then begin to fall. Even so, all three OECD regions and developing Asia are more dependent on oil imports by the end of the projection period, though markedly less so than in the Reference Scenario. Global oil demand reaches 103 mb/d in 2030 in the Alternative Policy Scenario – an increase of 20 mb/d on the 2005 level but 13 mb/d less than in the Reference Scenario. Measures in the transport sector produce close to 60% of all the oil savings in the Alternative Policy Scenario. More than two-thirds come from more efficient new vehicles. Increased biofuels use and production, especially in Brazil, Europe and the United States, also helps reduce oil needs. Globally, gas demand and reliance on gas imports are also sharply reduced vis-à-vis the Reference Scenario.

Energy-related carbon-dioxide emissions are cut by 1.7 Gt, or 5%, in 2015 and by 6.3 Gt, or 16%, in 2030 relative to the Reference Scenario. The actions taken in the Alternative Policy Scenario cause emissions in the OECD and in the transition economies to stabilise and then decline before 2030. Their emissions in 2030 are still slightly higher than in 2004, but well below the Reference Scenario level. Emissions in the European Union and Japan fall to below current levels. Emissions in developing regions carry on growing, but the rate of increase slows appreciably over the *Outlook* period compared with the Reference Scenario.

Policies that encourage the more efficient production and use of energy contribute almost 80% of the avoided CO_2 emissions. The remainder comes from switching to low- and or zero-carbon fuels. More efficient use of fuels, mainly through more efficient cars and trucks, accounts for almost 36% of the emissions saved. More efficient use of electricity in a wide range of applications, including lighting, air-conditioning, appliances and industrial motors, accounts for another 30%. More efficient energy production contributes 13%. Renewables and biofuels together yield another 12% and nuclear the remaining 10%. The implementation of only a dozen policies would result in nearly 40% of avoided CO_2 emissions by 2030. The policies that are most effective in reducing emissions also yield the biggest reductions in oil and gas imports.

New policies and measures would pay for themselves

In aggregate, the new policies and measures analysed yield financial savings that far exceed the initial extra investment cost for consumers – a key result of the Alternative Policy Scenario. Cumulative investment in 2005-2030 along the energy chain – from the producer to the consumer – is $560 billion lower than in the Reference Scenario. Investment in end-use equipment and buildings is $2.4 trillion higher, but this is more than outweighed by the $3 trillion of investment that is avoided on the supply side. Over the same period, the cost of the fuel saved by consumers amounts to $8.1 trillion, more than offsetting the extra demand-side investments required to generate these savings.

The changes in electricity-related investment brought about by the policies included in the Alternative Policy Scenario yield particularly big savings. On average, an additional dollar invested in more efficient electrical equipment, appliances and buildings avoids more than two dollars in investment in electricity supply. This ratio is highest in non-OECD countries. Two-thirds of the additional demand-side capital spending is borne by consumers in OECD countries. The payback periods of the additional demand-side investments are very short, ranging from one to eight years. They are shortest in developing countries and for those polices introduced before 2015.

Nuclear power has renewed promise – if public concerns are met

Nuclear power – a proven technology for baseload electricity generation – could make a major contribution to reducing dependence on imported gas and curbing CO_2 emissions. In the Reference Scenario, world nuclear power generating capacity increases from 368 GW in 2005 to 416 GW in 2030. But its share in the primary energy mix still falls, on the assumption that few new reactors are built and that several existing ones are retired. In the Alternative Policy Scenario, more favourable nuclear policies raise nuclear power generating capacity to 519 GW by 2030, so that its share in the energy mix rises.

Interest in building nuclear reactors has increased as a result of higher fossil-energy prices, which have made nuclear power relatively more competitive. New nuclear power plants could produce electricity at a cost of less than five US cents per kWh, if construction and operating risks are appropriately managed by plant vendors and power companies. At this cost, nuclear power would be cheaper than gas-based electricity if gas prices are above \$4.70 per MBtu. Nuclear power would still be more expensive than conventional coal-fired plants at coal prices of less than \$70 per tonne. The breakeven costs of nuclear power would be lower if a financial penalty on CO_2 emissions were introduced.

Nuclear power will only become more important if the governments of countries where nuclear power is acceptable play a stronger role in facilitating private investment, especially in liberalised markets. Nuclear power plants are capital-intensive, requiring initial investment of \$2 billion to \$3.5 billion per reactor. On the other hand, nuclear power generating costs are less vulnerable to fuel-price changes than coal- or gas-fired generation. Moreover, uranium resources are abundant and widely distributed around the globe. These two advantages make nuclear power a potentially attractive option for enhancing the security of electricity supply – if concerns about plant safety, nuclear waste disposal and the risk of proliferation can be solved to the satisfaction of the public.

The contribution of biofuels hinges on new technology

Biofuels are expected to make a significant contribution to meeting global road-transport energy needs, especially in the Alternative Policy Scenario. They account for 7% of the road-fuel consumption in 2030 in that scenario, up from 1% today. In the Reference Scenario, the share reaches 4%. In both scenarios, the United States, the European Union and Brazil account for the bulk of the increase and remain the leading producers and consumers of biofuels. Ethanol is expected to account for most of the increase in biofuels use worldwide, as production costs are expected to fall faster than those of biodiesel – the other main biofuel. The share of biofuels in transport-fuel use remains far and away the highest in Brazil – the world's lowest-cost producer of ethanol.

Rising food demand, which competes with biofuels for existing arable and pasture land, will constrain the potential for biofuels production using current technology. About 14 million hectares of land are now used for the production of biofuels, equal to about 1% of the world's currently available arable land. This share rises to 2% in the Reference Scenario and 3.5% in the Alternative Policy Scenario. The amount of arable land needed in 2030 is equal to more than that of France and Spain in the Reference Scenario and that of all the OECD Pacific countries – including Australia – in the Alternative Policy Scenario.

New biofuels technologies being developed today, notably ligno-cellulosic ethanol, could allow biofuels to play a much bigger role than that foreseen in either scenario. But significant technological challenges still need to be overcome for these second-generation technologies to become commercially viable. Trade and subsidy policies will be critical factors in determining where and with what resources and technologies biofuels will be produced in the coming decades, the overall burden of subsidy on taxpayers and the cost-effectiveness of biofuels as a way of promoting energy diversity and reducing carbon-dioxide emissions.

Making the Alternative Policy Scenario a reality

There are formidable hurdles to the adoption and implementation of the policies and measures in the Alternative Policy Scenario. In practice, it will take considerable political will to push these policies through, many of which are bound to encounter resistance from some industry and consumer interests. Politicians need to spell out clearly the benefits to the economy and to society as a whole of the proposed measures. In most countries, the public is becoming familiar with the energy-security and environmental advantages of action to encourage more efficient energy use and to boost the role of renewables.

Private-sector support and international cooperation will be needed for more stringent government policy initiatives. While most energy-related investment will have to come from the private sector, governments have a key role to play in creating the appropriate investment environment. The industrialised countries will need to help developing countries leapfrog to the most advanced technologies and adopt efficient equipment and practices. This will require programmes to promote technology transfer, capacity building and collaborative research and development. A strong degree of cooperation between countries, and between industry and government will be needed. Non-OECD countries can seek help from multilateral lending institutions and other international organisations in devising and implementing new policies. This may be particularly critical for small developing countries which, unlike China and India, may struggle to attract investment.

The analysis of the Alternative Policy Scenario demonstrates the urgency with which policy action is required. Each year of delay in implementing the policies analysed would have a disproportionately larger effect on emissions. For example, if the policies were to be delayed by ten years, with implementation starting only in 2015, the cumulative avoided emissions by 2030 vis-à-vis the Reference Scenario would be only 2%, compared with 8% in the Alternative Policy Scenario. In addition, delays in stepping up energy-related research and development efforts, particularly in the field of CO_2 capture and storage, would hinder prospects for bringing down emissions after 2030.

Larger energy savings would require an even bigger policy push

Even if governments actually implement, as we assume, all the policies they are considering to curb energy imports and emissions, both would still rise through to 2030. Keeping global CO_2 emissions at current levels would require much stronger policies. In practice, technological breakthroughs that change profoundly the way we produce and consume energy will almost certainly be needed as well. The difficulties in making this happen in the time frame of our analysis do not justify inaction or delay, which would raise the long-term economic, security and environmental cost. The sooner a start is made, the quicker a new generation of more efficient and low- or zero-carbon energy systems can be put in place.

A much more sustainable energy future is within our reach, using technologies that are already available or close to commercialisation. A recently published IEA report, *Energy Technology Perspectives*, demonstrates that a portfolio approach to technology development and deployment is needed. In this *Outlook*, a Beyond the Alternative Policy Scenario (BAPS) Case illustrates how the extremely challenging goal of capping CO_2 emissions in 2030 at today's levels could be achieved. This would require emissions to be cut by 8 Gt more than in the Alternative Policy Scenario. Four-fifths of the energy and emissions savings in the BAPS Case come from even stronger policy efforts to improve energy efficiency, to boost nuclear power and renewables-based electricity generation and to support the introduction of CO_2 capture and storage technology – one of the most promising options for mitigating emissions in the longer term. Yet the technology shifts outlined in the BAPS Case, while technically feasible, would be unprecedented in scale and speed of deployment.

Bringing modern energy to the world's poor is an urgent necessity

Although steady progress is made in both scenarios in expanding the use of modern household energy services in developing countries, many people still depend on traditional biomass in 2030. Today, 2.5 billion people use fuelwood, charcoal, agricultural waste and animal dung to meet most of their daily energy needs for cooking and heating. In many countries, these resources account for over 90% of total household energy consumption. The inefficient and unsustainable use of biomass has severe consequences for health, the environment and economic development. Shockingly, about 1.3 million people – mostly women and children – die prematurely every year because of exposure to indoor air pollution from biomass. There is evidence that, in countries where local prices have adjusted to recent high international energy prices, the shift to cleaner, more efficient ways of cooking has actually slowed and even reversed. In the Reference Scenario, the number of people using biomass increases to 2.6 billion by 2015 and to 2.7 billion by 2030 as population rises. That is, one-third of the world's population will still be relying on these fuels, a share barely smaller than today. There are still 1.6 billion people in the world without electricity. To achieve the Millennium Development Goals, this number would need to fall to less than one billion by 2015.

Action to encourage more efficient and sustainable use of traditional biomass and help people switch to modern cooking fuels and technologies is needed urgently. The appropriate policy approach depends on local circumstances such as per-capita incomes and the availability of a sustainable biomass supply. Alternative fuels and technologies are already available at reasonable cost. Halving the number of households using biomass for cooking by 2015 – a recommendation of the UN Millennium Project – would involve 1.3 billion people switching to liquefied petroleum gas and other commercial fuels. This would not have a significant impact on world oil demand and the equipment would cost, at most, $1.5 billion per year. But vigorous and concerted government action – with support from the industrialised countries – is needed to achieve this target, together with increased funding from both public and private sources. Policies would need to address barriers to access, affordability and supply, and to form a central component of broader development strategies.

Current trends in energy consumption are neither secure nor sustainable – economically, environmentally or socially. Inexorably rising consumption of fossil fuels and related greenhouse-gas emissions threaten our energy security and risk changing the global climate irreversibly. Energy poverty threatens to hold back the economic and social development of more than two billion people in the developing world. G8 leaders, meeting with the leaders of several major developing countries and heads of international organisations – including the IEA – at Gleneagles in July 2005 and in St. Petersburg in July 2006 endorsed these conclusions. They committed themselves to strong action to change energy trends in order to combat these threats. To this end, they requested the IEA to "advise on alternative energy scenarios and strategies aimed at a clean, clever and competitive energy future". This edition of the *Outlook* offers a response.

As in previous *Outlooks*, the analysis presented here starts with projections derived from a Reference Scenario, which assumes that no new government policies are introduced during the projection period (to 2030). This scenario provides a baseline vision of how global energy markets are likely to evolve if governments do nothing more to affect underlying trends in energy demand and supply. The appeal of such an approach is that it provides a platform against which alternative assumptions about future government policies can be tested. Since *WEO-2000*, an Alternative Policy Scenario analyses the impact of a package of additional measures to address energy-security and climate-change concerns. That scenario illustrates how far policies currently under discussion could take us and assesses their costs.

This *Outlook* takes this approach further. It analyses those policies and their effects in much greater depth. A much broader range of policies than in the past was also assessed, reflecting the greater sense of urgency on the part of policy-makers that has emerged in the last two years. The objective is to offer practical guidance to policy-makers about the potential impact of the many options they are currently considering and the costs and benefits associated with them. Above all, our goal is for the findings of the Alternative Policy Scenario to act as drivers for change. We highlight the results in 2015, to provide a practical medium-term basis for decision-making.

Information on more than 1 400 proposed policies and measures has been collected and analysed. We have expanded the detail on the sectoral and regional effects of specific policies and measures, to help identify the actions that can work best, quickest and at least cost. We have also quantified the changes in investment in supply infrastructure and on the demand side that would be needed (over and above those in the Reference Scenario) and calculated cost savings from reduced energy consumption. Greater attention has been given to China, India, Brazil and other developing countries.

The focus of policy-making has shifted in the past two years towards energy security in response to a series of supply disruptions, geopolitical tensions and surging energy prices. Notable events have included hurricanes in the Gulf of Mexico in 2005, the Russian-Ukrainian natural gas price dispute at the beginning of 2006, civil unrest in Nigeria, nationalisation of hydrocarbon resources in Bolivia, sudden changes in the investment and operating regime in Venezuela, the closure of the trans-Alaskan oil pipeline in August 2006 and persistent unrest in parts of the Middle East. New measures to improve energy efficiency, to promote indigenous production of fossil fuels and renewable energy sources, and, in some cases, to revive investment in nuclear power have already resulted. Although heightened energy insecurity has been the principal driver of these developments, their consequences for greenhouse-gas emissions invariably guide the design of policy responses – especially in OECD countries. Indeed, the primary rationale for many policies on the table today is environmental. The scope and types of policies analysed in the Alternative Policy Scenario reflect these twin priorities.

The structure of this *Outlook* reflects this analytical approach. It comprises three parts. Part A presents the results of the Reference Scenario, including the key assumptions, an overview of global energy trends and detailed projections for each of the main energy sectors: oil, gas, coal and electricity. Part B presents the results of the Alternative Policy Scenario. An overview of the methodological approach and global trends is followed by an assessment of the cost implications of the policies analysed and the detailed results by sector. A separate chapter discusses the hurdles to government action and goes beyond the Alternative Policy Scenario, looking at the additional policies and technological advances that would be needed in order to stabilise energy-related carbon-dioxide emissions by 2030, and longer-term prospects for technology. Finally, Part C looks at a number of pertinent issues: the impact of higher energy prices, current trends in oil and gas investment, prospects for nuclear power and biofuels, energy use for cooking in developing countries and the energy outlook for Brazil – the largest economy in Latin America, a growing oil producer and a leading supplier of biofuels.

PART A

THE REFERENCE SCENARIO

KEY ASSUMPTIONS

HIGHLIGHTS

- The Reference Scenario takes account of those government policies and measures that were enacted or adopted by mid-2006, though many of them have not yet been fully implemented. Possible, potential or even likely future policy actions are not considered.
- Global population is assumed to grow by 1% per year on average, from an estimated 6.4 billion in 2004 to 8.1 billion in 2030. Population growth slows progressively over the projection period, as it did in the last three decades. Population expanded by 1.5% per year from 1980 to 2004. The population of the developing regions continues to grow most rapidly, boosting their share of the world's population.
- The rate of growth in world GDP – the primary driver of energy demand – is assumed to average 3.4% per year over the period 2004-2030, compared with 3.2% from 1980 to 2004. It falls progressively over the projection period, from 4% in 2004-2015 to 2.9% in 2015-2030. China, India and other developing Asian countries are expected to continue to grow faster than any other region. All regions continue to experience a decline in the share of energy-intensive heavy manufacturing in economic output and a rise in the share of lighter industries and services, particularly in the developing world.
- Per-capita incomes grow more quickly in the transition economies and developing countries than in the OECD. Yet per-capita incomes in OECD countries, which increase by 57% to $44 720 in 2030, are still almost four times the average for the rest of the world.
- The IEA crude oil import price is assumed to average slightly over $60 per barrel (in real year-2005 dollars) through 2007 – up from $51 in 2005 – and then decline to about $47 by 2012. It is assumed to rise again slowly thereafter, reaching $55 in 2030. These prices are significantly higher than in *WEO-2005*. Natural gas prices broadly follow the trend in oil prices, because of inter-fuel competition and the continuing widespread use of oil-price indexation in long-term gas-supply contracts. The price of OECD steam-coal imports is assumed to stabilise at about $55 per tonne in the next few years and then rise to $60 in 2030.
- In general, it is assumed that energy-supply and end-use technologies become steadily more efficient, though at varying speeds for each fuel and each sector, depending on the potential for efficiency gains and the stage of technology development and commercialisation. New policies – excluded from the Reference Scenario – would be needed to accelerate the deployment of more efficient and cleaner technologies.

Government Policies and Measures

As in previous editions of the *Outlook*, the Reference Scenario takes account of those government policies and measures that have been enacted or adopted – in this case, by mid-2006 – though many of them have not yet been fully implemented. The impact on energy demand and supply of the most recent measures does not show up in historical market data, which are available only up to 2004 for all countries.[1] Many of them are designed to curb the growth in energy demand, in response to heightened concerns about energy security, as well as climate change and other environmental problems. These initiatives cover a wide array of sectors and involve a variety of policy instruments. Importantly, unlike the Alternative Policy Scenario, the Reference Scenario does not take into consideration possible, potential or even likely future policy actions. Thus, the Reference Scenario projections should not be considered forecasts, but rather a baseline vision of how energy markets would evolve if governments do nothing beyond what they have already committed themselves to doing to influence long-term energy trends. By contrast, the Alternative Policy Scenario, which forms Part B of this *Outlook*, analyses the impact of a range of policies and measures that countries in all regions are considering adopting or might reasonably be expected to adopt at some point over the projection period.

Although the Reference Scenario assumes that there will be no change in energy and environmental policies through the projection period, exactly how existing policies will be implemented in the future is not always clear. Inevitably, a degree of judgement is involved in translating stated policies into formal assumptions for modelling purposes. These assumptions vary by fuel and by region. For example, electricity and gas market reforms, where approved, are assumed to move ahead, but at varying speeds among countries and regions. Progress is assumed to be made in liberalising cross-border energy trade and investment, and in reforming energy subsidies, but these policies are expected to be pursued most energetically in OECD countries. In all cases, the rates of excise duty and value-added or sales tax applied to different energy sources and carriers are assumed to remain constant. As a result, assumed changes in international prices (see below) have different effects on the retail prices of each fuel and in each region, according to the type of tax applied and the rates currently levied. Similarly, in this Reference Scenario, it is assumed that there will be no changes in national policies on nuclear power. Nuclear energy will, therefore, remain an option for power generation only in those countries that have not officially banned it or decided to phase it out.

1. Data for some countries and some fuels are available for 2005 and are included.

Box 1.1: **Improvements to the Modelling Framework in *WEO-2006***

The IEA's World Energy Model (WEM) – a large-scale mathematical construct designed to replicate how energy markets function – is the principal tool used to generate detailed sector-by-sector and region-by-region projections for both the Reference and Alternative Policy Scenarios. The model, which has been developed over several years, is made up of five main modules: final energy demand; power generation; refinery and other transformation; fossil-fuel supply; and CO_2 emissions. The WEM underwent a major overhaul in 2004, involving the addition of several new features, including new regional demand models, more detailed coverage of demand by sector and fuel, and new supply models for oil and coal production and trade. The model has been further extended for the *WEO-2006*, including the following new features:

- Greater regional disaggregation, with the development of new, separate, models for the United States, Canada, Japan, Korea and North Africa.
- More detailed sectoral representation of end-use sectors for non-OECD countries, including aviation and detailed transport-stock models.
- Detailed analysis of the use of cooking and heating fuels in developing countries.
- More sophisticated treatment of biofuels use and supply, and of renewables for heating in end-use sectors.
- An updated analysis of power-generation capital and operating costs, including a more detailed assessment of nuclear power and renewable-energy technologies.
- Calibration of the oil and gas production and oil-refining models to the results of a detailed analysis of the near-term prospects for investment.

A key reason for implementing these improvements has been to deepen the analysis contained in the Alternative Policy Scenario. With the revised WEM, the impact of specific policies and measures on energy demand, production, trade, investment needs, supply costs and emissions can be evaluated with greater precision.

Population

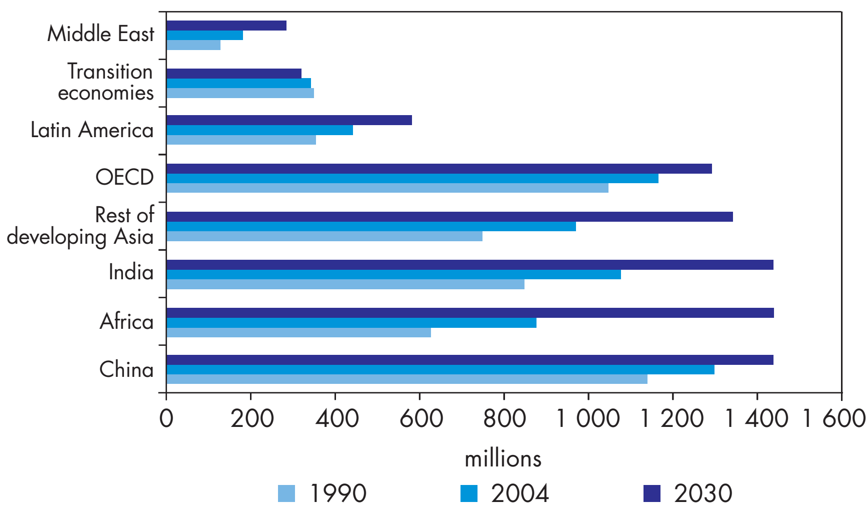
Population growth affects the size and pattern of energy demand. The rates of population growth assumed for each region in this *Outlook* are based on the most recent projections contained in the United Nations' report, *World Population Prospects: The 2004 Revision* (UNPD, 2005). Global population is projected to grow by 1% per year on average, from an estimated 6.4 billion in mid-2004 to over 8.1 billion in 2030. Population growth slows progressively over the projection period, as it did in the last three decades, from 1.1% per year in 2004-2015 to 0.8% in 2015-2030 (Table 1.1). Population expanded by 1.5% per year from 1980 to 2004.

Table 1.1: **World Population Growth** (average annual growth rates, %)

	1980-1990	1990-2004	2004-2015	2015-2030	2004-2030
OECD	**0.8**	**0.8**	**0.5**	**0.3**	**0.4**
North America	1.2	1.3	0.9	0.7	0.8
United States	*0.9*	*1.2*	*0.9*	*0.7*	*0.8*
Europe	0.5	0.5	0.3	0.1	0.2
Pacific	0.8	0.5	0.2	–0.1	0.0
Japan	*0.6*	*0.2*	*0.0*	*–0.3*	*–0.2*
Transition economies	**0.8**	**–0.2**	**–0.2**	**–0.3**	**–0.3**
Russia	0.6	–0.2	–0.5	–0.6	–0.5
Developing countries	**2.1**	**1.7**	**1.3**	**1.0**	**1.2**
Developing Asia	1.8	1.5	1.1	0.8	0.9
China	*1.5*	*1.0*	*0.6*	*0.3*	*0.4*
India	*2.1*	*1.7*	*1.3*	*0.9*	*1.1*
Middle East	3.6	2.4	2.0	1.6	1.7
Africa	2.9	2.4	2.1	1.8	1.9
Latin America	2.0	1.6	1.3	0.9	1.1
Brazil	*2.1*	*1.5*	*1.2*	*0.8*	*0.9*
World	**1.7**	**1.4**	**1.1**	**0.8**	**1.0**
European Union	*0.3*	*0.3*	*0.1*	*0.0*	*0.0*

The OECD's population is projected to rise modestly, with most of the increase coming from North America. Population in Russia and other transition economies is expected to decline (Figure 1.1). Mortality rates there have been stagnant or even increasing, largely as a result of deteriorating social conditions, unhealthy lifestyles and, in some cases, because of the spread of HIV. Russia's population is projected to drop from 144 million in 2004 to 125 million by the end of the projection period. The population of the developing regions will continue to grow most rapidly, boosting their share of the world's population from 76% today to 80% in 2030. Mortality is falling in most developing countries, but is rising in those most affected by the HIV/AIDS epidemic. Nonetheless, an expected expansion of programmes to distribute antiretroviral drugs to AIDS sufferers has led to higher average survivorship for people living with HIV than previously projected. Consequently, population growth rates are slightly higher in some regions than in the last *Outlook*.

Figure 1.1: **World Population by Region**



Macroeconomic Factors

The energy projections in the *Outlook* are highly sensitive to underlying assumptions about GDP growth – the main driver of demand for energy services. Energy demand has tended to rise broadly in line with GDP growth in the past three decades or so, though the ratio has gradually declined over time. Since 1990, each 1% increase in GDP (expressed in purchasing power parity terms)[2] has been accompanied by a 0.5% increase in primary energy consumption. Between 1971 and 1990, the corresponding increase was 0.7%. Demand has grown less rapidly relative to GDP in recent years largely due to warmer weather in the northern hemisphere, which has reduced energy needs

2. All GDP data cited in this chapter are expressed in year-2005 dollars using purchasing power parities (PPPs) rather than market exchange rates. PPPs compare costs in different currencies of a fixed basket of traded and non-traded goods and services and yield a broadly-based measure of standard of living. This is a more appropriate basis for analysing the main drivers of energy demand.

for heating, and faster improvements in end-use energy efficiency. Demand for transport fuels and electricity have continued to grow in an almost linear fashion with, though at a slower rate than, GDP since the 1970s.

Despite higher oil prices since 2002, the economies of most countries around the world have continued to grow strongly. The world economy grew by 5.3% in 2004 – the fastest rate since 1973. Preliminary estimates put growth at 4.9% in 2005. These rates are well above the average of 3.1% over the period 1980-2003. All major regions saw their growth accelerate in 2003 and 2004, though most countries experienced a slowdown in 2005 and early 2006. OECD countries' GDP grew by 2.8% in 2005, down from 3.3% in 2004. A revival of the Japanese economy and the continuing strength of the US economy have been partially offset by continuing sluggish growth across much of Europe. Developing countries and the transition economies have enjoyed above-average rates of GDP growth. China's GDP surged by around 10% in both 2004 and 2005, while growth in India averaged 8%. Middle East economies have picked up sharply, thanks to higher oil-export revenues. There are signs that GDP growth in most regions may decline further as interest rates rise in response to increasing inflationary pressures, resulting from the surge in oil and other commodity prices. Chapter 11 assesses in detail the macroeconomic impact of higher energy prices.

GDP growth is expected to slow gradually over the projection period in all regions (Table 1.2).[3] World GDP is assumed to grow by an average of 3.4% per year over the period 2004-2030. Growth drops from an average of 4% in 2004-2015 to 2.9% in 2015-2030. Developing Asian countries are expected to continue to grow faster than any other region, followed by the Middle East and Africa. The Chinese economy is assumed to grow fastest at 5.5% per year over the projection period, overtaking the United States as the world's largest economy in PPP terms by around 2015. Growth nonetheless slows as the economy matures and population levels off. GDP in the OECD as a whole is assumed to grow by 2.2% per year over the projection period. Growth rates in the three OECD regions are expected to slow progressively over the projection period, as population growth slows or reverses and their economies mature. All regions continue to experience a decline in the share of energy-intensive heavy manufacturing in economic output and a rise in the share of lighter industries and services, particularly in the developing world where the process is least advanced.

Combining our population and GDP growth assumptions yields an average increase in per-capita income of 2.4% per annum, from $9 253 in 2004 to $17 196 in 2030 (in PPP terms and year-2005 dollars). Per-capita incomes

3. The same macroeconomic and population assumptions are used in the Alternative Policy Scenario.

Table 1.2: **World Real GDP Growth** (average annual growth rates, %)

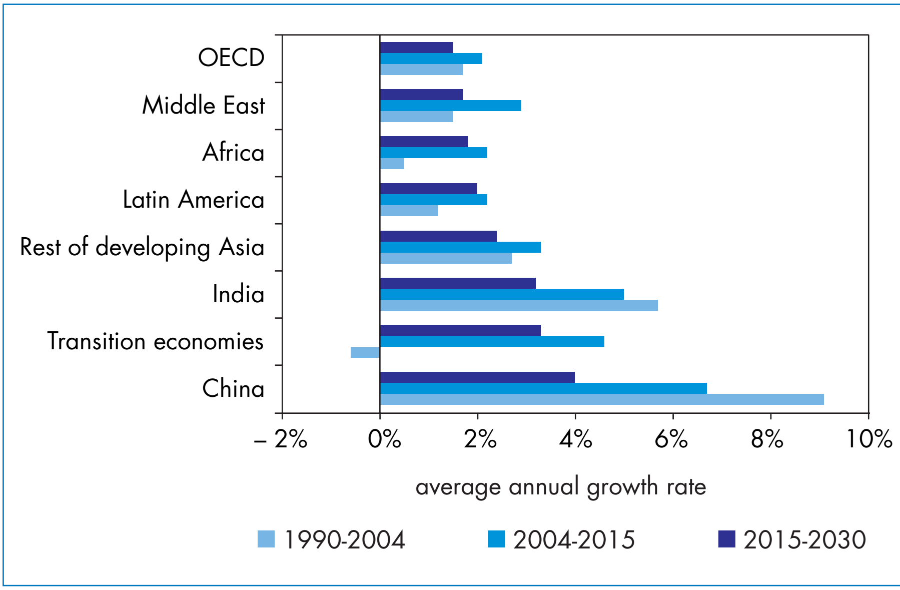
	1980-1990	1990-2004	2004-2015	2015-2030	2004-2030
OECD	**3.0**	**2.5**	**2.6**	**1.9**	**2.2**
North America	**3.1**	**3.0**	**2.9**	**2.0**	**2.4**
United States	*3.2*	*3.0*	*2.9*	*1.9*	*2.3*
Europe	2.4	2.2	2.3	1.8	2.0
Pacific	4.2	2.2	2.3	1.6	1.9
Japan	*3.9*	*1.3*	*1.7*	*1.3*	*1.4*
Transition economies	**–0.5**	**–0.8**	**4.4**	**2.9**	**3.6**
Russia	–	–0.9	4.2	2.9	3.4
Developing countries	**3.9**	**5.7**	**5.8**	**3.9**	**4.7**
Developing Asia	6.6	7.3	6.4	4.1	5.1
China	*9.1*	*10.1*	*7.3*	*4.3*	*5.5*
India	*6.0*	*5.7*	*6.4*	*4.2*	*5.1*
Middle East	–0.4	3.9	5.0	3.2	4.0
Africa	2.1	2.8	4.4	3.6	3.9
Latin America	1.3	2.8	3.5	2.9	3.2
Brazil	*1.5*	*2.6*	*3.3*	*2.8*	*3.0*
World	**2.9**	**3.4**	**4.0**	**2.9**	**3.4**
European Union	*2.4*	*2.1*	*2.2*	*1.8*	*2.0*

grow more quickly in the transition economies and developing countries than in the OECD (Figure 1.2). Yet incomes in OECD countries, which increase by 57% to $44 720 in 2030, are still almost four times the average for the rest of the world.

Energy Prices

As with any good, the price of an energy service (reflecting the price of the fuel used to provide it) affects how much of it is demanded. The price elasticity of demand varies across fuels and sectors, and over time, depending on a host of factors, including the scope for substituting the fuel with another or adopting more efficient energy-using equipment, the need for the energy service and the pace of technological change. Primary energy sources are traded on international markets and their prices are influenced by market forces, even where those markets are not entirely free. Where retail prices are not directly

Figure 1.2: **Growth in Real GDP Per Capita by Region**



controlled by the government, they generally move in line with international prices. But the percentage change in the retail price of a fuel is usually much less than that in the international price because of distribution costs (which tend to fluctuate much less), taxes and, in some cases, subsidies. Chapter 11 analyses in detail price elasticities, the impact of taxes and subsidies on actual retail prices, and recent trends in international and retail prices.

The Reference Scenario projections are based on the average retail prices of each fuel used in final uses, power generation and other transformation sectors. These prices are derived from assumptions about the international prices of fossil fuels (Table 1.3). Tax rates and excise duties are assumed to remain constant over the projection period. Final electricity prices are derived from marginal power-generation costs (which reflect the price of primary fossil-fuel inputs to generation, and the cost of hydropower, nuclear energy and renewables-based generation), and non-generation costs of supply. The fossil-fuel-price assumptions reflect our judgment of the prices that will be needed to stimulate sufficient investment in supply to meet projected demand over the projection period. Although the price paths follow smooth trends, prices are likely, in reality, to remain volatile.[4]

4. Some energy prices are assumed to change in the Alternative Policy Scenario. The impact of lower investment on oil prices, demand and supply is analysed in Chapter 3. The impact of higher oil prices on energy demand is analysed in Chapter 11.

Table 1.3: **Fossil-Fuel Price Assumptions in the Reference Scenario** ($ per unit)

	unit	2000	2005	2010	2015	2030
Real terms (year-2005 prices)						
IEA crude oil imports	barrel	31.38	50.62	51.50	47.80	55.00
Natural gas						
US imports	*MBtu*	*4.34*	*6.55*	*6.67*	*6.06*	*6.92*
European imports	*MBtu*	*3.16*	*5.78*	*5.94*	*5.55*	*6.53*
Japanese LNG imports	*MBtu*	*5.30*	*6.07*	*6.62*	*6.04*	*6.89*
OECD steam coal imports	tonne	37.51	62.45	55.00	55.80	60.00
Nominal terms						
IEA crude oil imports	barrel	28.00	50.62	57.79	60.16	97.30
Natural gas						
US imports	*MBtu*	*3.87*	*6.55*	*7.49*	*7.62*	*12.24*
European imports	*MBtu*	*2.82*	*5.78*	*6.66*	*6.98*	*11.55*
Japanese LNG imports	*MBtu*	*4.73*	*6.07*	*7.43*	*7.59*	*12.18*
OECD steam coal imports	tonne	33.47	62.45	61.74	70.19	106.14

Note: Prices in the first two columns represent historical data. Gas prices are expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. Nominal prices assume inflation of 2.3% per year from 2006.

The average IEA crude oil import price, a proxy for international oil prices, was $51 per barrel in 2005. It is assumed to average slightly over $60 per barrel (in real year-2005 dollars) through 2007, and then decline to about $47 by 2012. It is assumed to rise again slowly thereafter, reaching $50 in 2020 and $55 in 2030 (Figure 1.3). In nominal terms, the price will reach $97 in 2030 assuming inflation of 2.3% per year. Prices of the major benchmark crude oils, West Texas Intermediate (WTI) and Brent, will be correspondingly higher. In 2005, the average IEA crude oil import price was $5.97 per barrel lower than first-month WTI and $3.90 lower than dated Brent.

Prospects for oil prices remain extremely uncertain. The price assumptions described above are significantly higher than assumed in the last edition of the *Outlook*. This revision reflects the continuing recent tightness of crude oil and refined-product markets, resulting, to a large extent, from tight product-upgrading capacity. This is reflected in rising crude oil/light product price differentials and falling crude oil/heavy fuel oil differentials since 2003 (Figure 1.4). Geopolitical tensions in the Middle East, Russia, Africa and Latin America have contributed to the upward pressure on prices. Some commentators and investors predict further price rises, possibly to $100 per barrel for crude oil. Market fundamentals point to a modest easing of prices as new capacity comes on stream (see Chapter 12) and demand growth tempers. But new geopolitical tensions or, worse, a major supply disruption could drive prices even higher.

Figure 1.3: **Average IEA Crude Oil Import Price in the Reference Scenario**

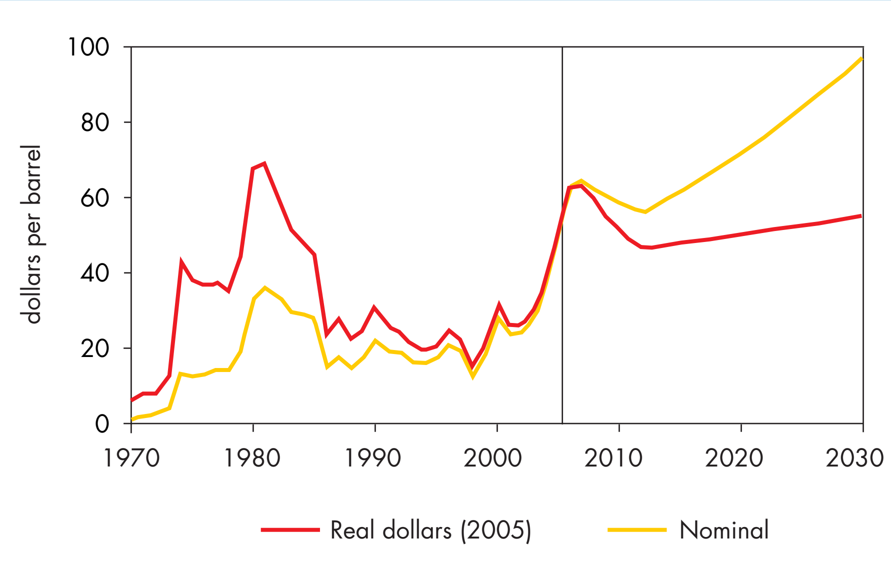
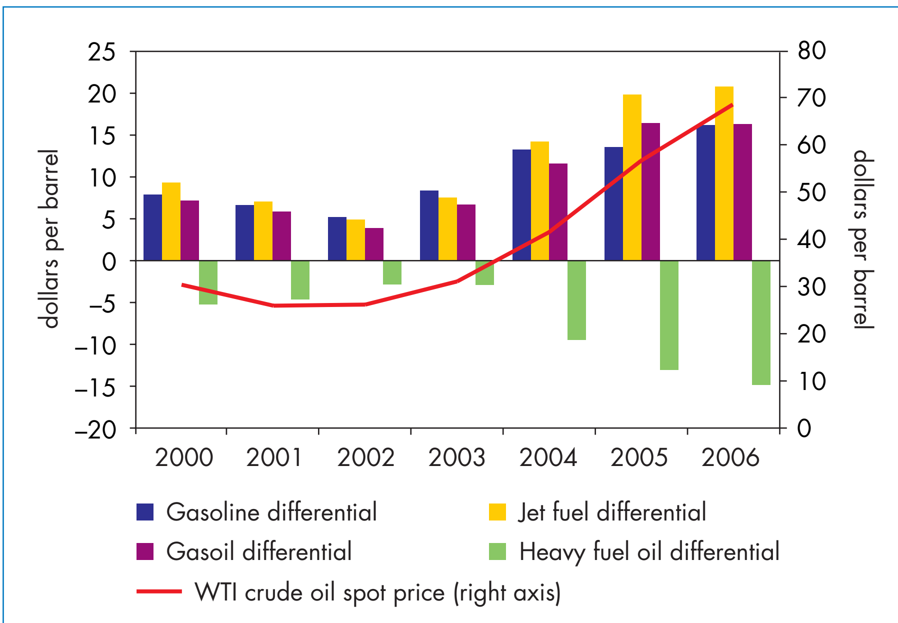


Figure 1.4: **Crude Oil Price and Differentials to Oil Product Prices**



Note: Product price differentials are averages, calculated using product prices on the northwest Europe, New York and Singapore spot markets and representative crude oil prices. 2006 is year to the end of August.
Source: IEA databases.

In the longer term, price trends will hinge on the investment and production policies of a small number of countries – mainly Middle East members of the Organization of the Petroleum Exporting Countries (OPEC) – that hold the bulk of the world's remaining oil reserves and on the cost of developing them. The assumed slowly rising trend in real prices after 2012 reflects an expected increase in the market share of a small number of major producing countries, together with a rise in marginal production costs outside OPEC. Most of the additional production capacity that will be needed over the projection period would logically be expected to be built in Middle East OPEC countries. The resulting growing concentration of production in these countries will increase their market dominance and, therefore, their ability to impose higher prices through their collective production and investment policies. It is nonetheless assumed that they will seek to avoid driving prices up too much and too quickly, for fear of depressing global demand and of accelerating the development of alternative energy sources.

Natural gas prices are assumed broadly to follow the trend in oil prices, because of the continuing widespread use of oil-price indexation in long-term gas supply contracts[5] and because of inter-fuel competition in end-use markets. Some divergences in oil and gas prices and between gas prices across regions are nonetheless expected. Increasing gas-to-gas competition will put downward pressure on gas prices relative to oil prices in some markets, but this factor is expected to be offset to some degree by rising supply costs – notably in North America and Europe. Increased short-term trading in liquefied natural gas (LNG), allowing arbitrage among regional markets, is expected to contribute to the convergence of regional prices over the projection period. International steam coal prices have risen steadily in recent years on the back of rising oil prices and strong demand, particularly from power generators and steel producers. The price of OECD steam coal imports is assumed to fall back slightly from a peak of $62 per tonne (in year-2005 dollars) in 2005 to around $55 in the next few years and then to increase slowly to $60 by 2030.

Technological Developments

The pace of technological innovation and deployment affects the cost of supplying and the efficiency of using energy. Our projections are, therefore, very sensitive to assumptions about technological developments. In general, it

5. The share of global gas supply that is traded under contracts with explicit oil-price indexation clauses is probably at least one-third and may be as high as half. Much of the remaining share of gas supply is not traded commercially. Almost all long-term contracts in continental Europe, which account for well over 95% of bulk gas trade, include oil-price indexation. Gas prices are indexed against oil prices in some way in virtually all long-term LNG supply contracts. In contrast, most gas is priced against spot or forward gas-price indices in North America and Great Britain.

is assumed that available end-use technologies become steadily more energy-efficient, though the pace varies for each fuel and each sector depending on our assessment of the potential for efficiency improvements and the stage of technology development and commercialisation. The rate at which available technologies are actually taken up by end users also varies, mainly as a function of how quickly the current and future stock of energy-using capital equipment is retired and replaced. In most cases, capital stock is replaced only gradually, so technological developments that improve energy efficiency will have their greatest impact on market trends towards the end of the projection period – a key message of a recent IEA study on technology (IEA, 2006).[6] But some capital equipment is replaced much more frequently: most cars and trucks are usually replaced within ten or fifteen years – or less in OECD countries. Heating and cooling systems and industrial boilers typically last a bit longer. But buildings, power stations and refineries and most of the current transport infrastructure last several decades or more. Retiring these facilities early would be extremely expensive. That is why governments will need to provide strong financial incentives if the rate of deployment of more efficient and cleaner technologies is to be accelerated. The impact of new policies on the deployment of more advanced technologies is analysed in detail in the Alternative Policy Scenario (Part B).

Technological advances are also assumed to improve the efficiency of producing and supplying energy. In most cases, they are expected to lower the cost of energy supply and lead to new and cleaner ways of producing and delivering energy services. There remains considerable scope for improving the efficiency of power generation, with improvements assumed to occur at different rates for different technologies. Neither CO_2 capture and storage nor second-generation biofuel technologies are assumed to become commercially attractive on a large scale before the end of the projection period in the Reference Scenario. Hydrogen fuel cells based on natural gas are expected to start to become economically attractive in some small-scale power generation applications and, to a much lesser extent, in the transport sector after 2020. Exploration and production techniques for oil and gas are also expected to improve, which could lower the unit production costs and open up new opportunities for developing resources. However, further increases in raw material and personnel costs – a worldwide phenomenon in the last few years – could offset the impact of new technology to some extent (see Chapter 12).

6. *Energy Technology Perspectives* analyses a range of different energy and technology developments and deployment options following a portfolio approach.

GLOBAL ENERGY TRENDS

HIGHLIGHTS

- Global primary energy demand in the Reference Scenario is projected to increase by 53% between 2004 and 2030 – an average annual rate of 1.6%. Over 70% of this increase comes from developing countries. The power-generation sector contributes close to one-half of the global increase. Demand grows by one-quarter in the period to 2015 alone.
- Globally, fossil fuels remain the dominant source of energy, accounting for 83% of the overall increase in energy demand between 2004 and 2030. As a result, their share of world demand edges up, from 80% to 81%. In contrast to *WEO-2005*, coal sees the biggest increase in demand in absolute terms, its percentage share in global demand – like that of gas – increasing slightly. The share of oil drops. Non-hydro renewables grow quickest, but from a small base.
- The world's remaining economically exploitable energy resources are adequate to meet the projected increases in demand through to 2030. With sufficient investment in production and transportation capacity, international energy trade would grow steadily over the *Outlook* period to accommodate the increasing mismatch between the location of demand and that of production. Energy exports from non-OECD to OECD regions rise by 47%. Oil remains the most heavily traded fuel in 2030, but gas trade grows most rapidly.
- Cumulative investment in energy-supply infrastructure amounts to just over $20 trillion (in year-2005 dollars) over 2005-2030 – significantly more than in *WEO-2005* because of higher unit costs. The power sector requires more than $11 trillion, equal to 56% of total energy investment needs (two-thirds if investment in the supply chain to meet the fuel needs of power stations is included). Capital expenditure amounts to $4.3 trillion in the oil sector and $3.9 trillion in the gas sector. Roughly half of all the energy investment needed worldwide is in developing countries, where demand and production are projected to increase fastest.
- Global energy-related carbon-dioxide emissions increase slightly faster than primary energy use, because the fuel mix becomes more carbon-intensive. The power sector contributes around half the increase in emissions from 2004 to 2030. Coal remains the leading contributor to global emissions over the *Outlook* period. China accounts for 39% of the increase between 2004 and 2030, overtaking the United States as the world's biggest emitter before 2010.

Demand

Primary Energy Mix

Global primary energy demand[1] in the Reference Scenario is projected to increase by 1.6% per year between 2004 and 2030, reaching 17.1 billion tonnes of oil equivalent (Table 2.1). The increase in demand amounts to almost 6 billion toe, or 53% of current demand. The average projected rate of growth is, nevertheless, slower than that over the period 1980-2004, when demand grew by 1.8% per year. The pace of demand growth slackens progressively over the projection period: in the period 2004-2015, it grows by 2.1%. By 2015, total global energy demand is one-quarter higher than in 2004. The rate of growth drops to 1.3% in 2015-2030.

Table 2.1: **World Primary Energy Demand in the Reference Scenario**
(Mtoe)

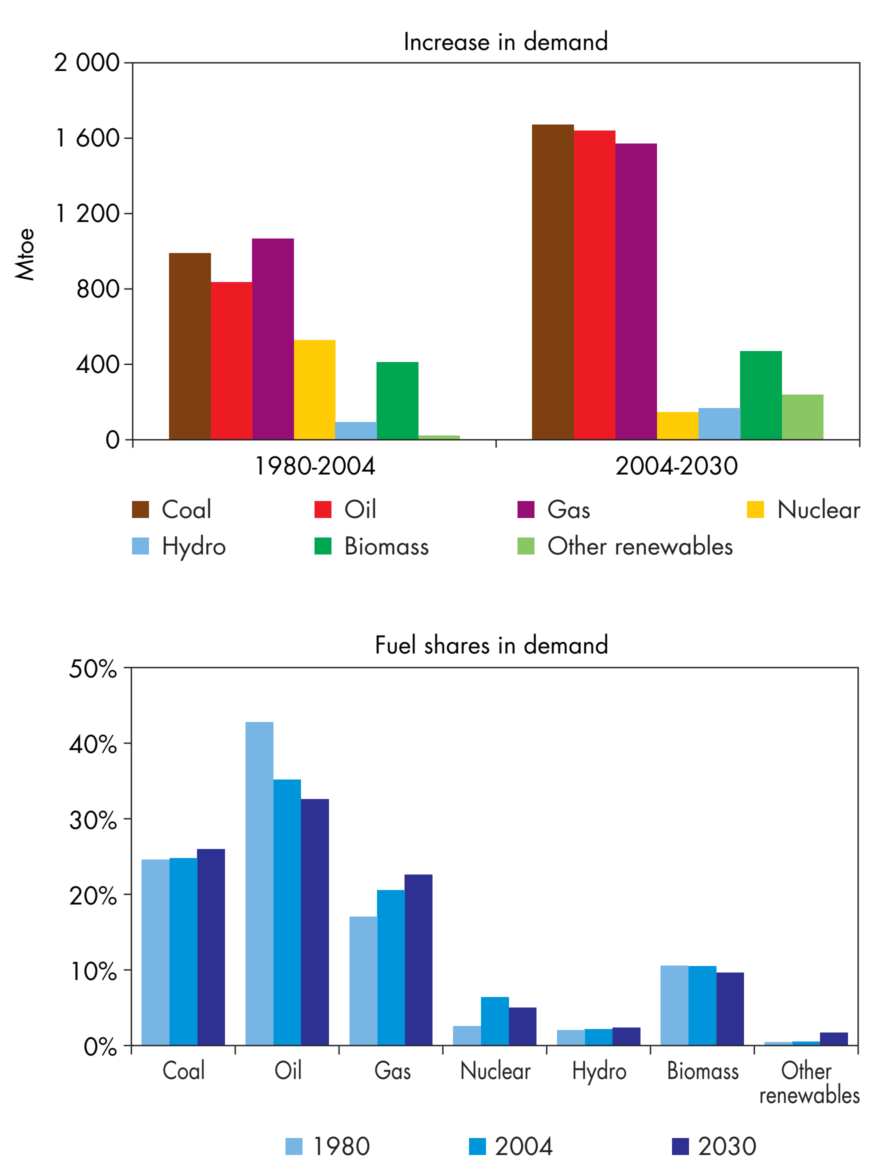
	1980	2004	2010	2015	2030	2004 - 2030*
Coal	1 785	2 773	3 354	3 666	4 441	1.8%
Oil	3 107	3 940	4 366	4 750	5 575	1.3%
Gas	1 237	2 302	2 686	3 017	3 869	2.0%
Nuclear	186	714	775	810	861	0.7%
Hydro	148	242	280	317	408	2.0%
Biomass and waste	765	1 176	1 283	1 375	1 645	1.3%
Other renewables	33	57	99	136	296	6.6%
Total	**7 261**	**11 204**	**12 842**	**14 071**	**17 095**	**1.6%**

* Average annual growth rate.

Fossil fuels are projected to remain the dominant sources of primary energy globally. They account for close to 83% of the overall increase in energy demand between 2004 and 2030. Their share of world demand edges up from 80% in 2004 to 81% in 2030. Coal sees the biggest increase in demand in volume terms in 2004-2030, closely followed by oil (Figure 2.1). In *WEO-2005*, oil and gas

1. World total primary energy demand, which is equivalent to total primary energy supply, includes international marine bunkers, which are excluded from the regional totals. Primary energy refers to energy in its initial form, after production or importation. Some energy is transformed, mainly in refineries, power stations and heat plants. Final consumption refers to consumption in end-use sectors, net of losses in transformation and distribution. In all regions, total primary and final demand includes traditional biomass and waste such as fuel wood, charcoal, dung and crop residues, some of which are not traded commercially.

Figure 2.1: **World Primary Energy Demand by Fuel in the Reference Scenario**



were projected to grow the most. Oil nonetheless remains the single largest fuel in the primary fuel mix in 2030, though its share drops, from 35% now to 33%. Coal remains the second-largest fuel, with its share increasing one percentage point to 26%. Gas demand grows faster than coal, but – in contrast to *WEO-2005* – does not overtake it before 2030. The growth in demand for gas has been revised down and that for coal up, mainly owing to relatively higher gas prices. In the Reference Scenario, the share of nuclear power is expected to fall (albeit less rapidly than in *WEO-2005*), on the assumption that few new reactors are built and that several existing ones are retired between now and 2030. Hydropower's share of primary energy use rises slightly. The share of traditional biomass falls, as developing countries increasingly switch to using modern commercial energy. Other renewable energy technologies, including wind, solar, geothermal, wave and tidal energy, see the fastest increase in demand, but their share of total energy use still reaches only 1.7% in 2030 – up from 0.5% today.

Global primary energy intensity, measured as energy use per unit of gross domestic product, falls on average by 1.7% per year over 2004-2030. The decline is most rapid in the non-OECD regions, mainly because they profit from the greater scope for improving energy efficiency and because their economies become less reliant on energy-intensive heavy manufacturing industries as the services sector grows faster. The transition economies see the sharpest fall in intensity, which almost halves between 2004 and 2030, as new technologies are introduced, wasteful practices are dealt with and consumption subsidies are reduced (see Chapter 11). Yet they remain far more energy-intensive than either developing or OECD countries in 2030. The shift to services is much more advanced in the OECD, so there is less scope for reducing energy intensity.

Regional Trends

Over 70% of the increase in world primary energy demand between 2004 and 2030 comes from the developing countries (Figure 2.2). OECD countries account for almost one-quarter and the transition economies for the remaining 6%. As a result, the OECD's share of world demand drops, from just under half in 2004 to 40% in 2030, while that of the developing countries jumps, from 40% to 50%. The share of China alone rises from 15% to 20%, though this projection is particularly uncertain (Box 2.1). The transition economies' share falls from 10% to 8%. The increase in the share of the developing regions in world energy demand results from their more rapid economic and population growth. Industrialisation and urbanisation boost demand for modern commercial fuels.

The developing regions account for 23 mb/d, or 71%, of the 33 mb/d increase in oil demand between 2005 and 2030, with demand growing most rapidly in volume terms in the developing Asian countries. Oil demand increases less quickly in the OECD regions and the transition economies. In volume terms, gas demand expands most in the Middle East. Coal demand grows most in developing Asia, where there are large, low-cost resources. Coal

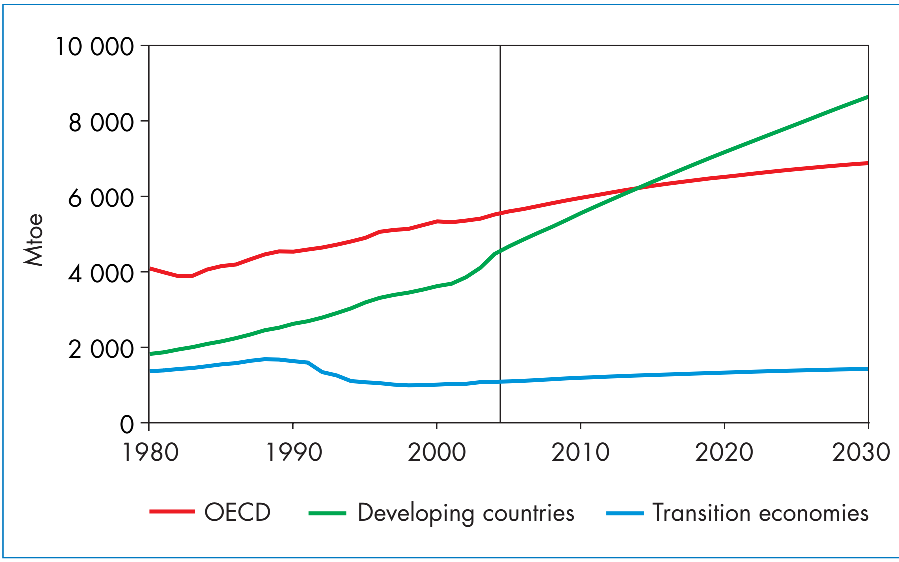
Box 2.1: **Uncertainty Surrounding China's Energy Trends**

China is a major source of uncertainty for our global energy projections. The country is already a key player in the global energy market, and its role is expected to grow significantly over the projection period. In the Reference Scenario, the country accounts for 20% of the world primary energy demand in 2030 – up from 15% today. Its share of global coal demand rises from 36% today to 46% in 2030 (on an energy-content basis). Small changes in the outlook for China would, therefore, have a significant impact on the global energy picture. For example, a one-percentage point higher average annual rate of growth in China's demand would raise world primary energy demand by nearly 1 000 Mtoe, or 6%, and oil demand by 4.4 million barrels per day, or 4%, in 2030. Several factors could change energy prospects in China:

- **Long-term macroeconomic prospects:** China's economy has grown by about 10% per year on average for the past two decades, the fastest rate of any major country. The government's 11th five-year plan aims to moderate growth to 7.5% per year between 2005 and 2010 to prevent the economy from over-heating. But the preliminary estimate for its growth rate in the first half of 2006 is nearly 11%. In the longer term, growth is nonetheless expected to slow as the economy matures and population growth declines, but how quickly this occurs is very uncertain.
- **The link between energy demand and GDP growth:** Energy demand has not grown in a stable ratio to GDP in the past. For example, primary coal demand grew steadily between 1971 and 1996, but fell between 1997 and 2001 – despite continuing rapid economic growth. Demand started to grow again in 2002, surging in 2003 and 2004 by around 20% per year. Demand for other fuels has also soared relative to GDP in the past few years (see Chapter 11). Several factors, such as a surge in vehicle ownership, periodic government measures to limit energy use, the Asian financial crisis and statistical problems help to explain these erratic trends in demand.
- **The impact of structural reforms in the energy sector:** End-use energy prices, which have been under the government's control, are expected to be more liberalised in future. How quickly this occurs will have a significant impact on energy markets. In the coal industry, the government has encouraged the closure and consolidation of inefficient small mines. By the end of 2005, more than 2000 small mines had been closed. Restructuring of the coal industry and the pace of demand growth will determine whether China remains a net coal exporter.

World Energy Outlook 2007 will be devoted to an extensive analysis of energy developments in China, as well as India, and their implications for global energy markets.

Figure 2.2: **World Primary Energy Demand by Region in the Reference Scenario**



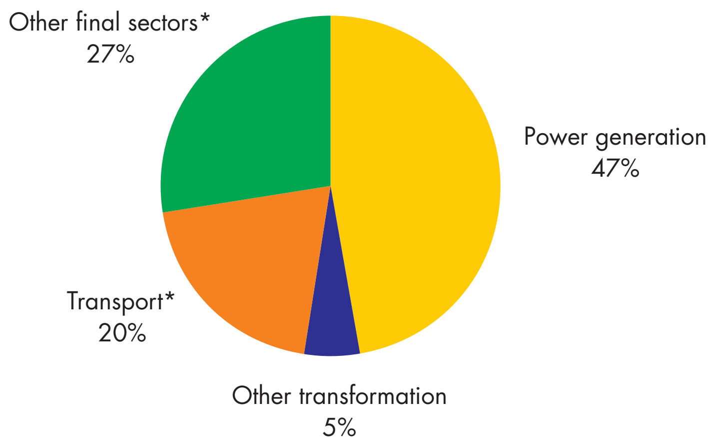
continues to dominate the fuel mix in India and China. By 2030, they account together for 57% of world coal demand, up from 43% in 2004. On the policy assumptions of the Reference Scenario, nuclear power declines in Europe, but increases in all other regions. The biggest increases in nuclear power production occur in Russia, Japan, Korea and developing Asian countries. Overall, nuclear power's share of world primary energy drops from 6% in 2004 to 5% in 2030.

Sectoral Trends

The power-generation sector accounts for 47% of the increase in global energy demand over the projection period (Figure 2.3). Its share of primary demand increases from 37% in 2004 to 41% in 2030. Demand for electricity-related services, the main determinant of how much fuel is needed to generate power, is closely linked to incomes. Nonetheless, continued improvements in the thermal efficiency of power stations mean that the rate of growth in power-sector energy demand is somewhat lower than that of final electricity demand. The transport sector (excluding electricity used in rail transportation) accounts for about another fifth of the increase in global demand.

World energy consumption in end-use sectors as a whole – industry, transport, residential, services (including agriculture) and non-energy uses – increases by 1.6% per year over 2004-2030, the same rate as primary demand. Among all major end-use energy sources, electricity is projected to grow most rapidly, by

Figure 2.3: **Incremental World Primary Energy Demand by Sector in the Reference Scenario, 2004-2030**



* Excluding electricity and heat.

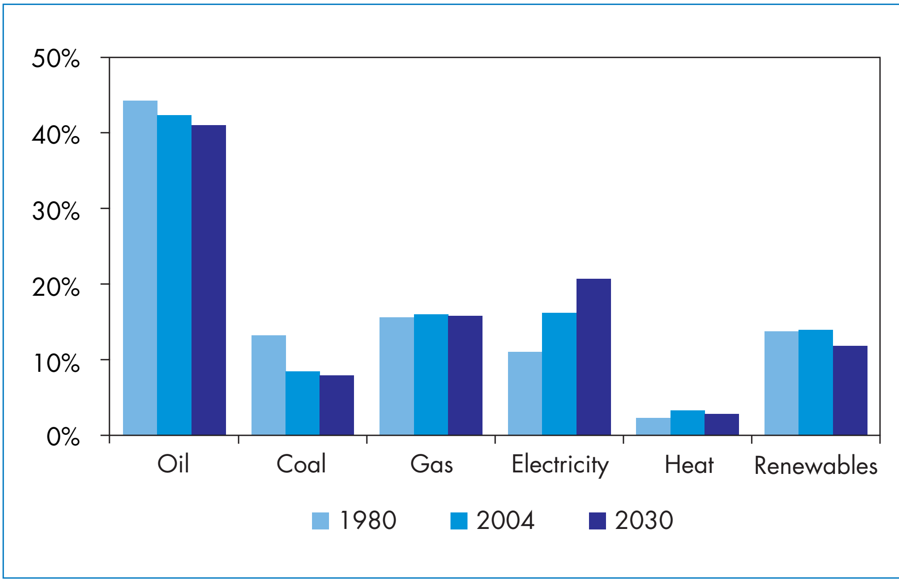
2.6% per year, nearly doubling between 2004 and 2030. As a result, electricity's share of total final consumption grows from 16% to 21% (Figure 2.4). In 1980, it was only 11%. Electricity use grows most rapidly in developing countries, as the number of people with access to electricity and incomes rises steadily. By 2030, the share of electricity in final energy use in developing countries almost reaches that of OECD countries. Yet per-capita consumption remains much lower, mainly because incomes are far smaller – even though the gap between OECD and developing country incomes narrows significantly over the projection period. In 2030, per-capita consumption reaches 26.9 kWh per day in OECD countries but only 6.2 kWh in non-OECD countries. The share of traditional biomass in final consumption declines, as developing-country households switch to modern fuels for cooking and heating (see Chapter 15). The share of other renewables increases, but is still less than 1% in 2030. The shares of all other fuels hardly change over 2004-2030.

Energy Production and Trade

Resources and Production Prospects

Sufficient resources exist worldwide to permit the world's energy industry to expand capacity in order to meet the projected increases in demand through to 2030 for each form of energy described above. The world's remaining economically exploitable fossil-fuel, hydroelectric and uranium resources are

Figure 2.4: **Fuel Shares in World Final Energy Demand in the Reference Scenario**



adequate. At issue is whether these resources will actually be developed quickly enough and at what cost. The Reference Scenario is predicated on the assumption that the stated prices will be high enough to stimulate sufficient investment in new supply infrastructure to enable all the projected demand to be met. Notwithstanding this assumption, it is far from certain whether energy companies will be willing or able to invest in developing those resources and in bringing them to market, and how much it will cost. A number of factors may impede required investments from being made in a particular sector or region. These include a worsening of the investment climate, changes in government attitudes to foreign investment and capacity expansions, the adoption of more stringent environmental regulations and less favourable licensing and fiscal conditions.[2]

Proven reserves of natural gas and coal are much larger than the cumulative amounts of both fuels that will be consumed over the projection period. Today, proven reserves are equal to 64 years of current consumption of gas and 164 years of coal. And substantial new reserves will undoubtedly be added between

2. The impact of a deferral of investment in the upstream oil industry is assessed in Chapter 3. A detailed assessment of current trends in oil and gas investment is provided in Chapter 12. The impact of new government policies to bolster energy security and curb energy-related greenhouse-gas emissions is assessed in the Alternative Policy Scenario, described in detail in Part B (Chapters 7-10).

now and 2030. Proven reserves of crude oil and natural gas liquids are much smaller in relation to current consumption, covering barely 42 years. Although that is enough to meet all the oil consumed in the Reference Scenario through to 2030, more oil would need to be found were conventional production not to peak before then. Even if it were to do so, non-conventional sources of oil – including oil sands and gas- and coal-to-liquids plants – could meet any shortfall in conventional oil supply if the necessary investment is forthcoming. There is no lack of uranium for projected nuclear power production in the Reference Scenario for the next several decades at least. There is also significant remaining potential for expanding hydropower and energy from biomass and other renewable sources.

The Middle East and North Africa, which have massive hydrocarbon resources (IEA, 2005a), are expected to meet much of the growth in world oil and gas demand over 2004-2030. Latin America (especially Venezuela and Brazil), Africa and the transition economies also increase production of both oil and gas. Conventional oil production declines in most other regions, including OECD North America and Europe. Production of natural gas, resources of which are more widely dispersed than oil, increases in every region other than Europe. Although there are abundant coal reserves in most regions, increases in coal production are likely to be concentrated in China, India, the United States, Australia, South Africa, Indonesia, and Colombia, where extraction, processing and transportation costs are lowest. The production prospects for each fuel are discussed in more detail in later chapters.

Inter-Regional Trade

International energy trade is expected to grow steadily over the *Outlook* period to accommodate the increasing mismatch between the location of demand and that of production. In the Reference Scenario, the OECD accounts for 23% of the total increase in world primary energy demand, but only 5% of the growth in output. As a result, exports from non-OECD regions to OECD regions expand by 47%. Total OECD imports, including trade between OECD regions, will also increase by 47% between 2004 and 2030 (Table 2.2). By 2030, 43% of all the primary energy consumed in the OECD is imported. The transition economies and the developing countries in aggregate become bigger net exporters. Trade between major non-OECD regions also increases sharply. The Middle East sees the biggest increase in energy exports, while imports grow most in developing Asia.

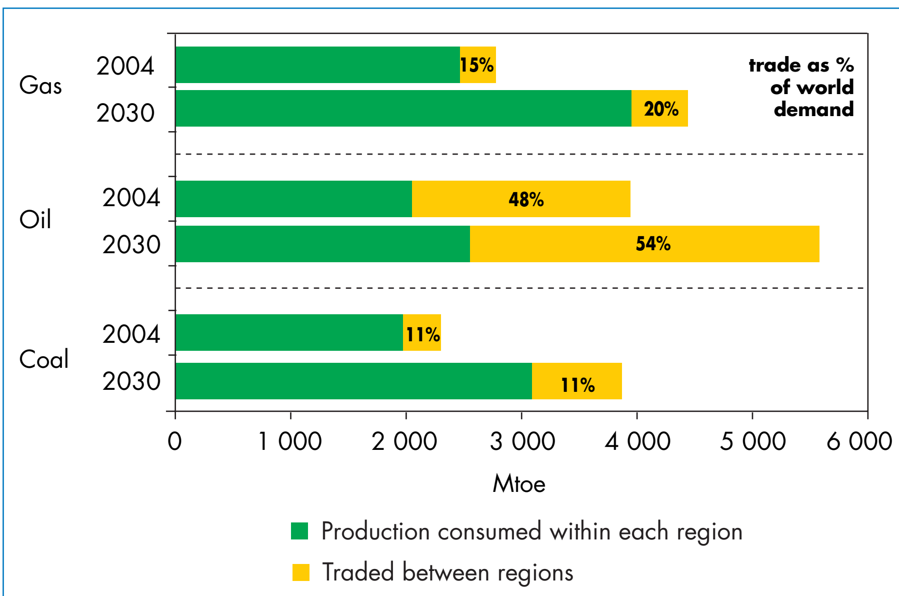
Almost all of the projected increase in inter-regional energy trade is in the form of conventional oil, gas and coal, but biofuels make a growing contribution. Trade in electricity remains minimal. Oil remains the most traded fuel in both percentage and volume terms (Figure 2.5). By 2030, 54% of all the oil

Table 2.2: **Net Energy Imports by Major Region** (Mtoe)

	2004	2015	2030
OECD	**1 657**	**2 123**	**2 444**
Coal	113	117	98
Oil	1 272	1 569	1 712
Gas	272	436	634
Transition economies	**–492**	**–641**	**–745**
Coal	–27	–39	–46
Oil	–345	–476	–541
Gas	–120	–126	–158
Developing countries	**–1 228**	**–1 549**	**–1 776**
Coal	–70	–71	–45
Oil	–1 007	–1 168	–1 256
Gas	–152	–310	–476

Note: Trade in other forms of energy is negligible. Negative figures are net exports. Total imports do not always equal total exports because of processing gains, international marine bunkers and statistical discrepancies.

Figure 2.5: **Share of Inter-Regional Trade in World Primary Demand by Fossil Fuel in the Reference Scenario**



Note: Takes account of all trade between *WEO* regions.

consumed in the world is traded between the *WEO* regions, up from 48% in 2004. The volume of oil traded grows by 60%. The Middle East accounts for the bulk of the increase in oil exports, with most of this oil going to developing countries, especially in Asia. The transition economies, Africa and Latin America also export more oil. OECD oil-import dependence, taking account of trade between OECD regions, rises from 56% now to 65% in 2030, as a result of dwindling indigenous production and rising consumption. Intra-regional trade, which is not captured by our projections, is also likely to expand.

Inter-regional natural gas trade expands quickly too, though the bulk of the gas consumed around the world is still produced within each consuming region in 2030. Most of the *additional* gas traded between now and 2030 is in the form of liquefied natural gas. An unprecedented boom in LNG developments is under way. LNG trade increased by almost one-third between 2000 and 2005, and it is expected to double by 2010, as projects that are currently under construction or that are at an advanced stage of planning come on stream. More liquefaction capacity is expected to be added through to 2030. Although a number of major long-distance pipelines are also likely to be completed, the share of piped gas in total inter-regional trade is expected to drop from 77% today to about 50% in 2030. The largest volume increases in gas imports occur in Europe and North America. Several developing countries – including China and India – emerge as major gas importers over the projection period. The Middle East, Africa and the transition economies meet most of the increase in demand for gas imports.

Inter-regional hard-coal trade increases in volume terms over 2004-2030, but the share of coal trade in total world coal supply is flat. Most of the increase in traded coal goes to OECD Europe, already the largest importing region, where demand is projected to rise and coal mining to continue to decline through to 2030. Steam coal accounts for a growing share of world hard-coal trade, driven mainly by power-sector needs.

Investment in Energy Infrastructure

The Reference Scenario projections in this *Outlook* call for cumulative investment in energy-supply infrastructure of just over $20 trillion (in year-2005 dollars) over 2005-2030. This projection is around $3 trillion higher than in *WEO-2005*. The increase is explained by recent sharp increases in unit capital costs, especially in the oil and gas industry. Projected capital spending includes that needed to expand supply capacity to meet rising demand and to replace existing and future supply facilities that will be retired during the projection period. Just over half of the investment will go simply to maintain the current level of supply capacity: much of the world's current production capacity for oil, gas, coal and electricity will need to be replaced by 2030. In addition, some of the new production capacity brought on stream in the early years of the projection period will itself need to be replaced before 2030. Many power plants, electricity and gas transmission and distribution facilities, and oil refineries will also need to be replaced or refurbished. Box 2.2 describes the methodology used to project energy investment.

Box 2.2: **Methodology for Projecting Energy Investment**

The projections of investment in both the Reference and Alternative Policy Scenarios for the period 2005-2030 are derived from the projections of energy supply. The calculation of the amount of investment corresponding to projected supply for each fuel and each region involved the following steps:

- New-build capacity needs for production, transportation and (where appropriate) transformation were calculated on the basis of projected supply trends, estimated rates of retirement of the existing supply infrastructure and natural decline rates for oil and gas production.
- Unit capital cost estimates were compiled for each component in the supply chain. These costs were then adjusted for each year of the projection period using projected rates of change based on a detailed analysis of the potential for technology-driven cost reductions and on country-specific factors.
- Incremental capacity needs were multiplied by unit costs to yield the amount of investment needed.

All the results are presented in year-2005 dollars. The projections take account of projects that have already been decided and expenditures that have already been incurred. Capital spending is attributed to the year in which the plant in question becomes operational. In other words, no attempt has been made to estimate the lead times for each category of project. This is because of the difficulties in estimating lead times and how they might evolve in the future. Investment is defined as capital expenditure only. It does not include spending that is usually classified as operation and maintenance.

The power sector requires more than $11 trillion of investment, 56% of that for the energy sector as a whole (Table 2.3). That share rises to two-thirds if investment in the supply chain to meet the fuel needs of power stations is included. More than half of the investment in the electricity industry is in transmission and distribution networks, with the rest going to power generation. Capital expenditure in the oil industry amounts to $4.3 trillion, or just over one-fifth of total energy investment. More than three-quarters of total oil investment is in upstream projects. Gas investment is $3.9 trillion, or 19%. The upstream absorbs 56% of total gas investment (Figure 2.6).[3] Coal investment is about $560 billion, or 3% of total energy investment. Producing, transporting and delivering coal to power stations and end users is much less capital-intensive than oil or gas, but operating and maintenance costs are higher per unit of output on an energy-content basis.

More than half of all the energy investment needed worldwide is in developing countries, where demand and production increase most quickly. China alone needs to invest about $3.7 trillion – 18% of the world total. Russia and other transition economies account for 9% of total world investment and the OECD for the remaining 37%.

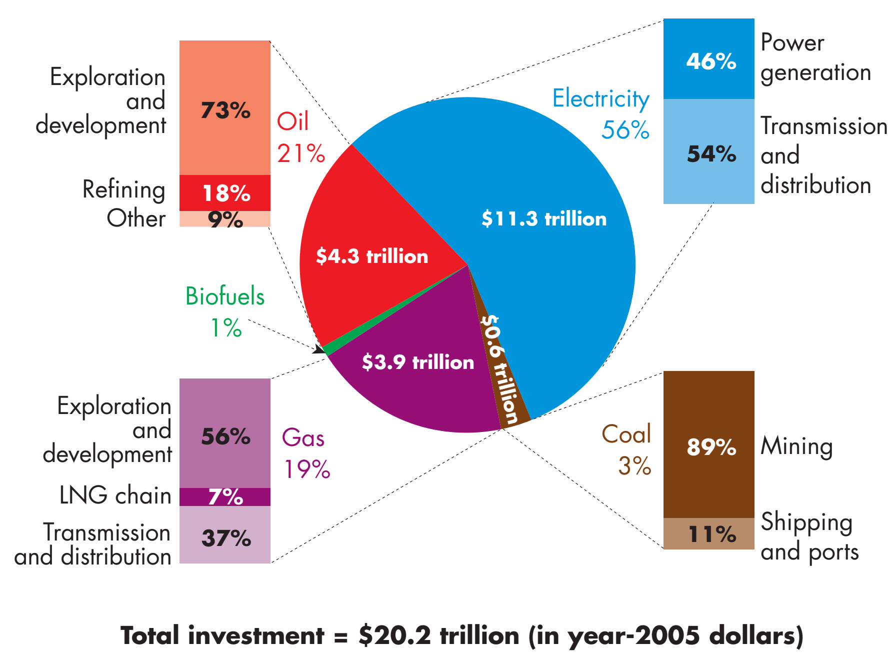
Table 2.3: **Cumulative Investment in Energy-Supply Infrastructure in the Reference Scenario, 2005-2030**
($ billion in year-2005 dollars)

	Coal	Oil	Gas	Power	Total
OECD	**156**	**1 149**	**1 744**	**4 240**	**7 289**
North America	80	856	1 189	1 979	4 104
Europe	34	246	417	1 680	2 376
Pacific	42	47	139	582	809
Transition economies	**33**	**639**	**589**	**590**	**1 850**
Russia	15	478	440	263	1 195
Developing countries	**330**	**2 223**	**1 516**	**6 446**	**10 515**
Developing Asia	298	662	457	4 847	6 264
China	*238*	*351*	*124*	*3 007*	*3 720*
India	*38*	*48*	*55*	*967*	*1 108*
Indonesia	*13*	*49*	*86*	*187*	*335*
Middle East	1	698	381	396	1 476
Africa	20	485	413	484	1 402
Latin America	12	378	265	719	1 374
Brazil	*1*	*138*	*48*	*252*	*439*
Inter-regional transport	45	256	76	–	376
World	**563**	**4 266**	**3 925**	**11 276**	**20 192**

Note: World total includes $161 billion of investment in biofuels.

3. See Chapter 12 for a detailed discussion of the near-term prospects for oil and gas investment.

Figure 2.6: **Cumulative Investment in Energy Infrastructure in the Reference Scenario by Fuel and Activity, 2005-2030**
(in year-2005 dollars)



Energy-Related CO_2 Emissions

Global energy-related carbon-dioxide (CO_2) emissions increase by 1.7 % per year over 2004-2030 in the Reference Scenario. They reach 40.4 billion tonnes in 2030, an increase of 14.3 billion tonnes, or 55%, over the 2004 level (Table 2.4). By 2010, emissions are 48% higher than in 1990. However, the aggregate increase is much smaller for Annex I countries with commitments to limit emissions under the Kyoto Protocol (Box 2.3). Power generation is projected to contribute a little less than half the increase in global emissions from 2004 to 2030. Transport contributes one-fifth, with other uses accounting for the rest. By 2030, the power sector accounts for 44% of total emissions, up from 41% today. Continuing improvements in the thermal efficiency of power stations are largely outweighed by the strong growth in demand for electricity. Transport remains the second-largest sector for emissions worldwide, with its share of total emissions stable at around 20% throughout the projection period.

Box 2.3: Will Signatories to the Kyoto Protocol Respect their Greenhouse-Gas Emission-Limitation Commitments?

The energy-related CO_2 emissions projected in the Reference Scenario give an indication of how likely it is that those countries that have agreed to limit their emissions, known as Annex I countries, under the Kyoto Protocol will meet their commitments. The Kyoto Protocol, which came into effect on 16 February 2005, sets binding targets for developed countries to reduce greenhouse-gas emissions by an average of 5.2% below 1990 levels by 2008-2012. The Protocol covers six types of emissions and the contribution of sinks (vegetation that absorbs carbon dioxide). Although our projections reflect only energy-related CO_2 emissions, these account for the bulk of greenhouse-gas emissions.

Our analysis suggests that, if total greenhouse-gas emissions rise at the same rate as energy-related emissions, Annex I countries in aggregate would not be able to meet the overall emissions-reduction target on current trends. In 2010, the total emissions of Annex I OECD countries are projected to be 29% above the target. Excluding the United States and Australia, which have not ratified the Protocol, the gap would be 19%. The emissions of Annex I transition economies are projected to be 22% *below* target. This would not be enough to make up all of the gap in all Annex I OECD countries, even if the United States and Australia are not included. Even if Annex I countries were to adopt a new set of policies and measures, they would be unlikely to significantly affect emission trends before 2010 – a key message that emerges from the Alternative Policy Scenario (see Part B). The recent surge in emissions makes it even less likely that the targets will be met: global emissions rose at a much faster rate in the four years to 2004 than they did in the 1990s (Figure 2.7).

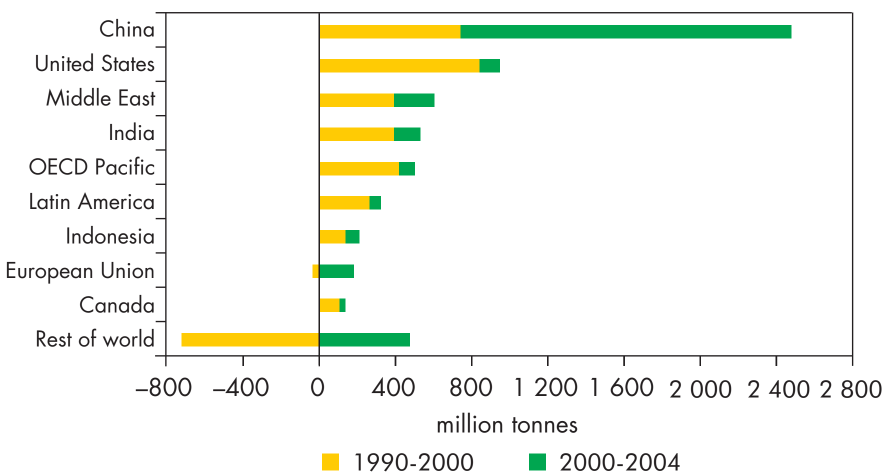
The Kyoto Protocol was always intended to be a first step. There is little that governments can do today that will have any significant effect on emissions before 2010. The challenge now is to forge an international framework that engages all major emitting countries in an effective long-term effort to mitigate greenhouse-gas emissions (IEA, 2005b). In May 2005, parties to the UN Framework Convention on Climate Change convened a seminar of government experts to discuss possible future efforts, but explicitly did not open negotiations on new commitments. In July 2005, at the Gleneagles Summit, G8 leaders pledged to introduce innovative measures to achieve substantial reductions in greenhouse-gas emissions as part of an agreed long-term plan. This pledge was reaffirmed at the 2006 St Petersburg Summit.

Table 2.4: **World Energy-Related CO_2 Emissions by Sector in the Reference Scenario** (million tonnes)

	1990	2004	2010	2015	2030	2004-2030*
Power generation	6 955	10 587	12 818	14 209	17 680	2.0%
Industry	4 474	4 742	5 679	6 213	7 255	1.6%
Transport	3 885	5 289	5 900	6 543	8 246	1.7%
Residential and services**	3 353	3 297	3 573	3 815	4 298	1.0%
Other***	1 796	2 165	2 396	2 552	2 942	1.2%
Total	**20 463**	**26 079**	**30 367**	**33 333**	**40 420**	**1.7%**

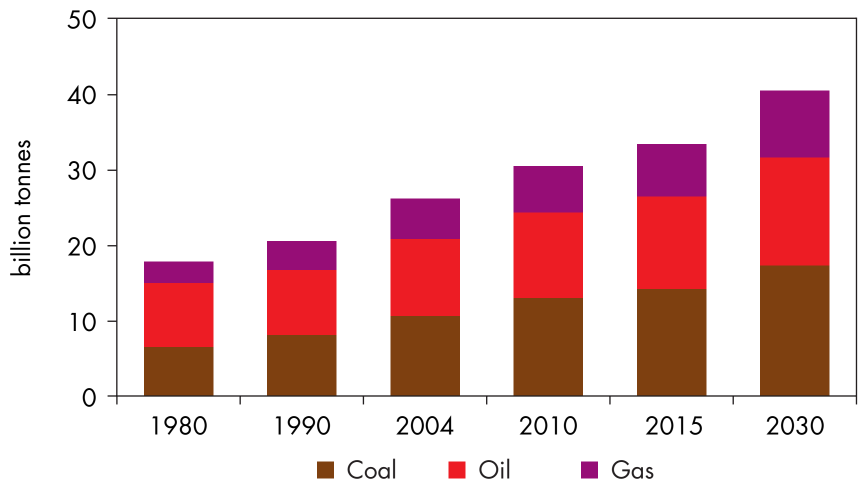
*Average annual growth rate. **Includes agriculture and public sector. ***Includes international marine bunkers, other transformation and non-energy use.

Figure 2.7: **Increase in Energy-Related CO_2 Emissions by Region**



Coal recently overtook oil as the leading contributor to global energy-related CO_2 emissions and, in the Reference Scenario, consolidates this position through to 2030 (Figure 2.8). Coal's share of emissions increases slightly, from 41% today to 43%. The share of natural gas also increases, from 20% to 22%, while that of oil falls, from 39% to 35%. Gas-related emissions increase most rapidly, by two-thirds between 2004 and 2030.

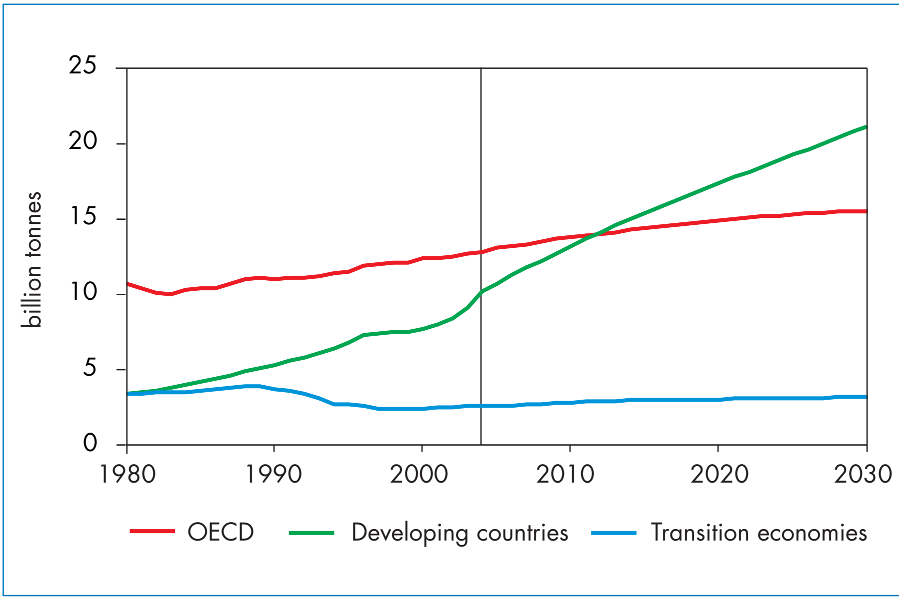
Figure 2.8: **World Energy-Related CO_2 Emissions by Fuel in the Reference Scenario**



Developing countries account for over three-quarters of the increase in global CO_2 emissions between 2004 and 2030. They overtake the OECD as the biggest emitter by around 2012 (Figure 2.9). The share of developing countries in world emissions rises from 39% at present to 52% by 2030. This increase is faster than that of their share in energy demand, because their incremental energy use is more carbon-intensive than that of the OECD and transition economies. In general, they use more coal and less gas. China alone is responsible for 39% of the rise in global emissions. China's emissions more than double between 2004 and 2030, driven by strong economic growth and heavy reliance on coal in industry and power generation. China overtakes the United States as the world's biggest emitter before 2010. Other Asian countries, notably India, also contribute heavily to the increase in global emissions.

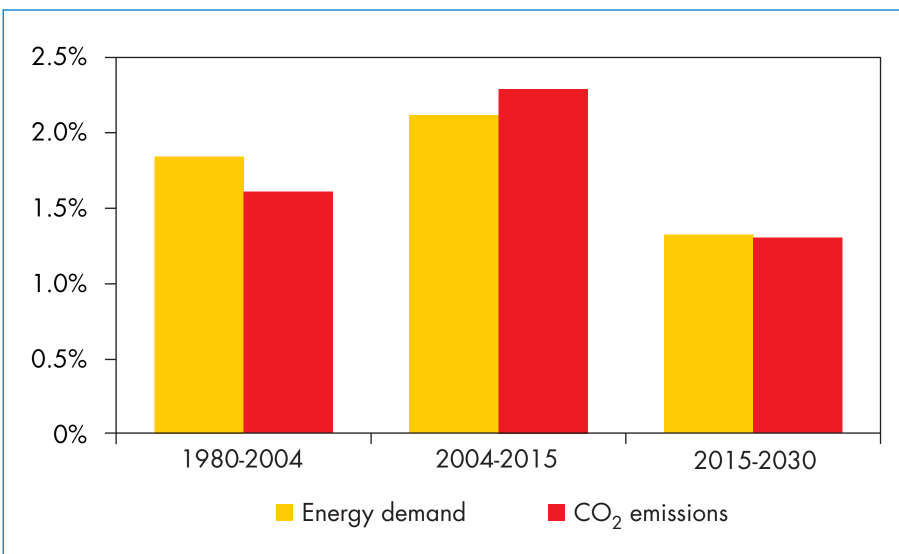
Over the past two-and-a-half decades, energy-related CO_2 emissions worldwide grew less rapidly than primary energy demand, largely because of the rising shares of gas, which is less carbon-intensive than coal and oil, and of nuclear power in the energy mix. Carbon emissions grew by 1.6% per year, while energy demand grew by 1.8%. In the Reference Scenario, the trend is reversed over the projection period, as the rate of growth in emissions, at 1.7% per year, is faster than the 1.6% rate of demand growth (Figure 2.10). This is because the average carbon content of primary energy consumption increases from 2.33 tonnes of CO_2 per toe of energy to 2.36 tonnes

Figure 2.9: **Energy-Related CO_2 Emissions by Region in the Reference Scenario**



Note: Excludes emissions from international marine bunkers.

Figure 2.10: **Average Annual Growth in World Energy-Related CO_2 Emissions and Primary Energy Demand in the Reference Scenario**



(Table 2.5). Per-capita emissions also rise, mainly because rising incomes push up per capita energy consumption. They grow most rapidly in the developing countries. Yet the OECD still has by far the highest per-capita emissions and developing countries the lowest in 2030. Developing countries have lower per-capita incomes and energy consumption, and rely more heavily on biomass and waste, which are assumed to produce no emissions on a net basis.[4] By contrast, the carbon intensity of the global economy, measured by emissions per unit of GDP, is projected to decline steadily in all regions in line with the fall in primary energy intensity.

Table 2.5: **World Energy-Related CO_2 Emission Indicators by Region in the Reference Scenario** (tonnes of CO_2)

	OECD			Non-OECD			World		
	2004	2015	2030	2004	2015	2030	2004	2015	2030
Per capita	11.02	11.69	11.98	2.45	3.09	3.55	4.11	4.65	4.97
Per unit of GDP*	0.39	0.33	0.27	0.49	0.39	0.30	0.44	0.37	0.29
Per toe of primary energy	2.33	2.30	2.26	2.30	2.41	2.42	2.33	2.37	2.36

* Thousand dollars in year-2005 dollars and PPP terms.

4. For the purposes of this analysis, all biomass is assumed to be replaced eventually. As a result, the carbon emitted when biomass fuels are burned is cancelled out by the carbon absorbed by the replacement biomass as it grows.

OIL MARKET OUTLOOK

HIGHLIGHTS

- Primary oil demand grows by 1.3% per year over 2005-2030 in the Reference Scenario, reaching 99 mb/d in 2015 and 116 mb/d in 2030 – up from 84 mb/d in 2005. The pace of demand growth slackens progressively over the projection period. More than 70% of the increase in oil demand comes from developing countries, which see average annual demand growth of 2.5%. Demand in OECD countries rises by only 0.6% per year. The transport sector absorbs most of the increase in global oil demand.
- Oil supply is increasingly dominated by a small number of major producers, where oil resources are concentrated. OPEC's share of global supply grows significantly, from 40% now to 42% in 2015 and 48% by the end of the *Outlook* period. Saudi Arabia remains by far the largest producer. Non-OPEC conventional crude oil output peaks by the middle of the next decade, though natural gas liquids production continues to rise.
- Conventional oil accounts for the lion's share of the increase in global oil supply between 2005 and 2030, but non-conventional resources – mainly oil sands in Canada – and, to a lesser extent, gas-to-liquids plants play an increasingly important role. Canadian oil-sands production is projected to triple to 3 mb/d by 2015 and climb further to almost 5 mb/d by 2030.
- The volume of inter-regional oil trade expands even faster than production, from 40 mb/d in 2005 to 51 mb/d in 2015 and 63 mb/d in 2030. The Middle East sees the biggest increase in net exports. All four major net oil-importing regions – the three OECD regions and developing Asia – become more dependent on oil imports by the end of the projection period.
- The oil industry needs to invest a total of $4.3 trillion (in year-2005 dollars) over the period 2005-2030, or $164 billion per year. The upstream sector accounts for the bulk of this. Almost three-quarters of upstream investments will be required to maintain existing capacity.
- It is far from certain that all this investment will actually occur. Resource nationalism and other factors could hold back capital spending. In a Deferred Investment Case, slower growth in OPEC oil production drives up the international oil price and, with it, the prices of gas and coal. Higher energy prices, together with slower economic growth, choke off energy demand in all regions, curbing demand for OPEC oil compared with the Reference Scenario. OPEC oil exports still grow, but much more slowly.

Demand[1]

Primary oil[2] demand is expected to continue to grow steadily over the projection period in the Reference Scenario, at an average annual rate of 1.3%. It reaches 99 mb/d in 2015 and 116 mb/d in 2030, up from 84 mb/d in 2005 (Table 3.1). The pace of demand growth nonetheless slackens

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

	1980	2004	2005	2010	2015	2030	2005-2030**
OECD	**41.9**	**47.5**	**47.7**	**49.8**	**52.4**	**55.1**	**0.6%**
North America	21.0	24.8	24.9	26.3	28.2	30.8	0.9%
United States	*17.4*	*20.5*	*20.6*	*21.6*	*23.1*	*25.0*	*0.8%*
Canada	*2.1*	*2.3*	*2.3*	*2.5*	*2.6*	*2.8*	*0.8%*
Mexico	*1.4*	*2.0*	*2.1*	*2.2*	*2.4*	*3.1*	*1.6%*
Europe	14.7	14.5	14.4	14.9	15.4	15.4	0.2%
Pacific	6.2	8.2	8.3	8.6	8.8	8.9	0.3%
Transition economies	**8.9**	**4.3**	**4.3**	**4.7**	**5.0**	**5.7**	**1.1%**
Russia	n.a.	2.5	2.5	2.7	2.9	3.2	1.0%
Developing countries	**11.4**	**27.2**	**28.0**	**33.0**	**37.9**	**51.3**	**2.5%**
Developing Asia	4.4	14.2	14.6	17.7	20.6	29.7	2.9%
China	*1.9*	*6.5*	*6.6*	*8.4*	*10.0*	*15.3*	*3.4%*
India	*0.7*	*2.6*	*2.6*	*3.2*	*3.7*	*5.4*	*3.0%*
Indonesia	*0.4*	*1.3*	*1.3*	*1.4*	*1.5*	*2.3*	*2.4%*
Middle East	2.0	5.5	5.8	7.1	8.1	9.7	2.0%
Africa	1.4	2.6	2.7	3.1	3.5	4.9	2.4%
North Africa	*0.5*	*1.3*	*1.4*	*1.6*	*1.8*	*2.5*	*2.4%*
Latin America	3.5	4.8	4.9	5.1	5.6	7.0	1.5%
Brazil	*1.4*	*2.1*	*2.1*	*2.3*	*2.7*	*3.5*	*2.0%*
Int. marine bunkers	**2.2**	**3.6**	**3.6**	**3.8**	**3.9**	**4.3**	**0.6%**
World	**64.4**	**82.5**	**83.6**	**91.3**	**99.3**	**116.3**	**1.3%**
European Union	*n.a.*	*13.5*	*13.5*	*13.9*	*14.3*	*14.1*	*0.2%*

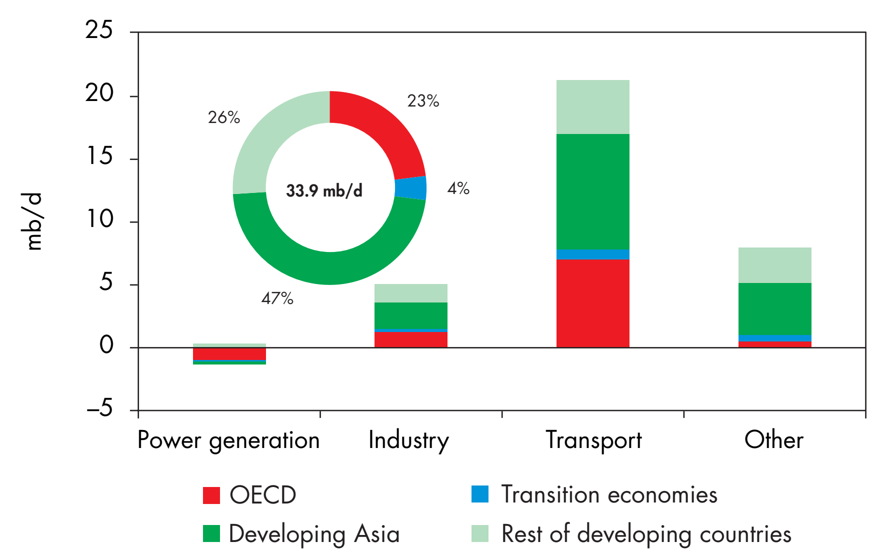
* Includes stock changes. ** Average annual growth rate.
n.a.: not available.

1. See Chapter 2 for a more detailed discussion of the role of oil in the overall energy mix.
2. Oil does not include biofuels derived from biomass. Transport demand for oil is modelled to take account of the use of biofuels (see Chapter 14). See Annex C for a detailed definition of oil.

progressively, broadly in line with GDP, averaging 1.7% in 2005-2015 – only just below the average of the last ten years – and 1.1% in 2015-2030. Preliminary data for 2005 indicate that global oil demand rose by 1.3% – well down on the exceptionally high rate of 4% in 2004.

Most of the increase in oil demand comes from developing countries, where economic growth – the main driver of oil demand[3] – is highest (Figure 3.1). China and the rest of developing Asia account for 15 mb/d, or 46%, of the 33-mb/d increase in oil use between 2005 and 2030, in line with rapid economic growth. At 3.4% per year on average, China's rate of oil-demand growth is nonetheless below the 5.1% rate of 1980-2004. The Middle East, which experiences the fastest rate of demand growth, accounts for a further 3.8 mb/d. Higher oil revenues than in the last two decades boost economic activity, incomes and, together with subsidies, demand for oil. Demand in OECD countries, especially in Europe and the Pacific region, rises much more slowly. Nonetheless, the absolute increase in North America – 5.9 mb/d over the *Outlook* period – is the second-largest of any region, because it is already by

Figure 3.1: **Incremental World Oil Demand by Region and Sector in the Reference Scenario, 2004-2030**



3. See Chapter 11 for a detailed analysis of the impact of economic growth and oil prices on demand.

far the largest consumer. The economies of non-OECD countries will remain considerably more oil-intensive, measured by the amount of oil used per unit of gross domestic product (at market exchange rates), than those of OECD countries.

The transport sector absorbs 63% of the increase in global oil demand in 2004-2030. In the OECD, oil use in other sectors hardly increases at all, declining in power generation and in the residential and services sectors, and growing in industry. Most of the increase in energy demand in non-transport sectors is met by gas, coal, renewables and electricity. In non-OECD countries, too, transport is the biggest contributor to oil-demand growth; but other sectors – notably industry – also see significant growth.

Supply

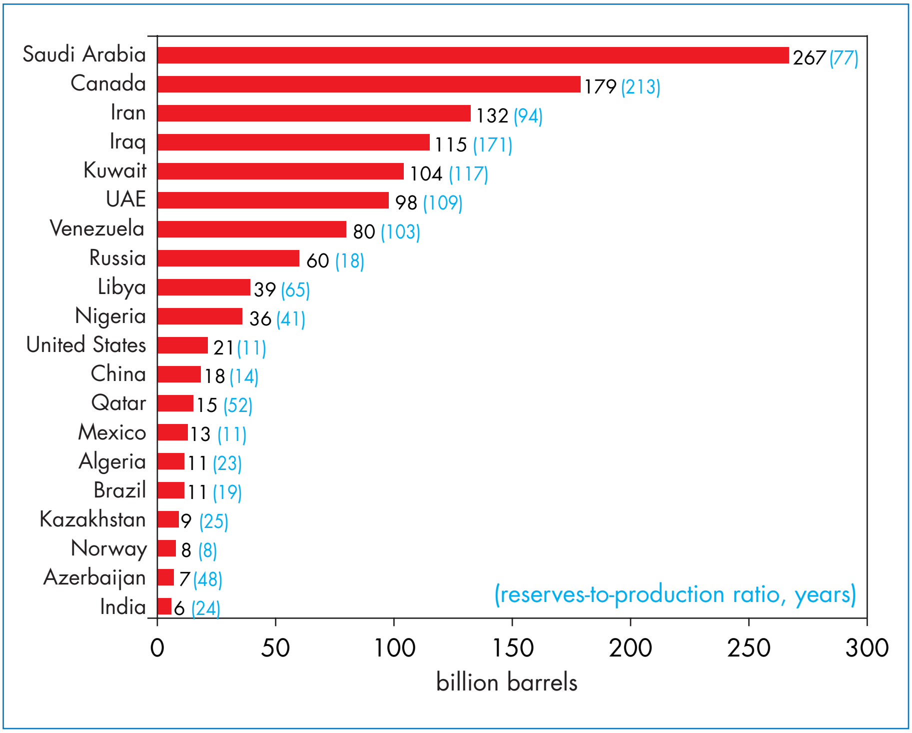
Resources and Reserves

According to the *Oil and Gas Journal*, the world's proven reserves[4] of oil (crude oil, natural gas liquids, condensates and non-conventional oil) amounted to 1 293 billion barrels[5] at the end of 2005 – an increase of 14.8 billion barrels, or 1.2%, over the previous year. Reserves are concentrated in the Middle East and North Africa (MENA), together accounting for 62% of the world total. Saudi Arabia, with the largest reserves of any country, holds a fifth. Of the twenty countries with the largest reserves, seven are in the MENA region (Figure 3.2). Canada has the least developed reserves, sufficient to sustain current production for more than 200 years. The world's proven reserves, including non-conventional oil, could sustain current production levels for 42 years.

Proven reserves have grown steadily in recent years in volume terms, but have remained broadly flat as a percentage of production. Since 1986, the reserves-to-production, or R/P, ratio has fluctuated within a range of 39 to 43 years. A growing share of the additions to reserves has been coming from revisions to estimates of the reserves in fields already in production or undergoing appraisal,

4. Oil that has been discovered and is expected to be economically producible is called a proven reserve. Oil that is thought to exist, and is expected to become economically recoverable, is called a resource. Total resources include existing reserves, "reserves growth" – increases in the estimated size of reserves as fields are developed and produced – and undiscovered resources. Comparison of reserves and resource assessments is complicated by differences in estimation techniques and assumptions among countries and companies. In particular, assumptions about prices and technology have a major impact on how much oil is deemed to be economically recoverable.
5. *Oil and Gas Journal* (19 December 2005). Includes proven oil-sands reserves in Canada.

Figure 3.2: **Top Twenty Countries' Proven Oil Reserves, end-2005**

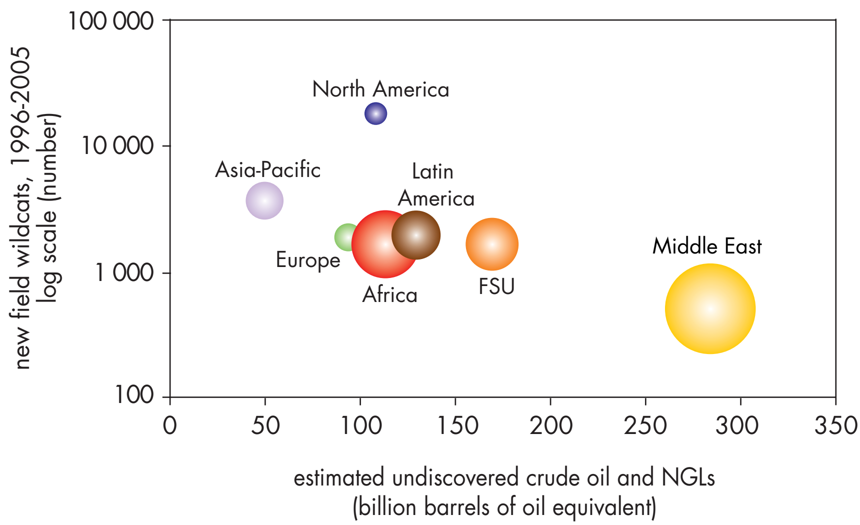


Note: Canada includes proven non-conventional reserves.
Source: *Oil and Gas Journal* (19 December 2005).

rather than from new discoveries. Some of these revisions have resulted from higher oil-price assumptions, allowing some oil that is known to exist to be reclassified as economically exploitable and, therefore, moved into the proven category. The application of new technology has also improved reservoir management and boosted recovery rates. The amount of oil discovered in new oilfields has fallen sharply over the past four decades, because of reduced exploration activity in regions with the largest reserves and, until recently, a fall in the average size of fields discovered. These factors outweighed an increase in exploration success rates.

Over the past ten years, drilling has been concentrated in North America, a mature producing region with limited potential for new discoveries. Less than 2% of new wildcat wells drilled were in the Middle East, even though the region is thought to hold over 30% of the world's undiscovered crude oil and condensates and is where the average size of new fields discovered in the ten years to 2005 have been higher than anywhere else (Figure 3.3).

Figure 3.3: **Undiscovered Oil Resources and New Wildcat Wells Drilled, 1996-2005**

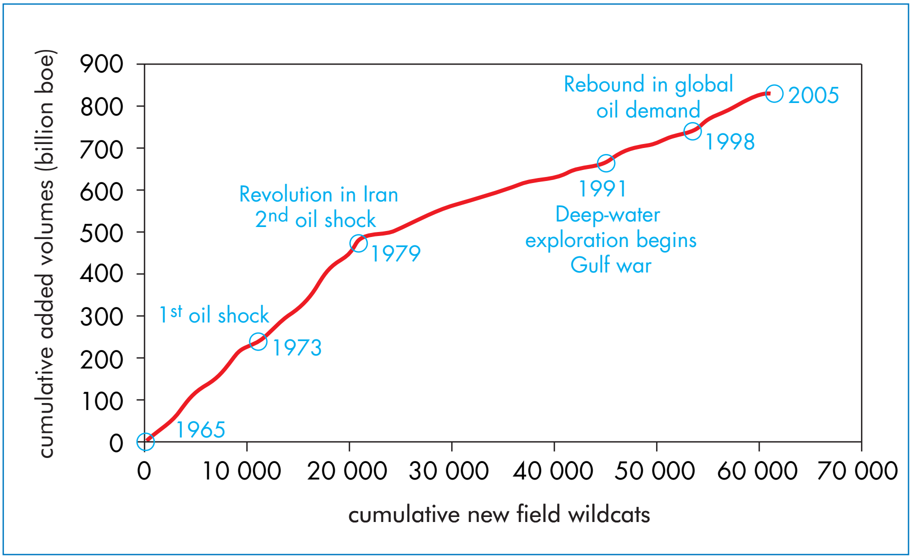


Note: The size of each bubble indicates the average size of new discoveries in 1996-2005.
FSU: Former Soviet Union.
Sources: Undiscovered resources – USGS (2000); new field wildcats – IHS databases.

There has recently been an increase in the average size of new hydrocarbon discoveries for each new field wildcat well drilled, bucking the trend of much of the period 1965-1998. The size of new fields that have been discovered has continued to decline, largely because exploration and appraisal activity has been focused mainly on existing basins. However, the application of new technology, such as 3D seismic, has increased the discovery success rate per wildcat well, particularly since 1998 – boosted by rising global oil demand and a resulting increase in exploration and appraisal activity – and, to a lesser extent, since 1991, with the advent of deep-water exploration (Figure 3.4). Nonetheless, the average size of discoveries per wildcat well – at around 10 million barrels – remains barely half that of the period 1965-1979. The reduction almost to zero of exploration in the Middle East, where discoveries have been largest, was the main reason for the lower average size of discoveries since the 1980s.

Exploration and appraisal drilling is expected to increase to offset rising decline rates at existing fields and the consequent need to develop new reservoirs – particularly in MENA, where some of the greatest potential for finding new fields exists. Proven reserves are already larger than the cumulative production

Figure 3.4: **Cumulative Oil and Gas Discoveries and New Wildcat Wells**



needed to meet rising demand until at least 2030. But more oil will need to be added to the proven category if production is not to peak before then. According to the US Geological Survey, undiscovered conventional resources that are expected to be economically recoverable could amount to 880 billion barrels (including natural gas liquids, or NGLs) in its mean case (USGS, 2000). Together with reserves growth and proven reserves, remaining ultimately recoverable resources are put at just under 2 300 billion barrels. That is more than twice the volume of oil – 1 080 billion barrels – that has so far been produced. Total non-conventional resources, including oil sands in Canada, extra-heavy oil in Venezuela and shale oil in the United States and several other countries, are thought to amount to at least 1 trillion barrels (WEC, 2004).

Production

Conventional crude oil and NGLs[6]

In the Reference Scenario, conventional oil production continues to be dominated by a small number of major producers in those countries where oil resources are concentrated. The share of production controlled by members of

6. "Conventional oil" is defined as crude oil and natural gas liquids produced from underground reservoirs by means of conventional wells. This category includes oil produced from deep-water fields and natural bitumen. "Non-conventional oil" includes oil shales, oil sands-based extra-heavy oil and derivatives such as synthetic crude products, and liquids derived from coal (CTL) and natural gas (GTL).

Table 3.2: **World Oil Supply** (million barrels per day)

	1980	2000	2005	2010	2015	2030	2005-2030*
Non-OPEC	**35.2**	**43.9**	**48.1**	**53.4**	**55.0**	**57.6**	**0.7%**
Crude oil	***32.2***	***38.1***	***41.6***	***45.5***	***45.4***	***43.4***	***0.2%***
OECD	14.6	17.2	15.2	13.8	12.4	9.7	–1.8%
North America	11.8	10.2	9.8	9.4	9.0	7.8	–0.9%
United States	*8.7*	*5.8*	*5.1*	*5.3*	*5.0*	*4.0*	*–1.0%*
Canada	*1.2*	*1.4*	*1.4*	*1.1*	*0.9*	*0.8*	*–2.2%*
Mexico	*1.9*	*3.0*	*3.3*	*3.1*	*3.1*	*3.0*	*–0.5%*
Pacific	0.5	0.8	0.5	0.7	0.5	0.4	–1.2%
Europe	2.4	6.2	4.8	3.8	2.9	1.5	–4.5%
Transition economies	11.5	7.7	11.4	13.7	14.5	16.4	1.5%
Russia	*10.7*	*6.3*	*9.2*	*10.5*	*10.6*	*11.1*	*0.7%*
Other	*0.8*	*1.4*	*2.2*	*3.3*	*3.9*	*5.3*	*3.6%*
Developing countries	6.0	13.2	15.1	17.9	18.5	17.4	0.6%
Developing Asia	2.9	5.3	5.9	6.3	6.1	5.0	–0.6%
China	*2.1*	*3.2*	*3.6*	*3.8*	*3.7*	*2.8*	*–1.0%*
India	*0.2*	*0.6*	*0.7*	*0.8*	*0.8*	*0.6*	*–0.2%*
Other	*0.6*	*1.4*	*1.6*	*1.7*	*1.6*	*1.6*	*0.0%*
Latin America	1.5	3.4	3.8	4.8	5.3	5.9	1.8%
Brazil	*0.2*	*1.2*	*1.6*	*2.6*	*3.0*	*3.5*	*3.1%*
Other	*1.3*	*2.2*	*2.2*	*2.2*	*2.3*	*2.5*	*0.5%*
Africa	1.2	2.6	3.5	5.2	5.5	4.9	1.4%
North Africa	*0.7*	*0.8*	*0.6*	*0.6*	*0.6*	*0.7*	*0.4%*
Other Africa	*0.5*	*1.8*	*2.9*	*4.6*	*4.9*	*4.3*	*1.6%*
Middle East	0.5	2.0	1.9	1.7	1.6	1.4	–1.1%
NGLs	***2.6***	***4.9***	***5.1***	***5.5***	***5.8***	***6.8***	***1.2%***
OECD	2.3	3.7	3.7	4.0	4.1	4.4	0.7%
Transition economies	0.2	0.5	0.5	0.4	0.5	0.6	1.2%
Developing countries	0.1	0.7	0.9	1.1	1.3	1.8	2.7%
Non-conventional oil	***0.4***	***0.9***	***1.4***	***2.5***	***3.7***	***7.4***	***7.0%***
Canada	0.2	0.6	1.0	2.0	3.0	4.8	6.4%
Others	0.2	0.3	0.4	0.5	0.7	2.7	8.2%

Table 3.2: **World Oil Supply** (million barrels per day) *(continued)*

	1980	2000	2005	2010	2015	2030	2005-2030*
OPEC	**28.0**	**30.9**	**33.6**	**35.9**	**42.0**	**56.3**	**2.1%**
Crude oil	***26.2***	***27.8***	***29.1***	***30.2***	***34.9***	***45.7***	***1.8%***
Middle East	17.9	19.5	20.7	22.0	25.7	34.5	2.1%
Saudi Arabia	*9.4*	*8.0*	*9.1*	*9.7*	*11.3*	*14.6*	*1.9%*
Iran	*1.5*	*3.7*	*3.9*	*3.9*	*4.4*	*5.2*	*1.1%*
Iraq	*2.6*	*2.6*	*1.8*	*2.2*	*2.8*	*6.0*	*4.9%*
Kuwait	*1.3*	*1.8*	*2.1*	*2.2*	*2.8*	*4.0*	*2.5%*
United Arab Emirates	*1.8*	*2.2*	*2.5*	*2.7*	*3.1*	*3.8*	*1.8%*
Qatar	*0.5*	*0.7*	*0.8*	*0.7*	*0.7*	*0.5*	*–1.9%*
*Neutral zone***	*0.8*	*0.6*	*0.6*	*0.5*	*0.5*	*0.5*	*–0.6%*
Non-Middle East	8.3	8.3	8.4	8.2	9.1	11.2	1.2%
Algeria	*0.9*	*0.8*	*1.3*	*1.1*	*1.1*	*0.7*	*–2.7%*
Libya	*1.8*	*1.4*	*1.6*	*1.7*	*1.9*	*2.7*	*2.0%*
Nigeria	*2.1*	*2.0*	*2.4*	*2.5*	*2.7*	*3.2*	*1.2%*
Indonesia	*1.5*	*1.2*	*0.9*	*0.8*	*0.8*	*0.8*	*–0.8%*
Venezuela	*2.0*	*2.9*	*2.1*	*2.2*	*2.8*	*3.9*	*2.5%*
NGLs	***1.8***	***2.9***	***4.3***	***5.4***	***6.3***	***9.0***	***3.0%***
Saudi Arabia	0.7	1.0	1.5	1.9	2.0	2.7	2.5%
Iran	0.0	0.1	0.3	0.4	0.6	1.1	4.8%
UAE	0.4	0.4	0.5	0.7	0.9	1.3	3.6%
Algeria	0.1	0.6	0.8	0.9	0.9	0.7	–0.3%
Others	0.6	0.8	1.2	1.5	1.9	3.3	4.1%
Non-conventional	***0.0***	***0.2***	***0.2***	***0.3***	***0.8***	***1.5***	***8.8%***
Venezuela	0.0	0.1	0.1	0.1	0.2	0.4	5.8%
Others	0.0	0.1	0.1	0.2	0.6	1.2	10.5%
TOTAL WORLD	**64.9**	**76.5**	**83.6**	**91.3**	**99.3**	**116.3**	**1.3%**
Crude oil	**58.3**	**66.0**	**70.8**	**75.7**	**80.3**	**89.1**	**0.9%**
NGLs	**4.4**	**7.8**	**9.3**	**10.8**	**12.2**	**15.8**	**2.1%**
Non-conventional oil	**0.4**	**1.1**	**1.6**	**2.8**	**4.5**	**9.0**	**7.2%**
Processing gains	**1.7**	**1.7**	**1.9**	**2.0**	**2.3**	**2.5**	**1.2%**

*Average annual growth rate.
** Neutral Zone production is shared by Saudi Arabia and Kuwait.

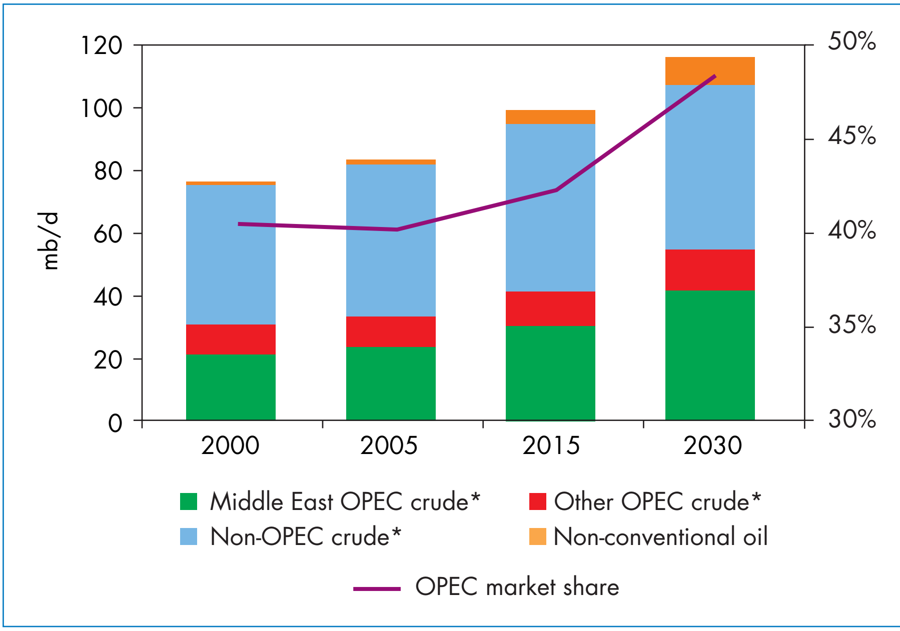
the Organization of the Petroleum Exporting Countries, particularly in the Middle East, grows significantly.[7] Their collective output of crude oil, NGLs and non-conventional oil grows from 34 mb/d in 2005 to 42 mb/d in 2015 and 56 mb/d in 2030, boosting their share of world oil supply from 40% now to 48% by the end of the *Outlook* period. Non-OPEC production increases much more slowly, from its current level of 48 mb/d to 55 mb/d in 2015 and 58 mb/d in 2030 (Table 3.2). Conventional oil accounts for the bulk of the increase in oil supply between 2005 and 2030, but non-conventional resources play an increasingly important role (Figure 3.5). The projections to 2010 take account of current, sanctioned and planned upstream projects (see Chapter 12).

Production in OPEC countries, especially in the Middle East, is expected to increase more rapidly than in other regions, because their resources are much larger and their production costs are generally lower. Saudi Arabia remains by far the largest producer of crude oil and NGLs. Its total output of crude and NGLs grows from 10.9 mb/d in 2005, to 13.7 mb/d in 2015 and to 17.6 mb/d in 2030 (including Saudi Arabia's half-share of Neutral Zone production). Most of the rest of the increase in OPEC production comes from Iraq, Iran, Kuwait, the United Arab Emirates, Libya and Venezuela. Other OPEC countries struggle to lift output, with production dropping in Qatar, Algeria and Indonesia. These projections are broadly commensurate with proven reserves. OPEC's price and production policies and national policies on developing reserves are extremely uncertain.

Outside OPEC, conventional crude oil production in aggregate is projected to peak by the middle of the next decade and decline thereafter, though this is partly offset by continued growth in output of NGLs (Figure 3.6). Production in several mature regions, including North America and the North Sea, which has been in steady decline in recent years, stabilises or rebounds in the near term. This reflects several factors, including the restoration of production capacity lost through hurricanes and other technical difficulties, and the impact on increased drilling to boost production in response to recent oil-price increases. But this trend is expected to be short-lived, as relatively high decline rates and rising costs soon drive output back down again. In the longer term, only Russia, Central Asia, Latin America and sub-Saharan Africa – including Angola and Congo – achieve any significant increases in conventional oil production.

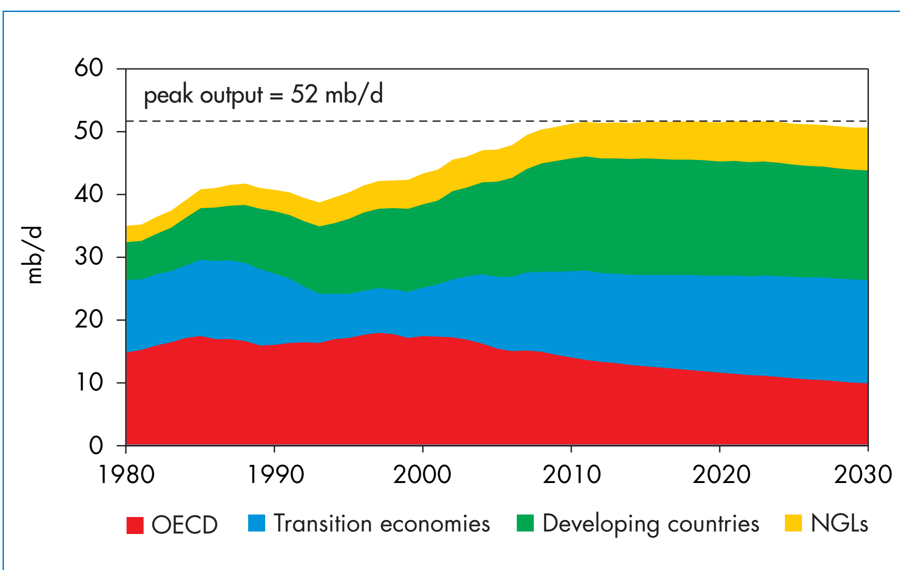
7. OPEC is assumed to be willing to meet the portion of global oil demand not met by non-OPEC producers at the prices assumed (see Chapter 1). A special analysis of the effect of lower OPEC investment in upstream capacity is presented at the end of this chapter.

Figure 3.5: **World Oil Supply by Source**



*Including NGLs.

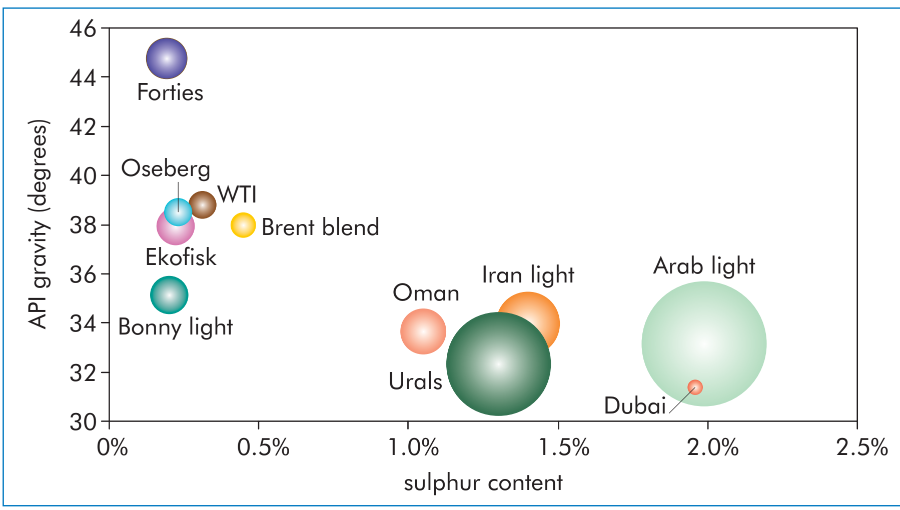
Figure 3.6: **Non-OPEC Conventional Crude Oil and NGLs Production**



A lack of reliable information on production decline rates makes it difficult to project new gross capacity needs. A high *natural* decline rate – the speed at which output would decline in the absence of any additional investment to sustain production – increases the need to deploy technology at existing fields to raise recovery rates, to develop new reserves and to make new discoveries. Our analysis of capacity needs is based on estimates of year-on-year natural decline rates averaged over all currently producing fields in a given country or region. The rates assumed in our analysis vary over time and by location. They range from 2% per year to 11% per year, averaging 8% for the world over the projection period.[8] Rates are generally lowest in regions with the best production prospects and the highest R/P ratios. For OPEC, they range from 2% to 7%. They are highest in mature OECD producing areas, where they average 11%.

The average quality of crude oil produced around the world is expected to become heavier (lower API gravity) and more sour (higher sulphur content) over the *Outlook* period.[9] This is driven by several factors, including the continuing decline in production from existing sweet (low-sulphur) crude oilfields, increased output of heavier crude oils in Russia, the Middle East and North Africa (Figure 3.7),

Figure 3.7: **Gravity and Sulphur Content of Selected Crude Oils, 2005**



Note: The size of each bubble indicates the level of production in 2005.
Sources: IEA analysis based on ENI (2006), Platts and IHS Energy databases.

8. These rates are based on information obtained in consultations with international and national oil companies, oilfield service companies and consultants. *Observed* decline rates are generally much lower, as they reflect investment to maintain or boost output at existing fields.
9. However, upstream projects under development may result in a marginal reduction in the sulphur content and a small increase in the API gravity of installed crude oil production capacity in the next five years, according to the IEA's *Oil Market Report* (12 September 2006).

and the projected growth of heavy non-conventional oil output. These trends, together with increasing demand for lighter oil products and increasing fuel-quality standards, is expected to increase the need for investment in upgrading facilities in refineries.

Production from Non-Conventional Resources

Production of non-conventional oil, mainly in non-OPEC countries, is expected to contribute almost 8% to global oil supplies by 2030 – up from less than 2% now. Output jumps from 1.6 mb/d to 9 mb/d. The bulk of this increase comes from oil sands in Canada.[10] Gas-to-liquids plants also make a small but growing contribution to non-conventional oil supplies, rising from 0.1 mb/d in 2005 to 0.3 mb/d in 2015 and 2.3 mb/d in 2030. Coal-to-liquids production is projected to reach 750 kb/d in 2030, with most of this output coming from China, where low-cost coal supplies are abundant (see Chapter 5). Several countries have significant oil-shale resources, though they are not expected to make a significant contribution to global oil supply before 2030.

Canadian non-conventional oil production is centred in the province of Alberta. The province contains an estimated 315 billion barrels of ultimately recoverable crude bitumen resources, with proven reserves of 174 billion barrels at year-end 2005 (NEB, 2006). Alberta produces diluted bitumen and upgraded crude, most of which is exported to the United States. In both cases, the primary hydrocarbon content, known as natural bitumen, is extracted from oil-sand deposits. This bitumen is then diluted with lighter hydrocarbons and transported to a refinery or upgraded on site into a high-quality synthetic crude oil, which can be refined in the normal way. In 2005, Canadian production of non-conventional oil totalled 1 mb/d. Output is projected to triple by 2015 and climb further to close to 5 mb/d by 2030.

There are currently 12 oil-sands projects under construction and another 38 proposed projects in Alberta. Investment of almost $80 billion is planned for the next 10 years. Some 36 of these projects involve mining or drilling while the rest are new or expanded projects involving upgrading facilities. Of the drilling projects, 45% are *in situ* steam-assisted gravity drainage – a process that involves the injection of steam into the oil-sands deposits to allow the bitumen to flow to well bores and then to the surface (Table 3.3). Our projections take account of the availability and cost of natural gas – the primary energy input to *in situ* oil-sands production. The majority of the new production is expected to be of the higher-quality upgraded crude. Many new players have entered the oil-sands industry, including several international oil and gas companies and foreign national oil companies. In the Reference Scenario, capital expenditure averages about $6.8 billion per year over the projection period.

10. Most of the production of extra-heavy bituminous crude oil in Venezuela is now classified as conventional oil.

Table 3.3: **Major New Oil-Sands Projects and Expansions in Canada**

Company	Project name	Production type	Start date	Bitumen capacity (kb/d)
Suncor	Voyager	Integrated	2010-12	500 – 550
Canadian Natural Resources Limited	Horizon Oil Sands	Integrated	2008-17	500
Imperial/ExxonMobil Canada	Kearl Mine	Integrated	2010-18	300
North West	North West upgrader	Integrated	2010-16	200
Husky	Lloydminster upgrader	Integrated	2007-09	150
BA Energy	Heartland upgrader	Integrated	2008-12	150
Petro-Canada/UTS/ Teck Cominco	Fort Hills phase 1	Integrated	n.a.	100
EnCana	Foster Creek	*In situ*	2010-15	500
Birch Mountain Resources	Birch Mountain	*In situ*	2011-23	200
Husky	Sunrise	*In situ*	2008-14	200
Shell	Carmon Creek	*In situ*	2009-15	90
Total E&P (formerly Deer Creek)	Joslyn	*In situ*	2006-11	40

Source: IEA databases.

We have revised significantly upwards our projections of output from Canadian non-conventional resources since the last edition of the *Outlook*, in response to higher oil prices and to growing interest in developing such resources. Higher oil prices have already boosted revenues from oil-sands and extra-heavy oil projects, though profitability has increased proportionately less because of higher electricity and natural gas prices. Non-conventional projects are very energy-intensive, so their profitability is very sensitive to energy-input prices.[11] For *in situ* production, the availability and price of diluent for blending and the differential between heavy and light crude oil prices are also

11. On average, about 30 cubic metres of natural gas is used in producing a single barrel of bitumen in Canada (NEB, 2006).

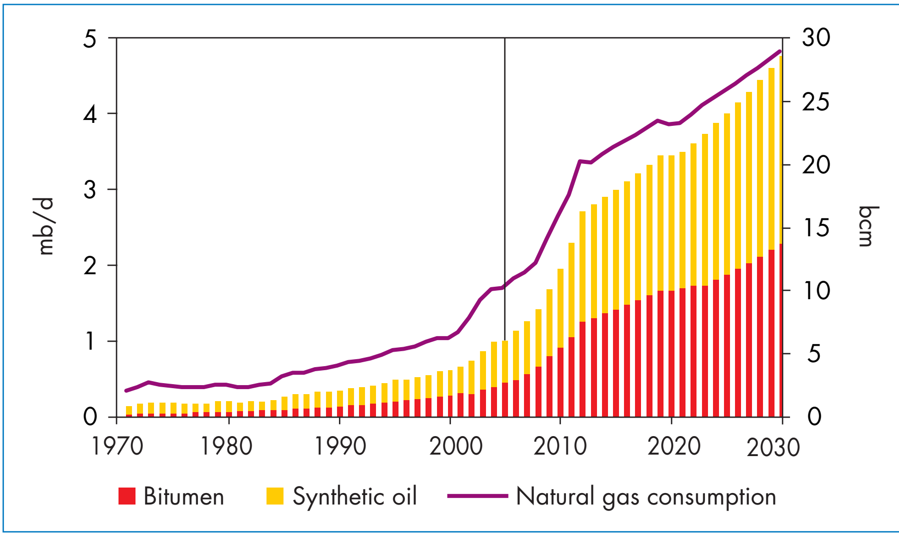
important factors. Higher differentials over the past few years have made the option of adding local upgrading capacity more attractive. As a result, most planned *in situ* projects now also include upgrading of the raw bitumen. For integrated mining and upgrading projects, the cost of building upgrading units is a critical factor. Capital costs have risen sharply in recent years as prices of steel, cement and equipment have soared (Box 3.1). Rapid development of the oil-sands industry has also led to a shortage of skilled labour and a fall in productivity.

Box 3.1: **Canadian Oil-Sands Production Costs**

Overall production costs – including capital, operating and maintenance, but excluding taxes – are typically lower for *in situ* projects. The cost of producing bitumen from greenfield projects is currently about US$ 16 per barrel. It is highly sensitive to the steam-to-oil ratio (SOR), a measure of how much energy must be applied to the reservoir to induce bitumen to flow into the producing-well bore. For pure steam, an increase of 0.5 in SOR translates into an additional 6 cubic metres of natural gas consumption per barrel of bitumen, as well as increased water handling costs. At current gas prices, this equates to nearly $2 per barrel. For integrated mining, the current cost of producing synthetic crude is about $33 per barrel. Each 10% increase in capital costs is estimated to increase the per-barrel production cost by $1.50 for *in situ* projects and $2 for integrated projects.

The energy efficiency of both *in situ* and integrated projects is expected to improve over the projection period. New technologies, such as bitumen or coke gasification, which are assumed to be introduced after 2012, contribute to a significant reduction in average gas intensity. Some new projects are expected to use only natural gas, but others will use gasification or a combination of the two. However, the fall in gas intensity may be partially offset by more intensive upgrading to produce higher-quality synthetic crude, which requires more hydrogen. Currently, about 60% of crude bitumen is transformed into various grades of synthetic crude or upgraded products. Although this percentage is expected to decline, we believe it will still be higher than 50% by 2015. Overall natural gas consumption for oil-sands production, including on-site gas-fired power production, is projected to rise from 10 bcm per year now to 21 bcm in 2015 and 29 bcm in 2030 (Figure 3.8). These projections assume that no financial penalty for carbon-dioxide emissions is introduced. As oil-sands production is very carbon-intensive, such a move could have a major impact on prospects for new investment.

Figure 3.8: **Non-Conventional Oil Production and Related Natural Gas Needs in Canada**



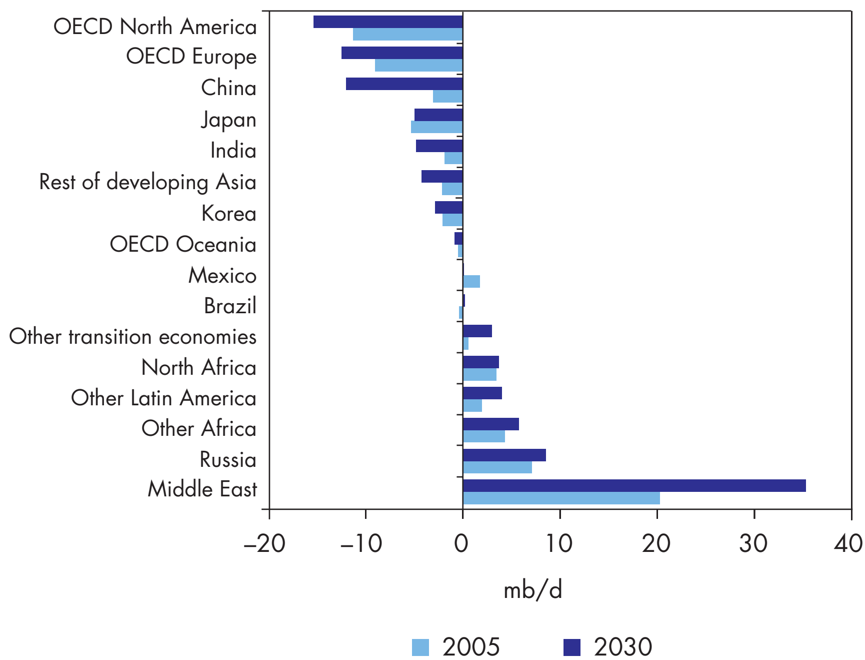
Trade

Inter-regional oil trade is set to grow rapidly over the projection period, as the gap between indigenous production and demand widens in all WEO regions. The volume of trade rises from 40 mb/d in 2005 to 51 mb/d in 2015 and 63 mb/d in 2030. The Middle East will see the biggest increase in net exports, from 20 mb/d in 2005 to 35 mb/d in 2030 (Figure 3.9).

All the major net oil-importing regions import more oil at the end of the projection period, both in absolute terms and as a proportion of their total oil consumption. The increase is sharpest for developing Asia, where imports jump from 48% of demand in 2004 to 73% in 2030 (Table 3.4). Among the three OECD regions, Europe's dependence grows most rapidly, from 58% to 80%, because of both rising demand and falling indigenous production. The OECD as a whole imports two-thirds of its oil needs in 2030 compared with 56% today.

Growing oil exports from the Middle East will focus attention on the world's vulnerability to oil-supply disruptions, not least because the bulk of the additional exports will involve transport along maritime routes susceptible to piracy, terrorist attacks or accidents. At present, more than 17 mb/d of crude oil and products flow through the Straits of Hormuz at the mouth of the Arabian Gulf – the world's busiest maritime oil-shipping route. If it were blocked, only a small share of the oil could be transported through alternative routes. Moreover, much of this oil is subsequently shipped through the Straits of Malacca – already the scene of repeated acts of piracy – to Far East markets.

Figure 3.9: **Net Oil Exports in the Reference Scenario**



Note: Takes account of trade between *WEO* regions only. Negative figures indicate net imports.

Table 3.4: **Oil-Import Dependence by Major Importing Region in the Reference Scenario** (net imports as % of consumption)

	1980	1990	2004	2010	2015	2030
OECD	**59%**	**53%**	**56%**	**60%**	**62%**	**65%**
North America	32%	31%	42%	45%	46%	49%
United States	*41%*	*46%*	*64%*	*66%*	*69%*	*74%*
Europe	82%	67%	58%	69%	75%	80%
Pacific	92%	90%	93%	91%	93%	95%
Japan	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Korea	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Developing Asia	**–2%**	**6%**	**48%**	**57%**	**63%**	**73%**
China	*–9%*	*–16%*	*46%*	*55%*	*63%*	*77%*
India	*69%*	*44%*	*69%*	*72%*	*77%*	*87%*
European Union	–	–	*79%*	*85%*	*89%*	*92%*

Investment

Cumulative global investment in the oil sector amounts to about $4.3 trillion (in year-2005 dollars) over the period 2005-2030, or $164 billion per year, in the Reference Scenario. Investment relative to increases in capacity is highest in OECD countries, where unit costs and production decline rates are high compared with most other regions. Projected oil (and gas) investment needs in this *Outlook* are higher than in previous editions, largely because of the recent unexpected surge in the cost of materials, equipment and skilled personnel. Unit costs are assumed to fall back somewhat after 2010, as oil-services capacity increases and exploration, development and production technology improves. Upstream investment accounts for 73% of total oil-industry investment.

The required rate of capital spending over the projection period is substantially higher than actual spending in the first half of the current decade, which averaged little more than $100 billion per year. Investment needs increase in each decade of the projection period as existing infrastructure becomes obsolete and demand increases. Our analysis of the spending plans of the world's leading oil and gas companies through to 2010 shows that they expect their spending to be much higher in the second half of the current decade than the first (see Chapter 12).

Upstream Investment

Upstream oil spending – more than 90% of which is for field development and the rest for exploration – averages $125 billion per year (Figure 3.10). Three-quarters of this investment is needed to maintain the current level of capacity in the face of natural declines in capacity at producing fields as reserves are depleted. This investment goes to drilling new wells, to working over existing wells at currently producing fields or to developing new fields. In fact, investment needs are far more sensitive to changes in natural decline rates than to the rate of growth of demand for oil.

Downstream Investment

Cumulative investment in oil refining amounts to around $770 billion ($30 billion per year) in the Reference Scenario. These projections include the investment needed to meet demand growth and additional spending on conversion capacity so that existing refineries are able to meet the changing mix of oil-product demand. Tighter fuel-quality standards aimed at mitigating the environmental impact of fuel use are also obliging the refining industry to invest in new quality-enhancement capacity. The required level of refining capacity, allowing for normal maintenance shutdowns, rises from 85 mb/d in 2004 to 117 mb/d in 2030. The largest investments occur in the Middle East and developing Asia (Figure 3.11). Most new refineries will be built outside the OECD (see below).

Figure 3.10: **Cumulative Oil Investment by Activity in the Reference Scenario, 2005-2030**

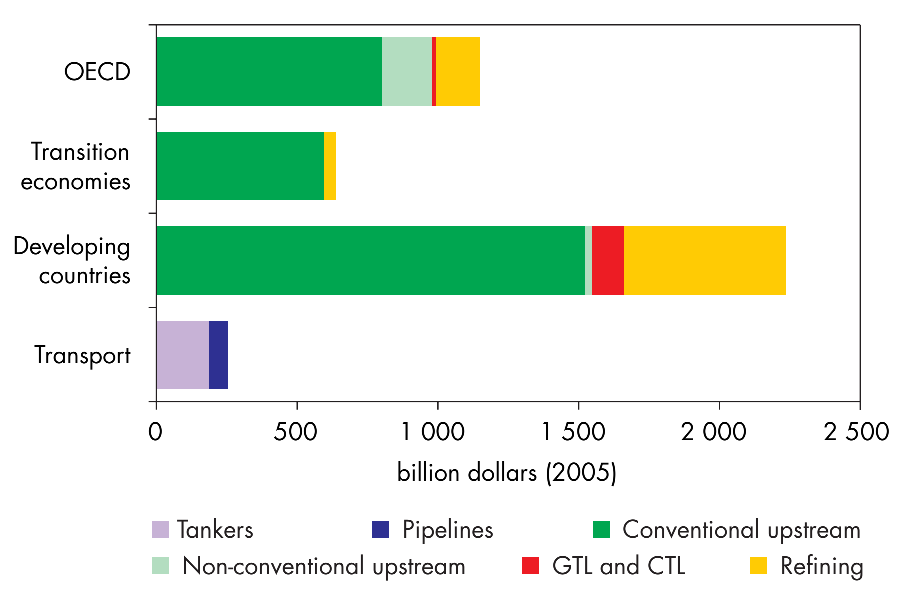
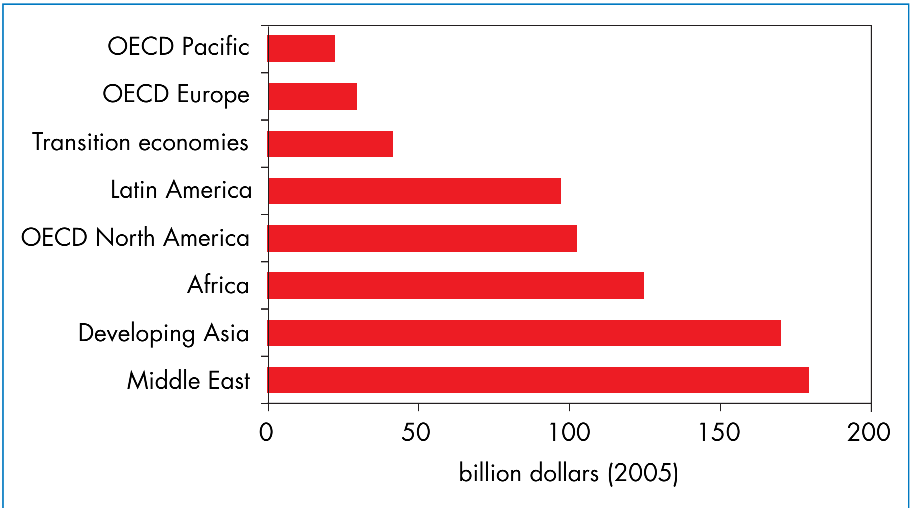


Figure 3.11: **Cumulative Investment in Oil Refining by Region, 2005-2030**



Although investment in oil tankers and inter-regional pipelines makes up a small proportion of total investment needs to 2030, the sum required rises rapidly throughout the projection period, because of the need to replace a large share of the world's ageing tanker fleet. Total cumulative capital spending amounts to around $260 billion. Investment in gas-to-liquids plants in 2005-2030 is expected to amount to $100 billion. Most of this investment occurs in the second half of the projection period. Investment in commercial coal-to-liquids plants, mostly in China, is projected to total over $30 billion.

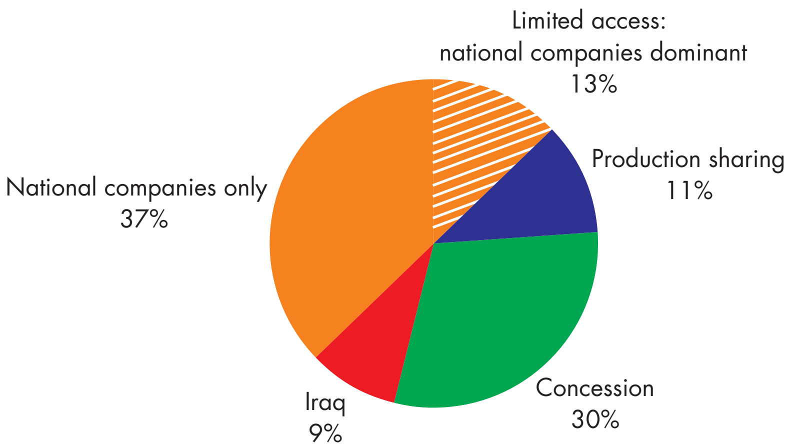
Investment Uncertainties and Challenges

Over the period to 2010, the total amount of investment that will be made in oil and gas infrastructure is known with a reasonable degree of certainty (see Chapter 12). Investment plans may change in response to sudden changes in market conditions and some projects may be cancelled, delayed or accelerated for various reasons. But the actual gross additions to supply capacity at various points along the oil-supply chain are unlikely to depart much from those projected in this *Outlook*. However, beyond 2010, there is considerable uncertainty about the prospects for investment, costs and the rate of capacity additions. The opportunities and incentives for private and publicly-owned companies to invest are particularly uncertain. Environmental policies could increasingly affect opportunities for building upstream and downstream facilities and their cost, especially in OECD countries. In the longer term, technological developments could open up new opportunities for investment and help lower costs.

The availability of capital is unlikely to be a barrier to upstream investment in most cases. But opportunities and incentives to invest may be. Most privately-owned international oil and gas companies have large cash reserves and are able to borrow at good rates from capital markets when necessary for new projects. But those companies may not be able to invest as much as they would like because of restrictions on their access to oil and gas reserves in many resource-rich countries. Policies on foreign direct investment will be an important factor in determining how much upstream investment occurs and where.

A large proportion of the world's reserves of oil are found in countries where there are restrictions on foreign investment (Figure 3.12). Three countries – Kuwait, Mexico and Saudi Arabia – remain totally closed to upstream oil investment by foreign companies. Other countries are reasserting state control over the oil industry. Bolivia recently renationalised all its upstream assets. Venezuela effectively renationalised 565 kb/d of upstream assets in April 2006, when the state-owned oil company, PdVSA took over 115 kb/d of private production and took a majority stake in 25 marginal fields producing 450 kb/d after the government unilaterally switched service agreements from private to mixed public-private companies. The Russian government has tightened its strategic grip on oil and gas production and exports, effectively ruling out foreign ownership of large fields and keeping some companies, including Transneft, Gazprom and Rosneft, in majority state ownership. Several other countries, including Iran, Algeria and Qatar, limit investment to buy-back or production-sharing deals, whereby control over the reserves remains with the national oil company.

Figure 3.12: **Access to World Proven Oil Reserves, end-2005**



Even where it is in principle possible for international companies to invest, the licensing and fiscal terms or the general business climate may discourage investment. Most resource-rich countries have increased their tax take in the last few years as prices have risen. The stability of the upstream regime is an important factor in oil companies' evaluation of investment opportunities. War or civil conflict may also deter companies from investing. No major oil company has yet decided to invest in Iraq. Geopolitical tensions in other parts of the Middle East and in other regions may discourage or prevent inward investment in upstream developments and related LNG and export-pipeline projects.

National oil companies, especially in OPEC countries, have generally increased their capital spending rapidly in recent years in response to dwindling spare capacity and the increased financial incentive from higher international oil prices. But there is no guarantee that *future* investment in those countries will be large enough to boost capacity sufficiently to meet the projected call on their oil in the longer term. OPEC producers generally are concerned that overinvestment could lead to a sharp increase in spare capacity and excessive downward pressure on prices. Sharp increases in development costs are adding to the arguments for delaying new upstream projects. For example, two planned GTL plants in Qatar were put on hold by the government in 2005 in response to soaring costs and concerns about the long-term sustainability of production from the North field. An over-cautious approach to investment would result in shortfalls in capacity expansion.

Environmental policies and regulations will increasingly affect opportunities for investment in, and the cost of, new oil projects. Many countries have placed restrictions on where drilling can take place because of concerns about the harmful effects on the environment. In the United States, for example, drilling has not been allowed on large swathes of US federal onshore lands – such as the Arctic National Wildlife Refuge (ANWR) – and offshore coastal zones for many years.[12] Even where drilling is allowed, environmental regulations and policies impose restrictions, driving up capital costs and causing delays. The likelihood of further changes in environmental regulations is a major source of uncertainty for investment.

Local public resistance to the siting of large-scale, obtrusive facilities, such as oil refineries and GTL plants, is a major barrier to investment in many countries, especially in the OECD. The not-in-my-backyard (NIMBY) syndrome makes future investments uncertain. It is all but impossible to obtain planning approval for a new refinery in many OECD countries, though capacity expansions at existing sites are still possible. The risk of future liabilities related to site remediation and plant emissions can also discourage investment in oil facilities. The prospect of public opposition may deter oil companies from embarking on controversial projects. Up to now, NIMBY issues have been less of a barrier in the developing world.

Technological advances offer the prospect of lower finding and production costs for oil and gas, and opening up new opportunities for drilling. But operators often prefer to use proven, older technology on expensive projects to limit the risk of technical problems. This can slow the deployment of new technology, so that it can take decades for innovative technology to be widely deployed, unless the direct cost savings are clearly worth the risk. This was the case with the rotary steerable motor system, which has finally become the norm for drilling oil and gas wells. These systems were initially thought to be less reliable and more expensive, even though they could drill at double or even triple the rate of penetration of previous drilling systems. The slow take-up of technology means that there are still many regions where application of the most advanced technologies available could make a big impact by lowering costs, increasing production and improving recovery factors. For example, horizontal drilling, which increases access to and maximises the recovery of hydrocarbons, is rarely used in Russia.

As well as lowering costs, technology can be used to gain access to reserves in ever more remote and hostile environments – such as arctic regions and deep water – and to increase production and recovery rates. New technology has enabled the subsurface recovery of oil from tar sands using steam-assisted gravity drainage and closely placed twin horizontal wells, while enhanced oil

12. In mid-2006, Congress was considering a bill to open up 8% of ANWR.

recovery has been made possible by injecting CO_2 into oil wells and by using down-hole electrical pumps, to allow oil to be produced when the reservoir pressure is insufficient to force the oil to the surface.

Although costs have risen sharply in recent years (see Chapter 12), much of the world's remaining oil can still be produced at costs well below current oil prices. Most major international oil companies continue to use a crude oil price assumption of $25 to $35 per barrel in determining the financial viability of new upstream investment. This conservative figure by comparison with current high oil prices partly reflects caution over the technical risks associated with large-scale projects and the uncertainty associated with long lead times and the regulatory environment.

The current wave of upstream oil investment is characterised by a heavy focus on such projects, involving the development of reserves that were discovered in the 1990s or earlier. Unless major new discoveries are made in new locations, the average size of large-scale projects and their share in total upstream investment could fall after the end of the current decade. That could drive up unit costs and, depending on prices and upstream-taxation policies, constrain capital spending. Capital spending may shift towards more technically challenging projects, including those in arctic regions and in ultra-deep water. The uncertainties over unit costs and lead times of such projects add to the uncertainty about upstream investment in the medium to long term.

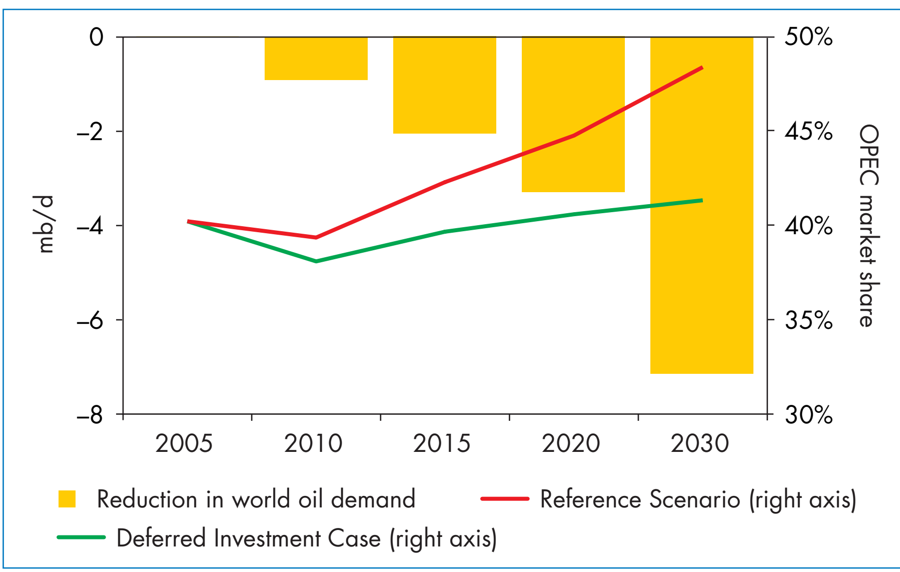
Implications of Deferred Upstream Investment

In light of the uncertainties described above, we have developed a Deferred Investment Case to analyse how oil markets might evolve if upstream oil investment in OPEC countries over the projection period were to increase much more slowly than in the Reference Scenario. This could result from government decisions to limit budget allocations to national oil companies or other constraints on the industry's ability or willingness to invest in upstream projects. For the purposes of this analysis, it is assumed that upstream oil investment in each OPEC country proportionate to GDP remains broadly constant over the projection period at the estimated level of the first half of the current decade of around 1.3%. This yields a reduction in cumulative OPEC upstream investment in the Deferred Investment Case *vis-à-vis* the Reference Scenario of $190 billion, or 25%, over 2005-2030. Upstream investment still grows in absolute terms.

Lower oil investment inevitably results in lower OPEC oil production. This is partially offset by increased non-OPEC production. Higher oil prices encourage this increased investment and production in non-OPEC countries. They also cause oil demand to fall relative to the Reference Scenario. Higher prices for oil and other forms of energy also reduce GDP growth marginally, pushing demand down further.[13] In 2030, the international crude oil price, for which the average IEA import price serves as a proxy, is $19 higher in year-2005 dollars and $33 higher in nominal terms (assuming annual inflation of 2.3%) than in the Reference Scenario – an increase of about 34%.

As a result of higher prices and lower GDP growth, the average annual rate of global oil-demand growth over 2005-2030 falls from 1.3% in the Reference Scenario to 1.1% in the Deferred Investment Case. By 2030, oil demand reaches 109 mb/d – some 7 mb/d, or 6%, less than in the Reference Scenario (Figure 3.13). This reduction is equal to more than the current oil demand of China. Higher oil prices encourage consumers to switch to other fuels, use fewer energy services and reduce waste. They encourage faster improvements in end-use efficiency. In the transport sector, they also encourage faster deployment of biofuels and other alternative fuels and technologies, such as hybrids. The size of these effects varies among regions. It is highest in non-OECD countries, because the share of non-transport uses in final demand (which is relatively price-elastic) is higher there than in the OECD and because the share of taxes, which blunt the impact on demand of higher international oil prices, is generally lower.

Figure 3.13: **Reduction in World Oil Demand and OPEC Market Share**



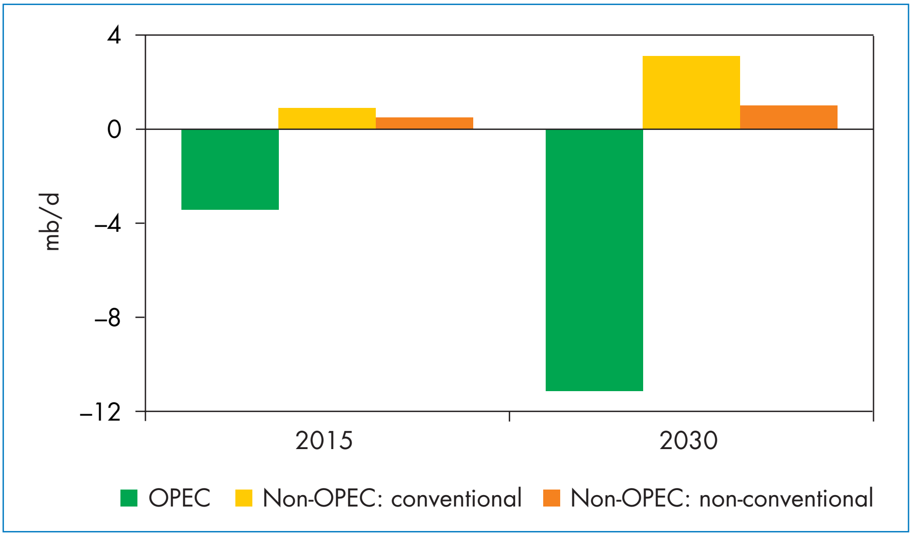
Note: Includes NGLs, condensates and processing gains.

13. See IEA (2005) for a detailed explanation of the methodology used to quantify the effects of lower investment on oil demand, supply and prices.

The drop in world oil demand that results from higher prices is accompanied by an equivalent decline in world production in the Deferred Investment Case. Unsurprisingly, OPEC oil production falls sharply in response to much lower investment (Figure 3.14). Including NGLs, OPEC output is just over 11 mb/d lower in 2030 than in the Reference Scenario, though, at 45 mb/d, it is still nearly 12 mb/d higher than in 2005. OPEC's share of world oil production remains essentially flat at about 40% over the projection period. In the Reference Scenario, the share rises to 48% in 2030.

The fall in OPEC production is largely offset by higher non-OPEC output, which climbs to 64 mb/d – some 4 mb/d higher than in the Reference Scenario and 14 mb/d higher than in 2005. Higher prices stimulate faster development of conventional and non-conventional reserves in all non-OPEC regions, as marginal fields become more commercial. About 1 mb/d, or 15%, of the increase in non-OPEC output comes from oil-sands in Canada. As a result, the share of non-conventional oil in total world supply increases from 2% in 2005 to more than 9% in 2030, compared with less than 8% in the Reference Scenario.

Figure 3.14: **World Oil Production in the Deferred Investment Case Compared with the Reference Scenario**



Note: Includes NGLs, condensates and processing gains.

GAS MARKET OUTLOOK

HIGHLIGHTS

- Primary gas consumption increases in all regions over the period 2004-2030 in the Reference Scenario, from 2.8 trillion cubic metres in 2004 to 3.6 tcm in 2015 and 4.7 tcm in 2030. Globally, demand grows by an average of 2% per year – well down on the 2.6% rate of 1980-2004 and slightly below the rate projected in *WEO-2005*. The biggest increase in volume terms occurs in the Middle East, though demand rises at a faster rate in China, India and Africa. OECD North America and Europe remain the largest markets in 2030. The power sector accounts for more than half of the increase in global primary gas demand.
- In aggregate, annual world gas production expands by almost 1.9 tcm, or two-thirds, between 2004 and 2030. The Middle East and Africa contribute most to this increase. Output also increases quickly in Latin America and developing Asia. Europe is the only region to experience a drop in output between now and 2030.
- Inter-regional gas trade expands even faster than output, because of the geographical mismatch between resource endowment and demand. The main gas-consuming regions become increasingly dependent on imports. In absolute terms, the biggest increases in imports occur in Europe and North America. LNG accounts for most of the increase in global inter-regional trade.
- The Middle East and Africa provide more than two-thirds of the increase in global inter-regional exports over the *Outlook* period. The bulk of the exports from these two regions goes to Europe and the United States. Africa overtakes the transition economies, including Russia, as the largest regional supplier to Europe. There are doubts about whether Russia will be able to raise production capacity fast enough to even maintain current export levels to Europe and to start exporting to Asia.
- Cumulative investment in gas-supply infrastructure amounts to $3.9 trillion over the period 2005-2030. Capital needs are highest in North America, where most spending goes simply to maintaining current capacity. The upstream absorbs 56% of global spending. Most of the investment to 2010 is already committed. Thereafter, it is far from certain that all the investment needed will, in fact, occur. A particular concern is whether the projected increase in exports in some regions, especially the Middle East, is achievable in light of institutional, financial and geopolitical factors and constraints.

Demand

Primary gas consumption is projected to increase in all regions over the next two-and-a-half decades. Globally, demand grows by an average of 2% per year from 2004 to 2030 – well down on the rate of 2.6% per year of 1980-2004 and slightly below the rate projected in *WEO-2005*. Demand grows at the fastest rates in Africa, the Middle East and developing Asia, notably China. The biggest increase in volume terms occurs in the Middle East, driven by demand from the power and petrochemical sectors. Nonetheless, OECD North America and Europe remain the largest markets in 2030 (Table 4.1). The share of gas in the global primary energy mix increases marginally, from 21% in 2004 to 23% in 2030. Our gas-demand projections in most regions have been scaled down since the last edition of the *Outlook*, mainly because the underlying gas-price assumptions have been raised and because of growing concerns about the security of imported gas supplies.

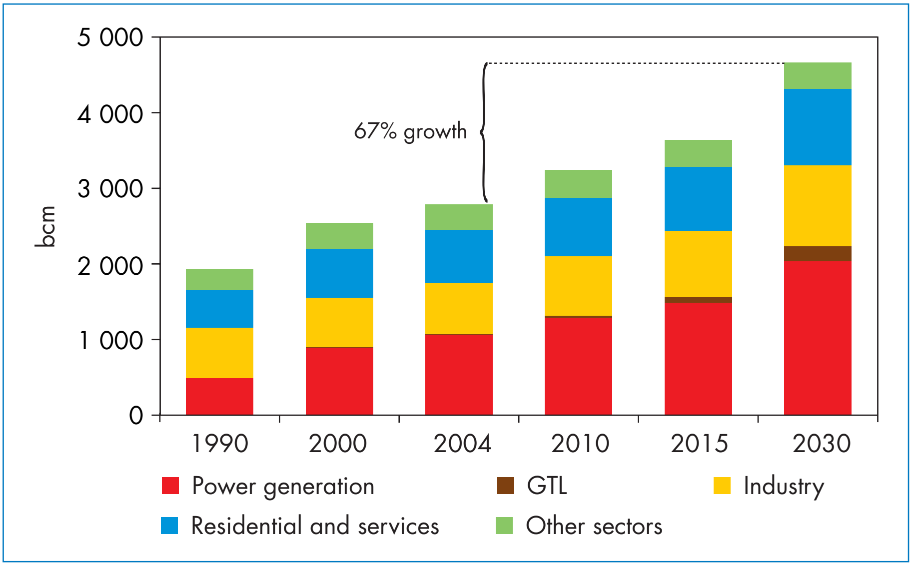
Table 4.1: **World Primary Natural Gas Demand in the Reference Scenario** (bcm)

	1980	2004	2010	2015	2030	2004-2030*
OECD	**959**	**1 453**	**1 593**	**1 731**	**1 994**	**1.2%**
North America	659	772	830	897	998	1.0%
United States	*581*	*626*	*660*	*704*	*728*	*0.6%*
Canada	*56*	*94*	*109*	*120*	*151*	*1.8%*
Mexico	*23*	*51*	*62*	*74*	*118*	*3.3%*
Europe	265	534	592	645	774	1.4%
Pacific	35	148	171	188	223	1.6%
Transition economies	**432**	**651**	**720**	**770**	**906**	**1.3%**
Russia	n.a.	420	469	503	582	1.3%
Developing countries	**121**	**680**	**932**	**1 143**	**1 763**	**3.7%**
Developing Asia	36	245	337	411	622	3.7%
China	*13*	*47*	*69*	*96*	*169*	*5.1%*
India	*1*	*31*	*43*	*53*	*90*	*4.2%*
Indonesia	*6*	*39*	*56*	*65*	*87*	*3.2%*
Middle East	36	244	321	411	636	3.7%
Africa	14	76	117	140	215	4.1%
North Africa	*13*	*63*	*88*	*104*	*146*	*3.3%*
Latin America	36	115	157	180	289	3.6%
Brazil	*1*	*19*	*28*	*31*	*50*	*3.8%*
World	**1 512**	**2 784**	**3 245**	**3 643**	**4 663**	**2.0%**
European Union	*n.a.*	*508*	*560*	*609*	*726*	*1.4%*

* Average annual growth rate.

The power sector accounts for more than half of the increase in primary gas demand worldwide (Figure 4.1). Its use of gas increases by 2.5% per year from 2004 to 2030. In many regions, gas is still preferred to other generation-fuel options – particularly for mid-load – because of its cost competitiveness and its environmental advantages over other fossil fuels. Distributed generation, which is expected to play an increasingly important role in power supply, and the shorter lead times and lower costs of building efficient gas-fired combined-cycle gas-turbines also favour the use of gas. In absolute terms, gas demand in the power sector increases most in the Middle East.

Figure 4.1: **World Primary Natural Gas Demand by Sector in the Reference Scenario**



In line with previous projections, gas-to-liquids (GTL) plants are expected to emerge as a significant new market for gas. Global GTL demand for gas is projected to increase from a mere 8 bcm in 2004 to 29 bcm in 2010, 75 bcm in 2015 and 199 bcm in 2030. In 2006, a new 34-kb/d plant called Oryx, built by Qatar Petroleum and Sasol in Qatar, was commissioned. This doubled existing capacity at two small plants in South Africa and Malaysia. Several other plants are under construction or planned, including a 95-kb/d facility in Nigeria due on stream in 2008-2009 and an expansion of the Oryx plant.[1] Much of the gas used by GTL plants is for the conversion process, which is extremely energy-intensive.

1. See Chapter 12 for more details on near-term GTL investment plans.

The long-term rate of increase in GTL production will hinge on reduced production costs, lower energy intensity, the ratio of gas to oil prices, the premium available for high-quality GTL fuels over conventional products and the economics of liquefied natural gas projects, which compete with GTL for use of available gas.

Final gas consumption grows markedly less rapidly than primary gas use – by 1.8% a year in industry and 1.4% in the residential, services and agricultural sectors. Final consumption slows in the OECD because of saturation effects, sluggish output in the heavy manufacturing sector and modest increases in population. Demand grows more strongly in developing countries and transition economies along with rising industrial output and commercial activity. But residential gas use nonetheless remains modest compared with OECD countries, because incomes are often too low to justify the investment in distribution infrastructure. End-use efficiency gains in the transition economies also temper the growth in residential gas demand. Some oil-producing developing countries continue to encourage switching to gas in order to free up more oil for export.

Supply

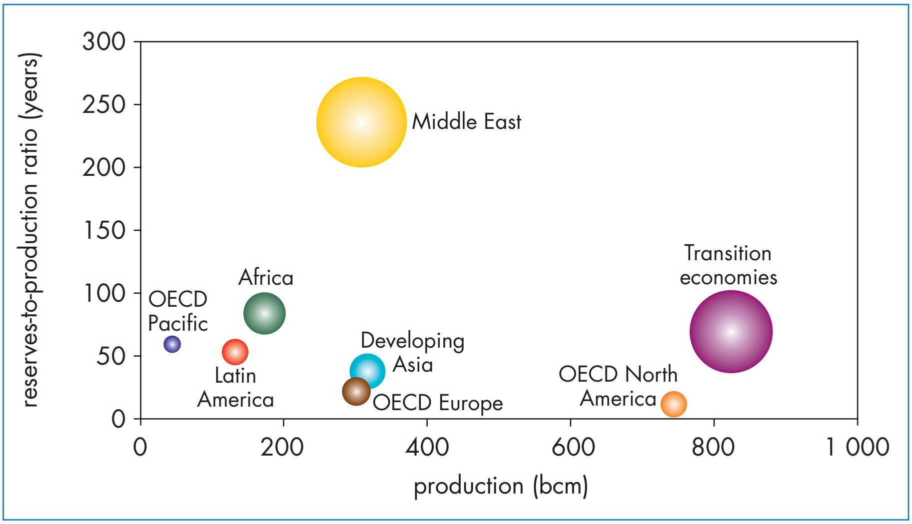
Resources and Reserves

Gas resources are more than sufficient to meet projected increases in demand to 2030. Proven reserves amounted to 180 trillion cubic metres at the end of 2005, equal to 64 years of supply at current rates (Cedigaz, 2006). Were production to grow at the 2% annual rate projected in the Reference Scenario, reserves would last about 40 years. Close to 56% of these reserves are found in just three countries: Russia, Iran and Qatar. Gas reserves in OECD countries represent less than a tenth of the world total (Figure 4.2).

Worldwide proven gas reserves have grown by more than 80% over the past two decades, with large additions being recorded in Russia, Central Asia and the Middle East. Much of this gas has been discovered while exploring for oil. In recent years, the larger share of reserve additions have come from upward revisions to reserves in fields that have already been discovered and are undergoing appraisal or development. As with oil, the gas fields that have been discovered since the start of the current decade are smaller on average than those found previously.

Ultimately recoverable remaining gas resources, including proven reserves, reserve growth and undiscovered resources, are considerably higher than reserves alone. According to the US Geological Survey, they could total 314 tcm in a mean probability case (USGS, 2000). Cumulative production to date amounts to only around 15% of total resources.

Figure 4.2: **Proven Gas Reserves and Production by Region, 2005**



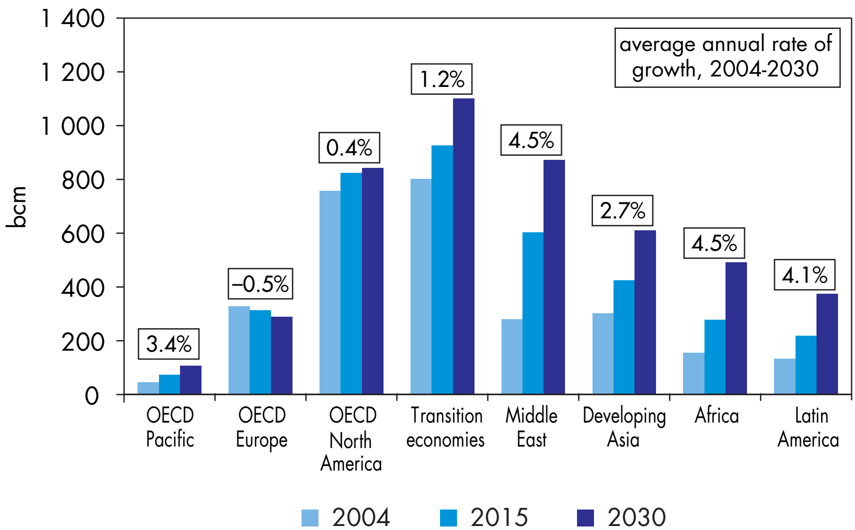
Note: The size of each bubble indicates the size of reserves at the end of 2005.
Source: Cedigaz (2006).

Production

Projected trends in regional gas production in the Reference Scenario generally reflect the relative size of reserves and their proximity to the main markets.[2] Production grows most in volume terms in the Middle East and Africa (Figure 4.3). Most of the incremental output in these two regions will be exported, mainly to Europe and North America. Output also grows quickly in Latin America, where Venezuela emerges as an important supplier to North America and possibly Europe too. Output is expected to grow less rapidly in Russia, despite the region's large reserves: much of that gas will be technically difficult to extract and transport to market. There are also doubts about how much investment will be directed to developing reserves in the transition economies (see below). Other developing Asia sees slower growth, as Indonesia struggles to develop its reserves for export to other countries in the region. Europe is the only region which experiences a drop in output between now and the end of the projection period, as North Sea production peaks early in the next decade and gradually declines thereafter. In aggregate, annual world production expands by almost 1.9 tcm, or two-thirds, between 2004 and 2030.

2. They also take into account special factors, including depletion policies, development costs, geopolitical considerations and the use of gas for reinjection to boost oil recovery.

Figure 4.3: **Natural Gas Production by Region in the Reference Scenario**



Most natural gas supplies will continue to come from conventional sources. The share of associated gas is expected to fall progressively, as more non-associated fields are developed to meet rising demand – despite a further reduction in the amount of associated gas flared. Several countries, especially in the Middle East and Africa, are implementing programmes to reduce gas flaring. Around 150 bcm of gas is flared each year, mostly in the Middle East, Nigeria and Russia (IEA, 2006b; World Bank, 2006). Non-conventional gas production, including coal-bed methane (CBM) and gas extracted from low permeability sandstone (tight sands) and shale formations (gas shales), increases significantly in North America. The United States is already the biggest producer of non-conventional gas, mainly tight sands gas and CBM from the Rocky Mountains. Together, they account for about one-quarter of total US gas output. In most other regions, information on the size of non-conventional gas resources is sketchy. In some cases, there is no incentive to appraise these resources, as conventional gas resources are large.

In general, the share of transportation in total supply costs is likely to rise as reserves located closest to markets are depleted and supply chains lengthen. Technology-driven reductions in unit production and transport costs could, however, offset the effect of distance on total supply costs to some extent. Pipelines will remain the principal means of transporting gas in North America, Europe and Latin America. Yet LNG is set to play an increasingly important role in gas transportation worldwide over the projection period, mainly to supply Asia-Pacific and Atlantic Basin markets.

Inter-Regional Trade

The geographical mismatch between resource endowment and demand means that the main gas-consuming regions become increasingly dependent on imports (Table 4.2). In volume terms, the biggest increase in imports is projected to occur in OECD Europe. Imports in OECD Europe jump by 280 bcm between 2004 and 2030, reaching almost 490 bcm – equal to about two-thirds of inland consumption. North America, which is largely self-sufficient in gas at present, emerges as a major importer. By 2030, imports – all of which are in the form of LNG – meet 16% of its total gas needs. Chinese gas imports also grow from around 1 bcm in 2004 to 56 bcm by 2030. The country's first LNG terminal, with a capacity of 3.7 million tonnes (6 bcm) per year was commissioned in 2006. Nonetheless, gas still meets only 5% of Chinese energy needs by 2030, up from 3% today.

The Middle East and Africa account for 72% of the increase in global exports over the *Outlook* period. The bulk of the exports from these two regions goes to Europe and the United States (Figure 4.4). Africa overtakes the transition economies, including Russia, as the largest regional supplier to Europe. In light of current investment plans, there are doubts about whether Russia will be able to raise production fast enough to maintain current export levels to European markets given rising domestic needs (IEA, 2006b). Russia, Central Asia, Australia and the Middle East emerge as new exporters of gas to China during the projection period. Russia is also expected to begin exporting gas to OECD Asia before 2030.

Gas continues to be traded on a largely regional basis, as there are few physical connections now between the main regional markets of North America, Europe, Asia-Pacific and Latin America. But these markets are set to become more integrated as trade in LNG expands. This will open up opportunities for arbitrage, leading to a degree of convergence of regional prices. LNG accounts for almost 60% of the increase in inter-regional trade (Figure 4.5). Exports of LNG grow from 150 bcm in 2004 to 200 bcm in 2010 and around 470 bcm in 2030. Much of the new liquefaction, shipping and regasification capacity that is due to come on stream by 2010 is either already being built or is at an advanced planning stage. Total liquefaction capacity worldwide would double between end-2005 and 2010, from 178 Mt (242 bcm) per year to 345 Mt (470 bcm) if all the projects under development are completed on time, though some will undoubtedly be delayed or cancelled.[3] North America is expected to see the biggest increase in LNG imports over the whole projection period (Box 4.1).

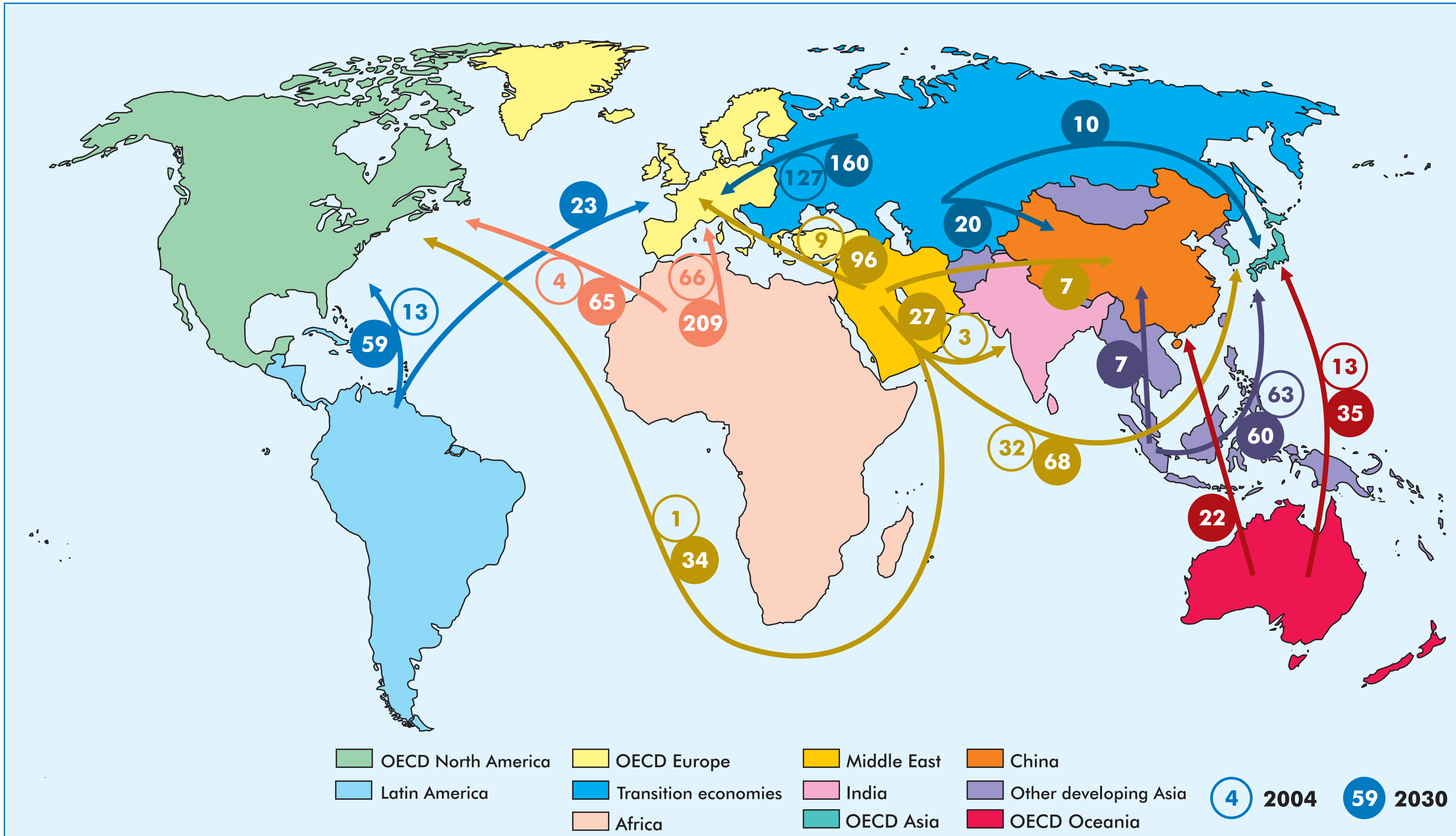
3. See Chapter 12 for a detailed near-term analysis of LNG and pipeline investment.

Table 4.2: **Inter-Regional* Natural Gas Trade in the Reference Scenario**

	2004		2015		2030	
	bcm	% of inland gas consumption**	bcm	% of inland gas consumption**	bcm	% of inland gas consumption**
OECD	**–328**	**22.6**	**–526**	**30.4**	**–764**	**38.3**
North America	–18	2.3	–77	8.6	–159	15.9
Europe	–214	40.1	–333	51.7	–488	63.0
Pacific	–96	65.0	–116	61.3	–117	52.7
OECD Asia	*–109*	*93.5*	*–145*	*96.7*	*–174*	*97.2*
OECD Oceania	*13*	*29.7*	*29*	*40.3*	*57*	*53.7*
Transition economies	**145**	**18.2**	**152**	**16.5**	**190**	**17.3**
Russia	202	32.7	194	27.8	222	27.7
Developing countries	**183**	**21.2**	**374**	**24.7**	**574**	**24.6**
Developing Asia	60	20.0	11	2.7	–15	2.4
China	*0*	*0.0*	*–27*	*27.6*	*–56*	*33.3*
India	*–3*	*9.7*	*–10*	*19.3*	*–27*	*30.1*
Middle East	40	14.4	189	31.5	232	26.7
Africa	70	45.3	137	49.4	274	56.0
Latin America	13	10.0	37	17.0	82	22.2
World	**401**	**14.8**	**634**	**17.4**	**936**	**20.1**

* Trade between *WEO* regions only. See Annex C for regional definitions.
** Production for exporters.
Note: Positive figures denote exports; negative figures imports.

Figure 4.4: **Main Net Inter-Regional Natural Gas Trade Flows in the Reference Scenario, 2004 and 2030** (bcm)



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Box 4.1: **LNG Set to Fill the Growing US Gas-Supply Gap**

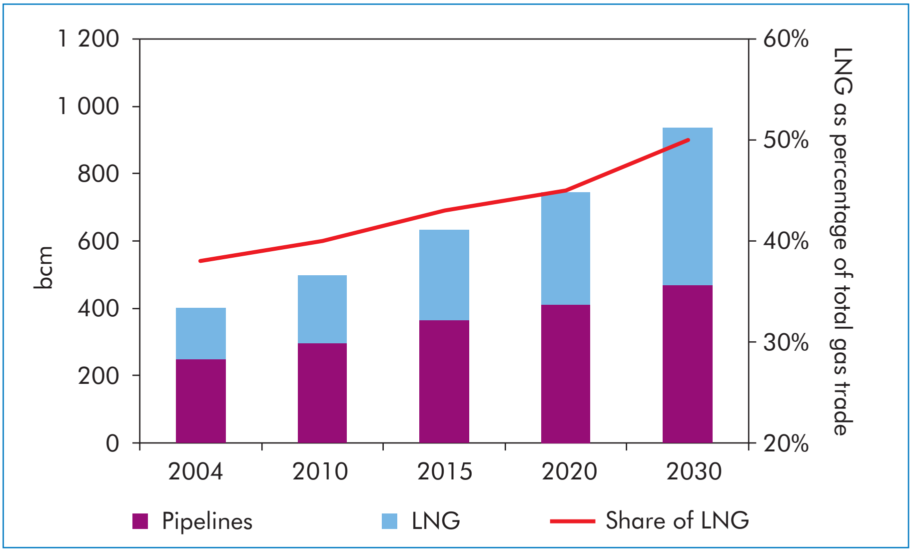
The roller-coaster rise of US natural gas prices in recent years bears testimony to the shifting balance of gas supply and demand. Average monthly well-head prices peaked at almost $11/MBtu in October 2005 in the wake of Hurricane Katrina, sliding to only $6.50 by March 2006 and remaining below $7 for most of the time through to July. The ratio of gas to oil prices is now at its lowest level since early 2000. The main reason is that rising prices since the end of the 1990s have choked off demand – particularly in the chemicals and power sectors. Warmer weather in the winter of 2005-2006 also curtailed demand. Higher prices have, by contrast, been much less effective in stimulating indigenous output, despite increased drilling: marketed production in 2005 would barely have increased had Katrina not occurred, even though the number of gas wells drilled reached almost 26 000 – an increase of 28% on 2004 and almost two-thirds on 2000. In fact, output in 2005 fell to its lowest level since 1992. Increased imports of LNG have made good most of the shortfall, with piped gas imports from Canada rising only modestly.

The diminishing additions to net capacity from increased drilling reflect the maturity of conventional gas basins, as drilling focuses on smaller and smaller pockets of gas and as decline rates at producing fields and wells gather pace. Raising US production in the long term will undoubtedly call for a shift in drilling to new basins, including non-conventional deposits. One of the most prospective areas is the Alaskan North Slope, but development of the region's vast gas reserves will require the construction of a pipeline system to connect with the existing systems in British Columbia and Alberta in Western Canada that export gas to the United States. A 40-50 bcm/year pipeline to ship gas from the North Slope, proposed by producers BP, ConocoPhillips and ExxonMobil, is assumed to be commissioned after 2015.

Supply from indigenous sources is nonetheless not expected to keep pace with demand over the projection period. We expect total US gas production to level off after 2015, leading to higher imports – mostly in the form of LNG. Five regasification terminals are under construction, another 12 projects have been approved by the national authorities and dozens more have been proposed. Local opposition may prevent some of these projects from going ahead. The terminals now being built will, alone, add about 65 bcm/year of capacity by 2010 to the 60 bcm/year of capacity at the country's five existing terminals. If all the approved projects go ahead, capacity would exceed 200 bcm/year.

Sources: IEA databases; EIA/DOE online databases (www.eia.doe.gov); IEA (2006a).

Figure 4.5: **World Inter-Regional Natural Gas Trade by Type in the Reference Scenario**

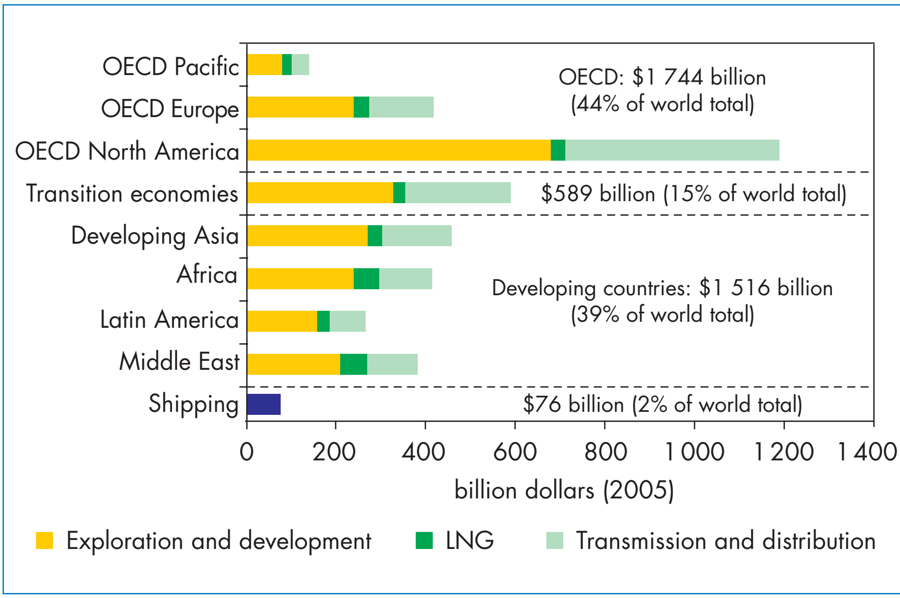


Investment

Cumulative investment in gas-supply infrastructure, including upstream facilities, liquefaction plants, LNG tankers and regasification terminals, transmission pipelines and storage facilities, and distribution networks, is projected to amount to $3.9 trillion ($151 billion per year) in the Reference Scenario over the period 2005-2030. Capital needs are highest in OECD North America, where demand increases strongly and where construction costs are high (Figure 4.6). The upstream absorbs 56% of total spending. Investment in new transmission pipelines and in extending existing distribution networks amounts to around $1.4 trillion over the period 2005-2030.

Decisions on the investment in gas-supply capacity additions that will come on stream by the end of the current decade have already been taken. So the amount of capacity that will be available by 2010 to meet the rise in demand that we project is known with a reasonable degree of certainty. The analysis of Chapter 12 suggests that there will be enough supply capacity to meet projected demand by then. However, it is far from certain that all the investment needed *beyond 2010* will in fact occur. As with oil, the opportunities and incentives to invest are a major source of uncertainty. Environmental policies and not-in-my-backyard resistance may impede the construction of upstream and downstream facilities and push up their cost, especially in OECD countries. On the other hand, technological developments could open up new opportunities for investment and help lower costs in the longer term. Chapter 3 outlines potential barriers to upstream investment, affecting both oil and gas development.

Figure 4.6: **Cumulative Investment in Gas-Supply Infrastructure by Region and Activity in the Reference Scenario, 2005-2030**



A particular concern is whether the high rates of increase in exports projected for some regions, especially the Middle East, are achievable in light of institutional, financial and geopolitical factors and constraints. A small number of countries are expected to provide the bulk of the gas to be exported, mainly as LNG. If problems were to arise within these countries or between these countries and importers, it would be less likely that all the required investments in export-related infrastructure would be forthcoming. The availability of LNG carriers and trained crews may also constrain investment in LNG chains. Any deferral of upstream oil investment, analysed in Chapter 3, would also reduce associated gas production.

The future rate of investment in Russia's gas industry is a particularly critical uncertainty. The bulk of Russia's gas production comes from three super-giant fields – Urengoy, Yamburg and Medvezhye – which are declining at a combined rate of 20 bcm per year (IEA, 2006b). Production at a fourth super-giant, Zapolyarnoye, which came on stream in 2001, has already peaked at 100 bcm per year. Enormous investments are needed to develop new fields in deeper strata and/or in the Arctic region and other regions where reserves are expensive to develop, simply to compensate for the depletion at the old super-giants. Gazprom, which produces 90% of Russia's gas, recently announced an increase in its capital spending to almost $13 billion per year, but this is still below the $17 billion per year that we estimate the Russian gas industry will need to spend on average over the projection period. Moreover, much of Gazprom's spending is being directed at foreign acquisitions and export infrastructure, rather than the domestic network and the upstream sector. One relatively low-cost option for augmenting supplies would be to allow oil companies and independent gas companies, which could sharply increase their marketed gas output, to gain access to Gazprom's network. Reducing waste in domestic consumption would free up more gas for export. The development of the Shtokman field in the Barents Sea and the Bovanenskoye field in Yamal, announced in October 2006, would also increase export availability.

Another source of uncertainty concerns the possibility of major gas-exporting countries coordinating their investment and production plans in order to avoid surplus capacity and to keep gas prices up. The Algerian national oil and gas company, Sonatrach, and Russia's Gazprom recently signed a memorandum of understanding on cooperation in upstream activities – a move that has raised concerns among European gas importers about its implications for competition and prices.

Investment in downstream gas infrastructure in consuming countries – including transmission pipelines, storage facilities and distribution networks – will hinge on appropriate regulatory frameworks, as much of the capital will have to come from the private sector. This is the case in many developing countries, where publicly-owned gas companies face difficulties in raising sufficient funds. Investment prospects are more secure for domestic downstream projects in OECD countries, particularly those that involve the extension or enhancement of existing pipeline networks. This type of investment is usually considered to be relatively low-risk, particularly where demand trends are reasonably stable and predictable and where returns are protected by the regulator through explicit price controls. The returns that can be made on such investments usually depend to a large extent on price controls. Most downstream gas transmission and distribution companies operating in regulated markets are also well-placed to obtain finance for new infrastructure investments.

Pricing policies are critical to incentives to invest in gas networks. The allowed rate of return is generally low relative to the average return on investment in other industries, reflecting the lower level of risk – especially where the investment is incremental and where the regulatory framework provides a high level of assurance to the investor that he will be able to recover his costs through regulated tariffs. There is nonetheless a danger that the regulator may fix the allowed rate of return too low, which can discourage investment and create bottlenecks. In OECD countries, regulated tariffs are generally set so as to cover the full cost of supply. In some cases, the regulatory regime may incorporate incentives for utilities to reduce costs – an approach pioneered in Great Britain. In the vast majority of non-OECD countries, price ceilings that keep retail prices below the full long-run marginal cost of supply can impede the capacity of gas utilities – whether private or public – to invest in expanding and maintaining the network (see the discussion of subsidies in Chapter 11). This is a major problem in Russia and several other transition economies.

COAL MARKET OUTLOOK

HIGHLIGHTS

- Global coal demand in the Reference Scenario is projected to grow at an average annual rate of 1.8% between 2004 and 2030, such that coal's share in the global energy mix remains broadly constant at around one-quarter. Coal use rises by 32% by 2015 and 59% by 2030 (expressed in tonnes) – a significantly faster rate of growth than in *WEO-2005*. Of the total increase in demand, 86% comes from developing Asia, particularly China and India. OECD coal use grows modestly.
- Power generation accounts for 81% of the increase in coal use to 2030, boosting its share of total coal demand from 68% in 2004 to 73%. Coal use in final sectors barely increases in many regions and falls in the OECD. Demand will remain sensitive to developments in clean coal technology and government policies on energy diversification, climate change and local pollution, as well as to relative fuel prices.
- Coal is the most abundant fossil fuel. Proven reserves at the end of 2005 amounted to around 909 billion tonnes, equivalent to 164 years of production at current rates. Around half of these reserves are located in just three countries – the United States, Russia and China – but twenty other countries each hold substantial reserves of at least 1 billion tonnes. Production, processing and transportation costs vary widely.
- Coal needs continue to be met mainly by indigenous production. China – already the world's leading coal producer – and India account for over three-quarters of the 3.3 billion-tonne increase in coal production in 2030 over 2004. The United States sees the biggest absolute rise in output among OECD countries, accounting for about 8% of global production growth. Australia, Indonesia, South Africa and Colombia also contribute significantly. Hard coal output in the European Union, where costs are generally high, falls as remaining subsidies are phased out, but brown coal output remains flat. Steam coal accounts for most of the growth in total world coal output between 2004 and 2030. Safety remains a major concern in the mining industry in some large producing countries.
- Global inter-regional trade in hard coal expands at the same rate as demand, from 619 Mt in 2004 to 975 Mt in 2030. Trade in steam coal grows much faster than that in coking coal. Trade in brown coal and peat remains negligible. Australia is expected to extend its lead as the world's biggest exporter of coking coal and, along with Indonesia, continues to dominate steam-coal trade. China remains an exporter, but loses market share, as more of its output is diverted to rapidly growing domestic markets.

Demand

Global coal use is projected to grow at an average annual rate of 1.8% between 2004 and 2030 (Table 5.1). Coal's share in the global energy mix remains broadly constant at around one-quarter over the projection period. Coal use rises by 32% by 2015 and 59% by 2030 (expressed in tonnes). The prospects for coal use have brightened since the last edition of the *Outlook* because coal prices are now expected to remain well below those of gas – the main competitor to coal, especially in power generation – and oil products in energy terms over the projection period. Coal demand in 2030 is now expected to be about 19% higher than projected in *WEO-2005*. The projected increase in global demand is significantly slower than that seen in the past five years, when it grew by more than 5% per year – mainly due to strong growth in China. Demand will remain sensitive to developments in clean coal technology and government policies on energy diversification, climate change and local pollution, as well as to relative fuel prices. Although coal is more carbon-intensive than oil or gas, coal supplies are regarded as more secure.

Prospects for coal demand differ markedly among regions. Most of the growth in demand comes from developing Asia, particularly China and India, where coal resources are abundant. In fact, these two countries account for over three-quarters of the entire increase in coal use between 2004 and 2030. Strong economic growth has led to a surge in their coal use in the last few years. In all three OECD regions, coal use grows much more slowly. The EU Emissions Trading Scheme introduced in 2005, which involves national caps on greenhouse-gas emissions and EU-wide trading of emission allowances, could contribute to the decline in coal demand in the European Union.

Power generation accounts for 81% of the increase in coal demand to 2030. Coal use in final sectors barely increases in many regions and falls in the OECD.[1] The power sector's share of global coal demand rises from 68% in 2004 to 73% in 2030 (Figure 5.1). The importance of power generation in coal demand varies considerably among regions. Among the *WEO* regions, it is highest in OECD North America. Demand from coal-to-liquids plants is expected to remain marginal over the *Outlook* period, the assumption being that costs will remain too high to make the technology economic in most cases (Box 5.1).

1. Steam and brown coals are used for the production of heat and power. Coking coal is used mainly in the iron and steel industries.

Table 5.1: **World Coal Demand*** (million tonnes)

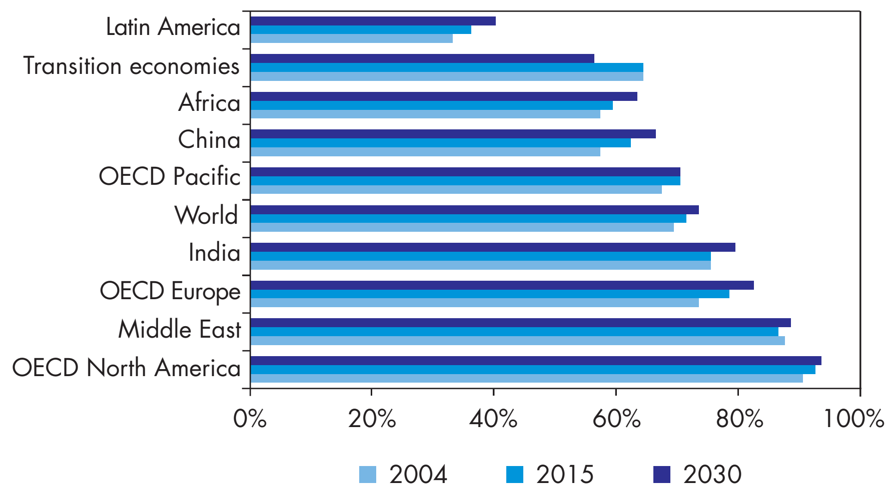
	1980	2004	2010	2015	2030	2004-2030**
OECD	**2 033**	**2 313**	**2 507**	**2 552**	**2 735**	**0.6%**
OECD North America	687	1 080	1 222	1 248	1 376	0.9%
United States	*646*	*1 006*	*1 135*	*1 151*	*1 282*	*0.9%*
Canada	*38*	*59*	*70*	*76*	*67*	*0.5%*
Mexico	*4*	*15*	*18*	*21*	*27*	*2.4%*
OECD Pacific	183	399	439	450	453	0.5%
OECD Asia	*114*	*262*	*293*	*296*	*287*	*0.3%*
OECD Oceania	*69*	*137*	*146*	*154*	*166*	*0.8%*
OECD Europe	1 163	834	846	855	905	0.3%
Transition economies	**842**	**521**	**560**	**575**	**491**	**–0.2%**
Russia	n.a.	215	239	234	216	0.0%
Developing countries	**917**	**2 766**	**3 643**	**4 215**	**5 647**	**2.8%**
Developing Asia	804	2 523	3 390	3 938	5 306	2.9%
China	*626*	*1 881*	*2 603*	*3 006*	*3 867*	*2.8%*
India	*114*	*441*	*534*	*636*	*1 020*	*3.3%*
Indonesia	*0*	*36*	*50*	*63*	*105*	*4.2%*
Other	*64*	*166*	*204*	*232*	*314*	*2.5%*
Latin America	18	34	39	44	63	2.3%
Brazil	*10*	*22*	*23*	*25*	*34*	*1.7%*
Africa	93	193	196	211	248	1.0%
Middle East	2	15	18	23	31	2.8%
World* **	**3 822**	**5 558**	**6 696**	**7 328**	**8 858**	**1.8%**
European Union	*n.a.*	*789*	*777*	*759*	*745*	*–0.2%*

* Includes hard coal (steam and coking coal), brown coal (lignite) and peat.
** Average annual rate of growth.
*** Includes statistical differences and stock changes.
n.a. = not available.

Reserves and Production

Coal is the most abundant fossil fuel. Proven reserves at the end of 2005 amounted to around 909 billion tonnes, equivalent to 164 years at current production rates (BP, 2006). Coal is found in many countries, but more than 80% of the reserves are located in just six (Figure 5.2). The three largest consumers – China, the United States and India – together hold about half of the global reserves, and Russia, Australia and South Africa account for another 31%. Many other countries hold large reserves. In total, 20 countries each hold more than 1 billion tonnes.

Figure 5.1: **Share of Power Generation in Total Coal Consumption by Region in the Reference Scenario**



Note: Power generation includes heat production.

Box 5.1: **The Economics of Coal-to-Liquids Production**

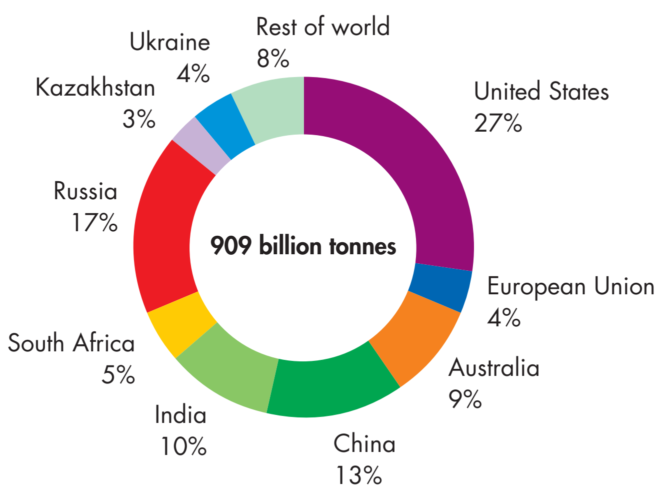
Concerns about oil-supply security have recently led to renewed interest in coal as an alternative feedstock for the production of transport fuels and chemicals. Coal-to-liquids (CTL) technologies include coal gasification, combined with Fischer-Tropsch synthesis to produce liquid fuels (in the same way as gas-to-liquids), and direct coal-liquefaction technologies, which are still under development. Coal gasification is already widely used in the production of chemicals and fertilizers, notably in China, where 8 000 coal gasifiers are in operation. Sasol, a South African company, operates two coal-to-liquids plants, with total capacity of 150 kb/d. Output consists of 80% synthetic diesel and 20% synthetic naphtha. China is building a 60 kb/d plant and has plans for further projects. In the United States, coal companies are assessing the commercial viability of new projects following the introduction of new incentives for CTL.

Process technologies for the production of synthesis gas from coal are well established, but unit costs of CTL production remain high compared with conventionally refined products. Nonetheless, where coal can be delivered at low cost, CTL could be competitive. For example, at a steam-coal price of $20 per tonne – less than half the current international price –

the average production cost of synfuels would be about $50 per barrel, making CTL competitive at a crude oil price of under $40. However, at current coal prices, oil prices would have to average well over $50 per barrel. Moreover, the capital costs of CTL plants are very high: around $5 billion for a 80-kb/d unit compared with less than $2 billion for a GTL plant of similar size. CTL plants must have access to reliable supplies of low-cost coal, ideally with adjacent reserves of at least 500 million tonnes. CTL processes are also very energy-intensive and result in seven to ten times more CO_2 emissions per unit of output than conventional oil refineries (without carbon capture and storage). For these reasons, CTL is likely to remain a niche activity over the *Outlook* period.

Source: IEA (2006).

Figure 5.2: **Proven Coal Reserves by Country** (end-2005)



Source: BP (2006).

In the Reference Scenario, China – already the world's leading coal producer – and India together account for over three-quarters of the 3 300 million-tonne increase in coal production over the *Outlook* period (Table 5.2). The United States sees the biggest absolute rise in output among OECD countries, accounting for about 8% of global production growth. However, its production will lag domestic requirements. Although it has vast reserves, they are relatively expensive to extract and transport in some parts of the country. Australia, Indonesia, South Africa and Colombia also raise their production significantly to meet rising domestic needs and to profit from growing international demand. In contrast, output of steam and coking coal in the European Union, where costs are high, declines as remaining subsidies are phased out in most countries. But EU brown-coal production, used almost exclusively in the power sector, remains more or less flat throughout the projection period on the assumption that subsidies are retained. The share of brown coal in total EU coal production on a volume basis rises from 68% in 2004 to 87% in 2030. Adjusted for energy content, total EU coal production falls by 38%. Globally, cumulative coal production to 2030 amounts to only 22% of current proven reserves.

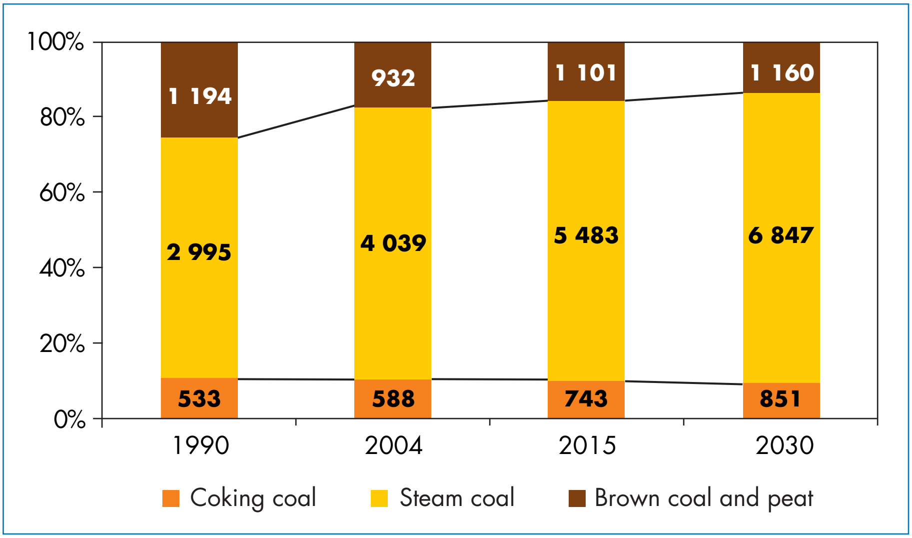
Table 5.2: **World Coal Production in the Reference Scenario** (million tonnes)

	1980	2004	2010	2015	2030	2004-2030*
OECD	**2 045**	**2 075**	**2 274**	**2 318**	**2 538**	**0.8%**
OECD North America	793	1 085	1 230	1 250	1 361	0.9%
United States	*753*	*1 009*	*1 139*	*1 150*	*1 267*	*0.9%*
Canada	*37*	*66*	*79*	*85*	*77*	*0.6%*
OECD Pacific	144	363	436	467	564	1.7%
OECD Asia	*37*	*3*	*2*	*0*	*0*	*n.c.*
OECD Oceania	*107*	*360*	*434*	*467*	*564*	*1.7%*
OECD Europe	1 108	627	609	601	614	–0.1%
Transition economies	**849**	**572**	**630**	**653**	**584**	**0.1%**
Russia	n.a.	260	304	306	301	0.6%
Developing countries	**929**	**2 913**	**3 791**	**4 357**	**5 737**	**2.6%**
Developing Asia	796	2 596	3 445	3 980	5 272	2.8%
China	*620*	*1 960*	*2 673*	*3 074*	*3 927*	*2.7%*
India	*116*	*413*	*494*	*586*	*937*	*3.2%*
Indonesia	*0*	*132*	*172*	*202*	*263*	*2.7%*
Other	*60*	*90*	*106*	*118*	*145*	*1.8%*
Latin America	11	67	83	94	130	2.6%
Brazil	*5*	*5*	*7*	*8*	*12*	*3.0%*
Africa	120	248	261	280	332	1.1%
Middle East	1	2	2	2	3	1.9%
World	**3 822**	**5 559**	**6 696**	**7 328**	**8 858**	**1.8%**
European Union	*n.a.*	*597*	*556*	*524*	*477*	*–0.9%*

* Average annual rate of growth.
n.a. = not available; n.c. = not calculable.

There is a shift in the breakdown of global production by type of coal over the *Outlook* period, reflecting demand trends and differences in local availability and production costs. Production of steam coal grows most rapidly, accounting for 85% of the total increase in output between 2004 and 2030 (Figure 5.3). Coking coal accounts for a mere 8%, and brown coal and peat for the rest. Most of the growth in brown coal production takes place in OECD Europe.

Figure 5.3: **Global Coal Production by Type in the Reference Scenario**
(million tonnes)



Inter-Regional Trade

Global inter-regional trade[2] in hard coal expands at a rate of 1.8% per year over 2004-2030, from 619 Mt in 2004 to 975 Mt in 2030 (Table 5.3). Even so, most coal will continue to be consumed within the region in which it is produced. Trade grows slightly quicker than demand, more so if China and India are excluded. The share of inter-regional trade in total hard coal consumption worldwide will remain flat at 13% between 2004 and 2030. Trade in brown coal and peat remains negligible. Trade in steam coal grows much faster than in coking coal, largely because demand increases more quickly. Steam coal accounts for 85% of the total expansion in coal trade growth. International steam-coal trade grows faster than demand, because demand outstrips indigenous production in some regions. As a result, the share of steam coal in global hard-coal trade increases from 71% in 2004 to 76% in 2030 (Figure 5.4).

2. As for oil and gas, the projections presented here cover only trade between *WEO* regions, not trade within those regions. In 2004, inter-regional trade accounted for about 80% of total international hard-coal trade.

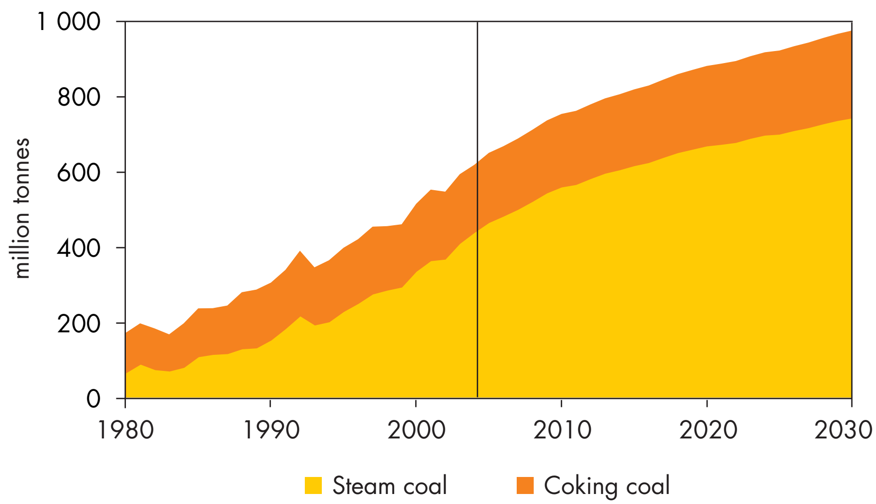
Table 5.3: **Hard Coal* Net Inter-Regional Trade in the Reference Scenario**
(million tonnes)

	1980	2004	2010	2015	2030
OECD	**19**	**218**	**224**	**225**	**188**
OECD North America	–82	–25	–16	–12	6
United States	*–83*	*–14*	*–4*	*1*	*16*
Canada	*1*	*–13*	*–16*	*–16*	*–17*
OECD Pacific	28	42	4	–17	–110
OECD Asia	*72*	*261*	*291*	*296*	*287*
OECD Oceania	*–43*	*–220*	*–288*	*–314*	*–397*
OECD Europe	73	201	237	254	292
Transition economies	**–4**	**–57**	**–73**	**–81**	**–95**
Russia	n.a.	–50	–65	–72	–85
Developing countries	**–17**	**–141**	**–150**	**–144**	**–91**
Developing Asia	2	–64	–56	–44	31
China	*–5*	*–72*	*–70*	*–67*	*–60*
India	*0*	*27*	*40*	*50*	*82*
Indonesia	*–0*	*–96*	*–122*	*–139*	*–157*
Other	*6*	*77*	*96*	*113*	*167*
Latin America	7	–33	–45	–51	–67
Brazil	*5*	*16*	*16*	*18*	*22*
Africa	–27	–57	–65	–69	–84
Middle East	1	13	16	20	28
World	**172**	**619**	**754**	**819**	**975**
European Union	*n.a.*	*187*	*219*	*234*	*267*

* Steam and coking coal.
Note: Negative figures denote exports; positive figures imports. World trade is calculated as the sum of steam coal and coking coal. The figures for each region show the net trade in both types of coal combined. As a result, the world total is slightly larger than the sum of the exports.
n.a. = not available.

Patterns of steam-coal trade see some significant changes. The Atlantic market continues to be supplied mainly by South Africa, Colombia and Russia, but the United States emerges as a new importer – albeit on a modest scale – alongside Europe. EU output falls even faster than demand, so imports continue to grow. In the Pacific market, India joins Japan, Korea and Chinese Taipei as a large coal importer as domestic power-sector needs outpace the growth of indigenous output. Indonesia, Australia and Russia meet an increasing proportion of Pacific steam-coal import needs. China remains an exporter, but loses market share, as an increasing proportion of the country's output is diverted to domestic markets. This projection is particularly uncertain: slightly faster demand or slower production growth than projected here could turn China into a net importer. Four countries – Australia, the United States, Canada and Russia – continue to account for the bulk of coking-coal exports. Australia's share continues to expand, from 63% in 2004 to 67% in 2030, extending its lead as the world's biggest exporter of coking coal.

Figure 5.4: **Net Inter-Regional Trade in Hard Coal in the Reference Scenario**



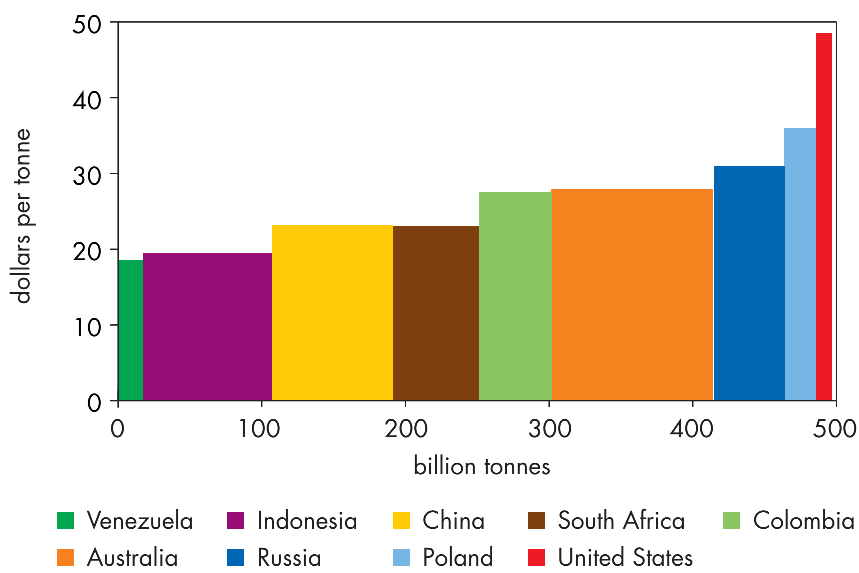
Coal Supply Costs and Investment

Supply costs are the primary determinant of where incremental coal production and export capacities are added. Assessing those costs is difficult, because they vary widely across countries and regions according to local factors, including geology, technology, infrastructure and labour costs. The average free-on-board cost of supply of steam coal, including production, processing, inland transportation and loading onto ships (but excluding capital charges and profit margins), ranges from less than $20 per tonne in Indonesia and Venezuela to about $50 in the United States (Figure 5.5). Much of the coal currently exported involves costs of around $25 to $30 per tonne.[3]

3. These estimates are based on an analysis of coal-supply costs carried out by the IEA Clean Coal Centre, submitted to the IEA in June 2006.

Consolidation of the mining industry has helped to lower production costs in several countries in the last decade or so. We expect costs in most major exporting countries to remain broadly flat in real terms over the projection period. Rationalisation programmes and the adoption of modern technology are expected to largely offset the higher costs associated with developing new underground and surface mines that will also require new above-ground infrastructure.

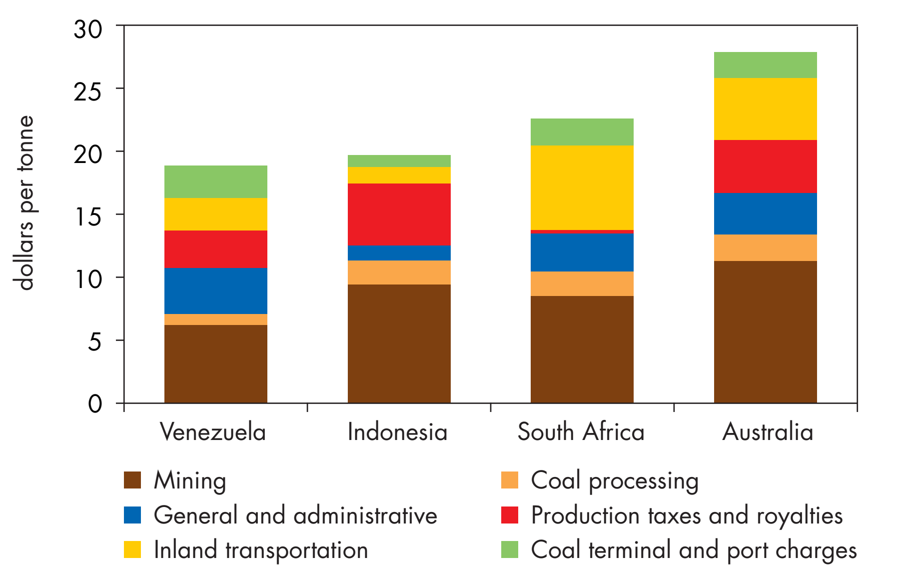
Figure 5.5: **Indicative Supply Costs for Internationally Traded Steam Coal**



Note: FOB cost, not including capital charges, based on a standardised heat content of 6 000 kcal/kg (comparable to a typical South African coal exported from Richard's Bay). The heat content of internationally traded coals ranges from 5 200 kcal/kg to 7 000 kcal/kg.
Source: IEA Clean Coal Centre analysis based on Devon and Ewart (2005) and RWE (2005).

In some regions, mining accounts for up to half the cost of coal supply (Figure 5.6). Mining costs vary depending on the type of mine extraction method deployed, the accessibility of the coal seams, the degree of preparation the coal needs prior to transporting and labour requirements. Average mine costs range from $7 per tonne for opencast, high-calorific-value coal in Venezuela to more than $10 in countries like Australia where underground mining accounts for a more significant share of total production. Underground coking-coal costs can sometimes exceed $40 per tonne, but coking coal produced at this cost can still be competitive because of its high

Figure 5.6: **Structure of Steam Coal Supply Costs for Major Exporting Countries**



Note: FOB cost, not including capital charges, based on a standardised heat content of 6 000 kcal/kg (comparable to a typical South African coal exported from Richard's Bay). The heat content of internationally traded coals ranges from 5 200 kcal/kg to 7 000 kcal/kg.
Source: IEA Clean Coal Centre analysis based on Devon and Ewart (2005).

value. The per-tonne cost of coal processing is typically around \$2, while administration and general management costs add another \$1 to \$3. Royalties and taxes can be significant, amounting to almost \$4 on average in Australia and Indonesia based on current prices. The cost of transporting coal from the mine to the port terminal, usually by rail, can account for a large share of total supply costs. Port facilities for loading coal onto ships cost between \$1 and \$3 per tonne. Seaborne freight charges depend on the vessel size and the voyage distance. In 2005, voyages in large capesize vessels (150 kt dead-weight) cost around \$10 to \$20 per tonne, and in smaller panamax vessels (50 kt) between \$15 and \$30. Fluctuations in demand for, and supply of, dry-bulk vessels, used to ship coal and other commodities, can create enormous volatility in the cost of transporting coal between continents. For example, in 2005, freight rates accounted for half the cost of South African steam-coal exports to Japan.

Several factors will influence supply costs and, therefore, the attractiveness of new investment in the coal industry in the coming decades:

- **Energy prices:** The recent surge in energy prices has put upward pressure on coal-supply costs. The price of electricity for running mining machinery and fuel for trucks directly affects mining costs.

- **Exchange rates:** A drop in the value of the dollar would increase supply costs, which are generally priced in local currencies, relative to export revenues, which are priced in dollars.
- **Taxation:** Changes in tax and royalty policies and other charges can have a major impact on the profitability of coal projects.
- **Geology:** The development of new seams at both existing and new mines can raise operating and processing costs, as development moves to less accessible deposits or seams that are located further from the mine head and existing processing and transport infrastructure.
- **The need for new transport infrastructure:** Most coal-export ports are currently operating at close to capacity and the scope for expansion at existing facilities is often limited. Building new ports is expensive – typically around $15 per tonne of annual capacity. In the United States, Russia and China, coal is transported by rail on networks that are frequently inadequate even for the volumes now carried.
- **Seaborne freight rates:** Chinese demand for dry bulk goods is driving the shipping market and keeping utilisation of the shipping fleet at over 90%. Orders for new vessels are at an all-time high. As new capacity becomes available in the next few years, freight rates are likely to ease.
- **Safety concerns:** Coal-mining safety remains a major concern, particularly in developing countries. In China, over 6 000 men lose their lives each year in coal-mining accidents, mainly in the small private and collective mines in towns and villages. Even in developed countries, accidents still occur occasionally.

Global coal industry investment needs over the next two-and-a-half decades amount to about $563 billion in the Reference Scenario. Unit investment costs to meet the increase in demand are expected to average about $50 per tonne per year for new supply capacity, including the cost of sea freight. Currently, there are plans to add about 62 million tonnes per year of steam and coking-coal production capacity at existing mines, compared with 35 Mt of capacity at new greenfield mines. In the longer term, capacity is expected to come increasingly from greenfield developments.

The recent surge in demand for coal has had an inflationary impact on mining costs, averaging about 9% in 2005 for materials. With lead times for mining equipment now extending to a year or more and with shortages of skilled labour, these costs have also risen significantly. Our projections assume that this boom cycle will be short-lived and that coal supply and demand will balance at the prices assumed (see Chapter 1).

POWER SECTOR OUTLOOK

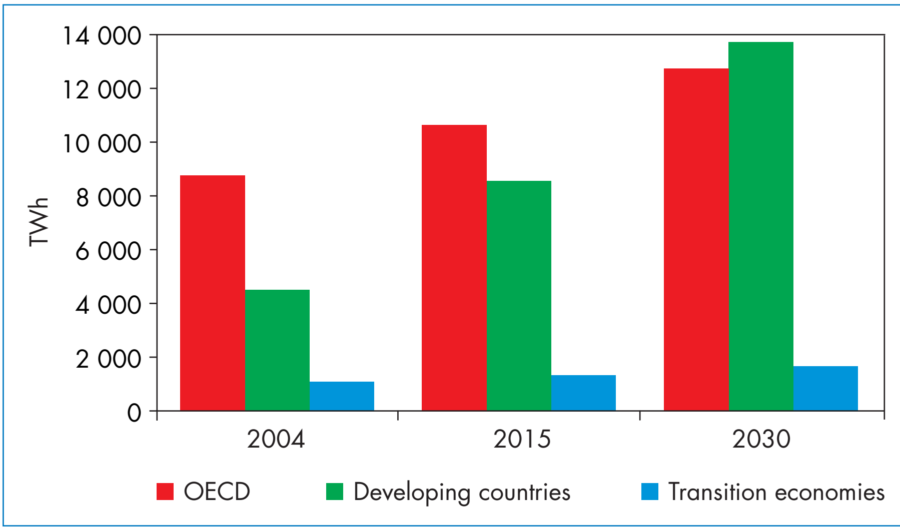
HIGHLIGHTS

- World electricity demand is projected to double by 2030 in the Reference Scenario, growing at 2.6% per year on average. Developing Asia is the main engine of growth: China and India see the fastest growth in demand.
- The share of coal in the power generation fuel mix increases, because of high natural gas prices and strong electricity demand in developing Asia, where coal is abundant. That region accounts for over three-quarters of the increase in coal-fired generation between now and 2030.
- Natural gas-fired electricity generation more than doubles between now and 2030, but the projected growth is lower than in past *Outlooks*, when gas prices were expected to remain lower than now assumed. The generating costs of CCGTs are now expected to be between 5 cents and 7 cents per kWh, as against 4 cents and 6 cents per kWh for coal-fired generation.
- Nuclear capacity increases to 416 GW by 2030, but the nuclear share in total electricity generation drops from 16% to 10%. Renewed interest in nuclear power could change this picture.
- Hydropower continues to expand, mostly in developing countries. Globally, less than a third of economic hydropower potential has been exploited. The share of other renewables is projected to increase from 2% now to 7% by 2030, most of the growth occurring in OECD countries.
- World CO_2 emissions from power plants are projected to increase by about two-thirds over the period 2004-2030. China and India alone account for nearly 60% of this increase.
- Total cumulative investment in power generation, transmission and distribution over 2004-2030 amounts to $11.3 trillion. China needs to invest most, some $3 trillion. In the developing world, private investment in the power sector remains concentrated in a few large countries. The prospects for investment in small, poor countries remain weak.
- Falling power capacity reserve margins and ageing infrastructure – both power plants and networks – give rise to a need for substantial increases in investment in many OECD countries. High and volatile gas prices, uncertain environmental policies, difficulties in siting new facilities and complicated and unreliable licensing processes are growing challenges for investors.
- There are still 1.6 billion people in the world without electricity. On present policies, that number would fall by only 200 million by 2030. To achieve the Millennium Development Goals, it would need to fall to less than one billion by 2015.

Electricity Demand Outlook

Global electricity demand[1] in the Reference Scenario is projected to practically double over the next 25 years, from 14 376 TWh in 2004 to 28 093 TWh in 2030, growing at 2.6% per year on average. Growth is stronger, at 3.3% per year in the period 2004-2015, falling to 2.1% per year thereafter. In developing countries, demand grows three times as fast as in the OECD, tripling by 2030 (Figure 6.1).

Figure 6.1: **World Electricity Demand by Region in the Reference Scenario**



The fastest growth in electricity demand, averaging 5.4% per year in 2004-2030, occurs in India, followed by China at 4.9% per year (Figure 6.2). In 2004-2015, China's demand for electricity grows by 7.6% per year, much higher than the world average, but below the 12% annual average rate seen over the past five years.

The share of electricity in total final energy consumption increases in industry, in households and in the services sector in all regions. Overall, the share of electricity in total final energy consumption worldwide is projected to rise from 16% in 2004 to 21% in 2030. Demand grows most rapidly in households, underpinned by strong demand for appliances, followed by the services sector. In absolute terms, industry is expected to remain the largest final consumer of electricity throughout the projection period, but its share in final electricity demand is projected to fall.

1. Demand refers to final consumption of electricity.

Figure 6.2: **Average Annual Growth in Electricity Demand by Region in the Reference Scenario**

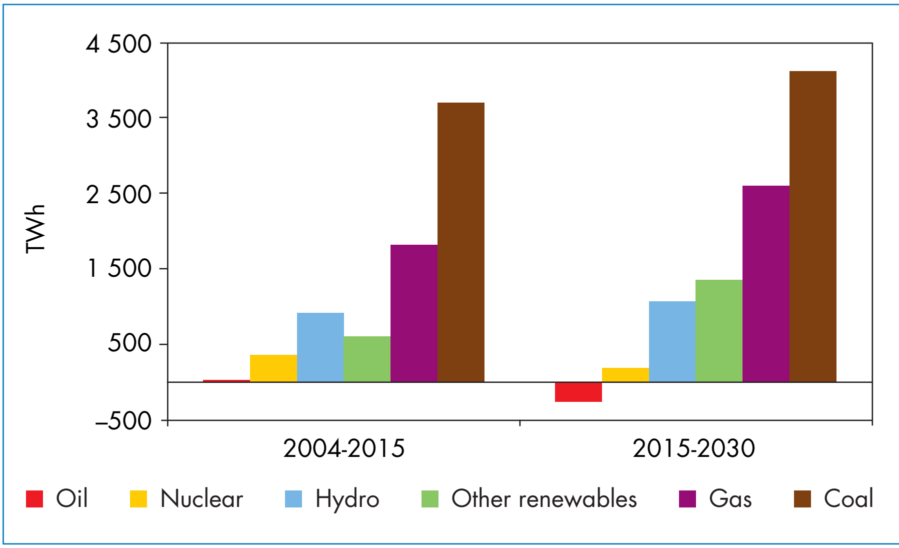
6

Power Generation Outlook

World electricity generation[2] almost doubles, from 17 408 TWh in 2004 to 33 750 TWh in 2030, in the Reference Scenario. The share of coal-fired generation in total generation increases from 40% now to 44% in 2030, while the share of gas-fired generation grows from 20% to 23%. Non-hydro renewable energy sources – biomass, wind, solar, geothermal, wave and tidal energy – continue to increase their market share, accounting for almost 7% of the total in 2030, up from 2% now. Oil use in power generation continues to shrink: its share in electricity generation drops to 3% by 2030. Hydropower accounts for a smaller share in 2030 than now. Nuclear power suffers the largest fall in market share, dropping from 16% in 2004 to 10% in 2030 (Figure 6.3).[3] Compared with the projections in previous *Outlooks*, the share of gas in 2030 is lower, while the shares of coal, nuclear and renewables are projected to be higher.

2. Electricity generation includes final demand, network losses and own use of electricity at power plants.
3. See also Chapter 13 for an analysis of nuclear power.

Figure 6.3: **World Incremental Electricity Generation by Fuel in the Reference Scenario**



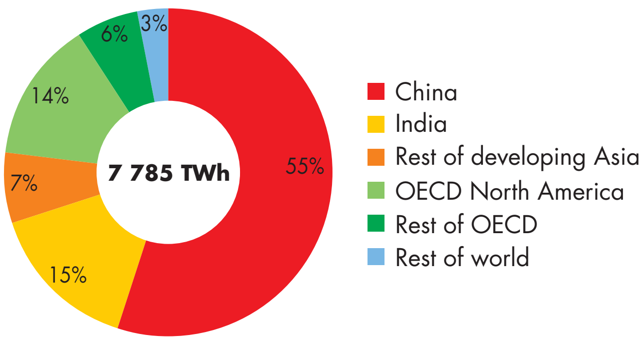
Coal-fired power plants produced 6 917 TWh in 2004, 40% of total world electricity output. Coal-fired generation is projected to reach 14 703 TWh in 2030. Most of the increase occurs in China, where strong demand for electricity continues to be met primarily by coal – the country's most abundant energy resource. Growth in coal-fired generation is also strong in India and in other developing Asian economies. Developing Asia as a whole accounts for more than three-quarters of the increase in coal-fired generation between now and 2030 (Figure 6.4). Worldwide, high natural gas prices are making coal-fired generation competitive again. A number of coal-fired power stations are now under construction in the United States and some companies have announced plans to build coal-based power plants in Europe.

Coal-fired generation technology has improved. New coal-fired power plants on the market now have efficiencies of up to 46%, compared to 42% in the early 1990s.[4] Efficiency is expected to improve further. Most new coal-fired power plants are expected to use conventional steam boilers, with the share of supercritical technology rising gradually. Integrated-gasification combined-cycle

4. On a net basis, using lower heating value (the heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapor and the heat is not recovered).

(IGCC) technology is expected to become increasingly competitive after 2015, reaching 46% efficiency in 2015 and 51% by 2030. Overall, 144 GW of IGCC capacity is expected to be commissioned during the projection period, more than half of it in the United States.

Figure 6.4: **Incremental Coal-Fired Electricity Generation by Region in the Reference Scenario, 2004-2030**



Natural gas-fired electricity generation is expected to more than double between now and 2030. The projected increase in gas-fired generation is more equally distributed between regions than coal. High natural gas prices are now expected to constrain demand for new gas-fired generation, but gas-fired generation carries a number of advantages that make it attractive to investors, despite high fuel prices. Combined-cycle gas turbines (CCGTs) will be used to meet base- and mid-load demand and the bulk of peak-load demand will be met by simple-cycle gas turbines. Gas turbines will also be used in decentralised electricity generation. Fuel cells using hydrogen from reformed natural gas are expected to emerge as a new source of distributed power after 2020, producing 1% of total electricity output in 2030.[5] Higher natural gas prices in the second half of the projection period make coal-fired generation more attractive for new plants.

Oil-fired electricity generation continues to lose market share, dropping from 7% of the world total in 2004 to just 3% by 2030. Oil continues to be used where gas is not available.

The share of *nuclear* power in world electricity generation is projected to drop from 16% in 2004 to 10% in 2030, despite an increase in nuclear power

5. Power generation from fuel cells is included in gas-fired power generation.

generating capacity from 364 GW in 2004 to 416 GW in 2030. Most of this increase occurs in Asia, notably in China, Japan, India and the Republic of Korea.

Hydropower output is projected to increase from 2 809 TWh in 2004 to 4 749 TWh by 2030, increasing at 2% year to year on average. The share of hydropower in total electricity generation continues its downward trend, falling from 16% to 14%. Only about 31% of the economic potential worldwide had been exploited by 2004. Most new hydropower capacity is added in developing countries, where the remaining potential is highest (Box 6.1). In the OECD, the best sites have already been exploited and environmental regulations constrain new development. Most of the increase in hydropower in the OECD occurs in Turkey and Canada. Some OECD countries provide incentives for small and mini hydropower projects.

Box 6.1: **Prospects for Hydropower in Developing Countries**

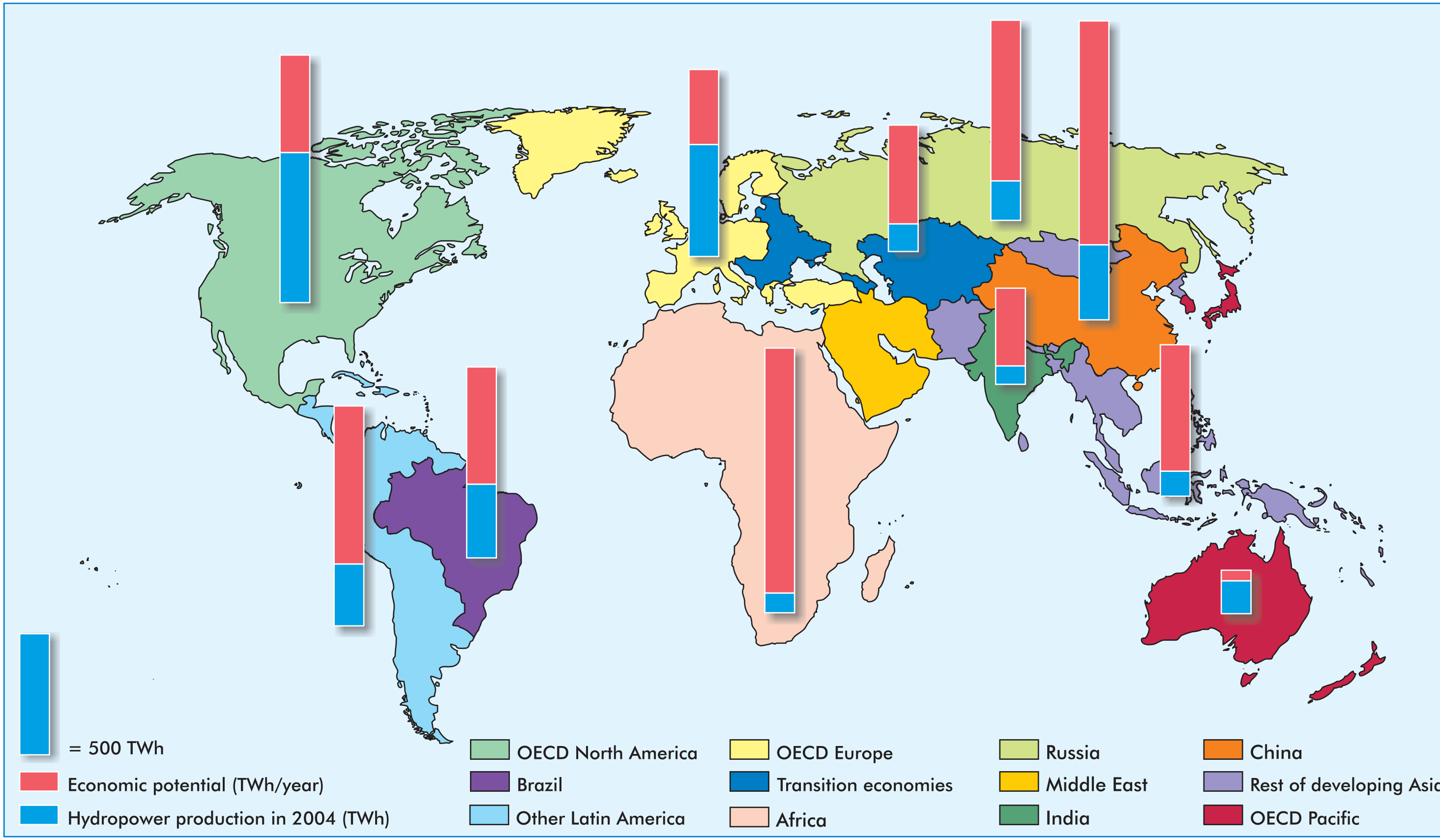
Over the past fifteen years, many large hydropower projects in developing countries have been adversely affected by concerns over the environmental and social effects of building large dams. Obtaining loans from international lending institutions and banks to finance such projects has become more difficult. Consequently, many projects have been delayed or cancelled. Five years ago, hydropower was the world's second-largest source of electricity; now it ranks fourth.

The remaining economic potential in developing countries is still very large (Figure 6.5). Several developing countries are focusing again on this domestic source of electricity, driven by a rapidly expanding demand for electricity, by the need to reduce poverty and to diversify the electricity mix. Support from international lenders and interest from the private sector is also growing.

There is a strong consensus now that countries should follow an integrated approach in managing their water resources, planning hydropower development in cooperation with other water-using sectors. There is significant scope for optimising the current infrastructure. The majority of reservoirs have been developed for water supply, primarily irrigation. Only about 25% of reservoirs worldwide have any associated hydropower facilities (WEC, 2004).

Properly managed, hydropower could help restrain the growth in emissions from burning fossil fuels. In Brazil, for example, where more than 80% of electricity is hydropower, the power sector accounts for just 10% of the country's total CO_2 emissions, four times less than the world average.

Figure 6.5: **World Hydropower Potential**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

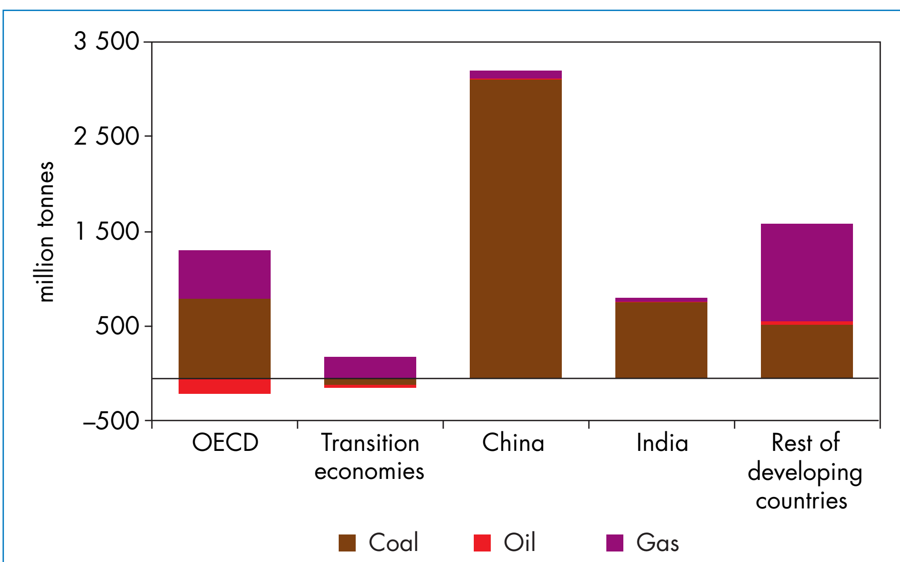
Sources: IEA databases; WEC (2004) for hydropower potential.

The share of *non-hydro renewable sources* in total electricity generation increases from 2% now to almost 7% by 2030. This increase occurs largely in OECD countries, though several developing countries are also adopting policies to increase the use of renewables, among them China. *Wind power* achieves the biggest increase in market share, from 0.5% now to 3.4% in 2030. The share of electricity generation from *biomass* increases from 1.3% to 2.4%. *Geothermal* power grows at 4.5% per year and its share increases from 0.3% to 0.5%. *Solar, tidal* and *wave* energy sources increase their contributions towards the end of the projection period.

Energy-Related CO_2 Emissions from Power Generation

In the Reference Scenario, world CO_2 emissions from power plants are projected to increase by two-thirds over the period 2004-2030, at a rate of 2% per year. Power generation is now responsible for 41% of global energy-related CO_2 emissions. This share rises to 44% in 2030, mainly because of the growing share of electricity in energy consumption. In developing countries, CO_2 emissions from this sector grow by 131%, while they increase by only 10% in transition economies and 25% in the OECD. China and India together account for 58% of the global increase in CO_2 from power generation over 2004-2030, because of their strong reliance on coal. In 2030, emissions from power plants in China and India will be greater than those from power plants in the OECD. Almost all of the increase in power-sector emissions in China and India combined can be attributed to coal-fired generation, as opposed to about a third in other developing countries and 70 % in the OECD (Figure 6.6).

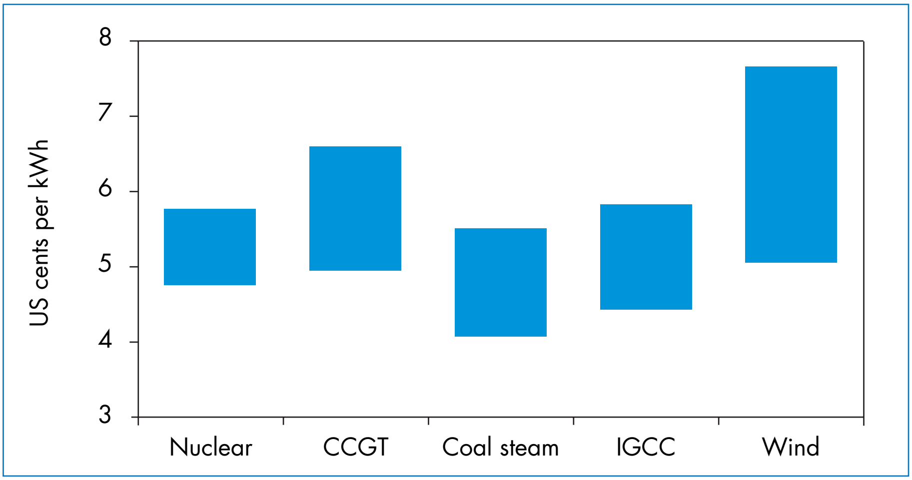
Figure 6.6: **Increase in Power-Sector CO_2 Emissions by Fuel in the Reference Scenario, 2004-2030**



The Economics of New Power Plants

Over the *Outlook* period, the main technologies available for large-scale baseload generation are expected to be CCGTs, coal steam, coal IGCC and nuclear and wind power.[6] The electricity generating costs of these technologies are shown in Figure 6.7, based on the technology expected to prevail over the next ten years and on gas prices of around \$6 to \$7 per MBtu. CCGTs are no longer expected to be the most competitive option for baseload electricity generation in most cases, reversing a trend seen in OECD markets since the early 1990s, based on earlier expectations of low gas prices of around \$3 per MBtu. The generating costs of CCGTs are now expected to be between 5 cents and 7 cents per kWh, while the generating costs of coal-fired plants are expected to range between 4 cents and 6 cents per kWh.

Figure 6.7: **Electricity Generating Cost Ranges of Baseload Technologies**



Note: The ranges of capital and fuel costs largely reflect regional differences. *Capital costs* range as follows: \$2 000 to \$2 500 per kW for nuclear; \$550 to \$650 per kW for CCGT; \$1 200 to \$1 400 per kW for coal steam; \$1 400 to \$1 600 per kW for IGCC and \$900 to \$1 100 per kW for onshore wind. *Fuel cost* ranges are \$0.4 to \$0.6 per MBtu for nuclear; \$5 to \$7 per MBtu for gas and \$40 to \$70 per tonne for coal. Wind average capacity factor ranges from 25% to 32%.

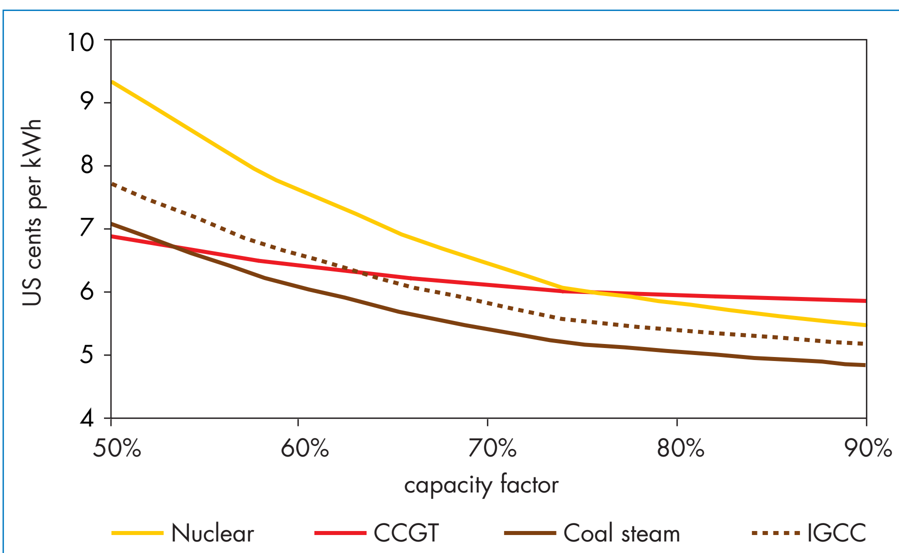
Coal-fired generation is now competitive in the US market and several coal-fired power plants are under construction or in the planning process. New gas-fired generation is constrained in the United States by high gas prices and

6. Wind power cannot be compared directly with traditional baseload technologies because of its variable nature. It is, however, useful to include it in the comparison of generating costs as it is becoming increasingly significant in several countries' electricity mix.

by insufficient LNG infrastructure. In many cases, the generating cost of new coal steam plants is not only lower than the generating cost of CCGTs but also lower than the cost of gas, which represents more than three-quarters of total CCGT generating costs. IGCC plants are not yet competitive. There are several projects now under construction or planned in the United States (16 GW, or about one-fifth of total planned coal-fired capacity), supported by government incentives. Their competitiveness is expected to improve over time along with technical improvements, capital cost reductions and stricter limits on conventional pollutants. In the OECD Pacific region, coal steam technology is generally the most competitive option.

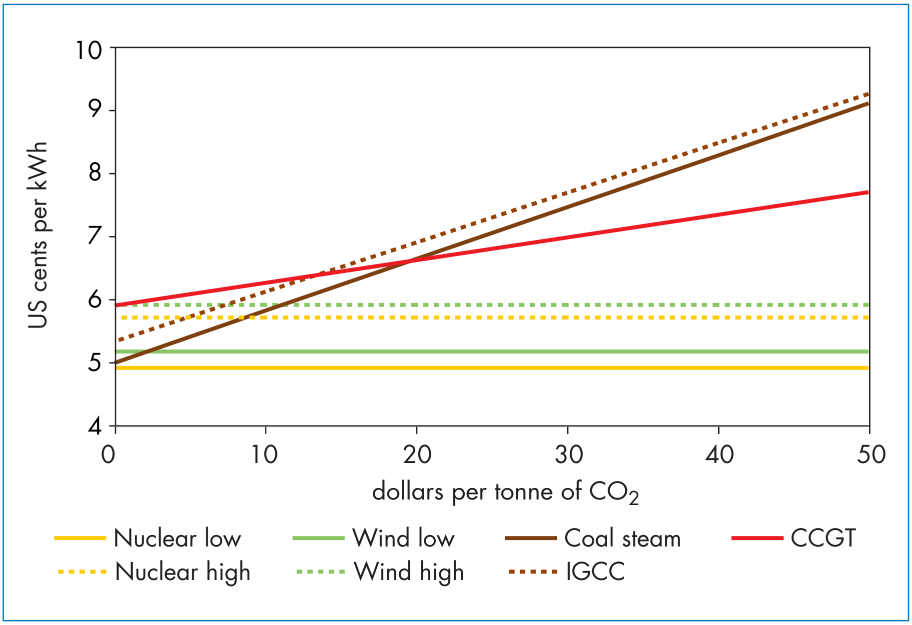
In Europe, coal-fired generation now appears to be cheaper than gas-fired generation. The difference between the two is less pronounced than in the United States, because European coal prices, on average, are about twice as high and gas prices somewhat lower. Most power plants now under construction or planned to be built over the next few years are CCGTs. In liberalised markets, the operating flexibility of CCGTs makes them an attractive choice. For CCGTs, fixed costs make up a lower proportion of total costs than is the case for coal and nuclear plants, so that the generating costs are less affected by a low capacity factor (Figure 6.8). CCGT plants can be built relatively quickly, usually in about three years and sometimes less. Expectations about stricter CO_2-emission regulations favour gas rather than coal. This trend is expected to change gradually, in favour of coal, as concerns grow over the security of gas supply. Plans to build new coal-fired power plants in some European countries are growing.

Figure 6.8: **Impact of Capacity Factor on Generating Costs**



Wind power generation is generally more expensive than coal and – to a lesser extent – than gas, but it can be competitive in certain locations. Incentives are widely available for development of wind farms and these are expected to continue to be available. Nuclear power is projected to be cheaper than gas-fired generation but more expensive than coal. The introduction of a carbon value would increase the costs of coal-fired generation and, to a lesser extent, of CCGT generation, making nuclear and wind power more attractive economically (Figure 6.9).

Figure 6.9: **Impact of Carbon Value on Generating Costs**



Note: Nuclear capital costs range between $2 000 and $2 500 per kW, reflecting uncertainties about the costs of new nuclear power plants (see also Chapter 13). Differences in wind power costs reflect different capacity factors.

Capacity Requirements and Investment Outlook

Over the *Outlook* period, a total of 5 087 GW of generating capacity is projected to be built worldwide in the Reference Scenario. More than half of this capacity is in developing countries (Table 6.1). OECD countries need over 2 000 GW. Power plants in OECD countries are ageing. Retirements of old coal-fired and nuclear plants become significant around the middle of the next decade. Most of these retirements are in OECD Europe, where environmental restrictions will force old and inefficient coal-fired units to close and present phase-out policies require 27 GW of nuclear power plants to be retired prematurely. Developing countries need to build some 2 700 GW of capacity, of which two-thirds will be in developing Asia. China alone builds almost 1 100 GW. China has recently been adding 50 GW to 70 GW of new capacity every year. Over the projection period, this rate is expected to average around 40 GW per year. China needs to build more capacity than any other country or region.

Table 6.1: **New Electricity Generating Capacity and Investment by Region in the Reference Scenario, 2005-2030**

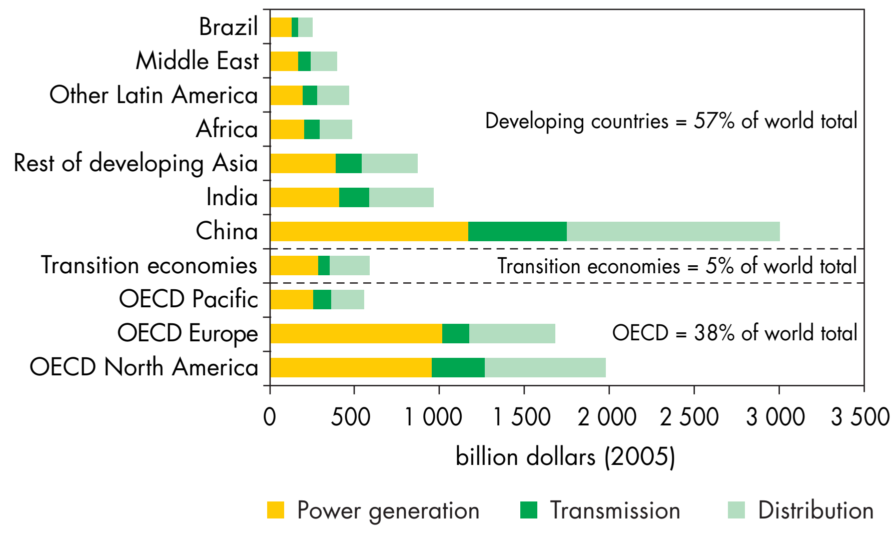
	Capacity additions* (GW)	**Investment in electricity sector** ($ billion) Generation	Transmission	Distribution	Total
OECD	**2 041**	**2 248**	**578**	**1 414**	**4 240**
North America	932	953	314	711	1 979
United States	*750*	*794*	*249*	*567*	*1 609*
Europe	928	1 014	159	507	1 680
Pacific	181	281	105	196	582
Japan	*65*	*129*	*47*	*82*	*259*
Transition economies	**329**	**285**	**67**	**237**	**590**
Russia	*153*	*149*	*25*	*88*	*263*
Developing countries	**2 717**	**2 653**	**1 196**	**2 598**	**6 446**
Developing Asia	1 824	1 965	908	1 974	4 847
China	*1089*	*1 170*	*579*	*1 258*	*3 007*
Indonesia	*84*	*83*	*33*	*71*	*187*
India	*330*	*408*	*176*	*383*	*967*
Middle East	335	166	73	158	396
Africa	216	203	89	193	484
North Africa	*73*	*154*	*29*	*62*	*246*
Latin America	342	320	126	274	719
Brazil	*98*	*127*	*39*	*86*	*252*
World	**5 087**	**5 186**	**1 841**	**4 249**	**11 276**
European Union	*862*	*925*	*137*	*429*	*1 491*

* Includes replacement capacity.

Total power-sector investment over 2005-2030, including generation, transmission and distribution, exceeds $11 trillion (in year-2005 dollars). Some $5.2 trillion of investment is required in generation, while transmission and distribution networks together need $6.1 trillion, of which more than two-thirds goes to distribution. The largest investment requirements, some

$3 trillion, arise in China. Investment needs are also very large in OECD North America and Europe (Figure 6.10). Investment to replace currently operating capacity accounts for over 40% of total investment in the OECD and over 50% in transition economies, but it is a very small share of total investment in developing countries (Figure 6.11).

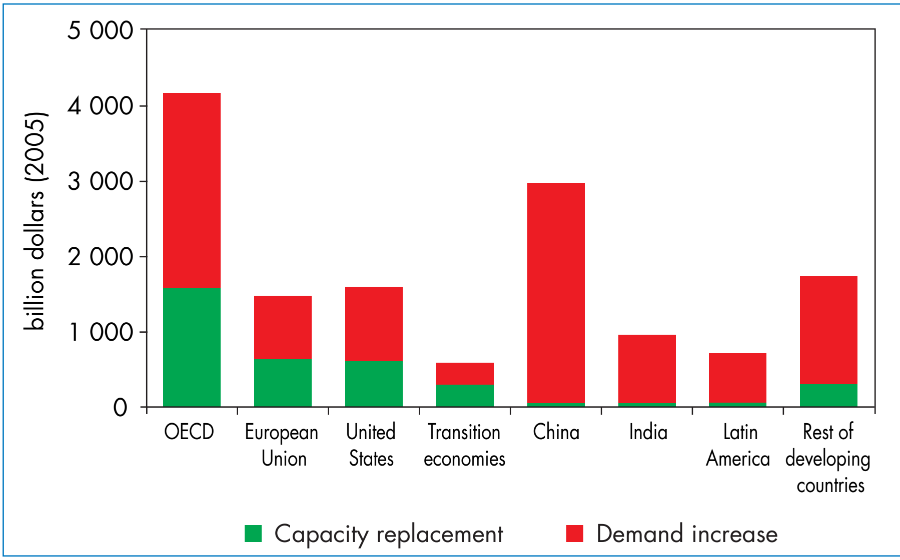
Figure 6.10: **Cumulative Power-Sector Investment by Region in the Reference Scenario, 2005-2030**



Box 6.2: **Siting New Power Infrastructure**

Over the next 25 years, the *Outlook* projects a need for substantial new investment in generation and transmission. But in many countries, particularly in the OECD, siting new power plants or transmission lines has become very difficult. Nuclear and coal-fired plants, wind farms and hydropower stations, all face stiff opposition. Many hydropower projects in developing countries have been delayed or abandoned (see Box 6.1). In the United States, several of the many newly proposed coal-fired power plants have already been challenged. Building onshore wind turbines is widely opposed. Transmission networks are even more unpopular. It is more than possible that much of the required new capacity will not be built in time.

Figure 6.11: **Cumulative Power-Sector Investment by Type in the Reference Scenario, 2005-2030**



Power Generation Investment Trends in the OECD

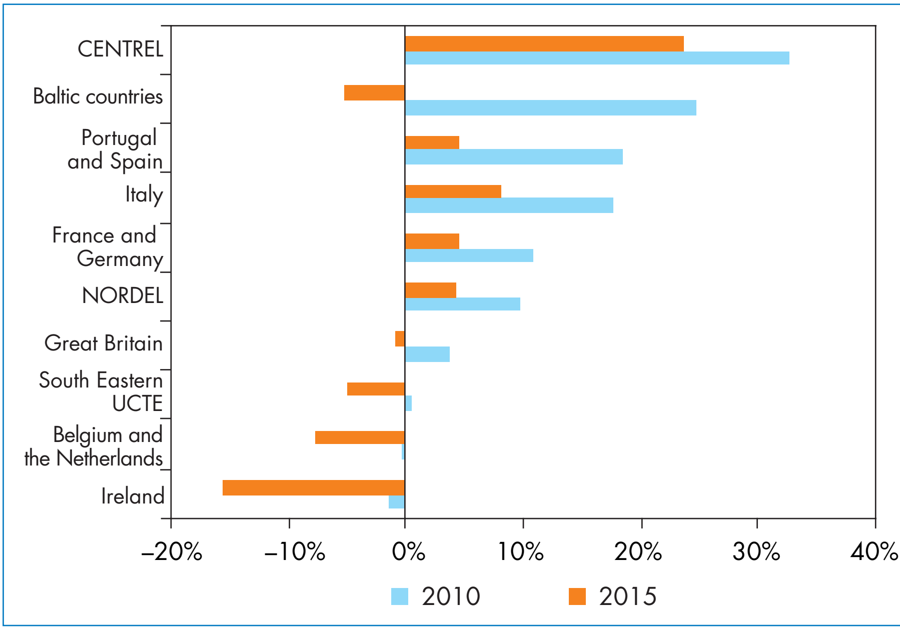
Electricity capacity reserve margins are declining in most OECD countries signalling the need for new investment.[7] The supply disruptions in parts of North America and Europe in summer 2006 have raised again questions about the adequacy of generation margins and investment in network infrastructure.

Reserve margins are expected to fall in most European countries. They are expected to remain adequate in at least France, Germany, Italy, Spain, Portugal and Central Europe over the period 2006-2010 (Figure 6.12). Spare capacity will be insufficient in Ireland, Belgium and the Netherlands, although existing interconnections can help improve security of supply. For the period 2010-2015, additional capacity must come on line everywhere to meet demand. Up to 2010, almost all new power plants are expected to be CCGTs or wind farms, but recent increases in gas prices have led a number of power companies to indicate that they plan to build coal-fired power stations, despite the existence of the European Union's Emissions Trading Scheme (ETS). Licensing procedures are becoming increasingly complicated and their outcomes unpredictable.

7. The reserve margin is the percentage of installed capacity in excess of peak demand. Differences in plant margin requirements reflect the nature of the different systems considered - factors such as interconnection capacity with neighbouring systems, transmission constraints, the frequency of peak loads, and the generation mix affect the required plant margin.

Plant retirements are expected to increase, but the extent is uncertain, as power companies do not have to report their retirements to the network operators long in advance. The ETS, together with the EU's Large Combustion Plant Directive (which requires power plants over 50 MW to comply with emission limit values for sulphur dioxide, nitrogen oxides and particulates), may make some power plants uneconomical – particularly older coal-fired power stations – forcing early retirement. On the assumption that Belgium, Germany and Sweden proceed with their nuclear phase-out policies, nuclear power plant retirements in these countries amount to 13 GW in the period 2005-2015 in the Reference Scenario.

Figure 6.12: **European Generation Margins**

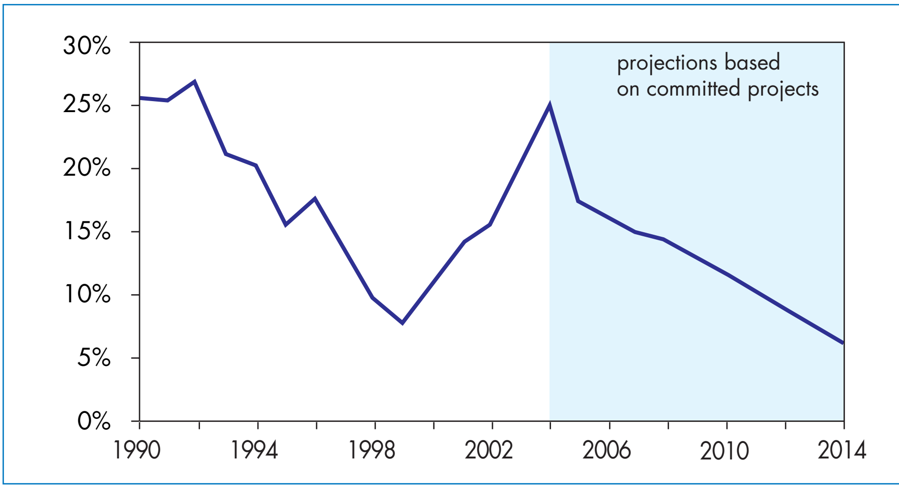


Notes: Only projects under construction or planned, but with a high degree of certainty that they will be built, are included. Data are for winter peak load. UCTE is the association of transmission system operators (TSOs) in continental Europe. CENTREL is the association of TSOs of the Czech Republic, Hungary, Poland and Slovakia. NORDEL is the association of TSOs in the Nordic countries (Denmark, Iceland, Finland, Norway and Sweden).
Sources: ETSO (2006) and UCTE (2005).

Growth in high-voltage transmission lines has been slow in a number of countries, though power companies in some, including the United Kingdom and Germany, have recently announced that they plan to increase spending on networks. Since peak demand does not occur simultaneously in all countries, interconnections can contribute to system security and lower overall costs.

Increasing interconnection capacity between European countries is one of the objectives of European market integration. But building new interconnections is a major challenge in some areas because of local opposition or, sometimes, because no clear arrangements yet exist to share costs between the different system operators. The uneven increase in wind power generation tends to reduce the availability of cross-border transmission capacity (European Commission, 2005).

Figure 6.13: **US Capacity Reserve Margins**



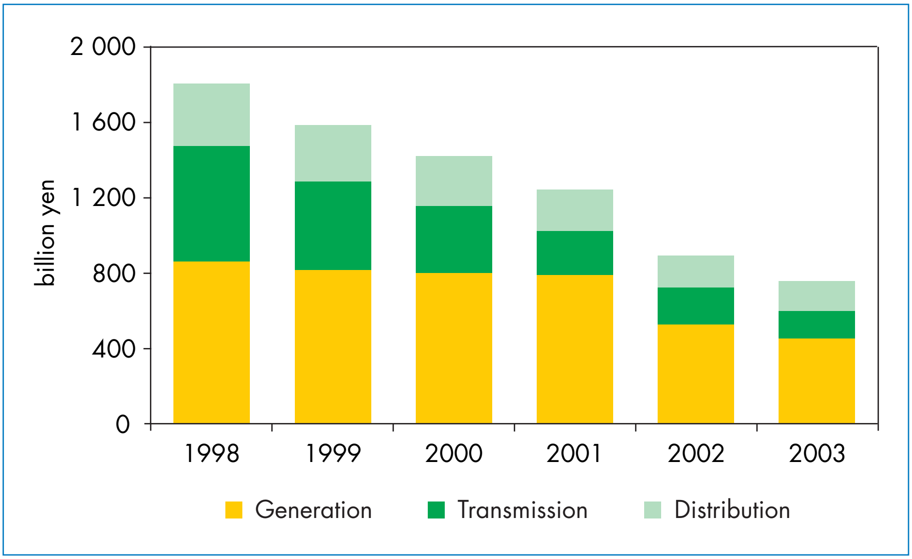
Source: North American Electric Reliability Council (2005).

In the United States, system capacity reserve margins increased substantially after 1999 (Figure 6.13). Between 2000 and 2004, new capacity of nearly 200 GW was built, mainly CCGT plants, which increased margins across the country from 7.6% in 1999 to 24.8% in 2004. Yet, strong demand growth is now reducing these margins, even though a total of 82 GW of additional capacity is expected to come on line in the United States by 2009. Over 60% of this capacity will be gas-fired (DOE/EIA, 2005). Up to 13 GW of coal-fired capacity could be built in this period. Some of these new projects are facing environmental opposition; if their construction is delayed, electricity supply could become tight over the next five years. Many states have introduced renewable portfolio standards to encourage the contribution of renewables, but new construction is likely to depend on the extension of the production tax credit, which expires at the end of 2007. This could have a negative impact on electricity supply.

Reserve margins vary widely across the United States. They are tight in some areas, notably in California and Texas. Gas-fired generation makes up a significant proportion of total US capacity so that electricity supply can be tight when gas supply is tight, particularly in periods of cold weather because of competing demand for gas for heating. Investment in transmission networks, which was at historically low levels in the late 1990s, has been increasing recently. However, some parts of the network may approach their operational limits as demand increases (NERC, 2005).

In Japan, investment in both power generation and network infrastructure has been declining in recent years (Figure 6.14). The intention is to hold reserve margins stable at around 10% after 2010. About 16.5 GW of generating capacity is now under construction, mainly gas-fired, coal-fired and nuclear power plants. A total of 28 GW is planned for the period to 2015.

Figure 6.14: **Japan Power-Sector Investment, 1998 to 2003**



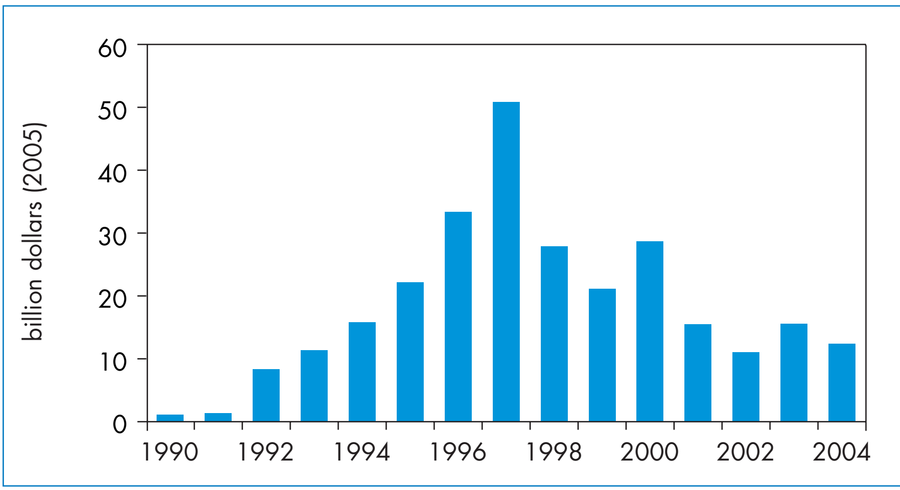
Note: Expansion investment only. Figures do not include investment in transformation and supply.
Source: FEPC (2005).

Investment Trends in Developing Countries

Trends in Private Investment

In the 1990s, many developing countries initiated electricity-sector reforms aimed at attracting private investment. Total private-sector investment in electricity between 1990 and 2004 in these countries amounted to $276 billion (in year-2005 dollars). These reforms attracted a strong initial response from the private sector, but private investment declined rapidly after 1997 (Figure 6.15). The reasons included poor design of the economic reforms, under-pricing of electricity, adverse exchange-rate movements, economic recession and more cautious business judgments. Many private companies have since sold their assets in developing countries, resulting in a sharp reduction in the number of active international investors. Investment rebounded in 2000, reaching $29 billion, but has since been fluctuating around $10 billion to $15 billion, only about 30% of the peak in 1997.

Figure 6.15: **Private Investment in Electricity Infrastructure in Developing Countries, 1990-2004**

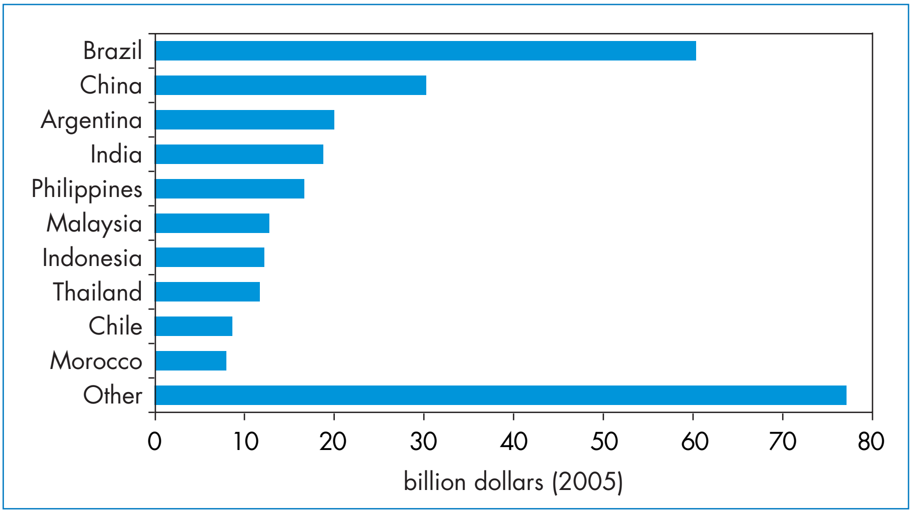


Source: World Bank Private Participation in Infrastructure (PPI) database.

Over the past decade, most private investment in electricity has gone into power generation, either into individual power plants or independent power producers. The bulk of the remaining investment has been made mainly in the distribution sector. Initially, most private investment went into the acquisition of existing facilities. But in the past few years, investment in greenfield projects has predominated (World Bank, 2005).

Over the period 1990-2004, private activity was selectively directed to projects in a few large developing economies, such as Brazil, China, Argentina and India. Out of nearly a hundred countries in total, the top ten received $200 billion, or 72% of the total. Brazil alone received $60 billion, accounting for more than one-fifth of the total private investment flow to developing countries (Figure 6.16). From 1990 to 2004, the low-income countries received only about $36 billion (about 14% of the total), while the lower-middle income countries and upper- to middle-income countries (as classified by the World Bank) received $116 billion (42%) and $122 billion (44%) respectively. In 2004, Brazil, India, Malaysia and Thailand were the largest recipients of private investment. Power plants accounted for three-quarters of investment in the sector, followed by transmission facilities and distribution companies.

Figure 6.16: **Cumulative Private Investment in Electricity Infrastructure in Developing Countries, 1990-2004**

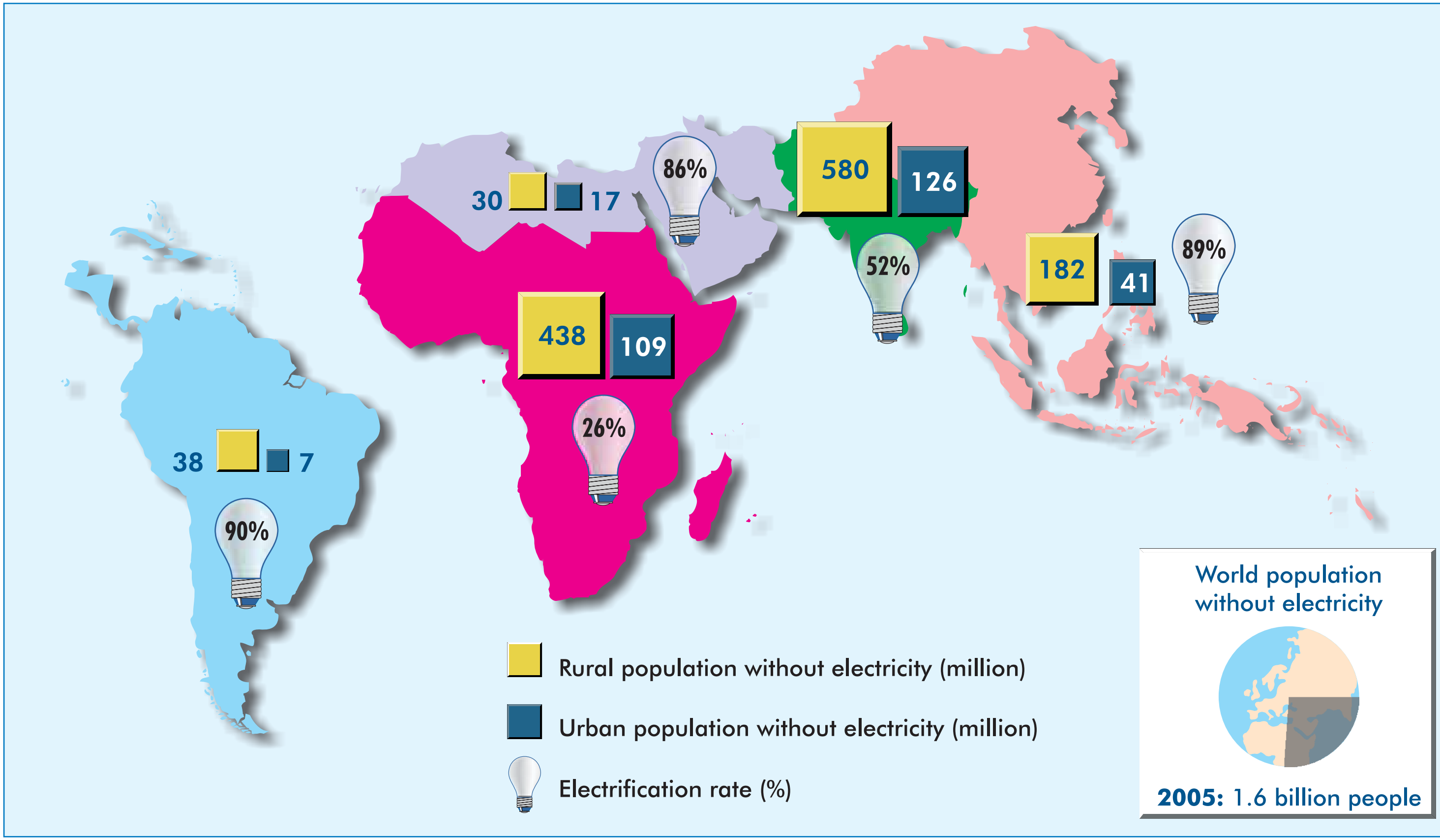


Source: World Bank PPI database.

The type of company pursuing infrastructure projects is also changing. Early investors, such as AES, EDF and Suez, have scaled back their investment in developing countries (World Bank, 2004). Corporations based in developing countries have emerged as important sponsors, with four of them ranking among the top ten investors in 2001-2004: Malakoff (Malaysia), China Light and Power (Hong Kong, China), Banpu (Thailand), and Sasol (South Africa). In India, local investors have been responsible for the recent revival of private activity in electricity.

Financing power generation in developing countries, particularly in the poorer of them, is a key challenge. The investment gap can be filled only by internal cash generation or increased private-sector financing. Both require significant improvements in governance and continued restructuring and reform. The gap between needs and investment is likely to remain in the worst-affected countries, deferring the timescale for widespread access to electricity.

Figure 6.17: **Population without Electricity, 2005**



Access to Electricity

The number of people without electricity today stands at around 1.6 billion, equal to over a quarter of the world population.[8] Electrification is very unevenly distributed worldwide.[9] Sub-Saharan Africa and South Asia are the regions with the highest proportion of the population still without access to electricity, both in urban and rural areas (Figure 6.17). With less than 7% of their population having access to electricity, Burkina Faso, Mozambique, the Democratic Republic of Congo and Afghanistan are the least electrified countries in the world.

Overall, 80% of those without access to electricity currently live in rural areas of developing countries. In the last 15 years, the number of people without electricity has fallen from 2 billion in 1990 to 1.6 billion in 2005, with China recording the swiftest progress. Excluding China, the number of people without electricity has steadily grown over the past 15 years. Because of continuing population growth, if no new policies are put in place, there will still be 1.4 billion people lacking access to electricity in 2030. To reach the Millennium Development Goals, this number would need to fall to less than one billion by 2015.

8. The electrification database has been updated since *WEO-2004* to take into account a number of factors, in particular rapid population growth outrunning the electrification process in the poorest countries, especially in sub-Saharan Africa.
9 See Annex B for detailed data on electrification by country.

PART B

THE ALTERNATIVE POLICY SCENARIO

MAPPING A NEW ENERGY FUTURE

HIGHLIGHTS

- The Alternative Policy Scenario analyses how the global energy market could evolve if countries were to adopt all of the policies they are currently considering related to energy security and energy-related CO_2 emissions. The aim is to understand how far those policies could take us in dealing with these challenges and at what cost.
- These policies include efforts to improve efficiency in energy production and use, increase reliance on non-fossil fuels and sustain the domestic supply of oil and gas within net energy-importing countries. They yield substantial savings in energy consumption and imports compared with the Reference Scenario. They thereby enhance energy security and help mitigate damaging environmental effects. Those benefits are achieved at lower total investment cost than in the Reference Scenario.
- World primary energy demand in 2030 is about 10%, or 1 690 Mtoe, lower in the Alternative Policy Scenario than in the Reference Scenario – roughly equivalent to China's entire energy consumption today. The impact of new policies is felt throughout the period; already in 2015, the difference between the two scenarios is 4%, or 534 Mtoe.
- The policies analysed halt the rise in OECD oil imports by 2015. OECD countries and developing Asia become more dependent on oil imports in 2030 compared to today, but markedly less so than in the Reference Scenario. Global oil demand reaches 103 mb/d in 2030 in the Alternative Policy Scenario – an increase of 20 mb/d on 2005 levels but a fall of 13 mb/d compared with the Reference Scenario. Globally, gas demand and reliance on gas imports are also reduced below the levels of the Reference Scenario.
- Energy-related CO_2 emissions are cut by 6.3 Gt, or 16%, in 2030 relative to the Reference Scenario and already 1.7 Gt, or 5%, by 2015. OECD emissions peak by around 2015 and then decline. Emissions in Japan and the European Union in 2030 are lower than 2004 levels. Global emissions nonetheless continue to rise, from 26 Gt in 2004 to 32 Gt in 2015 and 34 Gt in 2030.

- Policies encouraging more efficient production and use of energy contribute almost 80% of the avoided CO_2 emissions in 2030, the remainder arising from fuel switching. More efficient use of fuels, mainly through improved efficiency of cars and trucks, accounts for almost 36%. More efficient use of electricity in a wide range of applications, including lighting, air-conditioning, appliances and industrial motors accounts for 30%. Greater efficiency in energy production accounts for 13%. Renewables and biofuels contribute another 12% and nuclear the remaining 10%.

Background

Why an Alternative Policy Scenario?[1]

The Reference Scenario presents a sobering vision of how the global energy system could evolve in the next two-and-a-half decades. Without new government measures to alter underlying energy trends, the world consumes substantially more energy, mostly in the form of fossil fuels. The consequences for energy security and emissions of climate-altering greenhouse gases are stark. The major oil- and gas-consuming regions – including those that make up the OECD – become even more reliant on imports, often from distant, unstable parts of the world along routes that are vulnerable to disruption. Sufficient natural resources exist to fuel such long-term growth in production and trade, but there are formidable obstacles to mobilising the investment needed to develop and use them. The projected rate of growth in fossil-fuel consumption drives up carbon dioxide (CO_2) and other greenhouse-gas emissions even more quickly than in the past.

Policy-makers and the energy industry alike have increasingly acknowledged over the last few years the twin threats to energy security and global climate change. They accept the need for urgent action to address these threats. In July 2005, G8 leaders, meeting at Gleneagles with the leaders of several major developing countries and heads of international organisations, including the IEA, recognised that current energy trends are unsustainable and pledged themselves to resolute action to combat rising consumption of fossil fuels and related greenhouse-gas emissions. They called upon the IEA to, "advise on alternative energy scenarios and strategies aimed at a clean, clever, and competitive energy future".[2] The analysis presented in this part of the *WEO* is

1. The preparation of the Alternative Policy Scenario in this *Outlook* benefited from a high-level informal brainstorming meeting held at the IEA headquarters in Paris on 15 March 2006.
2. Gleneagles G8 Summit Communiqué, page 3. Available at: www.iea.org/G8/g8summits.htm.

one of the IEA's responses to that request, which the G8 reaffirmed in July 2006 at its summit in St. Petersburg.

The Alternative Policy Scenario[3] presented in the 2004 edition of the *Outlook* analysed how the global energy market could evolve if countries around the world were to adopt a set of policies and measures that they were then considering and might be expected to implement over the projection period. The aim was to provide a clear picture of how far policies and measures then under discussion could take us in dealing with energy-security and climate-change challenges.

This edition of the *Outlook* deepens and broadens that analysis. In particular, it takes a step further by offering guidance to policy-makers about the cost-effectiveness of policy options. To offer guidance on near-term policies, as well as on trends through to 2030, information is provided for the year 2015. Full details of the results of the analysis are presented in tabular form in Annex A, the first such complete presentation in the *World Energy Outlook* series.

Preparation for the Alternative Policy Scenario in this *Outlook* involved detailed quantitative assessments of the impact of different policies and measures. The range of policies assessed was broader than that for *WEO-2004*, reflecting in particular the heightened global interest in threats to energy security. Sectoral detail is provided on the effects of specific policies and measures in each region, so as to help policy-makers identify the actions that could work best and quickest for them and at what cost. Detailed country-by-country and sector-by-sector results are presented for energy savings and CO_2 emissions reductions. A comprehensive economic assessment also quantifies the investment requirements on both the supply and demand sides and the cost savings from reduced energy consumption. Greater attention is given to China, India and other developing countries because of their growing significance in the overall picture.

The first part of this chapter summarises the background to the Alternative Policy Scenario, including the methodological approach and key assumptions. This is followed by an overview of the resulting global energy trends, including a detailed analysis of fossil-fuel supply and the implications for inter-regional trade and energy-related CO_2 emissions. Chapter 8 sets out the economic costs and benefits of the Alternative Policy Scenario.

Chapter 9 analyses, sector by sector, the effects on energy demand and CO_2 emissions of the policies and measures included. Chapter 10 discusses what will be involved in implementing the policies of the Alternative Policy Scenario and

3. The Alternative Policy Scenario was first introduced in *WEO-2000*. Subsequent *WEO* editions expanded the regional, sectoral and technology coverage of the scenario: *WEO-2002* extended the analysis to all transformation and end-use sectors in OECD regions. The analysis in *WEO-2004* covered for the first time all world regions.

the additional policies and technological developments that would be needed in order to create by 2030 an energy outlook which could more properly be described as sustainable.

Methodology

The Alternative Policy Scenario takes into account policies and measures that countries are currently considering and are assumed to adopt and implement, taking account of technical and cost factors, the political context and market barriers. Only policies aimed at enhancing energy security and/or addressing climate change have been considered. Though their cost-effectiveness is discussed in Chapter 8, they have not been selected on a scale of economic cost-effectiveness: they reflect the proposals under discussion in the current energy policy debate.

An extensive effort has been made to update and substantially expand the list of energy-related policies and measures compiled for the Alternative Policy Scenario analysis of *WEO-2004*. The list now includes more than 1 400 policies from both OECD and non-OECD countries.[4] The first step was to distinguish those policies and measures that have already been adopted (taken into account in the Reference Scenario), from those which are still under consideration. Items on the second list were then scrutinised to enable a judgment to be made as to which of them were likely to be adopted and implemented at some point over the projection period in the country concerned.

Several new policies have been developed or proposed since *WEO-2004*. Each policy has been carefully scrutinised and analysed to verify that it genuinely belongs to the category of policies for inclusion in the Alternative Policy Scenario. No country is assumed to adopt policies that it does not have under consideration, even though they may be under consideration elsewhere. One country might, however, benefit incidentally (for example from technological advancements stimulated by another country's policies).

The modelling of the impact of the new polices on energy demand and supply involved two main steps. For each of the policies considered, it was first necessary to assess quantitatively their effects on the main drivers of energy markets. The second step involved incorporating these effects into the World Energy Model[5] (WEM) to generate projections of energy demand and supply, related CO_2 emissions, and investments. As many of these policies have effects

4. The updated list of policies, including proposed implementation dates and impacts on the energy sector can be found at www.worldenergyoutlook.org. Policy data are available not only for the OECD countries but also for developing countries, including China, India and Brazil.

5. A detailed description of the WEM, a large-scale mathematical model, can be found at www.worldenergyoutlook.org

at a micro-level, it was necessary to incorporate detailed "bottom-up" sub-models of the energy system into the WEM, allowing all policies to be analysed within a coherent and consistent modelling framework. These sub-models explicitly take account of the energy efficiency of specific technologies, as well as the activities that drive energy demand and the physical capital stock of energy-using equipment. The rebound effect on energy demand of introducing more efficient energy-consuming goods is also modelled.

Estimates of the rate of replacement of capital stock play a vital role in determining the overall effectiveness of policies on both the demand side and the supply side. The very long life of certain types of energy capital goods limits the rate at which more efficient technology can penetrate and reduce energy demand. The detailed capital stock turnover rates embedded in the sub-models capture these effects.

The policies of the Alternative Policy Scenario are expected to result in the faster development and deployment of more efficient and cleaner energy technologies. Although most technological advances will be made in OECD countries, non-OECD countries will be able to benefit from them. As a result, global energy intensity falls more rapidly in this scenario than in the Reference Scenario.

It is important to bear in mind that the projected energy savings and reductions in CO_2 emissions do not reflect the ultimate technical or economic potential. Even bigger reductions are possible; but they would require efforts that go beyond those currently enacted or proposed. Such additional efforts could further enhance the penetration of existing advanced technologies and lead to the introduction of additional new technologies in the energy sector.

Policy Assumptions

Over the past two years a series of supply disruptions, geopolitical tensions and surging energy prices have renewed attention on energy security. Notable events include the Russian-Ukrainian natural gas price dispute at the beginning of 2006, which led to natural gas supplies to Western and Central Europe being temporarily curtailed; hurricanes of unprecedented destructiveness in the Gulf of Mexico in 2005, which knocked out oil and gas production facilities; civil unrest in Nigeria, which curbed oil output; nationalisation of hydrocarbon resources in Bolivia; and the discovery of corrosion in the trans-Alaskan oil pipeline, causing its temporary closure, in August 2006.

These developments have prompted policy responses in many countries. In his annual State of the Union address in January 2006, President Bush announced new measures for improving energy efficiency and for promoting indigenous fossil-fuel and renewable energy sources,[6] an address followed by many initiatives at State level. In March 2006, the European Commission released a green paper addressing energy security (EC, 2006). In May 2006, Japan released the New National Energy Strategy which has energy security as its core (METI, 2006). The UK government has released an energy review to reinforce the United Kingdom's long-term energy policy in the face of the mounting threat to the global climate and to energy security (DTI, 2006).

Several countries have declared their intention to step up production of biofuels (Chapter 14). Others have announced plans to revive investment in nuclear power (Chapter 13). Interest in policies to improve energy efficiency and to boost the role of renewables has grown. Although high energy prices and considerations of energy security are the principal drivers of these developments, their policy design is invariably influenced by the implications for greenhouse-gas emissions – especially in OECD countries.

There have also been important developments in the field of climate-change policy since 2004. The Kyoto Protocol entered into force on 16 February 2005. All Kyoto Protocol Annex B countries have taken concrete steps to meet their commitments, although the measures adopted have, so far, met with varying degrees of success. A notable measure, the EU Greenhouse Gas Emissions Trading Scheme, which involves capping the emissions of electricity generation and of the major industrial sectors and the trading of emission allowances, came into operation in January 2005.

Australia, India, Japan, China, the Republic of Korea and the United States agreed in January 2006 to co-operate on the development and transfer of technology to enable greenhouse-gas emissions to be reduced. Under this agreement, known as the Asia-Pacific Partnership on Clean Development and Climate (AP6), member countries are working with private-sector partners in several industry and energy sectors to voluntarily reduce emissions.

The new policy environment is reflected in the increased number and breadth of the policies and measures that have been analysed beyond those in the Alternative Policy Scenario of *WEO-2004*. A selective list of policies included this time is provided in Table 7.1. The list, which is far from exhaustive, offers a general sense of the geographical and sectoral coverage of the policies. As with the Reference Scenario, a degree of judgment is inevitably involved in translating those proposed policies into formal assumptions for modelling. Box 7.1 illustrates how one policy is categorised and modelled. The main policies incorporated in the Alternative Policy Scenario by sector are detailed in Chapter 9.

6. The text of the 31 January 2006 State of the Union address by President Bush can be found at http://www.whitehouse.gov/stateoftheunion/2006/index.html

Box 7.1: **New Vehicle Fuel Economy in the United States**

The fuel economy of new cars and light trucks in the United States is regulated by Corporate Average Fuel Economy (CAFE) standards. These were first enacted by Congress in 1975, with the purpose of reducing energy consumption. CAFE standards are the responsibility of the Department of Transport (DOT) and the Environmental Protection Agency (EPA). DOT sets standards for the cars and light trucks sold in the United States, while EPA calculates the actual average fuel economy for each manufacturer.[7] The standards for passenger cars have remained practically unchanged since 1985 at 27.5 miles per gallon (mpg). Light truck standards have been increased by about 1 mpg since 1985. However, the fuel economy of the light-duty vehicle fleet as a whole has now dropped to 21 mpg from its 1987-1988 high of 22.1 mpg (EPA, 2006). This is due to the growing share of less-efficient but popular sports utility vehicles, which are classified as light trucks, but are increasingly used as passenger vehicles (ACEEE, 2006).

In the Reference Scenario, no change in CAFE standards is assumed during the projection period. Average fuel economy is nonetheless assumed to improve very slightly, by 2.5% between now and 2030 in that scenario. The Alternative Policy Scenario assumes the implementation of the reform of CAFE standards proposed by the National Highway Traffic Safety Administration (NHTSA), and the introduction in California of the California Air Resources Board (CARB) emission standards for light-duty vehicles. The NHTSA proposal, made in August 2005, would restructure CAFE standards for light trucks, resulting in significantly tighter standards overall, which would be fully operational for model years from 2011. On the strength of this reform, the average light truck fleet would be 14% more efficient than today even in 2010. CARB standards set CO_2 emissions targets for all vehicles sold in California: models sold in 2016 are expected to emit 30% less CO_2 than today.[8] Both CAFE and CARB standards are assumed to be met and prolonged in the Alternative Policy Scenario. As a result, new vehicle average fuel economy in 2030 is 31% higher than in the Reference Scenario (see Chapter 9).

7. Details on fuel economy regulations can be found at: http://www.nhtsa.dot.gov/

8. The automotive industry has filed a suit against CARB, arguing that California's greenhouse-gas emission standards are effectively fuel economy standards and that they are, therefore, pre-empted by a federal statute that gives the DOT exclusive authority to regulate fuel economy. (Energy Information Administration, 2006).

Table 7.1: **Selected Policies Included in the Alternative Policy Scenario***

Country	**Policy/measure**	**Implementation in the Alternative Policy Scenario**
Biofuels		
US	EPACT 2005 requires ethanol use to increase to 7.5 billion gallons in 2012, and remain at that percentage from 2013 onwards.	Target met and strengthened
Japan	A target of biofuel use in the transport sector of 500 000 kilolitres of oil equivalent in 2010.	Target met and prolonged
EU	To boost the percentage of biofuels to 5.75% of fuels sold by 2010.	Target met and strengthened
China	National standard for ethanol fuel usage. Pilot programmes are installed in 9 trial provinces.	Ethanol use increased
India	To promote biofuels through fiscal incentives, plus design and development efforts.	Increased use of biofuels
Other renewables		
US	State-based Renewable Portfolio Standards ensure that a minimum amount of renewable energy is included in the portfolio of electricity resources.	Met and strengthened over the period
EU	The Biomass Action Plan outlines measures in heating, electricity and transport to increase the use of biomass to about 150 Mtoe by 2010.	Met by 2020
China	Targets in 2020 for renewable energy for small-scale hydropower, wind, biomass-fired electricity, and small increases in solar, geothermal, ocean and tidal energy.	Overall target met and prolonged
India	To promote renewables (*e.g.* wind and solar) through fiscal incentives, plus design and development efforts.	Increased use of renewables
Nuclear power		
US	EPACT 2005 includes several provisions designed to ensure that nuclear energy will remain a major component of energy supply, including extending the Price-Anderson Act, production tax credits and insurance against regulatory delay for first 6 GW.	Increased nuclear power generation
China	A target to reach 40 GW of nuclear capacity by 2020.	Target met before 2030
India	A target for nuclear generating capacity to reach 40 GW in 2030.	25 GW in 2030
Industry sector		
Japan	Energy Conservation Law strengthened by raising the number of factories and workplaces responsible for promoting energy conservation from 10 000 to about 13 000.	Improved energy efficiency in industry
China	The Top 1 000 Enterprises programme requires monitoring with targets to improve efficiencies of the largest energy consumers in 9 industrial sectors.	Met and strengthened

Table 7.1: **Selected Policies Included in the Alternative Policy Scenario*** *(continued)*

Country	**Policy/measure**	**Implementation in the Alternative Policy Scenario**
Building sector		
EU	The Ecodesign Directive for minimum environmental performance requirements focusing on energy and water consumption, waste generation and extension of machinery lifetime of energy-using products.	Improved energy efficiency in industry
China	The energy conservation level of residential and public buildings to be close to, or reach, modern, medium-developed countries by 2020.	Improved efficiency in residential and services sector
India	Minimum requirements for the energy-efficient design and construction of buildings that use significant amounts of energy.	Met and strengthened
Transport sector		
US	Structural reform of Corporate Average Fuel Economy (CAFE) standards to allow for size-based fuel efficiency.	Implemented and strengthened
Japan	Top Runner programme sets efficiency standards for passenger cars and trucks according to the most efficient vehicle in each category.	Met and prolonged
EU	Expansion of the EU Emissions Trading Scheme (ETS) to other sectors, including civil aviation. Applicable to all flights departing from the EU for both EU and non-EU carriers.	Reduced aviation fuel demand
China	National standards require the car industry to limit vehicle fuel consumption, limits based on vehicle weight.	Met and strengthened
Other		
US	EPACT 2005 provides for tax credits for the construction of coal-fired generation projects, requisite on meeting efficiency and emissions targets.	Increased share of IGCC and clean coal
US	EPACT 2005 includes royalty relief for oil and gas production in Gulf of Mexico.	Increased share of domestic oil production
EU	Directive on the promotion of end-use efficiency and energy services ensures that all member States save at least 1% more energy each year.	Met and strengthened
China	The 11th 5-year plan stipulates massive restructuring and amalgamation of the coal industry, seeing the closure of many small plants and increased efficiency in large plants.	Improved efficiency of coal industry

* The full list of policies and measures analysed for the Alternative Policy Scenario can be downloaded from the *WEO* website, at www.worldenergyoutlook.org

Energy Prices and Macroeconomic Assumptions

The basic assumptions about economic growth and population are the same as in the Reference Scenario. Although there may be some feedback from the new policies to economic performance in practice, this factor was considered too complex and uncertain to model. However, changes in energy investment by energy suppliers and consumers are assessed.

The price for crude oil imports into the IEA and gas import prices are assumed not to change compared to the Reference Scenario. New policies that consuming countries are assumed to introduce to bolster their indigenous oil and gas production, together with the lower global demand that results from demand-side policies, would result in a drop in OPEC's market share. This could be expected to lessen OPEC members' ability and willingness to push for higher prices. At the same time, increased non-OPEC production would arguably not come forward without prices at least as high as in the Reference Scenario, for want of sufficient stimulus to investment. How these factors would balance is extremely hard to predict. For the sake of simplicity in this analysis, we assume that these considerations would effectively cancel themselves out, leaving prices unchanged. This assumption is consistent with an OPEC strategy that seeks to sustain a constant price by adjusting volume output as demand shifts (Gately, 2006).

As in the Reference Scenario, natural gas prices are assumed broadly to follow the trend in oil prices, because of the continuing widespread use of oil-price indexation in long-term gas supply contracts. Coal import prices, however, would be affected by the different supply-demand equilibrium established in the Alternative Policy Scenario. The significant contraction of the coal market is assumed to drive down coal prices, especially towards the end of the *Outlook* period when coal demand falls most heavily, with coal prices falling from \$62 per tonne in 2005 to \$55 in 2030. Electricity prices are also assumed to change, reflecting changes in fuel inputs and in the cost of power-generation technologies. Renewables and nuclear power, which are more capital-intensive than fossil-based thermal generation options, gain market share relative to the Reference Scenario. The price of grid-based electricity increases in some regions mainly because of the higher share of renewables, many of which require financial support. No global application of a financial penalty for CO_2 emissions (carbon price) has been assumed.

Technological Developments

The rate of technological deployment across all technologies, on both end use and production, is faster in the Alternative Policy Scenario than in the Reference Scenario. However, technologies that have not yet been demonstrated on a commercial basis are not included in the Alternative Policy

Scenario. This is because significant cost reductions would be needed for these technologies to become commercially available and widely deployed. It is also hard to predict if or when commercialisation might occur. For this reason, consideration of carbon capture and storage (Box 7.2), second-generation biofuels, plug-in hybrids and other advanced technologies are excluded from this scenario. This approach allows us to give an indication of the potential energy and CO_2 savings achievable with incremental improvements in existing technologies and their greater penetration of the market, but excluding major breakthroughs. The potential impact of the emergence of such technologies is nonetheless discussed in Chapter 10.

Box 7.2: **Current Status and Development of CO_2 Capture and Storage Technology**

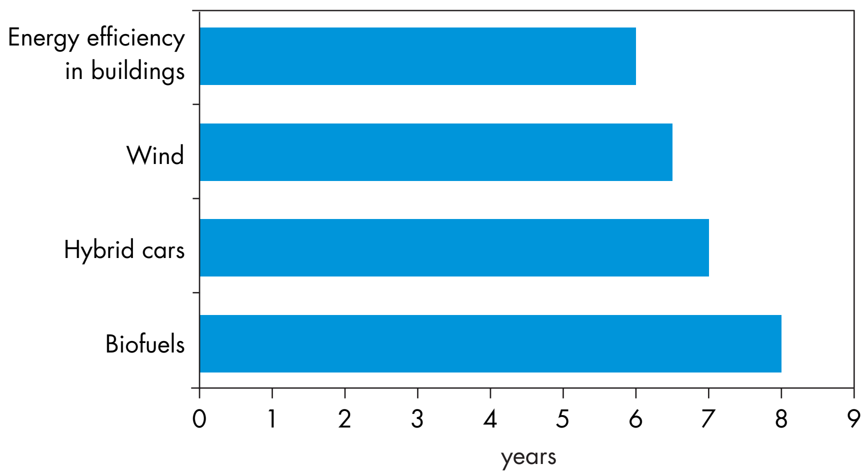
CO_2 capture and storage (CCS) involves separating the gas emitted when fossil fuels are burned, transporting it to a storage location and storing it in the earth or the ocean. Each of the component parts of the CCS process is already in use in various places around the world, including in commercial settings. However, there is relatively little experience in combining CO_2 capture, transport and storage into a fully-integrated CCS system.

CCS for large-scale power plants, the potential application of major interest, still remains to be implemented (IPCC, 2005). For this reason, CCS is not taken into account in the Alternative Policy Scenario. If all the eleven currently planned and proposed large-scale integrated CCS projects were to be successfully implemented, they would save up to 15 Mt of CO_2 emissions in 2015. This is equivalent to only 0.2% of coal-fired power generation emissions in the Alternative Policy Scenario in 2015.

CCS increases the cost of fossil-based power generation. Consequently, it will not be applied on a large scale without strong government support. Recent IEA analysis shows that CCS could play a significant role by 2050 in limiting CO_2 emissions from coal-fired power plants in rapidly growing economies with large coal reserves (IEA, 2006). This potential will be exploited only if at least ten large-scale integrated coal-fired power plants with CCS are demonstrated and commercialised within the next decade. A key policy which could help CCS to penetrate the market is the introduction of a carbon price.

Many of the policies considered in the Alternative Policy Scenario lead to faster deployment of more efficient and less polluting technologies. As those technologies are deployed under the stimulus of national policy, the unit cost of the technology falls, so that it subsequently becomes available globally at a lower cost than in the Reference Scenario. As a result, cleaner technologies are deployed sooner and more widely than in the Reference Scenario. For example, the level of production of biofuels reached in 2030 in the Reference Scenario is achieved eight years earlier in the Alternative Policy Scenario and the number of hybrid cars on the road in 2030 in the Reference Scenario is reached as early as 2023 in the Alternative Policy Scenario (Figure 7.1). The rate of decline in cost of the different technologies varies according to the maturity of the technology and the rate of transfer to other countries (IEA, 2005a).

Figure 7.1: **Years Saved in the Alternative Policy Scenario in Meeting the Levels of Deployment of the Reference Scenario in 2030**



In general, the rate of improvement in energy efficiency in the Alternative Policy Scenario is higher in developing countries and the transition economies than in OECD countries. This reflects the larger potential for efficiency improvements in those regions and the fact that additions to the physical capital stock are expected to be much larger in non-OECD countries than in the OECD. The rate of efficiency gain varies according to the end-use sector, the efficiency of the existing capital stock, the existing policy framework and the type and effectiveness of the policies adopted. Specific assumptions for each sector are provided in Chapter 9. Improved energy efficiency results in a faster decline in primary energy intensity – the amount of energy consumed per unit of gross domestic product. In aggregate, global energy intensity declines at an average rate of 2.1% per year over 2004-2030 in the Alternative Policy Scenario, compared with 1.7% in the Reference Scenario and 1.6% from 1990 to 2004.

The efficiency of supply-side technologies is also assumed to improve more quickly in the Alternative Policy Scenario. For example, the faster deployment of biofuels is expected to bring down their production cost more quickly than in the Reference Scenario. In the power sector, renewables-based technologies are assumed to be deployed more widely, the efficiency of thermal plants is assumed to increase, and transmission and distribution losses are assumed to be reduced.

Global Energy Trends

Primary and Final Energy Mix

In the Alternative Policy Scenario, the implementation of more aggressive policies and measures significantly curbs the growth in total primary and final energy demand. Primary demand reaches 15 405 Mtoe in 2030 – a reduction of about 10%, or 1 690 Mtoe, relative to the Reference Scenario (Table 7.2). That saving is roughly equal to the current energy demand of China. Demand still grows, by 37% between 2004 and 2030, but more slowly: 1.2% annually against 1.6% in the Reference Scenario. The impact of new policies is less marked in the period to 2015, but far from negligible: the difference between the two scenarios in 2015 is about 4%, or 534 Mtoe, close to the current consumption of Japan.

7

Table 7.2: **World Energy Demand in the Alternative Policy Scenario** (Mtoe)

	2004	2015	2030	2004-2030*	Difference from the Reference Scenario in 2030	
					Mtoe	%
Coal	2 773	3 431	3 512	0.9%	– 929	–20.9%
Oil	3 940	4 534	4 955	0.9%	– 621	–11.1%
Gas	2 302	2 877	3 370	1.5%	– 499	–12.9%
Nuclear	714	852	1 070	1.6%	209	24.3%
Hydro	242	321	422	2.2%	13	3.2%
Biomass and waste	1 176	1 374	1 703	1.4%	58	3.6%
Other renewables	57	148	373	7.5%	77	26.1%
Total	**11 204**	**13 537**	**15 405**	**1.2%**	**–1 690**	**–9.9%**

* Average annual rate of growth.

The cost of replacing capital stock prematurely is high, even when the new stock is more energy-efficient. This limits the opportunities for change, especially over the next ten years. In the longer term, more capital stock will be added and replaced, boosting opportunities for the introduction of more efficient technologies. The gap between the demand figures of the two scenarios accordingly widens progressively over the projection period (Figure 7.2).

The reduction in the use of fossil fuels is even more marked than the reduction in primary energy demand. It results from the introduction of more efficient technologies and switching to carbon-free energy sources. Nonetheless, fossil fuels still account for 77% of primary energy demand by 2030 (compared with 81% in the Reference Scenario). The biggest savings in both absolute and percentage terms come from coal (Figure 7.3).

Figure 7.2: **World Primary Energy Demand in the Reference and Alternative Policy Scenarios** (Mtoe)

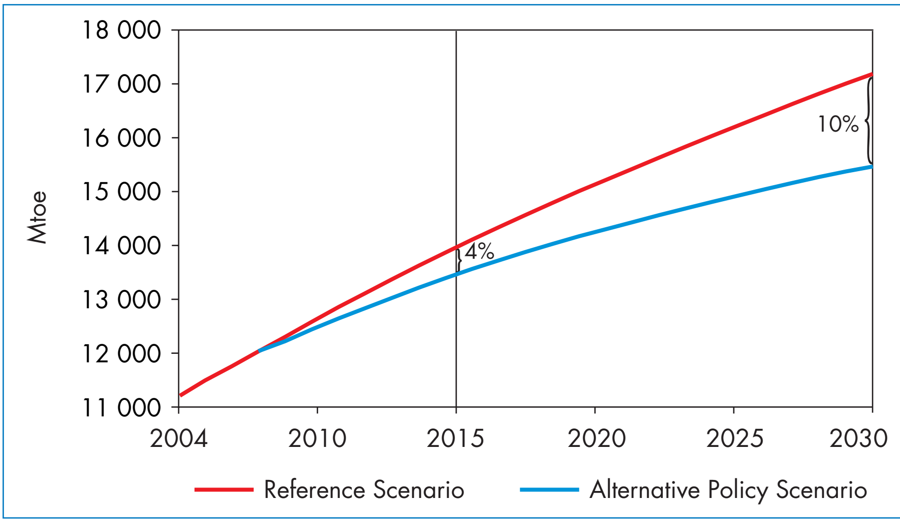
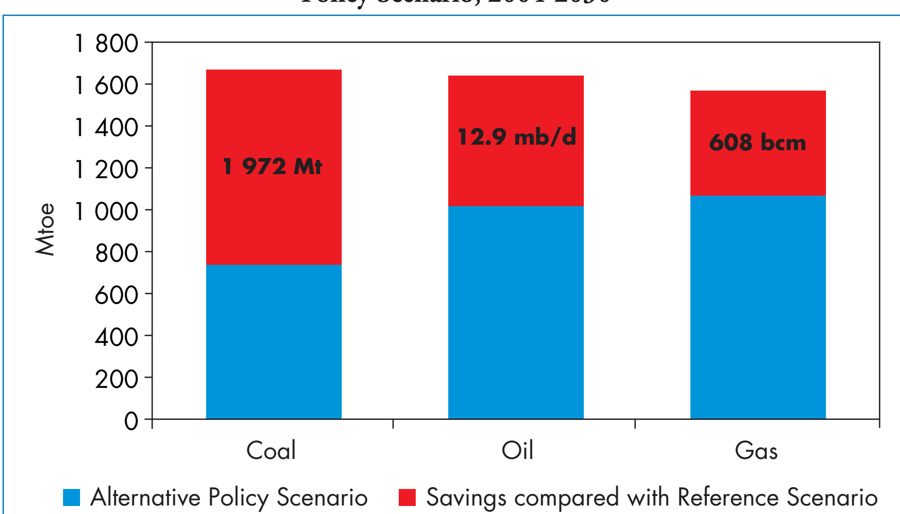


Figure 7.3: **Incremental Demand and Savings in Fossil Fuels in the Alternative Policy Scenario, 2004-2030**

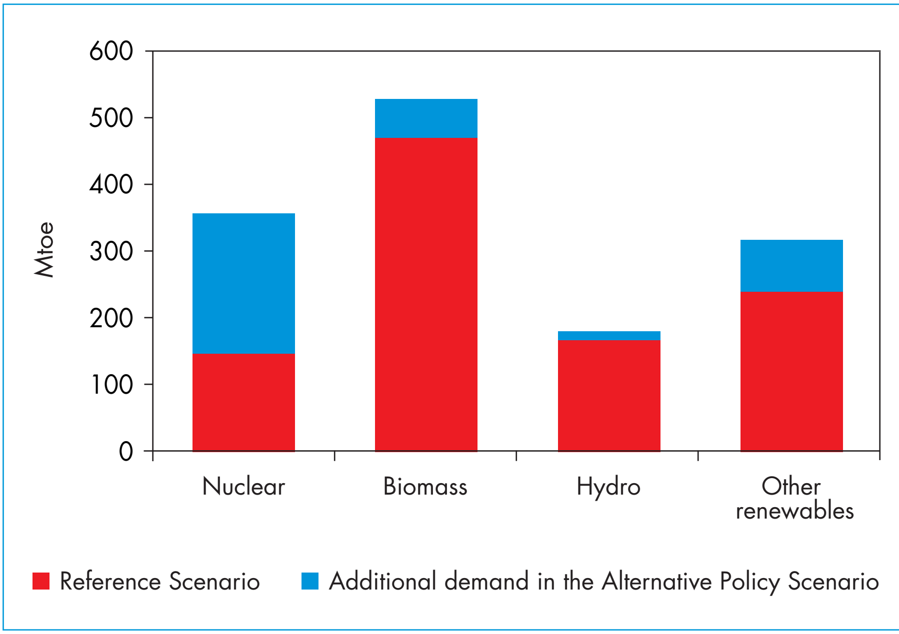


Demand for oil in the Alternative Policy Scenario grows on average by 0.9% per year, reaching just under 5 000 Mtoe in 2030 (or 103.4 mb/d) – 621 Mtoe, or 11%, lower than in the Reference Scenario. In 2030, the share of oil in total primary energy demand is 32% in the Alternative Policy Scenario, a drop of three percentage points compared to 2004. By 2015, oil demand will be 15% higher than in 2004, compared to 21% in the Reference Scenario. Increased fuel efficiency in new vehicles, together with the faster introduction of alternative fuels and vehicles, accounts for more than half of the oil savings in the Alternative Policy Scenario. Most of the rest comes from savings in oil use in the industry and building sectors.

Natural gas demand continues to grow steadily over the *Outlook* period in the Alternative Policy Scenario, reaching 2 877 Mtoe (or 3 472 bcm) in 2015 and 3 370 Mtoe (or 4 055 bcm) in 2030. The rate of growth over the full projection period, at 1.5% per year, is nonetheless 0.5 percentage points lower than in the Reference Scenario, and the level of demand in 2030 is 13% lower. Reduced gas use for power generation, resulting from less demand for electricity and fuel switching to non-carbon fuel, is the main reason for this difference. Demand for coal falls the most, by 6% in 2015 and 21% in 2030. It grows by only 0.9% per year over the period 2004-2030, compared with 1.8% in the Reference Scenario. As with natural gas, reduced electricity demand and fuel switching are the main reasons. Coal demand still grows to 2020, but then levels off. If CO_2 capture and storage were to become commercially available before 2030, the fall in coal demand could be significantly less marked. The potential impact of the introduction of CCS is analysed in Chapter 10.

Demand for energy from non-fossil fuel primary sources is 358 Mtoe, or 11%, higher in 2030 than in the Reference Scenario (Figure 7.4). Renewables and nuclear power partially displace fossil fuel. Nuclear power accounts for over half of the additional demand for non-fossil fuel energy, hydro for 4%, non-hydro renewables for 22% and biomass for the rest. Nuclear energy, which grows more than twice as fast between 2004 and 2030, is 24% higher in 2030 than in the Reference Scenario. Hydroelectric supply also grows more quickly, but only to a level 3% higher than in the Reference Scenario in 2030. Higher consumption of biomass results from several different factors. Switching away from traditional biomass for cooking and heating in developing countries (see Chapter 15) and, to a lesser extent, improvements in efficiency in industrial processes, drive demand down. However, this is outweighed by the increased use of biomass in combined heat and power production and electricity-only power plants and in biofuels for transport (see Chapter 14). On balance, global consumption of biomass is 58 Mtoe *higher* in 2030 in the Alternative Policy Scenario than in the Reference Scenario. The consumption of other renewables – wind, geothermal, and solar power – is also higher, by 26%, or 77 Mtoe in 2030. Power generation accounts for two-thirds of the increase in renewables; transport use of biofuels and, to a lesser extent, heating from solar water-heaters and geothermal use in final consumption contribute the rest.

Figure 7.4: **Incremental Non-Fossil Fuel Demand in the Reference and Alternative Policy Scenarios, 2004-2030**



At the final consumption level, electricity demand is 24 672 TWh in 2030 – a reduction of 12% compared to the Reference Scenario. It falls by 5% by 2015. Energy-efficiency measures in buildings, in particular those concerning appliances, air-conditioning and lighting, contribute two-thirds of the savings. The other one-third comes from improvements in the efficiency of industrial processes. Heat demand is also 5%, or 18 Mtoe, lower compared to the Reference Scenario, mainly because of stricter building codes and better insulation. The final consumption of all three fossil fuels is also lower, but slightly less in percentage terms than primary demand (Table 7.3).

Table 7.3: **Final Energy Consumption in the Alternative Policy Scenario** (Mtoe)

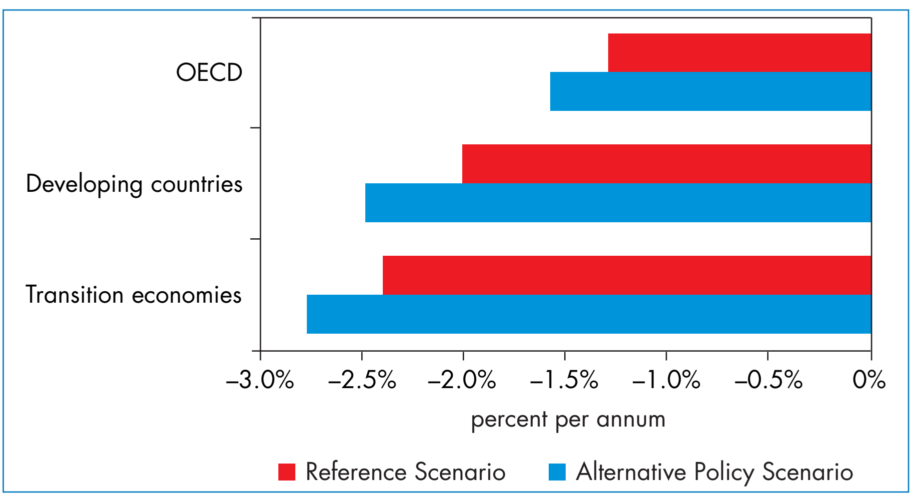
	2004	2015	2030	2004-2030*	Difference from the Reference Scenario in 2030 Mtoe	%
Coal	641	774	763	0.7%	–160	–17.3%
Oil	3 228	3 783	4 242	1.1%	–544	–11.4%
Gas	1 219	1 487	1 721	1.3%	–118	–6.4%
Electricity	1 236	1 682	2 121	2.1%	–294	–12.2%
Heat	255	280	306	0.7%	–18	–5.4%
Biomass & Waste	1 052	1 168	1 295	0.8%	–21	–1.6%
Other Renewables	7	33	93	10.3%	33	54.3%
Total	**7 639**	**9 207**	**10 542**	**1.2%**	**1 122**	**9.6%**

* Average annual rate of growth.

Energy Intensity

Global primary energy intensity falls by 2.1% per year through the *Outlook* period in the Alternative Policy Scenario, falling by 2.2% per annum in the intermediate period from 2004-2015. In the Reference Scenario, the annual decline from 2004-2030 is 1.7%. Over the period 1990-2004, intensity fell by 1.6% per annum. The difference between the two scenarios is more pronounced in developing countries and in the transition economies, because there is more potential in these regions for improving energy efficiency in power generation and in end uses (Figure 7.5). In the OECD, energy intensity falls by 1.6% per year over the projection period,

Figure 7.5: **Change in Primary Energy Intensity by Region in the Reference and Alternative Policy Scenarios, 2004-2030**



compared with 1.3% in the Reference Scenario. Per-capita primary energy continues to rise, from 1.76 toe in 2004 to 1.89 toe in 2015 and remains at this level through to 2030. It nonetheless is 10% lower in 2030, compared with the Reference Scenario.

Investment and Fuel Expenditures

The Alternative Policy Scenario yields considerable savings in energy demand, energy imports, CO_2 emissions from the Reference Scenario and requires less overall energy investment. The savings are attained through a combination of increased consumer investment on more energy-efficient goods and of fuel choice decisions in the power and transport sectors. Over the next two-and-a-half decades, households and firms have to invest $2.4 trillion more than in the Reference Scenario to buy more efficient goods. Consumers in the OECD countries bear two-thirds of the incremental investment. The incremental investment is more than offset in most cases by lower energy bills. The change in end-use investment patterns, the consequences for consumers' energy bills and energy supply investment for the Alternative Policy Scenario are analysed in detail in Chapter 8.

Oil Markets

Demand

Global oil demand reaches 103 mb/d in 2030 in the Alternative Policy Scenario – an increase of 20 mb/d on 2005 levels, but a fall of 13 mb/d compared with the Reference Scenario (Table 7.4). These savings are equivalent to the current combined production of Saudi Arabia and Iran. By 2015, demand reaches 95 mb/d, a reduction of almost 5 mb/d on the Reference Scenario. Measures in the transport sector – notably those that boost the fuel economy of new vehicles – contribute 59% of the savings over the projection period. Increased efficiency in industrial processes accounts for 13%, and fuel switching in the power sector and lower demand from other energy-transformation activities, such as heat plants and refining, for 9%. More efficient residential and commercial oil use makes up the rest.

The biggest savings occur in the United States, China and the European Union, which, combined, contribute almost half of the global oil savings by 2030. The US market remains the largest at that time, at 22.5 mb/d, followed by China, at 13.1 mb/d and the European Union at 12.8 mb/d. The impact of new policies differs markedly among these markets. EU oil demand peaks around 2015 and then declines at a rate of 0.5% per year. Japan follows a very similar trend with an even more pronounced decline, of 0.7% per year, after 2015. Demand in the United States levels out after 2015, but does not fall. On the other hand, oil demand in China continues to grow steadily, averaging 2.8% per year over the projection period, though the rate of increase does slow progressively. Demand in all other developing regions continues to grow, albeit at a more moderate pace than in the Reference Scenario.

Table 7.4: **World Oil Demand in the Alternative Policy Scenario*** (mb/d)

	2005	2015	2030	2005-2030**	Difference versus Reference Scenario in 2030 mb/d	%
OECD	**47.7**	**50.7**	**49.9**	**0.2%**	**–5.2**	**–9.5%**
North America	24.9	27.2	27.7	0.4%	–3.1	–10.2%
United States	*20.6*	*22.4*	*22.5*	*0.3%*	*–2.5*	*–10.1%*
Canada	*2.3*	*2.5*	*2.5*	*0.5%*	*–0.2*	*–8.2%*
Mexico	*2.1*	*2.4*	*2.7*	*1.1%*	*–0.4*	*–12.7%*
Europe	14.4	14.9	13.9	–0.1%	–1.4	–9.3%
Pacific	8.3	8.5	8.2	–0.0%	–0.7	–7.6%
Transition economies	**4.3**	**4.7**	**5.0**	**0.6%**	**–0.7**	**–11.8%**
Russia	2.5	2.7	2.9	0.5%	–0.4	–12.2%
Developing countries	**28.0**	**35.6**	**44.7**	**1.9%**	**–6.6**	**–12.9%**
Developing Asia	14.6	19.4	25.8	2.3%	–3.9	–13.2%
China	*6.6*	*9.4*	*13.1*	*2.8%*	*–2.2*	*–14.5%*
India	*2.6*	*3.6*	*4.8*	*2.5%*	*–0.6*	*–11.3%*
Indonesia	*1.3*	*1.5*	*2.2*	*2.0%*	*–0.2*	*–7.5%*
Middle East	5.8	7.7	8.8	1.7%	–0.9	–8.9%
Africa	2.7	3.3	4.2	1.8%	–0.7	–14.4%
Latin America	4.9	5.3	5.9	0.8%	–1.1	–15.8%
Brazil	*2.1*	*2.5*	*2.9*	*1.3%*	*–0.6*	*–16.0%*
Int. marine bunkers	**3.6**	**3.7**	**3.8**	**0.2%**	**–0.4**	**–9.8%**
World	**83.6**	**94.8**	**103.4**	**0.9%**	**–12.9**	**–11.1%**
European Union	*13.5*	*13.8*	*12.8*	*–0.2%*	*–1.3*	*–9.5%*

* Includes stock changes.

** Average annual growth rate.

Supply

In principle, lower global oil demand in the Alternative Policy Scenario would be expected to result in a lower oil price than in the Reference Scenario.[9] Production in higher-cost fields mainly located in OECD countries, would be reduced, declining even more rapidly after 2010 than in the Reference Scenario. But concerns about the security of supply might encourage OECD and other oil-importing countries to take action to stimulate development of their own oil resources. For example, the UK government is currently considering such policies (DTI, 2006) and the US Congress is considering allowing more offshore oil exploration and giving royalty relief for offshore

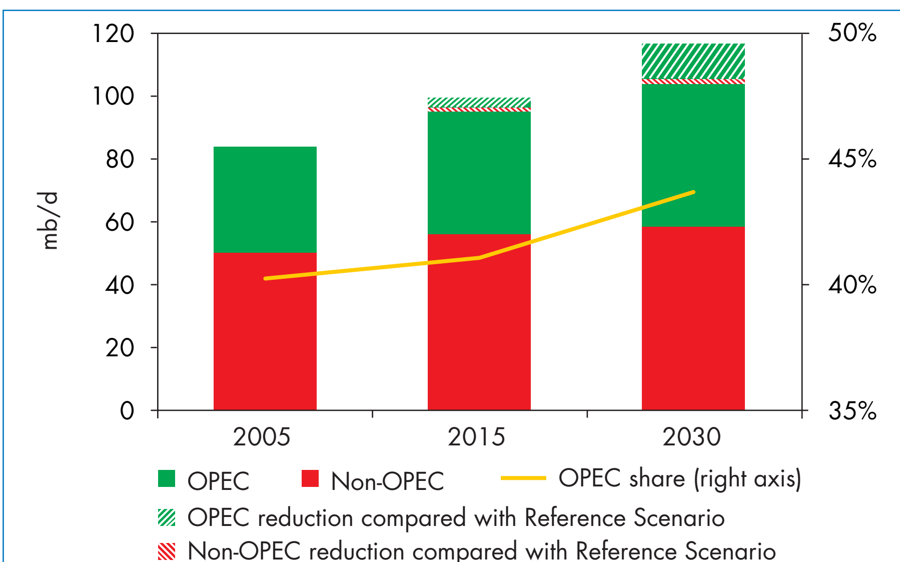
9. In *WEO-2004*, we estimated that the oil prices would be 15% lower over the projection period in the Alternative Policy Scenario compared with the Reference Scenario (IEA, 2004).

7

production. For these reasons, we assumed that oil production in OECD and other net oil-importing countries – as well as the international crude oil price – remain at the same levels as in the Reference Scenario. As a result, the call on oil supply from the net exporting countries is reduced in the Alternative Policy Scenario. OPEC members and major non-OPEC producing regions, including Russia, the Caspian region and west Africa, are most affected (Figure 7.6). OPEC production reaches 38.8 mb/d in 2015 and 45.1 mb/d in 2030. The average growth of 1.2% per year is just over half the growth in the Reference Scenario. OPEC's share of the global oil market rises from the current 40% to nearly 44% in 2030, but this is five percentage points lower than that in the Reference Scenario.

Crude oil production outside OPEC is projected to increase from 50 mb/d in 2005 to 56 mb/d in 2015 and 58.3 mb/d in 2030 (though 1.8 mb/d or 3% lower than in the Reference Scenario). The transition economies are expected to account for half of this increase. Latin America and West Africa account for most of the remainder. Production in OECD countries is expected to decline steadily from 2010 onwards, as in the Reference Scenario. The share of non-conventional oil production in this scenario in 2030, at 8.7%, is an increase of 7.4 mb/d over current levels. The production of biofuels is also expected to increase substantially, especially in oil importing countries. Globally, biofuel production will grow almost 10 times, from 15 Mtoe in 2004 to 147 Mtoe in 2030. Most of the additional growth, over and above Reference Scenario levels, is expected to occur in the United States and the European Union (see Chapter 14 for a detailed discussion of projections and underlying policy assumptions).

Figure 7.6: **Oil Supply in the Alternative Policy Scenario**



Inter-Regional Trade

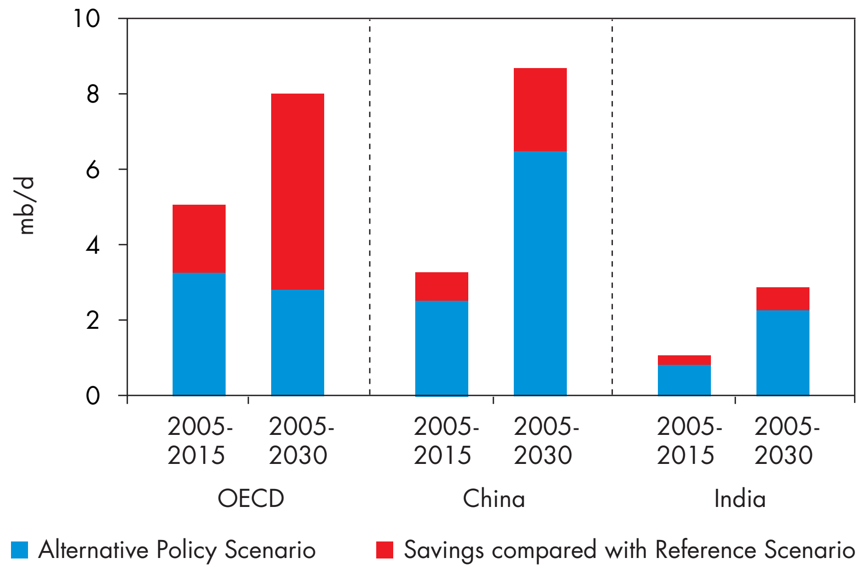
In the Alternative Policy Scenario, all the major net oil-importing regions – including all three OECD regions and developing Asia – continue to become more dependent on oil imports by the end of the projection period than they were in 2005 (Table 7.5). The volume of inter-regional trade accordingly continues to expand – but considerably less than in the Reference Scenario. Indeed, the differences between the two scenarios are significant, particularly for the countries of the OECD. In sharp contrast with the Reference Scenario, where OECD oil-import needs continue to increase throughout the *Outlook* period to a level of 35.7 mb/d in 2030, in the Alternative Policy Scenario oil imports into the OECD reach a peak of 30.9 mb/d around 2015 and then *begin to fall*. By contrast, oil imports into developing countries do continue to increase over the period, albeit at a slower rate (Figure 7.7). China and India will temper their imports compared to the Reference Scenario, but they will still rise significantly – by 6.6 mb/d from 2005 to 2030, reaching 9.6 mb/d in 2030 for China and rising by 2.3 mb/d from 2005 to 2030, reaching 4.1 mb/d in 2030 for India.

Table 7.5: **Net Oil Imports in Main Importing Regions** (mb/d)

		Alternative Policy Scenario		**Reference Scenario**	
	2005	**2015**	**2030**	**2015**	**2030**
OECD	**27.6**	**30.9**	**30.5**	**32.7**	**35.7**
North America	11.1	12.1	11.9	13.0	15.0
Europe	8.8	11.0	10.8	11.5	12.2
Pacific	7.7	7.9	7.8	8.2	8.5
Developing Asia	**7.1**	**11.7**	**17.8**	**13.0**	**21.7**
China	3.0	5.6	9.6	6.3	11.8
India	1.8	2.7	4.1	2.9	4.7
Rest of developing Asia	2.3	3.3	4.1	3.8	5.2
European Union	*10.9*	*12.2*	*11.7*	*12.7*	*13.0*

Exports by producers in the Middle East, and OPEC producers generally, fall markedly compared with the Reference Scenario, but not by as much as production. This is because domestic demand in these countries falls in response to new measures to curb oil use, freeing up more oil for export. Nevertheless, the call on OPEC supply still increases from 33.6 mb/d in 2005 to 38.8 mb/d in 2015, highlighting the need to expand production capacity.

Figure 7.7: **Increase in Net Oil Imports in Selected Importing Regions in the Alternative Policy Scenario**



Gas Markets

Demand

Primary natural gas consumption is projected to climb to 4 055 bcm in 2030, at an average annual growth rate of 1.5% – half a percentage point lower than in the Reference Scenario. In 2030, gas demand is 13% lower. The saving is about 610 bcm, an amount comparable to the current gas demand of the United States, the world's largest gas consumer. At 170 bcm, the saving is also significant as early as 2015. Global gas demand in the Alternative Policy Scenario is, nonetheless, 46% higher in 2030 than today. The share of gas in the global primary energy mix increases marginally, from 21% in 2004 to 22% in 2030 – one percentage point lower than in the Reference Scenario.

Gas demand continues to rise in all regions throughout the projection period, except in the United States and Japan, where demand dips slightly between 2015 and 2030. In the United States, demand is significantly lower than in the Reference Scenario in the power generation sector, mainly due to reduced electricity demand and a bigger role for nuclear power and renewables, in industry, where more efficient processes are introduced, and in buildings, where stricter building codes are applied. In Japan, the increased role of nuclear power and lower electricity demand are the primary reasons for the downturn in gas consumption. China actually *increases* its use of gas compared with the

Table 7.6: **World Primary Natural Gas Demand in the Alternative Policy Scenario** (bcm)

	2004	2015	2030	2004-2030*	Difference from Reference Scenario in 2030 bcm	%
OECD	**1 453**	**1 662**	**1 780**	**0.8%**	**–215**	**–10.8%**
North America	772	874	917	0.7%	–81	–8.1%
United States	*626*	*690*	*682*	*0.3%*	*–46*	*–6.3%*
Canada	*94*	*113*	*130*	*1.2%*	*–21*	*–14.0%*
Mexico	*51*	*71*	*105*	*2.8%*	*–13*	*–11.3%*
Europe	534	605	679	0.9%	–96	–12.4%
Pacific	148	183	184	0.9%	–38	–17.3%
Transition economies	**651**	**740**	**777**	**0.7%**	**–129**	**–14.2%**
Russia	420	476	508	0.7%	–74	–12.7%
Developing countries	**680**	**1 070**	**1 499**	**3.1%**	**–264**	**–15.0%**
Developing Asia	245	398	584	3.4%	–38	–6.2%
China	*47*	*108*	*198*	*5.7%*	*29*	*17.1%*
India	*31*	*52*	*83*	*3.9%*	*–7*	*–7.7%*
Indonesia	*39*	*64*	*84*	*3.0%*	*–3*	*–3.5%*
Middle East	244	368	490	2.7%	–146	–23.0%
Africa	76	133	188	3.6%	–28	–12.8%
Latin America	115	171	237	2.8%	–52	–18.0%
Brazil	*19*	*31*	*42*	*3.1%*	*–7*	*–15.0%*
World	**2 784**	**3 472**	**4 055**	**1.5%**	**–608**	**–13.0%**
European Union	*508*	*571*	*636*	*0.9%*	*–90*	*–12.4%*

* Average annual growth rate.

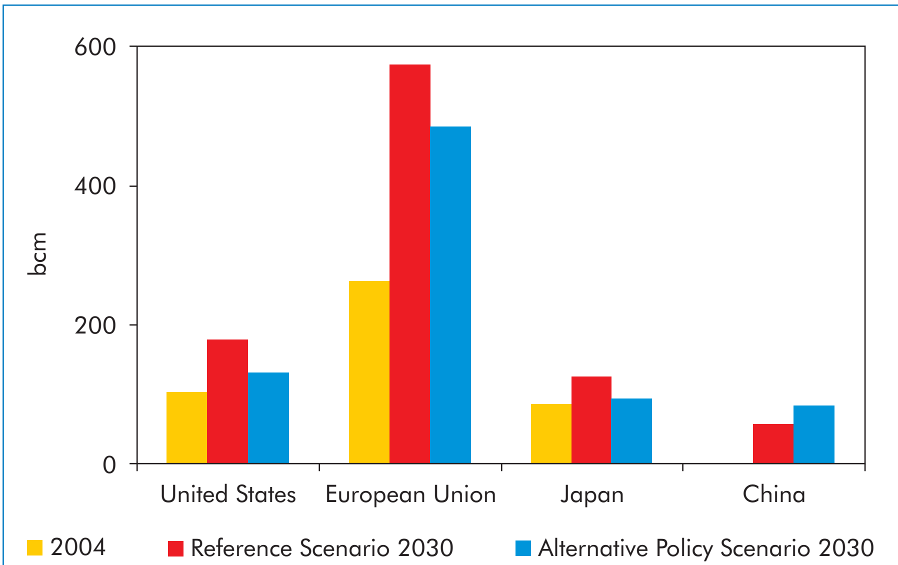
Reference Scenario, because of aggressive policies to switch away from coal for environmental reasons. Our gas-demand projections in most regions and in both scenarios have been scaled down since the last edition of the *Outlook*, mainly because the underlying gas-price assumptions have been raised and because of growing concerns about the security of imported gas supplies.

Production and Trade

The fall in gas production consequent upon lower global demand compared to the Reference Scenario is borne by all exporting regions, but disproportionately by the main exporting regions – namely the Middle East, Russia and Africa. A significant proportion of the projected increase in output in those regions is driven by export demand. As the need for imports in the main consuming markets is significantly lower in the Alternative Policy Scenario, the call on exporters' gas is reduced. Most of the projected rise in global output still occurs in the Middle East, Africa and Russia, though the amount of the increase is significantly lower. Their combined production grows from 1 050 bcm in 2004 to 1 685 bcm in 2030, only 60%, compared with the 106% observed in the Reference Scenario. Gas production in OECD countries rises marginally from 1 123 bcm in 2004 to 1 231 bcm in 2030 – the same increase as in the Reference Scenario.

Inter-regional gas trade grows more slowly in the Alternative Policy Scenario. It totals 749 bcm in 2030, or 18% of world production, against 936 bcm (20%) in the Reference Scenario. All the major net importing regions need more imports in 2030 than now, but – with the exception of China – significantly less than required in the Reference Scenario (Figure 7.8).

Figure 7.8: **Natural Gas Imports in Selected Importing Regions in the Reference and Alternative Policy Scenarios**



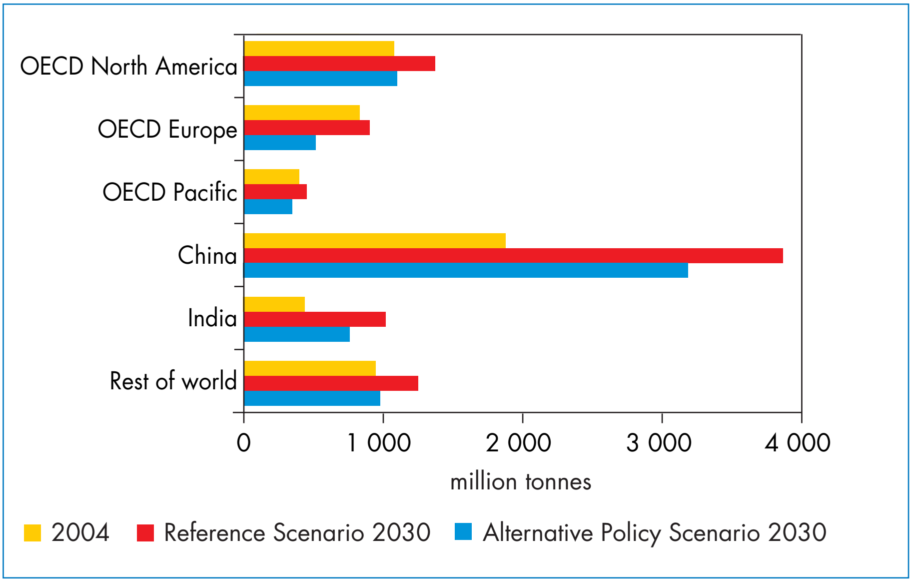
Coal Markets

Demand

New policies reduce the growth in demand for coal more than any other fuel in the Alternative Policy Scenario. By 2030, global coal demand is 24% higher than today, reaching 6 900 million tonnes, but this represents a fall of around one-fifth from the Reference Scenario. More than three-quarters of this reduction is due to lower coal consumption in the power sector. The savings in electricity demand account for 35% of the reduction in coal use in the power sector, and the remainder to fuel switching. In 2030, coal's share in electricity generation globally is expected to be three percentage points lower than today. The biggest coal savings in absolute terms occur in China, where demand is 678 Mt lower, in the European Union (323 Mt), in the United States (235 Mt) and in India (259 Mt). Together, those regions account for over 85% of the total reduction in coal use in 2030.

In contrast to the slight increase seen in the Reference Scenario, coal consumption in the OECD will peak before 2015 and then decline at 1.2% per year. This decrease is more than offset by the consumption growth in developing countries, which is expected to continue at 1.9% per year through the *Outlook* period, driven by China and India. In fact, the Alternative Policy Scenario sees Chinese coal demand overtake that of the entire OECD region around 2010.

Figure 7.9: **Coal Demand in the Reference and Alternative Policy Scenarios**



There is a large degree of uncertainty in these demand trends. They are particularly sensitive to the policies and technologies adopted in the major markets: China, the United States and India. While neither the Reference nor the Alternative Policy Scenario assumes any significant penetration of carbon capture and storage, this technology could significantly change the demand trends depicted. Faster penetration of coal to liquids, discussed in Chapter 5, could also alter those trends. The former is likely to offer more potential for coal in a carbon-constrained world, the latter to enhance security in the transport sector by increasing the alternatives to oil-based products.

Production and Trade

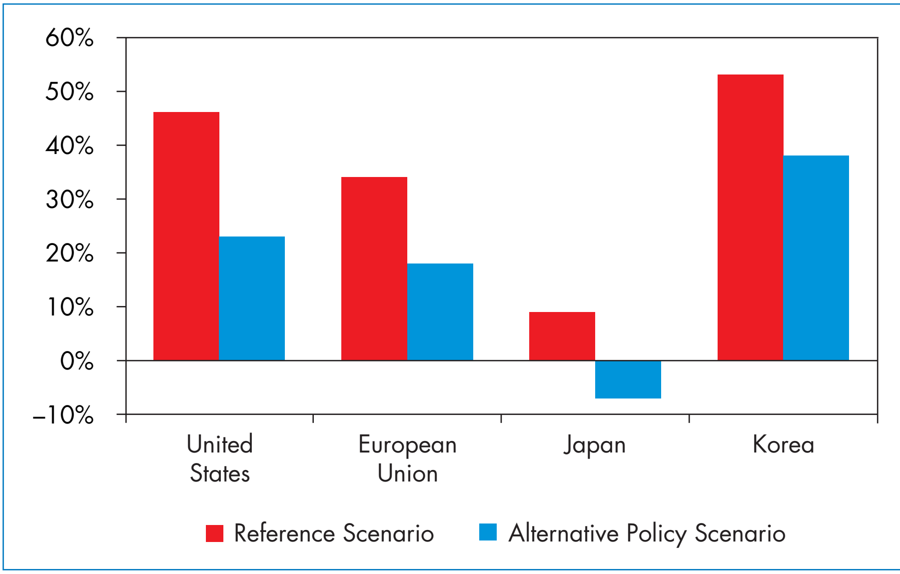
As in the Reference Scenario, most of the increase in coal demand is met by domestic production. Production adjusts to the lower demand levels. However, the decline in international coal prices affects most the producers with higher marginal production costs, notably the United States and Europe (Figure 5.5 in Chapter 5). In both cases, the decline in domestic production is more marked than the decline in domestic demand, high domestic production costs making imports a more cost-effective option than domestic production. China, Australia and New Zealand, and India account for most of the still substantial growth in global coal production. Their combined production increases by 60% compared to the current level.

Globally, coal trade grows by 21% compared to current levels. This growth levels off towards the end of the *Outlook* period, caused by slower demand growth. Global coal exports are 211 Mt, or 23%, lower than in the Reference Scenario in 2030, exemplified by the largest exporting region – OECD Oceania – decreasing its exports by 76 Mt, or 19% compared with the Reference Scenario. However, exports from Australia and New Zealand remain 46% higher than current levels. The strongest growth in imports through the *Outlook* period occurs in India, though it falls from 4.4% to 4.2% per annum in the Alternative Policy Scenario. The growth in trade in steam coal, which accounts for the bulk of total inter-regional coal trade, is affected by lower growth in electricity and fuel switching. Trade in steam coal falls more than trade in coking coal for the industry sector, which remains relatively stable.

Energy Security in Importing Countries

As energy demand grows in net importing countries, their energy security is increasingly linked to the effectiveness of international markets for oil, gas and coal and to the reliability of suppliers. Over the next two-and-a-half decades oil and gas production will become increasingly concentrated in fewer and fewer countries. This will add to the perceived risk of disruption and the risk that some countries might seek to use their dominant market position to force up prices. Exposure to disruption from these risks increases over time in both the Reference and the Alternative Policy Scenarios as net energy imports increase and supply chains lengthen. However, the Alternative Policy Scenario at least mitigates those risks, by reducing the growth in oil and gas imports. For example, the oil and gas imports into the United States grow by 23% compared to the current level, rather than the 46% of the Reference Scenario. Similar trends apply in the European Union and Korea. Japan actually reduces its oil and gas import needs compared to today’s level (Figure 7.10).

Figure 7.10: **Change in Oil and Gas Imports in the Reference and Alternative Policy Scenarios, 2004-2030**



The degree to which energy-importing countries are dependent on imports differs markedly between the two scenarios. In the Reference Scenario, the gas and oil import dependence of OECD countries, taken as a whole, rises from 30% in 2004 to 38% in 2030. Much of the increase depends upon exports from Middle Eastern and North African countries (IEA, 2005b). In the Alternative Policy Scenario, the OECD's energy import dependence still increases, but to 33%, a level reached within the next 10 years in the Reference Scenario. For developing countries there is also a difference, but it is less marked than in OECD countries.

As the share of transport in total oil use continues to grow in all regions in the scenarios described in this *Outlook*, the inflexibility of this class of oil demand increases the vulnerability of importing countries. However, demand for oil-based transport fuels grows significantly less in the Alternative Policy Scenario, compared to the Reference Scenario, both because of lower transport demand and because the share of non-oil fuels in global transport increases from 6% in 2004 to 10% in 2030. This is mainly due to increased use of biofuels in road transport and, to a lesser extent, to switching to other forms of transport.

The security of electricity supply is a multi-faceted problem. Different risks affect power plants and transmission and distribution networks. Factors that can improve security of supply in the short term (the management of power-generation facilities and the network to match supply and demand in real time) can be usefully distinguished from factors that can improve security of supply in the long run (in particular maintaining adequate investment in the power infrastructure). Several factors in the Alternative Policy Scenario improve the prospects for a secure power supply in all regions, both in the short and long term as compared to the Reference Scenario. On the demand side, lower electricity intensity improves the resilience of the economy to potential power supply disruptions, while the reduction of electricity demand (by 12% worldwide in 2030) reduces the pressure on power generation and distribution networks. On the supply side, a more diverse fuel mix (the combined share of the two dominant power generation fuels – coal and gas – is reduced from 67% to 57% worldwide) creates more potential for fuel switching and, by increasing the use of renewables and nuclear, whose share increases by nine percentage points worldwide in 2030, lowers dependence on fuels that must be imported.

Energy-Related CO_2 Emissions

The policies and measures analysed in the Alternative Policy Scenario significantly curb the growth of energy-related carbon-dioxide emissions. Lower overall energy consumption and a larger share of less carbon-intensive fuels in the primary energy mix together yield, in 2030, savings of 6.3 gigatonnes (Gt), or 16%, in emissions compared with the Reference Scenario. The total avoided emissions by 2030 are equal to more than the current emissions of the United States and Canada combined. The change in emissions trends is noticeable by 2015, by which point the Alternative Policy Scenario yields annual savings of 1.7 Gt, an amount equal to the current emissions of Japan and Korea combined. Notwithstanding the improvements, global CO_2 emissions nonetheless continue to rise, from 26 Gt in 2004 to 32 Gt in 2015 and 34 Gt in 2030 – a 21% increase by 2015 and a 31% increase by 2030.

The policies of the Alternative Policy Scenario lead to stabilisation and then reduction of emissions in OECD countries before 2030 (Figure 7.11). Emissions there peak around 2015, at close to 14 Gt, and then tail off to less than 13 Gt in 2030. That is still slightly higher than in 2004, but well below the Reference Scenario level in 2030 of 15.5 Gt. Europe and the Pacific regions are responsible for the decline in emissions after 2015: their emissions are even lower in 2030 than today. By contrast, emissions in the United States – by far the largest emitting country in the OECD – peak some time before 2020 and fall only marginally before 2030.

Growth in emissions continues in non-OECD regions, though the rate of increase slows appreciably over the *Outlook* period. Developing-country emissions grow at 2.1% annually on average through to 2030, reaching 14.4 Gt in 2015 and 17.5 Gt in 2030 – up from 10.2 Gt in 2004. In the Reference Scenario, their emissions reach 21.1 Gt in 2030. Emissions in China alone rise by 4 Gt between 2004 and 2030, accounting for half of the global increase (Figure 7.12).

As in the Reference Scenario, China overtakes the United States as the single largest CO_2 emitter before 2010. By 2030, its emissions reach 8.8 Gt or half of total developing-country emissions. At 2.5% and 2.3% per year respectively, Indonesia and India have the fastest rate of emissions growth of all regions. The increase in emissions in the transition economies is much slower, peaking at 2.9 Gt around 2020 and then stabilising at 2.8 Gt in 2030.

Figure 7.11: **Energy-Related CO_2 Emissions by Region in the Alternative Policy Scenario**

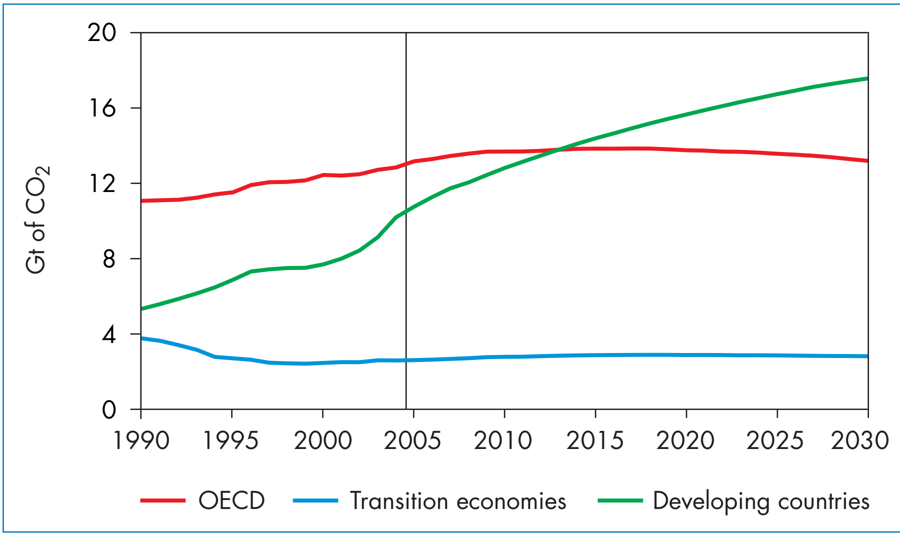
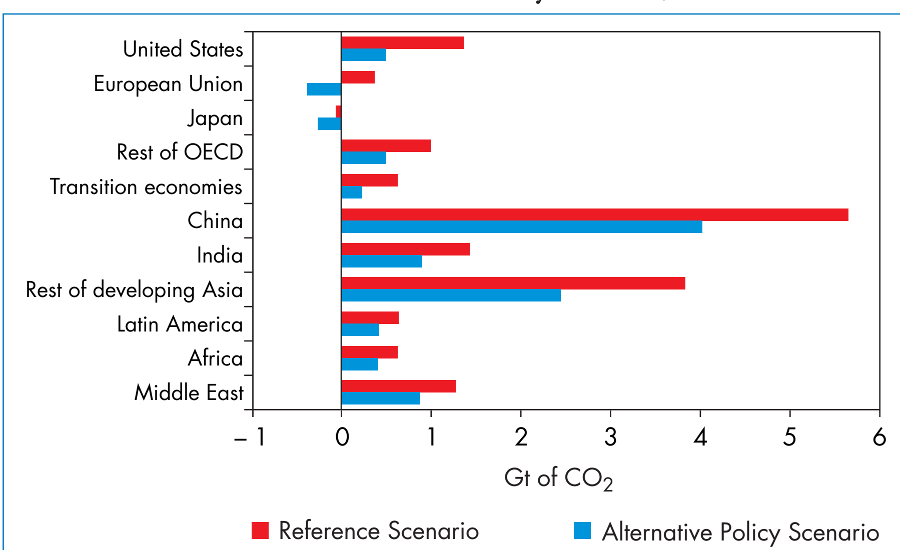


Figure 7.12: **Change in Energy-Related CO_2 Emissions by Region in the Reference and Alternative Policy Scenarios, 2004-2030**



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Notwithstanding the rates of growth in national emissions, the gap between developed and developing countries in emissions per capita remains wide. OECD per-capita emissions increase slightly from 2004 levels of 11.0 tonnes, peak around 2010, decrease to 11.2 tonnes in 2015, and then continue to fall to 10.2 tonnes in 2030. Conversely, emissions in the developing world, starting in 2004 at 2.1 tonnes per capita, grow steadily, rising to 2.7 tonnes in 2030 – still a factor of four less. These per-capita differences reflect substantially lower energy consumption per person. On a CO_2-intensity basis, they also reflect both the relative inefficiency of the energy systems in the developing world and their high reliance on fossil fuels for power.

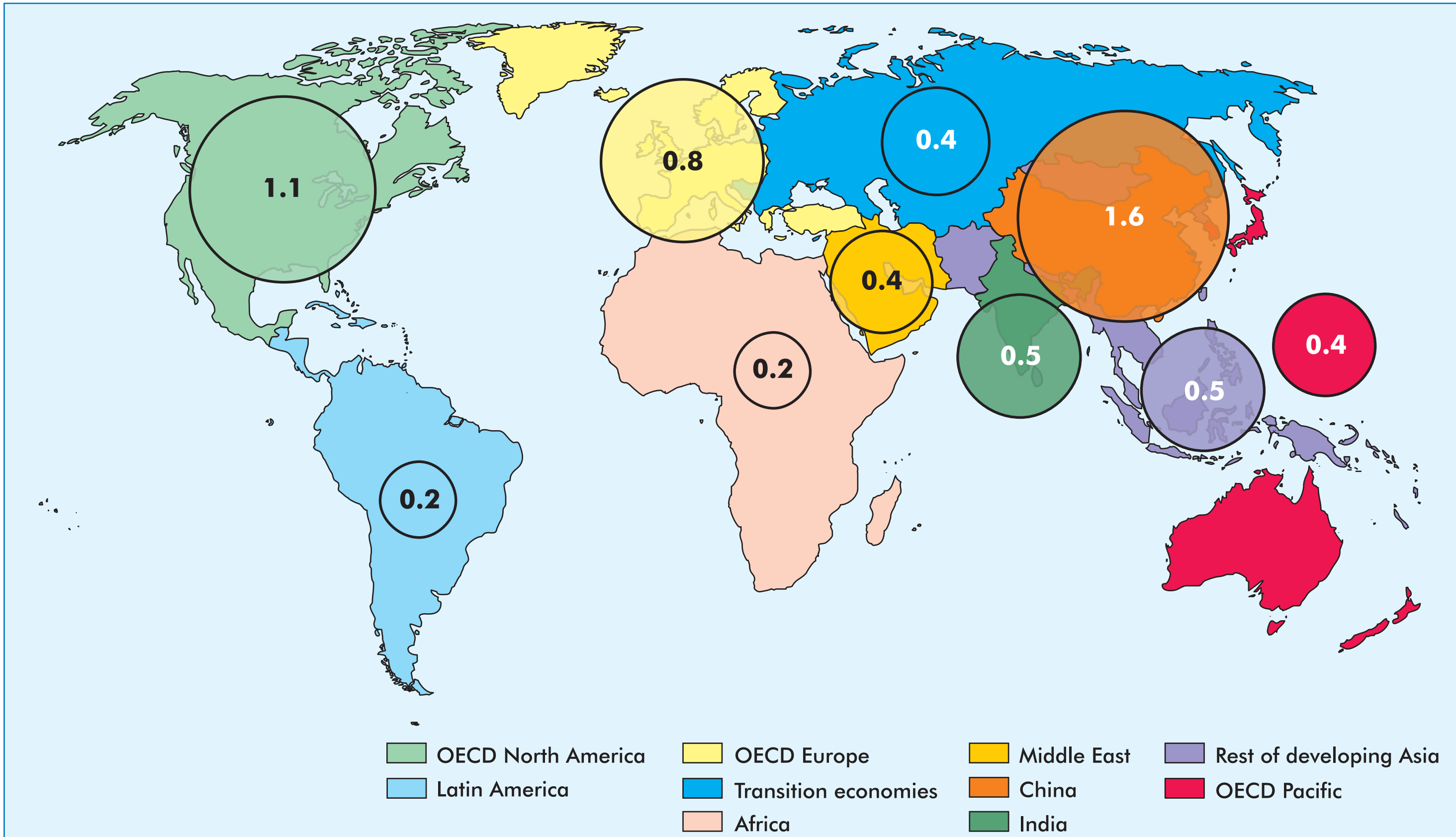
On an absolute basis, the reduction in CO_2 emissions in the Alternative Policy Scenario is greatest in countries that emit the most (Figure 7.13). Thus, China shows the largest reduction from the Reference to the Alternative Policy Scenario by 2030, with 1.6 Gt, followed by OECD North America (1.1 Gt) and OECD Europe (0.8 Gt). The smallest emissions reduction, both in absolute and percentage terms, occurs in the least developed regions, notably Africa and Latin America.

At the point of use, the largest contributor to avoided CO_2 emissions is improved end-use efficiency, accounting for nearly two-thirds of total savings (Figure 7.14).[10] Fuel savings, achieved through more efficient vehicles, industrial processes and heating applications, contribute 36% in 2030, while lower electricity demand, from more efficient appliances, industrial motors and buildings, represents 29%. Switching to less carbon-intensive fossil fuels, mainly from coal to gas in power generation, and improved supply-side efficiency account for a further 13%. Increased use of renewables in power generation and of biofuels in transport account for 12%. Increased reliance on nuclear is responsible for the remaining 10%.

Looking at the sources of emissions, the biggest contribution to avoided emissions comes from power generation, where emissions peak towards the end of the period, and are 3.9 Gt lower in 2030 in the Alternative Policy Scenario than in the Reference Scenario. This sector alone contributes almost two-thirds of avoided emissions globally. Emissions savings from this sector result principally from policies to promote carbon-free power generation, including policies to encourage nuclear power, and discourage the use of coal. The fastest annual growth in emissions over the *Outlook* period occurs in the transport sector, averaging 1.3%. Savings in this sector in 2030 in the Alternative Policy Scenario are small relative to other sectors, at 0.9 Gt, because of the limited

10. Curbing CO_2 emissions through energy efficiency policies has, in most cases, significant local air pollution benefits, as the emissions of other pollutants are reduced. Those "ancillary benefits" are greater in developing countries, where air quality in big cities is, on average, worse than in the OECD (Markandya and Rübbelke, 2003).

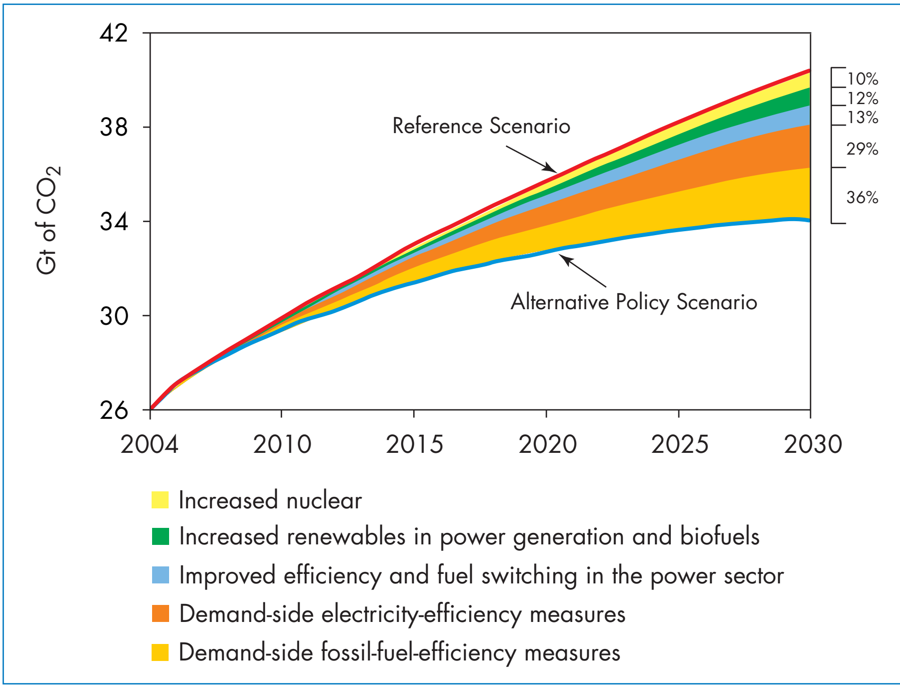
Figure 7.13: **Energy-Related CO_2 Emissions Savings by Region in the Alternative Policy Scenario*, 2030** (Gt)



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

*Compared with the Reference Scenario.

Figure 7.14: **Global Savings in CO_2 Emissions in the Alternative Policy Scenario Compared with the Reference Scenario**



scope for widespread switching to carbon-free fuels. As a result, emissions reductions result primarily from reduced consumption, stemming from increased efficiency, increased use of less carbon-intensive fuels or switching between modes of transport. Emissions from industry are 0.9 Gt lower in 2030, equal to 14% of the total reduction in emissions compared with the Reference Scenario. Avoided emissions from the residential and the services sectors account for the remainder.

ASSESSING THE COST-EFFECTIVENESS OF ALTERNATIVE POLICIES

HIGHLIGHTS

- The Alternative Policy Scenario yields considerable savings in energy demand, energy imports, and CO_2 emissions at a lower total investment cost. The savings require a profound shift in energy investment patterns and are attained through a combination of increased investment in more energy-efficient goods and processes, and different fuel choices in the power and transport sectors.
- Meeting demand for energy services requires less investment in the Alternative Policy Scenario than in the Reference Scenario. Cumulative investments in 2005-2030 – by both the producers and consumers – are $560 billion lower than in the Reference Scenario. Consumers spend $2.4 trillion more, reducing energy supply investment needs by $3 trillion.
- In the electricity chain, the avoided investment is $1.1 trillion. Additional demand-side investment in electricity is $950 billion, but this is more than offset by net savings on the supply side of $2.1 trillion. Demand-side investments in more efficient electrical goods are particularly economic overall; on average, an additional $1 invested in more efficient electrical equipment and appliances avoids more than $2 in investment on the supply side. This ratio is higher in non-OECD countries.
- The cumulative oil-import bills of OECD and developing Asia combined are $1.9 trillion lower over the *Outlook* period in the Alternative Policy Scenario. This is achieved with additional cumulative investment of only $800 billion in more efficient cars and other oil-consuming goods. In 2005-2015, the oil-import savings in the OECD amount to $130 billion, compared with additional investment of only $50 billion.
- Although overall investment is reduced, end users invest more in the Alternative Policy Scenario, while energy producers invest less. Consequently, the additional investment is made by a large number of small investors. Two-thirds of the additional demand-side capital spending is borne by consumers in OECD countries. Consumers see savings in their energy bills of $8.1 trillion, comfortably offsetting the $2.4 trillion in increased investment required to generate these savings. The payback period of the additional demand-side investments is very short, especially in developing countries and for those policies taken before 2015. Government intervention would nonetheless be needed to mobilise the necessary investments.

Investment in Energy-Supply Infrastructure and End-Use Equipment

Overview

The reductions in energy demand, energy imports and energy-related carbon-dioxide emissions that are brought about by the policies and measures analysed in the Alternative Policy Scenario require a profound shift in energy investment patterns. Consumers – households and firms – invest more to purchase energy-efficient equipment. Energy suppliers – electricity, oil, gas and coal producers – invest less in new energy-production and transport infrastructure, since demand is reduced by the introduction of new policies compared with the Reference Scenario. Overall, over 2005-2030, the investment required by the energy sector – ranging from end-use appliances to production and distribution of energy – is \$560 billion less (in year-2005 dollars) in the Alternative Policy Scenario than in the Reference Scenario (Figure 8.1). This capital would be available to be deployed in other sectors of the economy.

Box 8.1: **Comparing Costs and Savings**

This chapter discusses the economics of the Alternative Policy Scenario, providing analyses of:

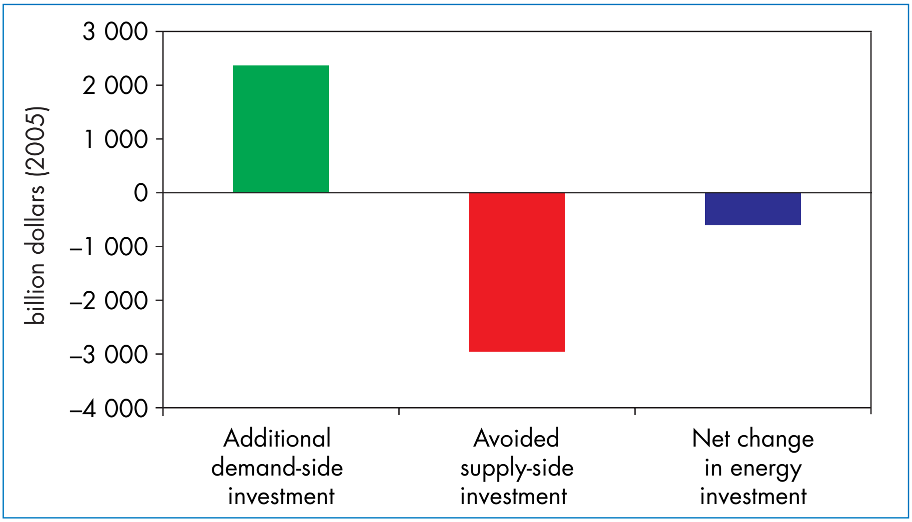
- The net change in investment by energy suppliers and energy consumers.
- The net change in energy import bills and export revenues.
- How the cost to consumers of investing in more energy-efficient equipment compares with the savings they make through lower expenditure on energy bills.

Demand-side investments are consumers' outlays for the purchase of durable goods, that is, end-use equipment. Increases in demand-side investments are thus increases in cash outlays on durable goods.[1] All investments and consumers' savings in energy bills are expressed in year-2005 dollars. Consumers' outlays are attributed to the year in which the equipment is purchased, but their savings are spread over a number of years. Strictly speaking, these savings should be discounted to allow for the higher value of benefits which arise earlier. But there is no generally accepted discount rate, at the global level, to reflect this "time preference" of society. Its value varies from sector to sector, and between different types of purchase.

The offsetting savings in energy costs quoted here are, accordingly, not discounted. Our analysis suggests that the undiscounted cumulative savings in energy bills are more than three times the additional demand-side investments. This implies that even using a relatively high discount rate, *i. e.* 20%, consumers, at least on a collective basis, are better off in the Alternative Policy Scenario.

1. Transaction costs and changes in non-energy operating costs in the Alternative Policy Scenario are not included.

Figure 8.1: **Change in Cumulative Demand- and Supply-Side Investment in the Alternative Policy Scenario*, 2005-2030**



* Compared with the Reference Scenario.

The macroeconomic gains from more efficient energy use involve transfers of income in part from energy producers to producers of consumer end-products and new technologies, and in part from energy consumers to equipment producers and technology providers. Ultimately, consumers invest an estimated $2.4 trillion more over the projection period compared with the Reference Scenario. That additional investment is the consequence of more costly purchases of more efficient cars, industrial motors, appliances and other types of equipment. It reduces global demand for energy by 10% in 2030. As a result, the need for investment in oil, gas, coal, and electricity production and distribution is significantly lower. Cumulative investment in energy-supply infrastructure over 2005-2030 amounts to $17 trillion in the Alternative Policy Scenario, about $3 trillion less than in the Reference Scenario.

Investment not only shifts from supply to demand in the Alternative Policy Scenario; responsibility for investment decisions also shifts, to the innumerable individual firms and households purchasing these new goods. In the Reference Scenario, investments are made by a much smaller group of actors, primarily large energy producers and distributors. To give an idea of the magnitude of the shift, consider the output of one mid-load CCGT plant producing some 2 TWh of electricity per year. To save the same amount of electricity per year, some 16 million European consumers would need to buy a 40% more efficient refrigerator.[2] This would equate to 80% of annual refrigerator sales in Europe.

2. According to current labels, this is equivalent to moving from a class A refrigerator to a class A++.

Investment along the Electricity Chain

In the Alternative Policy Scenario, the avoided investment throughout the electricity chain – from the producer to the consumer – is $1.1 trillion (Table 8.1). Total additional investment on the demand side of electricity amounts to about $950 billion, while savings on the supply side total $2.1 trillion. On average, an additional $1 invested on demand-side electricity in the Alternative Policy Scenario avoids more than $2 in investment on the supply side (including generation, transmission and distribution). This ratio varies by geographic region. In OECD countries, the ratio is $1 invested to $1.6 avoided, while in developing countries, the ratio is larger, at $1 in investment to more than $3 in supply costs avoided.

Demand-side investment in the Alternative Policy Scenario across all regions amounts to about $950 billion more than in the Reference Scenario over the next twenty five years, as consumers purchase more efficient equipment. Their purchases include:

- **Industry and agriculture:** motors, pumps, compressor systems, irrigation pumping systems.
- **Residential sector:** heating, ventilation, air-conditioning, lighting, appliances (*e. g.* refrigerators, washing machines, televisions), hot water systems.
- **Services sector:** heating, ventilation, air-conditioning, lighting, office appliances (*e. g.* PC, mainframes).

More efficient and cleaner technologies, energy-efficient equipment and appliances generally cost more in OECD countries than in non-OECD countries. In the OECD, equipment efficiency at the outset is already higher. More than two-thirds of overall additional spending on the demand side will be by consumers in those countries. On a per-capita basis, the incremental cost in OECD countries is eight times higher than in non-OECD countries. Globally, demand-side investments result in slower growth in electricity demand, reducing global electricity generation needs by 3 900 TWh in 2030. As a result, there is less need to build transmission and distribution lines: cumulative network investment is $1 630 billion lower than in the Reference Scenario.

Not all policies in the Alternative Policy Scenario drive supply-side investments down. Policies to promote renewable energy and nuclear power result in an additional total investment in these types of generating plant of $600 billion. However, the net supply-side investment in this scenario is still lower than in the Reference Scenario, because the higher spending on renewables-based and nuclear plants is more than offset by the reduction in total capacity. Total new fossil-power plant investment in the Alternative Policy Scenario is $1 030 billion lower than in the Reference Scenario.

Most of the avoided net investment along the entire electricity chain occurs in developing countries, where savings amount to some $680 billion. Avoided investment in OECD countries is smaller, largely because the additional capital spending on end-use equipment is bigger.

Table 8.1: **Change in Cumulative Electricity Investment in the Alternative Policy Scenario*, 2005-2030**
($ billion in year-2005 dollars)

		Electricity Supply				
	Electrical equipment and appliances	**Renewables and nuclear generation**	**Fossil-fuel generation**	**Transmission and distribution**	**Total electricity supply**	**Overall electricity investment**
OECD	**667**	**244**	**–508**	**–756**	**–1 020**	**–352**
North America	258	78	–214	–306	–442	–184
Europe	288	132	–242	–337	–447	–159
Pacific	121	33	–52	–112	–131	–10
Transition economies	**34**	**32**	**–46**	**–89**	**–103**	**–69**
Developing countries	**252**	**329**	**–475**	**–783**	**–929**	**–677**
Developing Asia	139	257	–397	–589	–730	–590
China	*94*	*138*	*–201*	*–312*	*–375*	*–282*
India	*3*	*62*	*–73*	*–101*	*–112*	*–109*
Latin America	77	16	–26	–101	–111	–34
Africa	12	44	–29	–47	–32	–20
Middle East	23	12	–22	–46	–56	–33
World	**954**	**604**	**–1 028**	**–1 629**	**–2 053**	**–1 099**

* Compared with the Reference Scenario.

Demand-Side Investment

Additional demand-side investment in the Alternative Policy Scenario amounts to $2.4 trillion (Table 8.2).[3] Of this, investment in transport increases by $1.1 trillion, close to half of the total additional demand-side investments for all sectors worldwide. Investment in the residential and services sectors (including agriculture) is more than $920 billion higher than in the Reference Scenario, while industry invests an extra $360 billion.

Table 8.2: **Additional Demand-Side Investment in the Alternative Policy Scenario*, 2005-2030** ($ billion in year-2005 dollars)

	OECD	Non-OECD	World
Industry	210	152	362
of which electrical equipment	*121*	*74*	*195*
Transport	661	415	1 076
Residential and services	622	304	926
of which electrical equipment	*546*	*212*	*758*
Total	**1 492**	**872**	**2 364**

*Compared with the Reference Scenario.

Consumers in OECD countries, where the capital cost of more efficient and cleaner technologies is high, need to invest $1.5 trillion, two-thirds of the additional global investment in end-use equipment. The share of additional demand-side investment that occurs in non-OECD countries ranges from 33% of the global total of $926 billion in the residential and services sectors to 42% of the total of $362 billion in the industrial sector. These smaller shares are a result of the generally lower capital cost of the end-use technologies applied in developing and transition countries (Box 8.2).

3. The estimates of capital costs for end-use technology used in this analysis are based on the results of work carried out in co-operation with a number of organisations, including the UNEP Risoe Centre on Energy, Climate and Sustainable Development, the European Environment Agency (EEA, 2005), Centro Clima at COPPE/UFRJ, the Indian Institute of Management, and the Energy Research Institute in China. We are particularly grateful to Argonne Laboratory in the United States for its support to part of this analysis through the AMIGA model (Hanson and Laitner, 2006). A number of independent sources were used for consistency-checking purposes, *e.g.* ADB (2006), Chantanakome (2006) and Longhai (2006). Given the variability in the quality of many of the specific regional and sectoral data used, there are many uncertainties surrounding these estimates.

Box 8.2: **Energy Efficiency Codes and Standards in China's Residential and Services Sectors**

Much work is under way in China on establishing and improving building codes, appliance standards and energy efficiency labels. Basic building codes are in place for many regions in China; a national commercial building code was approved in April 2005. In March 2005, China launched a mandatory appliance energy information label programme with pilot projects for refrigerators and air-conditioners (The Energy Foundation, 2006).

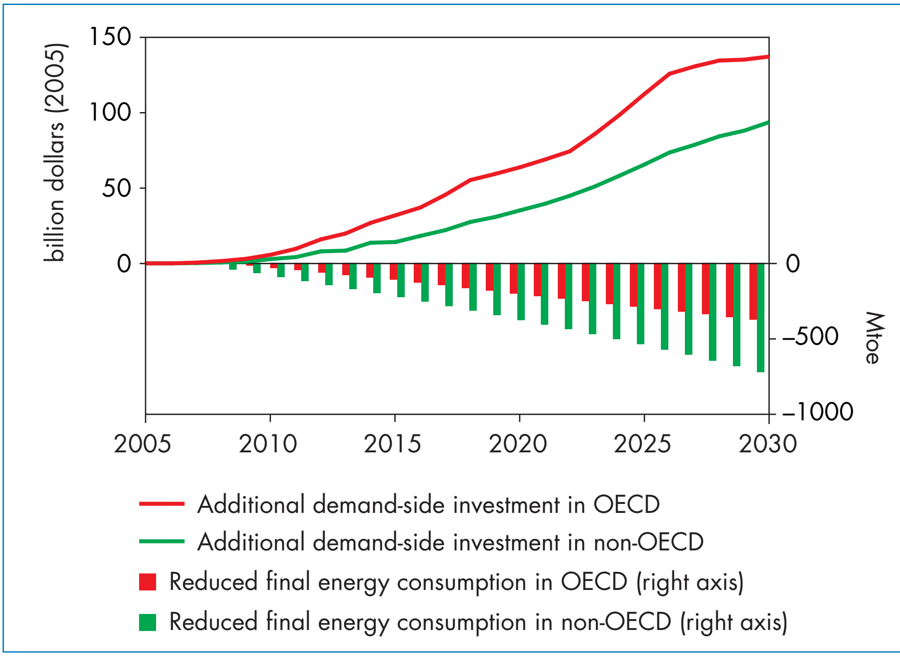
The challenge for China and other developing countries is to bring appliance efficiency and building standards up to best international levels and to improve monitoring and enforcement at all levels. There are some clear incentives: in contrast to OECD countries, where paybacks on energy-efficiency investments range from one to eight years, paybacks on investment in China are shorter.

As an example, consider electricity use in the residential and services sectors. In China the payback on investments to conform with higher appliance standards, labelling and building codes is estimated at two years. Thus, with average annual investments of $2 billion (in year-2005 dollars) starting in 2007 for ten years, China would create an increase in net wealth of $70 billion over the ten-year period. During all but the initial two years, there would be a net income gain (*i.e.* savings exceed outlays).

China has a number of specific advantages. It may be reasonably anticipated that, as a major global manufacturer of appliances and electrical equipment, China can ensure that sufficiently efficient products reach the domestic market. Investment capital, historically a critical bottleneck in most developing countries, is not scarce in China. The country is, therefore, particularly well-placed to make major gains in energy efficiency at an investment cost which would be much lower than that required to meet unconstrained energy demand. Further, energy-efficiency investments in new building construction or retrofit should achieve even higher rates of return than those projected in OECD countries, because of China's lower labour costs.

The additional investment needs of households and firms grow steadily over the *Outlook* period (Figure 8.2). In OECD countries, the additional outlays reach $140 billion in 2030, while those in non-OECD countries reach $95 billion. This is explained partly by the fact that the costs of investments in more efficient equipment rise with time, as low-cost opportunities have already been exploited, and partly by the growth over time in the stock of appliances, cars and buildings. Overall, the additional expenditure represents a very small percentage of GDP over the *Outlook* period, 0.13% for OECD countries and 0.07% for non-OECD countries, though the sums involved can be large for individual investors.

Figure 8.2: **Demand-Side Investment and Final Energy Savings by Region in the Alternative Policy Scenario***



* Compared with the Reference Scenario.

Transport

Additional investment in the transport sector amounts to $1.1 trillion. Half of this investment, or $560 billion, goes to light-duty vehicles. Improved efficiency in trucks and more use of buses and high-speed trains account for another $330 billion, while investments in aviation account for some $190 billion. Although aviation accounts for almost 20% of the total additional transport investment, it achieves only 11% of the total reduction in energy demand in the transport sector. The high share of aviation in the total is a function of the high cost of improving average fleet fuel efficiency for aircraft.

OECD countries make 60% of the incremental transport investment, a similar share across transport modes. This high share is a function of the higher cost of increasing fuel economy in OECD countries and their larger share of cumulative vehicles sales over the projection period.

A variety of technologies contributes to energy savings. In the Alternative Policy Scenario, some of the improvements in the technology of the internal combustion engine (ICE) are assumed to be applied to increase vehicle power, but many go to fuel efficiency. In addition, energy savings come from hybrid cars and alternative fuel vehicles and from the more rapid market penetration of light-weight materials. Such technological advances come at a cost: in 2030, the additional cost per vehicle is between $200 and $600 in non-OECD countries and between $400 and $800 in OECD countries, compared to the Reference Scenario. This increment represents only an average 3% and 5% increase in the vehicle price respectively. Improving vehicle efficiency is, of course, cheaper in countries with a larger share of inefficient vehicles, especially heavy ones, in the existing fleet.

Other Sectors

Three-quarters of the additional investment in the industry and in the residential and services sectors is for electrical equipment. Additional investment in the Alternative Policy Scenario in electrical equipment – industrial motors, appliances and lighting – in industry and buildings amounts to $950 billion. Around three-quarters of this investment occurs in the buildings sector. Investment in efficient lighting and appliances accounts for more than 80% of additional investment in the residential and services sectors. Additional investment in motor systems and other electrical equipment accounts for the bulk of additional investment in industry (see Box 8.3).

8

Box 8.3: **Energy Efficiency Project in Industry in China**

The Global Environment Facility (GEF) is providing funds to back loan guarantees to commercial banks in China to promote Energy Management Companies' (EMCs) work on energy performance contracting (World Bank, 2002 and 2005). The expansion of the EMC industry is one of the main means the Chinese government is using to promote energy conservation. EMCs carry out projects at industrial companies on a contractual basis, providing the design, financing and implementation of the project. EMCs and their industrial clients are free to choose the efficiency measures to be implemented. Equipment installed during the project is handed over by the EMC at the end of the contract (usually one to three years).

The GEF project was built in two phases. The first one has been completed and the second has started. More than 140 measures have been implemented during the first phase of the programme. They have already yielded significant savings in industrial energy consumption, 75% of which were in the form of reduced coal burn and the remainder in the form of reduced electricity consumption.

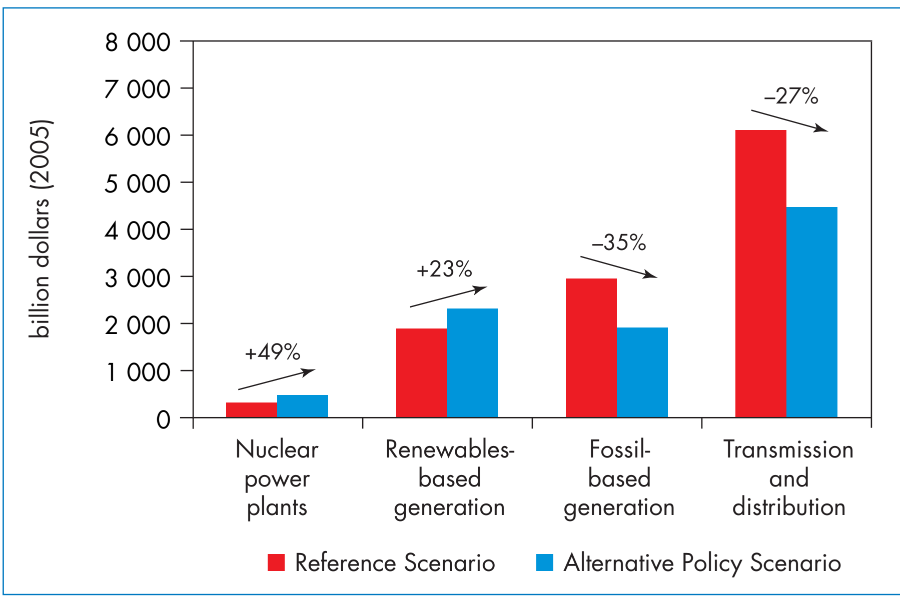
Total expected investment over the second phase of the project is $384 million. Planners project that, over its lifetime, the programme should result in 35 million tonnes of coal equivalent (25 Mtoe) energy savings as well as a reduction of 86 Mt of CO_2 emissions. On the basis of 2005 end-use prices to industrial customers and the fuel mix of the first phase, the average payback time amounts to less than one year.

Supply-Side Investment

In the Alternative Policy Scenario, the worldwide investment requirement for energy-supply infrastructure over the period 2005-2030 is $17.3 trillion – $2.9 trillion, or 14%, less than in the Reference Scenario. The cumulative reduction in supply-side investment in developing countries and transition economies amounts to about $1.8 trillion, a fall of 14% compared with the Reference Scenario. The reduced investment in OECD countries is $1.1 trillion, or 15%.

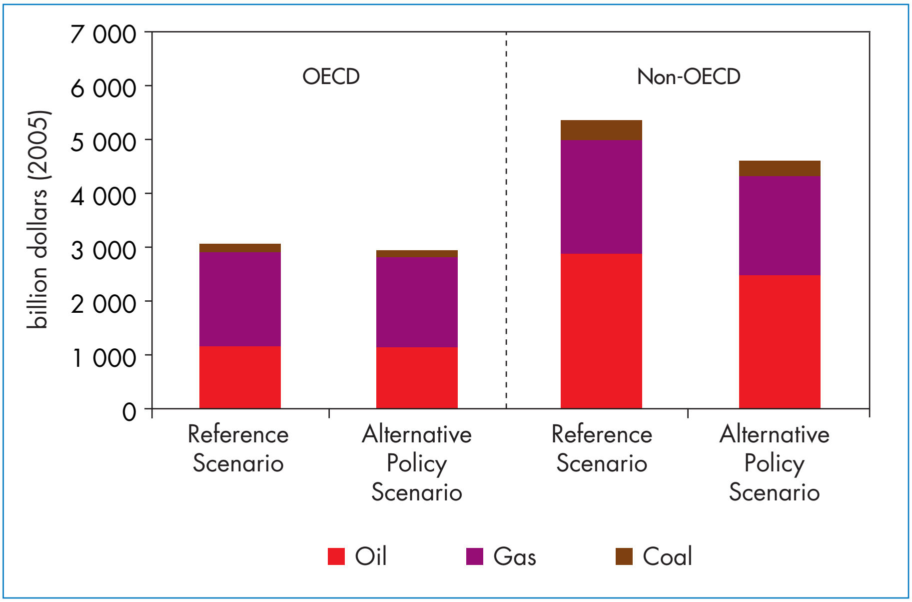
Reduced electricity-supply investment accounts for more than two-thirds of the overall fall. The capital needed for transmission and distribution networks is almost $1.6 trillion lower, thanks mainly to lower demand but also to the wider use of distributed generation. The fall in cumulative investment in power generation, at $420 billion, is proportionately much smaller. This is because the capital intensity of renewables, nuclear power and some forms of distributed generation is higher than that of fossil fuels (Figure 8.3).

Figure 8.3: **Cumulative Global Investment in Electricity-Supply Infrastructure by Scenario, 2005-2030**



Total fossil-fuel investment in the Alternative Policy Scenario continues to rise over the *Outlook* period but falls below the levels projected in the Reference Scenario: total investment worldwide in oil and gas is $800 billion, or 10%, lower than in the Reference Scenario, mainly because there is less demand and consequently less need to expand production (Figure 8.4). Given that many countries, for reasons of energy security, are seeking to develop domestic resources, it is projected that the greatest impact of these investment reductions will be in exporting countries. Thus, for example, the difference in investment between the Alternative Policy and the Reference Scenarios in OECD oil and gas supply investment is very small. In contrast, reduced investment in oil exploration and development in Middle East and North Africa makes up a significant part of the decrease in non-OECD oil investment. Reduced investment for gas-transportation infrastructure contributes the largest share of the $360 billion global reduction in gas investment. Investment needs in the coal industry are reduced by 22%, from $560 billion in the Reference Scenario to around $440 billion. Reduced investment in coal in China alone accounts for about a third of that difference.

Figure 8.4: **Investment in Fossil-Fuel Supply in the Reference and Alternative Policy Scenarios, 2005-2030**



Implications for Energy Import Bills and Export Revenues

In the Alternative Policy Scenario, major oil and gas *importing* regions will benefit from a decrease in their oil and gas import bills (see Table 8.3). Over the *Outlook* period the oil import bills of OECD countries will be 6% – or $900 billion – lower than in the Reference Scenario. The United States will see

Table 8.3: **Cumulative Oil and Gas Import Bills in Main Net Importing Regions by Scenario, 2005-2030** (in year-2005 dollars)

	Reference Scenario		**Alternative Policy Scenario**		**Difference**		**Percentage difference**	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
	$ trillion		$ trillion		$ trillion		%	
OECD	**16.0**	**6.6**	**15.1**	**6.0**	**–0.9**	**–0.6**	**–6%**	**–9%**
United States	7.7	1.0	7.2	0.8	–0.5	–0.2	–6%	–20%
Japan	2.4	0.8	2.3	0.8	–0.1	0.0	–4%	0%
European Union	5.9	4.8	5.6	4.4	–0.3	–0.4	–5%	–8%
Developing Asia	**7.0**	**0.3**	**6.0**	**0.5**	**–1.0**	**0.2**	**–14%**	**67%**
China	3.5	0.2	3.0	0.4	–0.5	0.2	–14%	100%
India	1.6	0.1	1.4	0.1	–0.2	0.0	–13%	0%

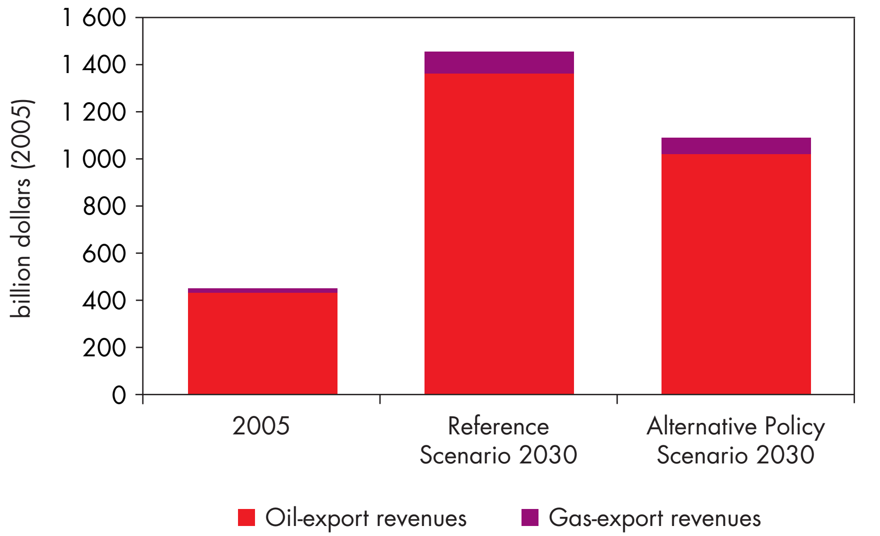
its bill reduced the most, both in absolute and percentage terms ($500 billion and 6% respectively). Developing country importers, in particular China and India, will also benefit from the fall in oil import bills: China will see a decline of $500 billion (14%) and India a drop of $200 billion (13%).

Approximately 60% of the savings in oil demand, and consequently in net import requirements, accrue from reduced demand in the transport sector. In all net-importing countries, the additional investment required in the transport sector is outweighed by the savings in oil import bills. Savings in oil import bills are already noticeable by 2015: by then, OECD countries save $130 billion, as a result of additional investment of only $50 billion – mainly in the transport sector.

Gas bills for the OECD and developing Asia are also lower – $400 billion less than in the Reference Scenario over the *Outlook* period. All importing countries except China will see declining gas bills. While the European Union experiences a large reduction in absolute value (at $400 billion), China will see an increase in its gas import bill, because of aggressive policies to switch away from coal for environmental reasons.

The lower demand for oil and gas translates into a lower call on Middle East and North Africa exports. This results in a 25% reduction in the region's cumulative oil and gas export revenues over 2005-2030, compared to the Reference Scenario, although the region still sees an increase of 140% over 2005 levels (Figure 8.5). Other exporting countries, like Russia, will also see their export revenues fall below the level of the Reference Scenario, although these countries also see an increase over today's level.

Figure 8.5: **Oil and Gas Export Revenues in the Middle East and North Africa in the Reference and Alternative Policy Scenarios**



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Implications for Consumers

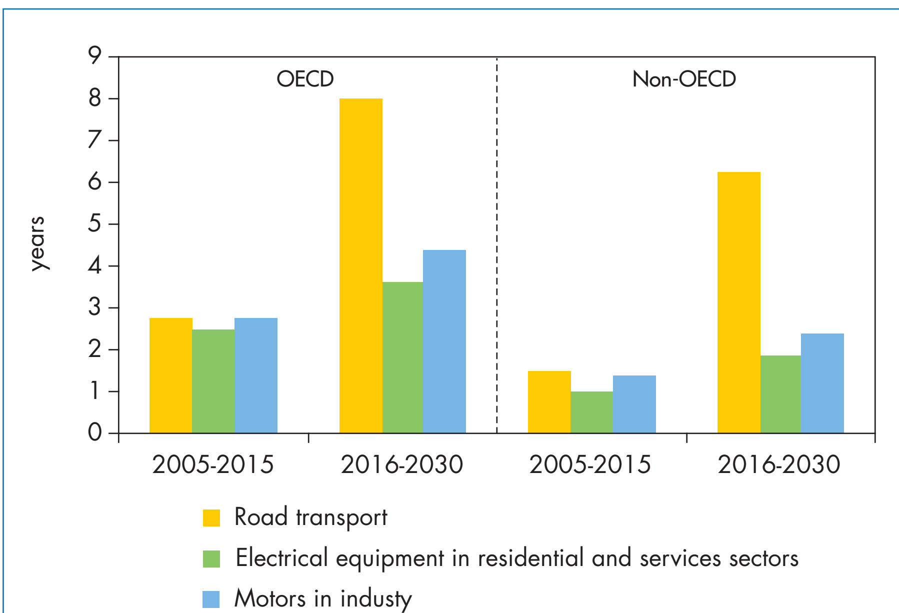
The energy and emissions savings in the Alternative Policy Scenario can be achieved at net benefit (negative cost) to society. This is not to say the savings are free, but rather that the higher capital spending to improve energy efficiency is more than offset by savings in consumers' fuel expenditures over the lifetime of the equipment. These benefits are coupled with the additional benefits of improved energy security and lower emissions of CO_2 and other pollutants. These environmental and security gains, though difficult to express in monetary terms, are nonetheless of increasingly high value to society. In some cases, policy-makers may consider them to be large enough alone to justify the policy intervention; and, in certain circumstances, the public at large might agree. More efficient appliances also often bring other, non-energy related benefits, such as longer equipment lifetimes and lower maintenance costs.

It should be noted that all calculations here of the net economic benefit to consumers are made using a zero discount rate (Box 8.1). In reality, consumers will discount the benefits of the reduced energy bills. Discount rates will vary according to the goods purchased. For example, consumers use one discount rate – and different rates in different regions – to buy a double-glazed window and another to buy a car. But there is no available scale of generally accepted discount rates for different goods and regions. We accordingly provide the undiscounted values of the additional outlays and the reduced fuel bills.

The payback time of the policies included in the Alternative Policy Scenario is usually very short. Payback times of about two years can be achieved in commercial lighting retrofits or generally in buying compact fluorescent lamps instead of incandescent bulbs (IEA, 2006). Payback times in OECD countries are usually longer than in non-OECD countries. Payback times are also longer for investment made later in the projection period. This is because the marginal cost of improving efficiency is higher once the cheaper options available in early years have been exploited. Payback periods vary between one and eight years. The longest payback is in the transport sector in OECD countries (Figure 8.6).

A significant number of demand-side measures across various sectors are feasible both in OECD and non-OECD countries (Boxes 8.2 and 8.4). High-efficiency industrial motors and irrigation pumps in most developing countries, for instance, can save electricity at a cost in the range of $5 to $30 per MWh (World Bank, 2006). Our analysis shows that investment required to save 1 kWh in the residential and services sectors in non-OECD countries

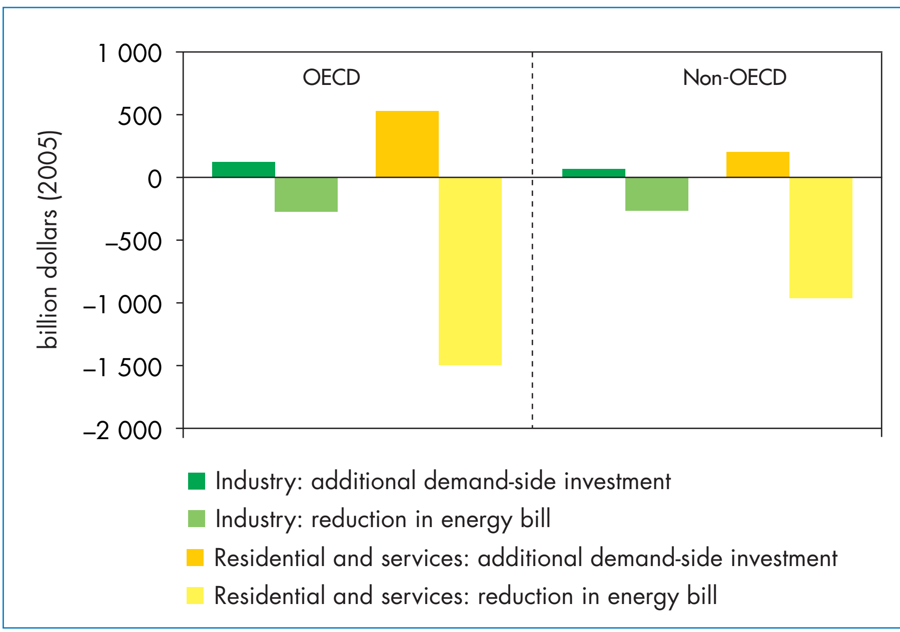
Figure 8.6: **Indicative Average Payback Period of Selected Policies in the Alternative Policy Scenario by Region**



is around US 1.5 cents[4] and in the OECD US 3 cents to US 4.5 cents, compared with electricity prices in the OECD of between US 9 cents and US 15 cents per kWh. In non-OECD countries prices are tipically lower because of subsidies.

In aggregate terms, over the next two-and-a-half decades, the Alternative Policy Scenario would require additional investment in electricity-using equipment of $1 trillion beyond that projected in the Reference Scenario. Over the same time frame, savings in consumers' electricity bills would come to more than $3 trillion (Figure 8.7). In non-OECD countries, energy-efficiency investment made in the residential and services sectors at the beginning of the projection period pays off very quickly for the consumer, in most cases in less than a year. Over the projection period as a whole, the saving in electricity bills in the

Figure 8.7: **Change in End-Use Electricity Investment and in Consumers' Electricity Bills in the Alternative Policy Scenario*, 2005-2030**



* Compared with the Reference Scenario.

4. The Brazilian National Program for Energy Efficiency in Power Sector (PROCEL) during 1996 to 2003 achieved electricity savings at a cost of US 1.2 cents per kWh (Guerreiro, 2006).

Box 8.4: Energy Savings Programme in the UK Residential Sector

The Electricity Act 1989 and Gas Act 1986, as amended by the Utilities Act, make provision for the government to set energy efficiency targets on energy suppliers. In the 3-year period from 2002 to 2005, the government set a target of cumulative energy savings of 62 TWh. Electricity and gas suppliers were required to achieve these energy savings through the encouragement of efficiency measures among their customers in the residential sector.

The cumulative energy savings achieved surpassed the target and amounted to 38 TWh of electricity and 53 TWh of fossil fuel, of which an estimated 90% is gas. The total cost of the programme, including the direct and indirect costs incurred by the energy suppliers, contributions from households and contributions from other parties amounted to 690 million pounds ($1 190 million).

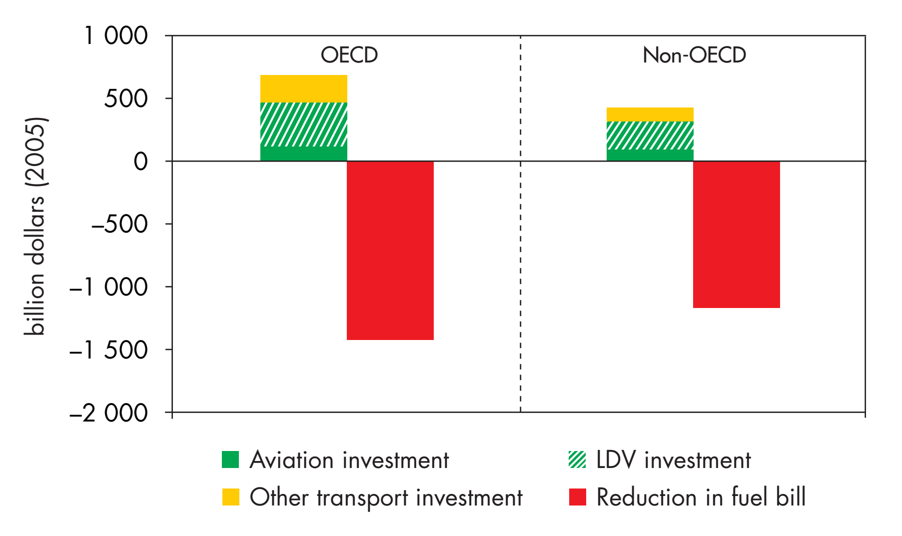
The net present value of the benefits to households, after deducting their direct contributions and the energy suppliers' total costs, is estimated at about $5.2 billion. The total cost of saving a delivered unit of electricity or gas was 2.2 cents per kWh and 0.9 cents per kWh respectively (Lees, 2006). The greater part of the savings was achieved by a relatively small number of measures, including wall and loft insulation, installation of higher-efficiency freezers and washing machines, and replacement of incandescent lights by compact fluorescent lamps.

The programme has been followed up by a second commitment period that is to run from 2005 through 2008. The overall target for this next phase is 130 TWh. This follow-up programme is taken into account in the Alternative Policy Scenario.

residential and commercial sectors in non-OECD countries is more than four times higher than the additional investment required.

A similar set of benefits and costs is observed in the transport sector. In both OECD and non-OECD countries, the savings in spending on fuel by consumers more than offset the incremental capital cost (Figure 8.8). In OECD countries, the value of fuel savings is more than twice as high as the additional capital expenditure. In non-OECD countries, it is almost three times higher. As the lifetime of light-duty vehicles (LDV) is usually from 8 to 15 years, most investments in more efficient vehicles would be profitable to the consumer (Box 8.5), although the gradual payback over time may

Figure 8.8: **Change in End-Use Investment in Transport and Consumers' Fuel Bills in the Alternative Policy Scenario*, 2005-2030**



* Compared with the Reference Scenario.

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Box 8.5: **Increasing Light-Duty Vehicle Efficiency**

Using current technologies to improve the fuel economy of light-duty vehicles rather than to increase power and size could lead to significant fuel savings – and could be achieved with little if any cost penalty. In the United States and Canada, assuming a fuel economy improvement of 32% by 2030 compared to today, the payback period for a consumer buying a new vehicle and driving it about 10 000 km per year would be between one and six years (depending on the technology used). The shorter payback occurs when all the technology improvements are devoted to fuel economy improvements; the longer period would be required where the initially higher capital cost of introducing hybrids has to be covered.

In the European Union, using the same assumptions for vehicle use and applying a fuel economy improvement of 35% by 2030, the payback period would range between one and four years. The European Union's shorter payback compared to that in the United States is due to higher end-use fuel prices in the European Union. In Japan, payback periods are typically longer, since relatively low-cost technological options to improve fuel economy have already been adopted.

With the exception of China (where stringent fuel economy standards have been enacted) and, to some extent, Brazil, most developing countries' new light-duty vehicle sales over the projection period will be dominated by proven technologies that are widespread in the OECD. The marked cost advantages of adopting new vehicle fuel economy improvements in these circumstances keep the payback period short. Developing countries, on average, have payback periods for transport efficiency measures ranging from one to five years. With its stringent standards, China is the exception: its payback periods are the longest among non-OECD countries and range from four to five years. However, the net benefits to China of reduced oil imports have led decision-makers to accept the slightly longer payback periods.

necessitate intervention to overcome the problem of financing initial capital requirements.

Barriers to Investment in End-Use Energy Efficiency

Compared with investment in supply, end-use efficiency improvements in the transport, industry, commercial and residential sectors involve many more individual decision-makers and a much greater number of individual decisions. Financing comes from the private sector or the consumers themselves. The most effective way of encouraging investment in energy-efficiency improvements in these circumstances is well-designed and well-enforced regulations on efficiency standards, coupled with appropriate energy-pricing policies (World Bank, 2006a). In most cases, buying more efficient energy-consuming equipment would bring a net financial benefit to the consumer, at least over time. However, it is highly unlikely that an unregulated market will deliver least-cost end-use energy services. Market barriers and imperfections include:

- Energy efficiency is often a minor factor in decisions to buy appliances and equipment.
- The financial constraints on individual consumers are often far more severe than those implied by social or commercial discount rates or long-term interest rates. The implicit discount rate in the services sector may be as high as 20%, compared with less than 10% for the public sector and 4% to 6% for long-term interest rates.
- Missing or partial information regarding the energy performance of end-use equipment or energy-using systems.
- A lack of awareness regarding the potential for cost-effective energy-savings.

- The decision-makers for energy-efficiency investments are not always the final users who have to pay the energy bill. Thus, the overall cost of energy services is not revealed by the market. For example, landlords and property developers have less incentive to make buildings more efficient, as the tenants and future owners are liable for the running costs and this factor is not fully reflected in the value of the property.

A market cannot operate effectively when the value of the goods or services being bought is unknown or unclear. Despite numerous important policy-driven improvements in this regard over recent years, the energy performance of many energy-using systems is still either invisible or obscure to end-users.

In fast-growing economies, such as India and China, the energy efficiency of new energy-consuming capital stock is of crucial importance to future energy-demand trends. However, rapid growth in itself may also compromise energy efficiency, as the pressure to build new capacity quickly and cheaply often outweighs longer-term considerations about efficiency and running costs (World Bank, 2006b). Even if investment in energy efficiency is considered by economists to be profitable and by policy-makers to be crucial to meeting energy-security and environmental goals, it is likely to be necessary to offer incentives for such investments. But such policies have been adopted only slowly. Investment directed to energy efficiency by the World Bank over the past 15 years represents a tiny percentage of its total energy investment (Figure 8.9).

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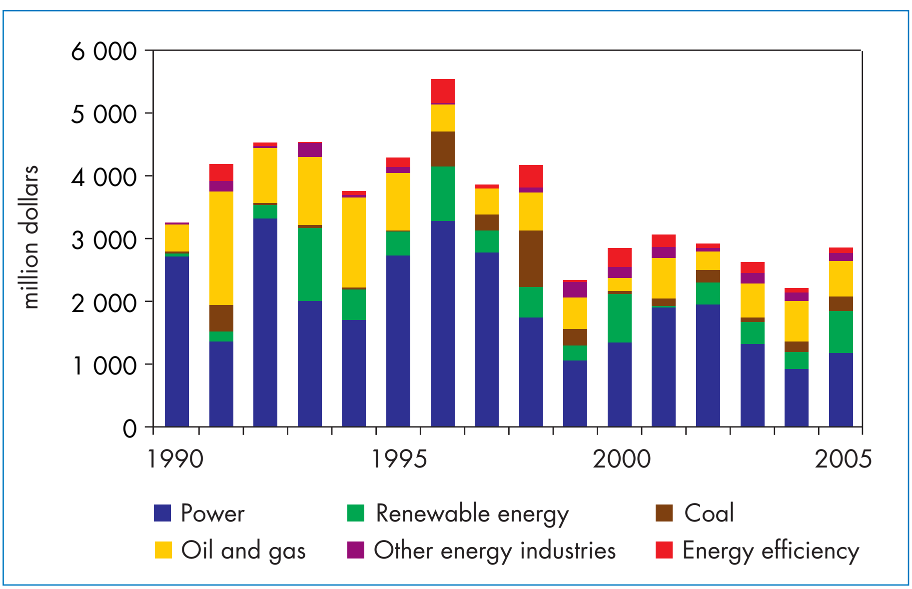
Figure 8.9: **World Bank Investment in Energy by Sector, 1990-2005**



DEEPENING THE ANALYSIS: RESULTS BY SECTOR

HIGHLIGHTS

- World electricity generation is 12% lower in 2030 than in the Reference Scenario, mainly because of greater end-use efficiency. The shares of renewables, nuclear power and combined heat and power are higher. The efficiency of fossil-based generation is also higher. Global CO_2 emissions from power plants are reduced by 22%, almost 4 gigatonnes. More than half of this reduction occurs in developing countries. In the OECD, power sector emissions are 6% lower than in 2004.
- Measures in the transport sector produce 7.6 mb/d of savings in global oil demand by 2030, close to 60% of all the oil savings in the Alternative Policy Scenario. Half of the savings come from just three regions – the United States, China and the European Union – and more than two-thirds from more efficient new vehicles. Improved conventional internal combustion engines and the introduction of hybrid vehicles contribute most to efficiency improvements in the Alternative Policy Scenario. Biofuels use is also higher, helping to cut oil needs. Efficiency improvements in new aircraft save 0.7 mb/d by 2030, but they cost more than savings in other transport modes.
- Global industrial energy demand is 337 Mtoe, or 9%, lower in 2030 than in the Reference Scenario. Reduced consumption of coal accounts for 38% of total savings, while electricity accounts for 27%, oil for 23% and gas for 12%. Over half of global energy savings in the industry sector are the result of more energy-efficient production of iron and steel, chemicals and non-metallic products. Nearly three-quarters occur in non-OECD countries. The savings in China alone exceed those in all OECD countries.
- The electricity saved in the residential and commercial sectors combined accounts for two-thirds of all the electricity savings in the Alternative Policy Scenario. By 2030, the savings in these two sectors avoid the need to build 412 GW of new capacity – slightly less than the total installed capacity of China in 2004. Introduction of more efficient appliances, air-conditioning and lighting account for the bulk of these savings. Stricter building codes cut oil and gas use for heating by 10% by 2030. Most of these savings occur in non-OECD countries, where the building stock and appliances are expected to grow the most.

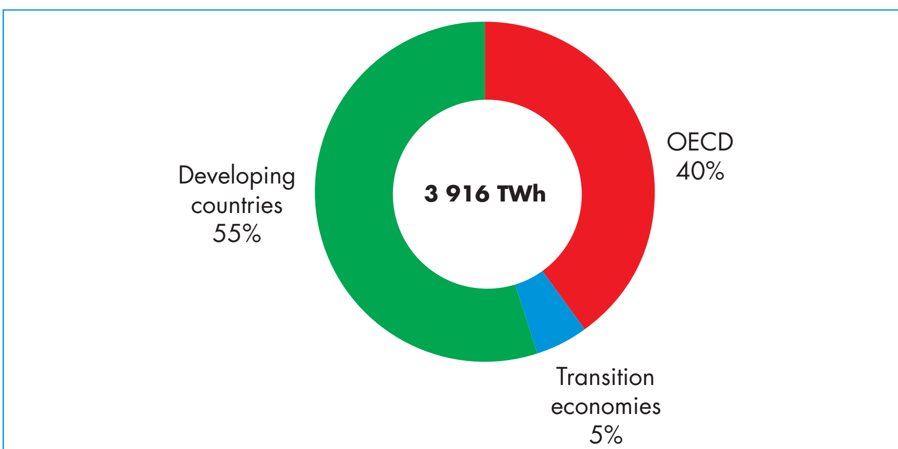
Power Generation

Summary of Results

Power generation is the fastest-growing sector, both in terms of energy demand and carbon-dioxide emissions. In the Reference Scenario, the share of electricity in world energy demand is projected to increase from 16% in 2004 to 21% in 2030. The power sector now accounts for 41% of total energy-related CO_2 emissions. This share rises to 44% in 2030 in the Reference Scenario. The power sector can use a wide range of fuels and offers numerous options to alter these trends, reducing emissions and improving security of supply.

In the Alternative Policy Scenario, new policies cut CO_2 emissions by 22% in 2030. They also reduce dependence on imported fuels, notably gas. Power-generation demand for gas is 22% lower in 2030. World electricity generation reaches 29 835 TWh in 2030, 12% lower than in the Reference Scenario, mainly as a result of end-use efficiency improvements. The reduction corresponds approximately to seven years of demand growth. In other words, electricity generation in 2030 in the Alternative Policy Scenario roughly corresponds to electricity generation in 2023 in the Reference Scenario. The savings are greater than all the electricity now generated in OECD Europe in a year. Over half of the savings occur in developing countries, where the potential to improve end-use efficiency is greatest (Figure 9.1).

Figure 9.1: **Reduction in Electricity Generation in the Alternative Policy Scenario* by Region, 2030**



* Compared with the Reference Scenario.

The projected trends in the Alternative Policy Scenario imply a more rapid decline in electricity intensity – electricity consumption per unit of GDP – than in the Reference Scenario and a substantial deviation from recent trends

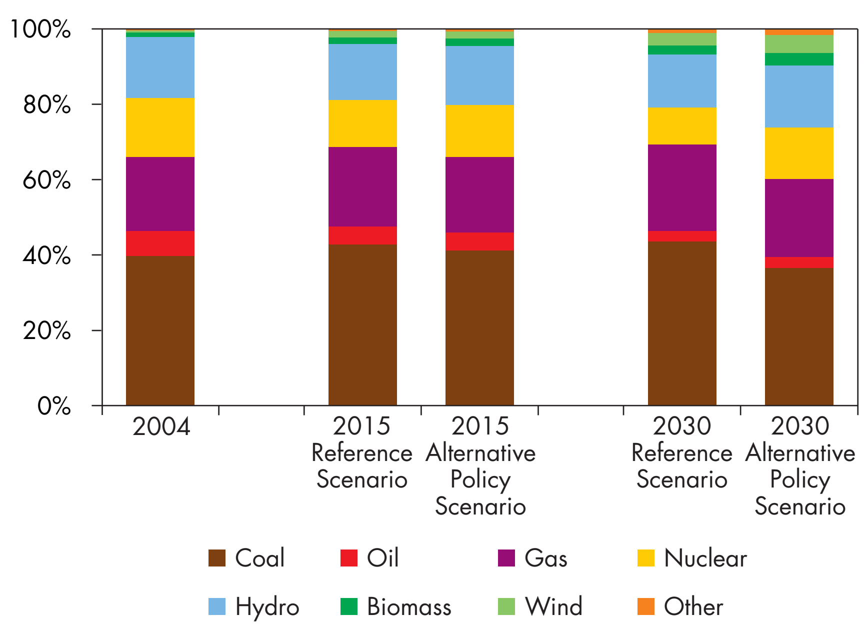
(Table 9.1). Even so, average per-capita electricity generation in 2030 is one-third higher than today globally and 15% higher in the OECD.

Table 9.1: **Electricity Generation and Electricity Intensity Growth Rates**

	Electricity generation (%)	Electricity intensity (%)
1990-2004	2.8%	–0.5%
2004-2030 Reference Scenario	2.6%	–0.8%
2004-2030 Alternative Policy Scenario	2.1%	–1.3%

In the Reference Scenario, the power sector relies increasingly on fossil fuels: about two-thirds of electricity generation is based on fossil fuels in 2030. Coal and gas make up nearly three-quarters of the additional electricity generation. In the Alternative Policy Scenario, the share of fossil fuels in electricity generation mix falls to 60% by 2030. The current share is 66%. The largest fall is in the share of coal, which drops to 37% in 2030 – nearly seven percentage points lower than in the Reference Scenario (Figure 9.2). The change in the electricity mix is more pronounced in the second half of the *Outlook* period, reflecting the rate of capital-stock turnover, the long lead times for some types of power plants, improvements in technology and reductions in the capital costs of new technologies.

Figure 9.2: **Global Fuel Shares in Electricity Generation**



Note: "Other" includes geothermal, solar, tidal and wave energy.

Table 9.2 shows the changes in electricity-generating capacity. Global installed capacity is 770 GW lower in 2030 compared with the Reference Scenario, roughly evenly split between the OECD and the developing world. Coal-fired capacity is reduced by 680 GW and gas-fired capacity by 409 GW. There is less need for baseload and mid-load gas-fired capacity, but gas is still the main fuel used in gas turbines to meet peak-load demand. Nuclear power generating capacity is more than 100 GW, or 25%, higher in 2030. Two-thirds of this increase occurs in OECD countries. There are about 258 GW of additional renewables-based capacity in the Alternative Policy Scenario.

New power plants are more efficient than in the Reference Scenario, by about two percentage points on average. The efficiency of new coal-fired power plants exceeds 50% in 2030. Combined-cycle gas turbines (CCGTs) achieve thermal efficiencies approaching 65% and open-cycle gas turbines between 40% and 45%.

Distributed generation – production of energy close to where it is used – plays a greater role in the Alternative Policy Scenario. It helps save fuel and CO_2 emissions because it reduces network losses. It also reduces investment in transmission networks. Distributed generation in the Alternative Policy Scenario involves greater use of combined heat and power (CHP) – mainly in industry – and photovoltaics in buildings. CHP generation relies on gas (which improves the economics of gas-fired generation) and biomass. Fuel cells using natural gas have a higher market share and they are used increasingly in CHP. Their efficiency increases up to 70% by 2030.

Electricity Mix

Total coal-fired electricity generation reaches about 10 900 TWh in 2030, 26% less than in the Reference Scenario but still 58% higher than today. The total reduction in coal-fired generation is almost as large as the current level of coal-fired electricity generation in the OECD. Most of the reduction in coal-fired generation is in China, India and the OECD (Figure 9.3). Coal nonetheless remains the world's largest source of electricity in 2030.

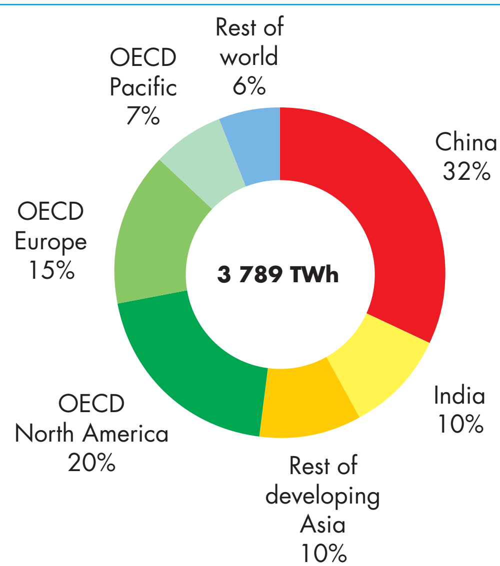
Gas-fired electricity generation is 21% lower in 2030 than in the Reference Scenario. The share of gas in total generation drops by two percentage points. The total reduction in 2030 amounts to 1 619 TWh. The OECD contributes 45% to this reduction, developing countries 40% and the transition economies 15%. There are substantial reductions in CCGT capacity but overall there is a higher share of gas-fired CHP and electricity generation from fuel cells.

Table 9.2: **Changes in Electricity-Generating Capacity Additions in the Alternative Policy Scenario*, 2005-2030** (GW)

	World	OECD	Developing countries	Transition economies
Decreases				
Coal	–680	–298	–367	–15
Oil	–42	–28	–14	0
Gas	–409	–183	–173	–54
Increases				
Nuclear	+103	+66	+26	+10
Hydro	+58	+13	+42	+3
Biomass	+28	0	+26	+2
Wind onshore	+88	+26	+58	+4
Wind offshore	+21	+18	+3	0
Solar photovoltaics	+50	+29	+21	0
Solar thermal	+7	+6	+1	0
Geothermal	+2	+1	+1	0
Tidal and wave	+4	+3	0	0
Net change	**–770**	**–346**	**–375**	**–50**

* Compared with the Reference Scenario.

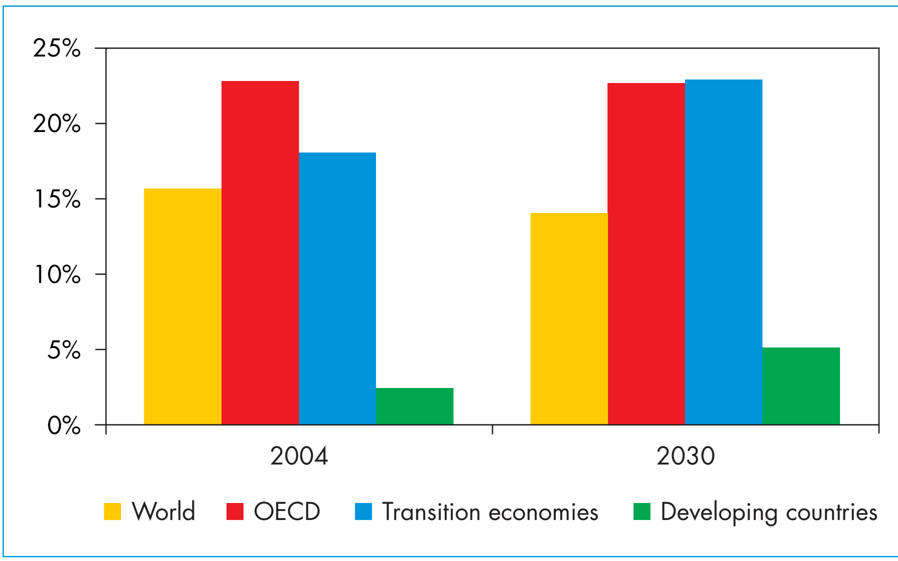
Figure 9.3: **Reduction in Coal-Fired Generation by Region in the Alternative Policy Scenario***



* Compared with the Reference Scenario.

Nuclear power capacity rises to 519 GW in 2030, about 100 GW more than in the Reference Scenario. This is because fewer nuclear power plants are shut down over the period 2005-2030 and because more new nuclear power plants are built. Globally, the share of nuclear power in electricity generation is 14% in 2030, compared with 16% in 2004. In the OECD, the share of nuclear power in 2030 is about the same as now, at 22%. The share of nuclear power increases both in the transition economies and in the developing world (see Chapter 13). Nuclear power generating capacity in the OECD reaches 362 GW in 2030, up from 305 GW in 2004. There are substantial increases in China (50 GW of installed capacity in 2030), India (25 GW) and Russia (40 GW).

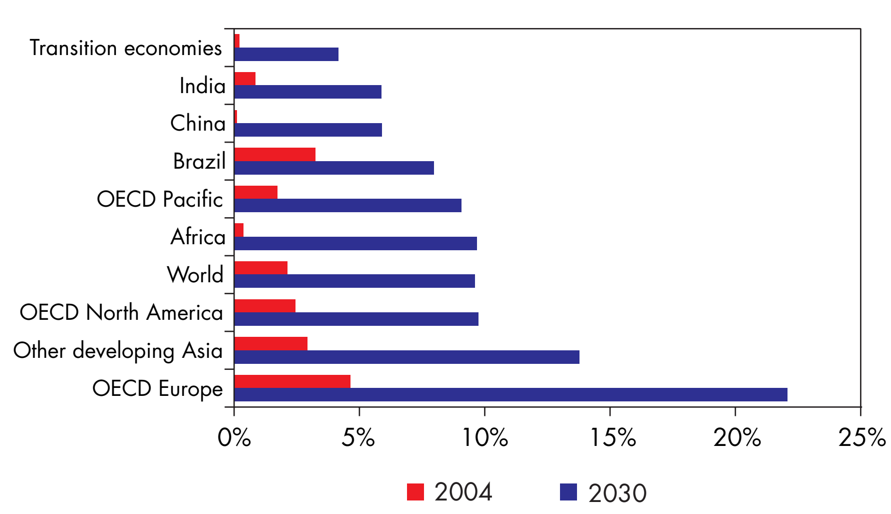
Figure 9.4: **Share of Nuclear Power in Electricity Generation by Region in the Alternative Policy Scenario**



In the Alternative Policy Scenario, renewable energy plays a major role in the global electricity mix in 2030, supplying 26% of total electricity. On a regional basis, the share of hydropower and other renewables increases by ten percentage points above current levels in the OECD, by four points in developing countries and by four points in the transition economies. In the OECD, the most dramatic increase is projected for OECD Europe, where 38% of electricity is based on renewables in 2030.

More hydropower plants are built than in the Reference Scenario, mostly in developing countries, where the unexploited potential is still large. The share of hydropower is 16% in 2030, the same as now. Total hydropower capacity reaches 1 431 GW in 2030, compared with 851 GW now and 1 373 GW in 2030 in the Reference Scenario. In the Alternative Policy Scenario, hydropower capacity in China increases from 105 GW in 2004 to 298 GW in 2030.[1] In India, it increases from 31 GW to 105 GW. Electricity from biomass, wind, solar, geothermal and tide and wave power reaches 2 872 TWh in 2030, almost eight times higher than now and 27% higher than in the Reference Scenario. Their share in electricity generation grows from 2% now to 10% in 2030. Most of the growth is in wind power and biomass. These substantial increases reflect new policies to support the development of renewables as well as cost reductions resulting from technological learning (Figure 9.6).

Figure 9.5: **Shares of non-Hydro Renewable Energy in Electricity Generation by Region in the Alternative Policy Scenario**



At 13.7 gigatonnes, power-sector CO_2 emissions in 2030 are 22% lower in the Alternative Policy Scenario than in the Reference Scenario. Emissions per unit of electricity produced drop substantially, mainly because of the larger shares of nuclear power and renewables in the electricity mix (Figure 9.7). Overall, the electricity mix decarbonises at a rate of 1.1% per year. In the OECD, power-sector emissions are roughly stable through to 2020 and start falling thereafter. In 2030, they are 6% lower than in 2004. In developing counties, CO_2 emissions from power plants are 22% lower than in the

1. Recent plans of the Chinese government call for an increase to 300 GW by 2020.

Figure 9.6: **Investment Costs of Renewables-Based Power-Generation Technologies in the Alternative Policy Scenario, 2004 and 2030**

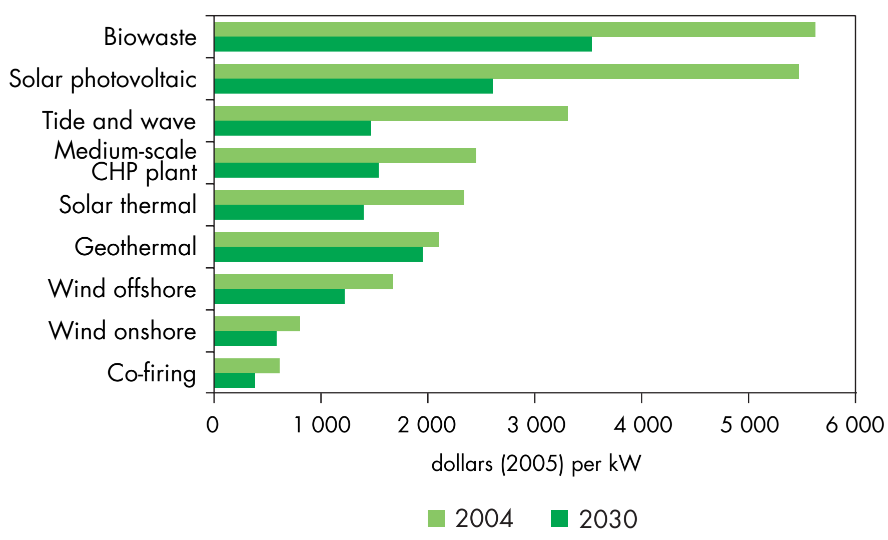
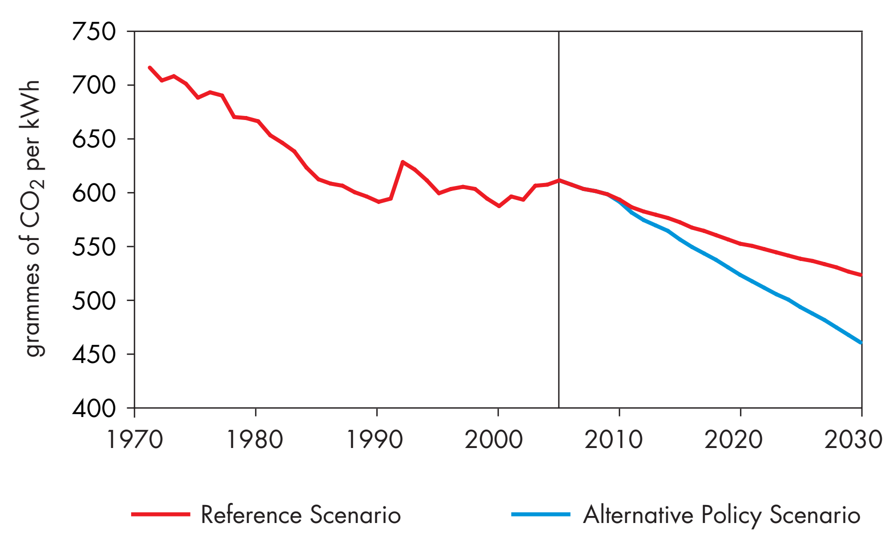


Figure 9.7: **CO_2 Emissions per kWh of Electricity Generated in the Reference and Alternative Policy Scenarios**



Reference Scenario, although they still increase from 4.4 Gt in 2004 to 7.9 Gt in 2030. In the Alternative Policy Scenario, emissions from power plants in China and India in 2030 are 1.3 Gt, or 18%, lower than in the Reference Scenario.

Policy Assumptions and Effects

The policies under consideration that affect the power sector are mainly driven by concern to increase the use of low-carbon technologies or to reduce dependence on imported fuels. The most important policies and measures considered in the Alternative Policy Scenario include:

- Incentives and regulations to boost the use of renewables.
- Programmes to improve the efficiency and reduce the cost of advanced technologies in power generation.
- Policies to increase the use of nuclear power.
- Incentives to promote the use of CHP.

Many governments, particularly in the OECD, favour the use of renewable energy as a means of reducing CO_2 emissions and increasing reliance on domestic energy sources. Typical measures include guaranteed buy-back tariffs (for example, in several European countries) or renewables portfolio standards (an approach requiring a stated proportion of generation to come from renewables, which is now common in the United States, where 19 states have adopted such policies). In the Alternative Policy Scenario, it is assumed that policies are put in place to ensure that these targets are met. Policy support for renewables is now spreading to the developing world. China adopted a renewable energy law in 2005. India has also taken steps to provide more incentives for renewables and already has a thriving wind-power industry. In Brazil, the federal PROINFA programme provides incentives for the development of alternative sources of energy (see also Chapter 16).

Several countries, particularly in the OECD, are assumed to increase incentives for using CHP. Most new CHP capacity is likely to be used for on-site generation in industry. CHP also benefits from incentives for renewable energy. Biomass-fired CHP increases considerably. The share of electricity produced from CHP plants is in general from one to three percentage points higher in the Alternative Policy Scenario than in the Reference Scenario.

Advanced power-generation technologies are assumed to become available earlier than in the Reference Scenario. There is now a strong focus on cleaner coal technologies. The United States and China, the two largest users of coal in power generation, are promoting the development of advanced coal technologies.

The Alternative Policy Scenario assumes that measures are adopted to extend the lifetime of existing nuclear power plants or to accelerate the construction of new ones. A number of countries plan to expand the use of nuclear power. Japan, Korea, Russia, China and India have specific development targets. Extending the lifetime of existing reactors from 40 to 60 years helps maintain a higher share of nuclear power.

The European Union Emissions Trading Scheme (ETS) is assumed to lead to CO_2 emission reductions in the countries of the European Union through short-term switching of coal to gas in power generation in both scenarios. At the moment, there are many uncertainties about how the ETS will evolve and what the size of the caps will be. Because of the uncertainties of the scheme, long-term investment decisions are not assumed to be affected by it. In the Alternative Policy Scenario, policies that provide incentives for energy efficiency and renewables play a larger role than ETS in reducing power-sector CO_2 emissions.

Transport

Summary of Results

In the Alternative Policy Scenario, oil savings in the transport sector account for around 60% of the total reduction in global oil demand. Energy demand in the transport sector reaches 2 800 Mtoe in 2030, about 300 Mtoe, or 10%, less than in the Reference Scenario (Table 9.3). The oil saved in transport amounts to 7.6 mb/d in 2030, equal to slightly more than the current production of Iran and the United Arab Emirates combined. Those savings have profound implications for oil import needs, as described in Chapter 7. Oil products still account for 90% of transport demand in 2030, reflecting the extent of the challenge of developing commercially viable alternatives to oil to satisfy mobility needs. Because road transport currently accounts for about 80% of total transport energy demand, savings in this sector have a large impact on projected growth. In the Alternative Policy Scenario, demand for oil for road transport is 14% lower in 2030 than in the Reference Scenario. Improvements in vehicle fuel efficiency, increased use of alternative fuels – mainly biofuels – and modal shifts (shifts to different forms of transport) explain this trend. Reduced demand for aviation fuels accounts for 11% of total savings in transport energy demand.[2]

OECD countries see a saving of 146 Mtoe, or 9%, in this sector in 2030 in the Alternative Policy Scenario. This is driven by two divergent underlying trends. Oil savings of 183 Mtoe, or 12%, are larger than total energy savings, but they are partially offset by an increase in biofuels, gas and electricity consumption of 36 Mtoe, or 40%. The same trends occur in non-OECD countries, where

2. Later in this chapter, the impact of policies on aviation fuel use is examined for the first time in the *Outlook*.

Table 9.3: **Transport Energy Consumption and Related CO_2 Emissions in the Alternative Policy Scenario**

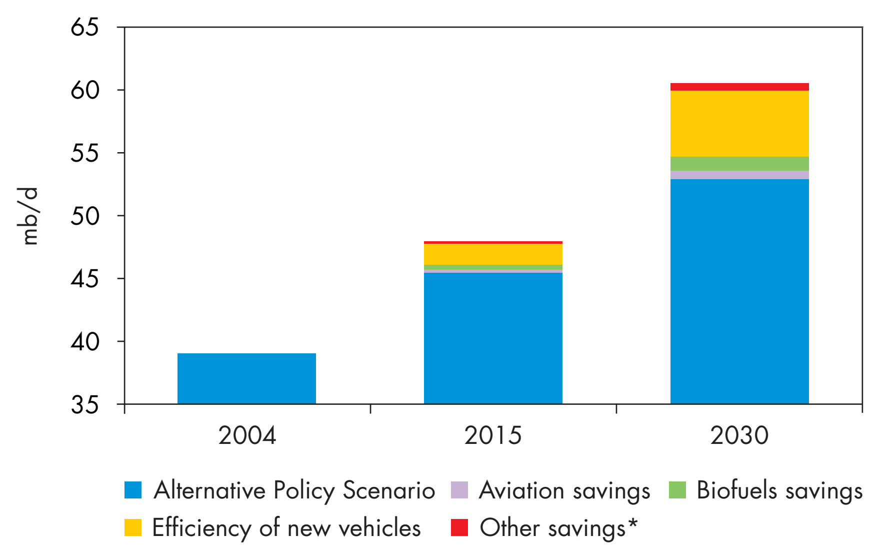
	2004	2015	2030	2004-2030 (%)*	Change in 2030 (%)**
Total energy (Mtoe)	**1 969**	**2 354**	**2 804**	**1.4**	**–9.9**
Road (Mtoe)	1 567	1 841	2 159	1.2	–11.2
Aviation (Mtoe)	238	316	419	2.2	–7.6
Other (Mtoe)	165	197	226	1.2	–0.2
CO_2 emissions (Mt)	**5 289**	**6 265**	**7 336**	**1.3**	**–11.0**

* Annual average growth rate. ** Compared with the Reference Scenario.

total savings in 2030 of 161 Mtoe are driven by a fall of 181 Mtoe in oil consumption and an increase of 21 Mtoe in biofuels, gas and electricity use.

Policies resulting in improved new vehicle fuel efficiency produce more than two-thirds of the oil savings in the Alternative Policy Scenario (Figure 9.8). Increased use of biofuels accounts for 14%, decreased aviation fuel consumption for 9% and modal shifts and reduced fuel consumption in other modes for the remainder.

Figure 9.8: **World Transport Oil Demand in the Alternative Policy Scenario and Savings Compared with the Reference Scenario by Source**



* Includes modal shift, pipeline, navigation and other non-specified.

As oil is the principal fuel in transport and transport CO_2 emissions are closely linked to fuel consumption, emissions trends are broadly similar to the consumption trends discussed above. Projected transport-related emissions in 2030 of 7.3 Gt represent a saving of 0.9 Gt compared with the Reference Scenario. In 2015, the saving is 0.3 Gt. Slightly over half of these savings occur in the OECD countries, 40% in developing countries and the rest in the transition economies. The growth in transport emissions slows from 1.7% per year in 2004-2030 in the Reference Scenario to 1.3% in the Alternative Policy Scenario. This is driven by a halving of the growth rate in the OECD from 1% to 0.5% per annum, a fall in the rate in developing countries from 3.2% to 2.7% and a fall in the transition economies from 1.5% to 1.1%.

Road Transport

In the Alternative Policy Scenario, road transport energy demand grows by 1.2% per year over the projection period, reaching 2 160 Mtoe in 2030. This compares with an annual growth of 1.7% in the Reference Scenario and 2.4% per year growth in the period 1990-2004. Road transport accounts for 77% of transport demand in 2030, slightly decreasing from 80% in 2004. Road transport demand in OECD countries increases at 0.4 % per annum over the projection period, to 1 180 Mtoe. All OECD regions see demand level out around 2015. Road transport growth is driven largely by the developing countries, which grow to 893 Mtoe in 2030, a growth rate of 2.8% per annum. The principal source of growth is China, which sees demand increase at 5.6% per annum to reach 289 Mtoe in 2030, comparable to total current road transport demand in the European Union. The largest savings potential in going from the Reference Scenario to the Alternative Policy Scenario is in the OECD countries, seeing savings of 140 Mtoe by 2030, over half of which occurs in the United States and almost one-quarter in the European Union. Developing countries achieve savings of 114 Mtoe by 2030, one-quarter of which occurs in China (Fig. 9.9).

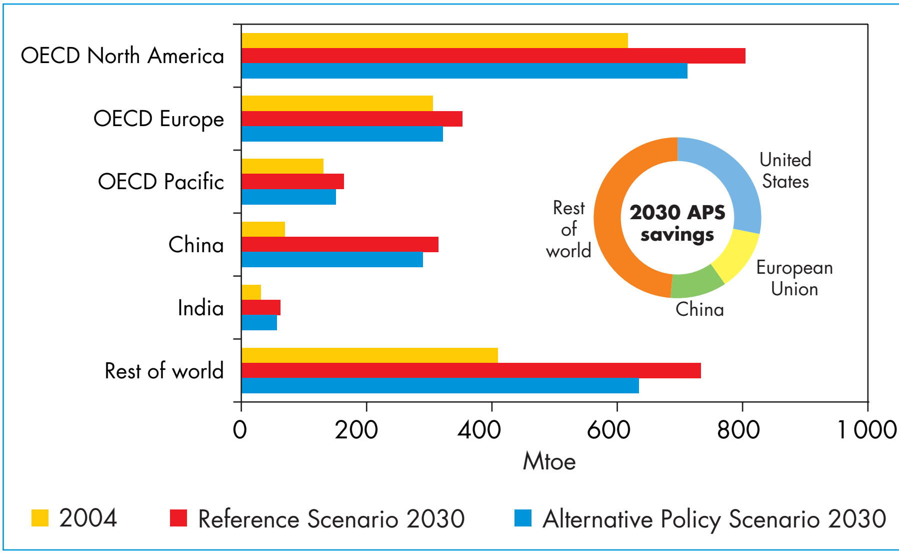
Policy Assumptions and Effects

These savings are achieved by policies that affect fuel type, new vehicle fuel economy and modal shift.[3] Modal shift policies are limited to a few regions, mainly the EU, Japan and China. Their impact on global fuel consumption and emissions is much smaller than that of policies influencing fuel type and fuel economy.[4]

3. Vehicle ownership is assumed to remain unchanged in the Reference and Alternative Policy Scenarios.

4. Policies whose effects are confined to a city or a local region are not quantifiable within the World Energy Model framework.

Figure 9.9: **Road Transport Demand in the Reference and Alternative Policy Scenarios**



Fuel Type

9

Biofuels are the alternative fuel that has been receiving by far the greatest attention from policy-makers, for reasons of security of supply, environmental protection and agricultural support. They are discussed in depth in Chapter 14, but the results of the Alternative Policy Scenario are briefly summarised here. Biofuels consumption in 2030 soars to 147 Mtoe, an increase of 54 Mtoe, or almost 60%, compared with the Reference Scenario. The share of biofuels in total road transport fuel demand reaches 7% in 2030, compared with 4% in the Reference Scenario. It is only 1% today. Biofuels consumption increases in all regions. The European Union and the United States account for more than half of the additional growth in biofuels consumption. In both regions, strong policies to spur biofuels consumption are already in place. In the Alternative Policy Scenario, we assume that those policies are strengthened and extended. As a result, biofuels account for 12% of road transport energy use in the European Union in 2030 and 7% in the United States in 2030. Brazil, while expanding its role as a biofuel exporter, does not see a big difference in domestic consumption between the two scenarios. Biofuels demand in developing countries as a whole jumps from 6 Mtoe in 2004 to 62 Mtoe in 2030. In the Reference Scenario, it reaches only 40 Mtoe. In both scenarios, only first-generation biofuels are assumed to be economically viable before 2030. There is also an increase in natural gas use in CNG cars, but the increase, 3 Mtoe by 2030, or 16% compared to the Reference Scenario, is negligible compared to biofuels growth.

Fuel Economy

Governments intervene extensively in the transport sector, though frequently for reasons not primarily focused on the reduction of energy consumption and greenhouse gas (GHG) emissions, such as road safety or reduced impact on the local environment. Some examples include traffic restrictions, education programmes for travellers, and parking and congestion charges. The effects of these policies on energy consumption and GHG reduction are more difficult to quantify than those of policies such as direct taxation on the purchase of vehicles and fuels, as well as stringent fuel economy standards for new vehicles. There are relatively fewer policies currently under discussion relating to the freight transport sector than to the passenger sector, which accounts for 65% of total road-fuel consumption. Although energy demand for freight transport is expected to increase at a slightly faster rate than energy for passenger transport, it accounts for no more than 40% of road transport energy demand in 2030. Demand for freight transport is closely linked to economic activity and, given that fuel expenditures constitute a major cost of their business, freight operators have a strong financial incentive to be efficient. The assumed improvements in the efficiency of freight transport stem from operational improvements, logistical changes, shifts in modal choices and improved loading techniques aimed at reducing wasted loading space. Changes in vehicle technologies also reduce fuel consumption, but to a lesser extent than for passenger transport, which is the focus of the remainder of this subsection.

Several countries have passed legislation regulating passenger car fuel efficiency, either with mandatory fuel-economy standards or through voluntary agreements with manufacturers (Table 9.4). Some countries have adopted or are considering the introduction of taxes on car ownership which are differentiated according to the fuel economy of the car. The United States, Japan and China regulate passenger car fuel efficiency through mandatory standards. Japan also regulates heavy-duty vehicle fuel economy. The European Union, Canada, Australia and Switzerland have agreed on voluntary targets for car manufacturers and importers. Japan's Top Runner programme and the EU ACEA's (European Automobile Manufacturers Association) voluntary targets are the most ambitious ones. US CAFE (Corporate Average Fuel Economy) standards are far less stringent, but new standards adopted by California in 2006 are more stringent (see Box 7.1).

Car manufactures can use technological advances in vehicle design either to increase the power and performance of the vehicle or to improve its fuel efficiency. Often these aims conflict, with power improvements damaging fuel efficiency. Market forces often favour increased power. Governments can play an important role by introducing fuel efficiency regulations to force automakers to devote new technology to improving fuel efficiency.

Table 9.4: **Key Selected Policies on Light-Duty Vehicle Fuel Economy in the Alternative Policy Scenario**

Country	Scope	Timeline	Structure
Australia	Reduction in average test fuel consumption for new petrol-fuelled passenger cars to 6.8 litres/100 km by 2010 (from 8.3 litres/100 km in 2001). Light trucks are excluded.	2010	Passenger cars, voluntary
Canada	Progressive tightening of corporate average fuel economy standards in line with US standards. Reduction of annual GHG emissions from Canada's vehicle fleet by 5.3 Mt in 2010 (interim reduction goals of 2.4 Mt in 2007, 3.0 Mt in 2008 and 3.9 Mt in 2009).	2007-2011	Cars and light trucks, voluntary
China	Reduction of the fuel consumption of passenger cars by approximately 10% by 2005 and 20% by 2008.	2008	Weight-based, mandatory
European Union	Reduction of fleet-average vehicle CO_2 emissions to 140 g/km by 2008 and 120 g/km by 2012.	2008 - 2012	Overall light-duty fleet, voluntary
Japan	Reduction of the fuel consumption of passenger cars from 1995 to 2010 by approximately 23% (for passenger cars) and by 13% (for light trucks).	Progressive	Weight-based, mandatory
United States	Progressive increase from 20.7 mpg in 2004 to 22.2 miles per gallon for light-duty trucks by model year 2007. The light-truck fuel economy targets will increase from 22.2 in 2007 to an average equivalent of 24 miles per gallon in 2011 under reformed CAFE standards. California: reduction by 2016 of CO_2 equivalent emissions from light-duty vehicles by about 30% (33% for passenger cars and 25% for light trucks) compared with 2002.	2007-2011 California: 2009-2016	Cars and light trucks, mandatory

The broad categories of policy mentioned above underlie the on-road fuel economy assumptions for new light-duty vehicle sales in the Reference and Alternative Policy Scenarios in Table 9.5. In the Reference Scenario, there is a relatively stable trend for fuel economy improvements, assuming that a consistent fraction of all technological advances would be used to increase vehicle power, size and comfort, while a limited amount of this potential would be dedicated to fuel economy. Some targets, such as those in the voluntary agreement in the European Union, are not met in the Reference Scenario. On the other hand, in the Alternative Policy Scenario the targets set by government authorities or included in the voluntary agreements between governments and manufacturers are assumed to be met, and further fuel economy improvements are taken into account after the existing commitment periods. However, a small part of the gains from these improvements is lost to the rebound effect, where improved fuel economy leads to lower driving costs, so encouraging increased vehicle usage and longer journeys.

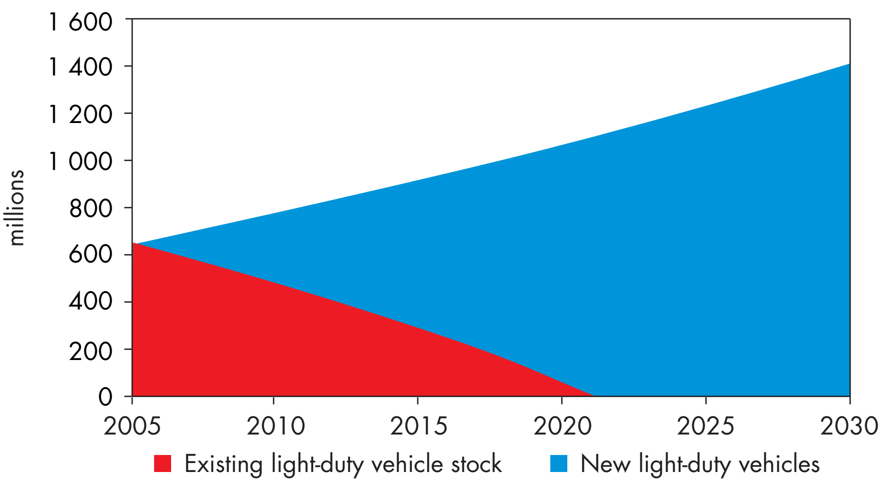
Table 9.5: **Average On-Road Vehicle Fuel Efficiency for New Light-Duty Vehicles in the Reference and Alternative Policy Scenarios** (litres per 100 km)

	2004	**Reference Scenario 2030**	**Alternative Policy Scenario - 2030**
OECD	**9.3**	**8.3**	**6.2**
North America	11.6	11.3	7.8
Europe	7.7	6.1	5.1
Pacific	8.6	6.9	5.7
Transition economies	**10.0**	**9.0**	**7.0**
Developing countries	**10.3**	**9.1**	**7.1**
China	11.3	9.0	7.5
India	10.1	8.9	7.1
Brazil	9.1	8.5	6.2

Implications for Light-Duty Vehicles Sales and Technology

The number of light-duty vehicles in use worldwide is expected to double over the projection period, from 650 million in 2005 to 1.4 billion in 2030. Increasing income per capita boosts global light-duty vehicle ownership from 100 light-duty vehicles per 1 000 persons today to 170 in 2030 in both scenarios. We do not include in the Alternative Policy Scenario policies that will alter vehicle ownership per capita, but only – as already said – those which affect vehicle fuel consumption and vehicle use. The typical lifetime of a light-duty vehicle is some 10 to 15 years in a developed country and somewhat longer in developing countries. As a result, many light-duty vehicles in use today will be retired by 2015-2020, so the medium-term potential for the introduction of more efficient technologies and for energy and CO_2 savings is considerable (Figure 9.10).

Figure 9.10: **World On-Road Passenger Light-Duty Vehicle Stock***

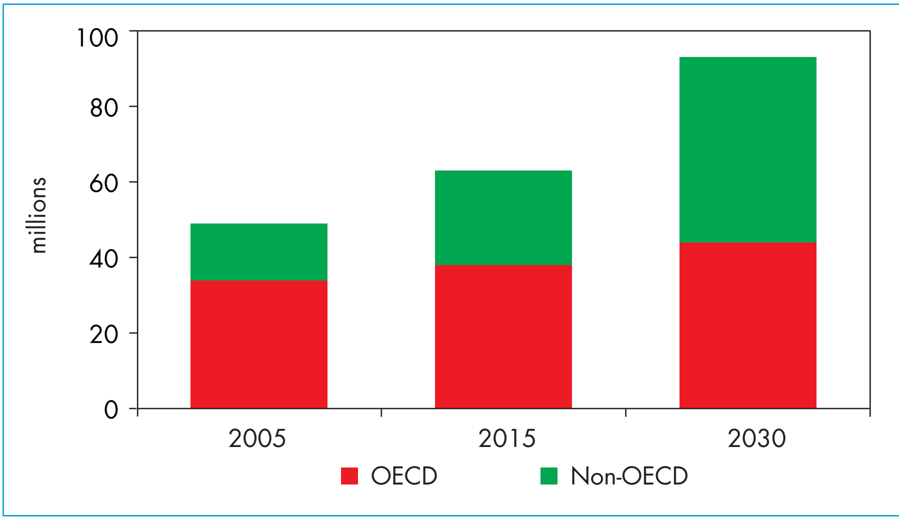


* In both the Reference and Alternative Policy Scenarios.

In both scenarios, annual sales of new vehicles in OECD countries over the *Outlook* period are expected to increase slightly. In contrast, vehicle sales in non-OECD countries more than triple by 2030 (Figure 9.11). Light-duty vehicle ownership in the United States and Japan is close to saturation and is projected to remain stable over the *Outlook* period. In developing countries, however, light-duty vehicle ownership will continue to grow rapidly. It is projected to grow by 10% per year in China and 9% in India. The light-duty vehicle stock in China climbs from 9 million today to more than 100 million in 2030; in India, it grows from 6.5 million to 56 million. Vehicle manufacturing is currently concentrated in OECD countries, but this is changing. The number of vehicles manufactured in China has nearly doubled over the past five years and in 2004 was about equal to the number of vehicles manufactured in Japan. Policies aimed at regulating fuel economy standards will become more and more important in non-OECD countries, where most of future sales will happen. Transfer of technology through multinational automakers[5] is also expected to play a very significant role in increasing the fuel economy of light-duty vehicles in developing countries in the Alternative Policy Scenario.

5. Five multinational automakers – General Motors, Ford, Toyota, Volkswagen and DaimlerChrysler – produce about half of all motor vehicles sold worldwide (WRI, 2005).

Figure 9.11: **New Vehicle Sales by Region, 2005-2030***



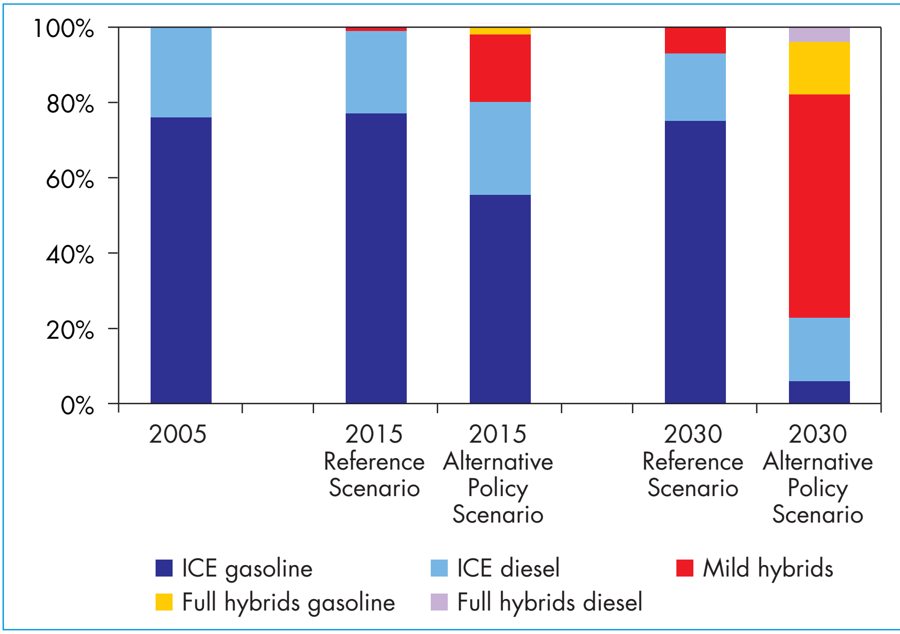
* In both the Reference and Alternative Policy Scenarios.

Technologies are available to automakers today which can achieve the vehicle fuel economy standards assumed in the Alternative Policy Scenario. In countries where fuel economy regulations have been relatively weak, like the United States, Canada and non-OECD countries, there is potential for major efficiency improvements at very low additional costs (see Box 8.5).

Achieving the additional efficiency improvements assumed in the Alternative Policy Scenario (see Table 9.5) requires improvements in the efficiency of internal combustion engines (ICEs), advanced vehicle technologies,[6] and a higher penetration rate of mild[7] and full hybrid technologies. Mild hybrids would need to represent 60% of global new light-duty vehicle sales in 2030 (Figure 9.12) and full hybrids 18% of light-duty vehicle sales. If the fuel economy improvement potential of the technologies mentioned here was exploited partly to offer increased power and performance, the share of mild and full hybrids in the new light-duty vehicle market might actually be higher, but without further improving the overall energy savings.[8]

6. Includes the use of lighter materials, improved aerodynamics and low rolling resistance tyres.
7. The term "mild hybrid" (sometimes called light hybrid) identifies those hybrid configurations in which there is only one electric motor connected to the ICE, acting as a starter and an alternator at the same time. Mild hybrids use "idle-off" technology, where the ICE is switched off instead of idling as a conventional engine would.
8. The technology penetration considered requires a diesel fuel share in 2030 roughly equal to current levels.

Figure 9.12: **Technology Shares in New Light-Duty Vehicles Sales in the Reference and Alternative Policy Scenarios**



9

Aviation

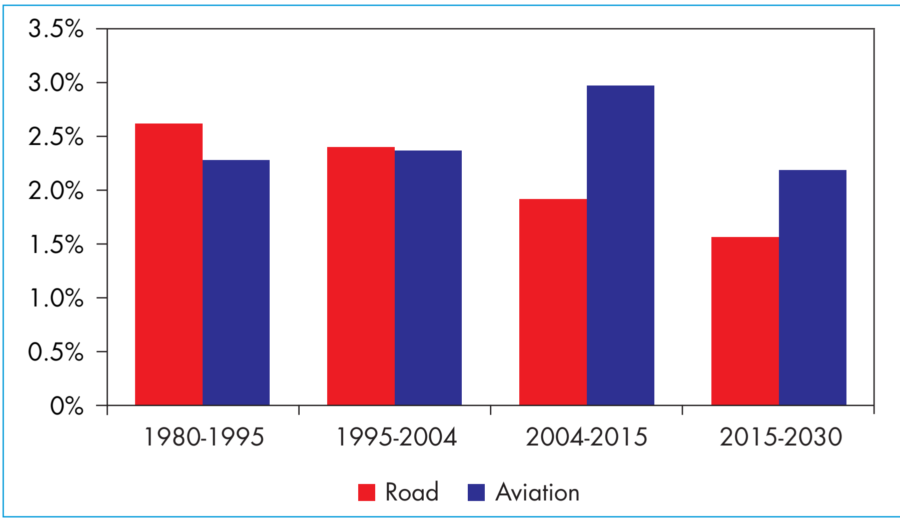
Energy Trends

Aviation recently overtook road as the fastest growing transport mode despite the slowdown following the events of 11 September 2001. Aviation grew at 7.3% from 2003 to 2004, double the rate of road transport. Oil demand for aviation increased from 2.9 mb/d in 1980 to 5 mb/d in 2004. International flights accounted for 62% of incremental aviation oil consumption from 1971 to 2004, and they are expected to become even more important in the future.

In the Reference Scenario, the biggest increase in aviation oil consumption over 2004-2030 occurs in non-OECD countries. By 2030, OECD consumption reaches 265 Mtoe, up from 163 Mtoe today. In non-OECD countries, demand increases from 75 Mtoe to 189 Mtoe. Globally, aviation oil consumption rises on average by 2.5% per year through to 2030, reaching 454 Mtoe.

Aviation oil consumption depends on three factors: growth in air traffic, fleet efficiency and, to a lesser extent, air traffic control practices. Today there are 16 800 commercial aircraft in operation. Their number is projected to grow by 3.8% per year over the *Outlook* period in the Reference Scenario, reaching more than 44 000 by 2030. Over half of the current fleet of planes will be retired between 2004 and 2030. As a result, four-fifths of the world's fleet will be composed of aircraft brought into service at some point during the projection period. The fleet grows most rapidly in non-OECD countries, especially in China, India and Latin America (Boeing, 2005; Airbus, 2004). Growth in global aviation traffic, measured in revenue passenger-kilometres[9], is faster than fleet growth, at 4.7% per annum over the *Outlook* period. This is due to improved aircraft load factors from increased aircraft occupancy and larger aircraft.

Figure 9.13: **Growth in Road and Aviation Oil Consumption in the Reference Scenario**



In the Reference Scenario, efficiency is assumed to continue to improve at a rate of 1.8% per year, in line with past trends[10]. Fuel costs range from as little as 10% to as much as 30% of the total operating costs of an aircraft, depending on its age and efficiency and prevailing jet-kerosene prices. Fuel prices are, therefore, a major factor in the fuel efficiency of aircraft: prolonged high fuel prices encourage the use of newer, more efficient aircraft. The potential for technical improvements in efficiency from turbine technology, improved aerodynamics and weight reductions is estimated at 1.0% to 2.2% per year through to 2025 (Lee *et al.*, 2001). Optimised air traffic control and more direct air routes could yield 0.4% to 1% per year improvement (IPCC, 1999).

9. Revenue passenger-kilometres, defined as the number of passengers multiplied by the number of kilometres they fly, is a commonly used measure of air traffic.
10. Alternatives to kerosene-based fuels are promising but are a long-term option. Hydrogen fuel requires new approaches to aircraft design and supply infrastructure (IEA, 2005).

Despite growing energy consumption and CO_2 emissions from aviation, relatively few policies are currently under discussion to combat these trends. The most significant is the inclusion of aviation in the European Union Emissions Trading Scheme (ETS). Another possibility is increased taxation on aviation, both domestic and international. Policies encouraging a shift from aviation to high-speed rail in Europe, Japan and China could also lower demand for aviation fuel. In the United States, the Federal Aviation Administration and the National Aeronautics and Space Administration are pursuing strategies to improve aviation fuel efficiency and reduce its impact on the global climate.

In the Alternative Policy Scenario, we assume that aviation is included in the ETS in Europe, that new aviation taxes being discussed in France, Germany and Norway are introduced, and that a modal shift to high-speed rail takes effect. These policies are assumed to create an incentive for airlines to introduce more efficient aircraft more quickly, resulting in an overall increase in fleet efficiency of 2.1% per year. As a result, aviation oil consumption falls by 0.7 mb/d, or 7%, in the Alternative Policy Scenario compared with the Reference Scenario, reaching 419 Mtoe in 2030. OECD countries see their consumption rise to 258 Mtoe in the Alternative Policy Scenario in 2030, a saving of 7 Mtoe on the Reference Scenario, whereas non-OECD countries' consumption increases to 161 Mtoe, a saving of 27 Mtoe.

9

Table 9.6: **Aviation Fuel Consumption and CO_2 Emissions in the Alternative Policy Scenario**

	1990	2004	2015	2030	Reduction in 2030*
Oil consumption (mb/d)	3.8	4.9	6.4	8.6	0.7
CO_2 emissions (Mt)	458	685	909	1 206	99

* Compared with the Reference Scenario.

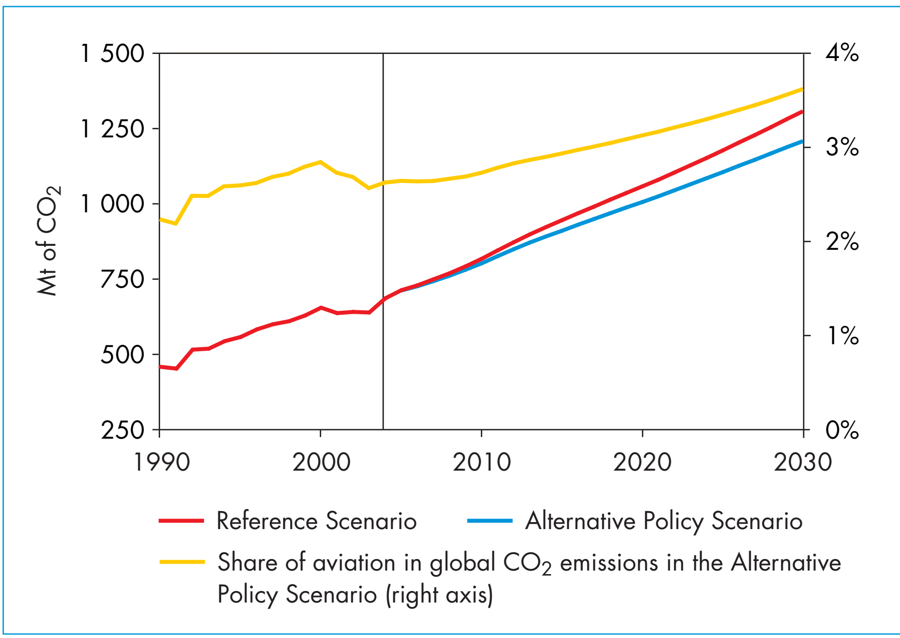
CO_2 Emissions Trends

Aviation currently accounts for 13% of CO_2 emissions from transport, a share that has been growing for many years. Emissions from aircraft at high altitudes are thought to have a disproportionately larger effect on the environment than emissions from most other sources (ECMT, 2006). The impact of aviation on climate change is complex and uncertain with CO_2, NO_X and contrails all playing a part. Because of the combined effects of these phenomena, the Intergovernmental Panel on Climate Change estimates that the total climate impact of aviation is two to four times greater than the impact of its CO_2

emissions alone (IPCC, 1999). Using advanced aircraft scheduling techniques may prove possible to avoid a significant proportion of the effects associated with contrails and associated cirrus clouds.

Consumption in the United States is currently responsible for over one-third of global CO_2 aviation emissions. In the Reference Scenario, aviation CO_2 emissions almost double over the *Outlook* period, from 685 Mt in 2004 to 1 305 Mt in 2030. In the Alternative Policy Scenario, they rise to 1 206 Mt – 8% lower (Figure 9.14). The share of aviation in total global energy-related CO_2 emissions is nonetheless higher in the Alternative Policy Scenario, because emissions from other sectors fall more by comparison with the Reference Scenario, reflecting the wider range of policies under consideration to mitigate CO_2 emissions in those sectors.

Figure 9.14: **World Aviation CO_2 Emissions** (Mt)



Note: In line with accepted practice, the regional totals for CO_2 emissions shown in the tables in Annex A do not include CO_2 emissions from international aviation.

Industry

Summary of Results

Global industrial energy demand is 337 Mtoe, or 9%, lower in 2030 in the Alternative Policy Scenario than in the Reference Scenario (Table 9.7). Reduced consumption of coal accounts for 38% of total savings, while electricity accounts for 27%, oil for 23% and gas for 12%. Improved efficiency in developing countries contributes nearly two-thirds of global savings and China alone for over one-third. OECD countries account for about one-quarter and transition economies for the rest. By 2030, savings relative to the Reference Scenario are 6.5% in the OECD, 9.6% in developing regions and 10.5% in the transition economies.

Table 9.7: **Change in Industrial Energy Consumption in the Alternative Policy Scenario*, 2030**

	OECD	Transition economies	Developing countries	World
Change in industrial energy consumption (%)				
Coal	–8.2	–12.2	–18.7	–17.0
Oil	–4.7	–11.5	–13.3	–9.1
Gas	–7.6	–11.7	0.1	–4.8
Electricity	–9.4	–8.3	–10.8	–10.0
Heat	–4.9	–8.7	11.3	–0.5
Biomass and waste	–0.3	–	12.6	7.2
Total	**–6.5**	**–10.5**	**–9.6**	**–8.6**
Contribution to total change by fuel (Mtoe)				
Coal	–8	–5	–123	–136
Oil	–20	–5	–58	–83
Gas	–28	–15	0	–43
Electricity	–33	–6	–56	–95
Heat	–1	–4	5	–1
Biomass and waste	0	–	20	20
Total	**–91**	**–35**	**–211**	**–337**

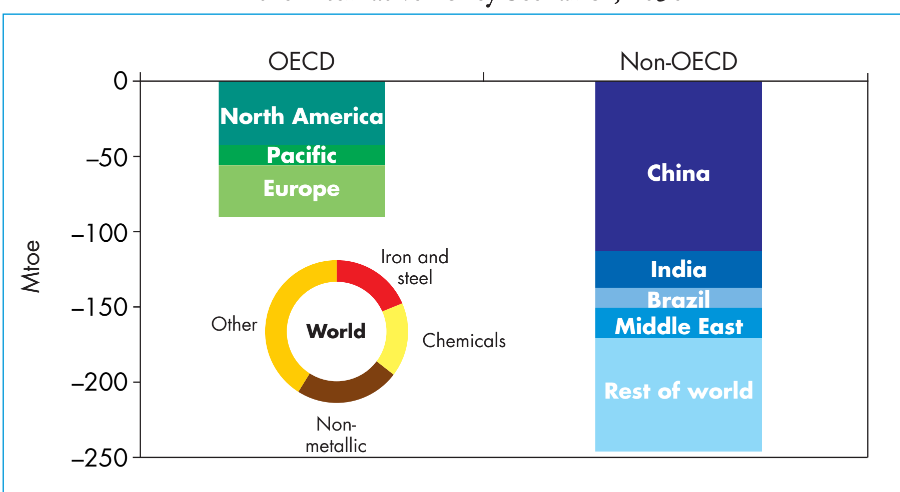
* Compared with the Reference Scenario.

In developing countries, a large part of the reduction of coal use by industry results from the substitution by natural gas in China. In the Alternative Policy Scenario, use of gas by industry in China is 61% higher than in the Reference Scenario, while coal demand is 94 Mtoe lower. Industrial demand for oil in developing countries falls by 13% in 2030, thanks to fuel switching and to improvements in process heat and boiler efficiencies. In the Reference Scenario, the share of gas in industrial energy use remains high in the transition economies throughout the *Outlook* period. Efficiency improvements in their industrial processes in the Alternative Policy Scenario yield large savings in gas use, amounting to 12% of demand in the Reference Scenario in 2030 and representing 43% of the total energy saved by the region's industry. Biomass and waste consumption increases in the Alternative Policy Scenario, with other developing Asian countries accounting for over half the increase. There is greater use of biomass- and gas-fired combined heat and power in industry in the Alternative Policy Scenario (see section on power generation above). CHP contributes to gas savings in industry. Biomass consumption is higher because we assume biomass replaces gas and coal.

In the OECD, electricity contributes 37% of total industrial energy savings by 2030, primarily as a result of policies aimed at improving the efficiency of motor systems (IEA, 2006a). Electricity savings are largest in OECD Europe, because electrical efficiency is currently lower there than in North America and the Pacific. Gas accounts for about a third of the reduction in industrial energy demand in the OECD. Gas savings in OECD North America account for some 60% of the reduction in industrial gas demand in the OECD. Nearly half of the energy savings in OECD countries result from lower demand in the United States and Canada. OECD Europe accounts for another 39%, with a decline of over 7% in its industrial energy use. Demand is 11 Mtoe lower in the OECD Pacific.

Energy savings in industry in non-OECD countries are over two-and-a-half times greater than comparable savings in OECD countries (Figure 9.15). The gains in China, some 114 Mtoe, are greater than in the entire OECD region. In the Middle East, efficiency improvements lead to a 21 Mtoe drop in industrial energy demand. India reduces its consumption by 24 Mtoe and Brazil by 12 Mtoe.

Figure 9.15: **Change in Industrial Energy Demand by Region and Sector in the Alternative Policy Scenario*, 2030**



* Compared with the Reference Scenario.

Over half of global energy savings in the industry sector are the result of efficiency improvements in the iron and steel, chemicals and non-metallic industries. Energy savings in the chemical industry contribute significantly to total industrial savings in all regions, because of this sector's large share in total industrial energy use.[11] In the OECD, the iron and steel industry sees incremental intensity gains of between 9% and 11% by 2030 compared with the Reference Scenario. Efficiency gains in iron and steel in Russia, China and Brazil combined are roughly of the same magnitude. In 2030, one-quarter less energy than is projected in the Reference Scenario will be required to produce one tonne of steel in India. This results largely from consolidation in the industry. In developing countries, the efficiency of production of non-metallic minerals increases considerably, providing nearly a third of their total savings of industrial energy use by 2030.

In the Alternative Policy Scenario, CO_2 emissions in the industry sector are 6.4 Gt in 2030, some 0.9 Gt, or 12%, less than in the Reference Scenario. However, because of the relatively larger efficiency gains in the transport and power generation sectors, industry's share of total energy-related emissions, at 19%, is one percentage point higher in the Alternative Policy Scenario. A 607-Mt reduction in coal-related emissions accounts for 70% of the total fall in emissions from industry. Lower coal demand in China accounts for the bulk of the reduction, with CO_2 emissions from the burning of coal 419 Mt lower than in the Reference Scenario. Switching to gas offsets these gains to some extent: gas-related emissions in China rise by 48 Mt. Global oil-related emissions in the industry sector are 160 Mt, or 9%, lower in the Alternative Policy Scenario, while gas-related emissions are 97 Mt, or 5%, lower.

Developing countries account for more than three-quarters of the total reduction in CO_2 emissions in the industry sector worldwide in 2030. Another 14% comes from OECD countries, where industry emissions are some 120 Mt lower. North America and Europe each register a 6% reduction in CO_2 emissions from industry compared with the Reference Scenario. Gas-related emissions are also reduced significantly in percentage terms in transition economies, to 243 Mt in 2030 in the Alternative Policy Scenario compared with 275 Mt in the Reference Scenario.

Policy Assumptions and Effects

Estimating the overall impact of policies on industrial energy use is complicated by the limited availability of data at the subsectoral level and the diversity of industrial processes and technologies. For the Alternative Policy Scenario analysis, energy use per tonne of output was calculated for different

11. This occurs despite the fact that no policies are considered in the Alternative Policy Scenario that would reduce feedstock use.

energy-intensive processes in both OECD and non-OECD countries. In this way, regional differences in the potential for energy-efficiency improvements were taken into account. The projected improvements in efficiency in the Alternative Policy Scenario are derived from changes in the energy efficiency of each process and from changes in the mix of processes used. A rapid decline in energy intensity in transition economies and developing countries is already incorporated into the Reference Scenario, on the assumption that the energy intensity of industrial production will approach OECD levels by 2030. In the Alternative Policy Scenario, the gap in efficiency between OECD and non-OECD narrows even further. The energy intensity of industrial processes varies considerably worldwide (Table 9.8). Japan is the world's most efficient producer of steel and cement, because of relatively higher energy costs. Russia, India and China tend to have the lowest efficiencies.

Table 9.8: **Energy Intensities in the Steel, Cement and Ammonia Industries in Selected Countries, 2004** (Index, 100=most efficient country)

	Primary steel	Cement clinker	Ammonia
Japan	100	100	n.a.
Korea	105	110	n.a.
Europe	110	120	100
United States	120	145	105
China	150	160	133
India	150	135	120
Russia	150	165	111
Technical potential with best available technology	75	90	60

Sources: METI (2004), IEA databases.

The methodological approach used here differs between OECD and non-OECD regions. For OECD countries, the Alternative Policy Scenario analyses the impact of new policies to improve energy efficiency in process heat, steam generation and motive power. Policies include standards and certification for new motor systems, voluntary programmes to improve the efficiency of industrial equipment and to accelerate the deployment of new boilers, machine drives and process-heat equipment, and research and development to improve the efficiency of equipment entering the market after 2015.

For non-OECD regions, the analysis focuses on efficiency improvements in the production of iron and steel, ammonia, ethylene and propylene, aromatics, cement and pulp and paper. For each process, the efficiency of new capital stock is assumed to approach that of the *current* stock in OECD countries. However, in some industries, including aluminium, efficiency is already substantially higher in non-OECD countries than in OECD countries. Changes in the process mix are based on the assumption that state-owned firms will be restructured more quickly than assumed in the Reference Scenario, stimulating investments in larger-scale and more efficient processes. These policies are of particular importance in China and India. A switch from coal to more efficient gas-based processes is assumed in China only. In major cities such as Beijing and Shanghai, policies are already in place to replace coal with gas in order to reduce local air pollution. In the Alternative Policy Scenario, these policy efforts are assumed to be strengthened.

Box 9.1: **The Efficiency of Energy Use in the Aluminium Industry**

For most industries, new plants are typically based on the most efficient technology available, regardless of location. As a result, a country with relatively new capital stock will be more energy-efficient than a country with a more mature stock. The aluminium industry, in particular, is very energy-intensive: energy costs represent the bulk of total production costs. Older aluminium smelters are mostly located in OECD countries and newer plants tend to be built in non-OECD countries. Consequently, efficiency in non-OECD countries is generally higher. Africa has the most efficient aluminium smelters in the world (Table 9.9). As the capital stock of all industries matures in developing countries and older stock is replaced in industrialised countries, differences in energy efficiency among regions will tend to diminish.

Table 9.9: **Average Electricity Intensity of Primary Aluminium Production, 2004** (kWh/tonne)

Africa	14 337
Oceania	14 768
Europe	15 275
Asia	15 427
Latin America	15 551
North America	15 613
World	**15 268**

Source: World Aluminium (2006).

The structure of an industry can limit its energy efficiency potential. About half of China's iron and steel industry is comprised of large and medium-sized plants. These plants have an average energy intensity per tonne of steel of 705 tonnes of coal equivalent (tce) – 7% higher than the average intensity in Japan. Smaller-scale iron and steel plants in China, however, have an average energy intensity of more than 1 000 tce per tonne of steel. The predominance of small-scale plants is due to the country's inadequate transport infrastructure. Plants are generally built close to coal resources and demand centres.

Turnkey process operations are supplied by international engineering companies and contractors, while small-scale operations are usually based on local or national knowledge. The energy efficiency of turnkey operations is similar across the world. To improve the efficiency of turnkey operations, policies need to focus on research and development and on overcoming barriers in global supply chains. For small-scale industrial operations, the potential for energy-efficiency improvement is substantial, but policies need to be tailored to sectors and take account of national circumstances.

Resource availability is also important for improved industrial energy efficiency, for example cement clinker substitutes and scrap. The ratio of iron to steel in China was 0.92 in 2003, while in the United States it was only 0.44. China lacks indigenous scrap resources and, unlike the United States, is not a significant importer of scrap and steel products. The iron to steel ratio in China is expected to remain above that in the United States, and, consequently, the energy intensity of its iron and steel industry will remain much higher, even if individual process operations attain the same energy efficiency. In addition, large-scale industries are usually more energy-efficient than small-scale ones. International collaboration and technology exchange are important drivers for achieving higher energy efficiency through economies of scale in developing countries.

The Alternative Policy Scenario incorporates many new policies to improve the efficiency of motors and motor systems. These policies lead to an average decline in global electricity demand of some 10% in 2030 compared with the Reference Scenario. A range of measures is assumed to be adopted (Box 9.2). In addition to the energy savings, substantial cost savings would also be achieved (see Chapter 8).

Box 9.2: **Improving the Energy Efficiency of Motor Systems**

Motors and motor systems consume about two-thirds of electricity demand in the industry sector.[12] The potential for energy-efficiency improvements in motors, based on technologies available today, is estimated to be roughly 20% to 25%. This potential is greater if savings from improved distribution and use are taken into account. High-efficiency technologies for motors are commercially available, as are guidelines for proper maintenance and repair. Most OECD countries and a number of non-OECD countries have implemented policies to encourage greater motor efficiency, including minimum energy performance standards and energy-

12. Motor systems in this case means a machine, such as a pump, fan or compressor, that is driven by a rotating electrical machine (motor).

efficiency programmes. In countries that have implemented standards, such as Canada and the United States, the market share of high-efficiency motors is over 70%. In European countries, which have not adopted such standards, the market share is often below 15%, despite voluntary programmes. Standards for electric motors in Australia have prevented lower-efficiency imported motors from flooding the domestic market. Replacing standard-efficiency motors with high-efficiency ones, however, only accounts for about 10% of the energy-saving potential assumed in the Alternative Policy Scenario. The rest comes from policies aimed at better motor sizing, appropriate use of adjustable speed drives and other measures.

Source: IEA (2006a).

Residential and Services Sectors

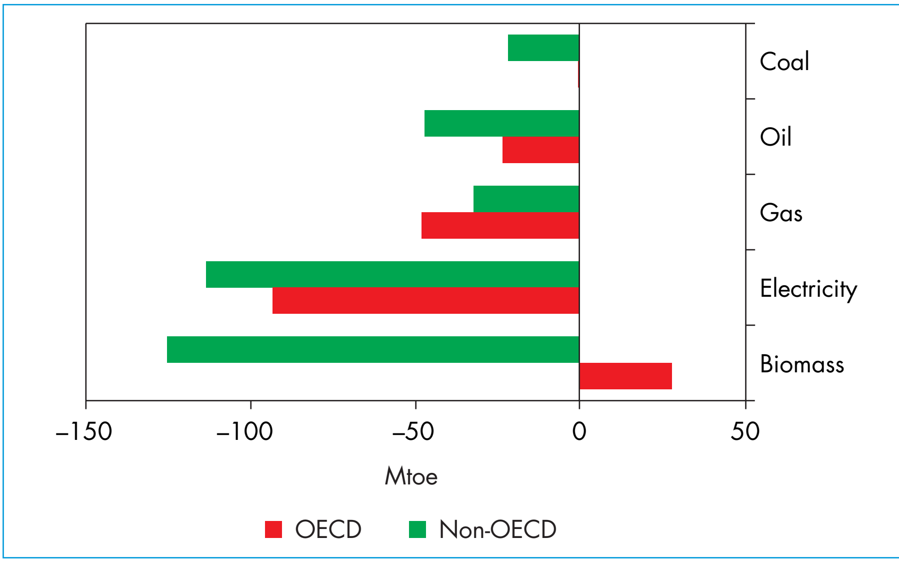
Summary of Results

Global energy use in the residential and services sectors combined is 444 Mtoe, or 11%, lower in 2030 in the Alternative Policy Scenario than in the Reference Scenario. This saving is equal to almost the current combined consumption of these sectors in the European Union. The two sectors account for 40% of savings in final consumption by 2030 and for 68% of electricity savings. The residential sector accounts for 72% of the consumption and 70% of the savings in 2030.

Energy savings in the Alternative Policy Scenario in the residential and services sectors are almost three times higher in non-OECD countries than in the OECD countries. Of global savings, 200 Mtoe, or 45%, are in electricity. Electricity consumption varies greatly by region in the residential and services sectors, accounting for 42% of total consumption in OECD and 26% in non-OECD in the Alternative Policy Scenario in 2030. The other fuel showing large regional disparities is biomass, accounting for 7% of the energy use of these sectors in the OECD and 43% in non-OECD countries in 2030 in the Alternative Policy Scenario. The change in biomass consumption in the Alternative Scenario is also very different by region (Figure 9.16). It increases by 27 Mtoe in the OECD but falls by 123 Mtoe in non-OECD, compared with the Reference Scenario. This is due to increased heating from modern biomass technologies encouraged by the EU Biomass Action Plan in Europe and faster switching in developing countries from traditional biomass for heating and cooking to modern fuels and cleaner technologies, such as more efficient stoves. While other renewables will still amount to only 2% of total consumption in these sectors in 2030 in the Alternative Policy Scenario, the increase from 55 Mtoe in the Reference Scenario to 87 Mtoe is nonetheless substantial.

Almost all of the 21 Mtoe savings in global coal use in 2030 in the two sectors and the 17 Mtoe savings in heat, as well as two-thirds of the 66 Mtoe in oil savings, occur in non-OECD regions. Only gas savings are bigger in the OECD, accounting for 60 % of the 76 Mtoe saved in 2030. CO_2 emissions in these sectors are 0.4 Gt lower in the Alternative Policy Scenario, with almost half of the savings occurring in developing countries, 40% in the OECD and the rest in the transition economies.

Figure 9.16: **Change in Final Energy Consumption in the Residential and Services Sectors in the Alternative Policy Scenario* by Fuel, 2030**

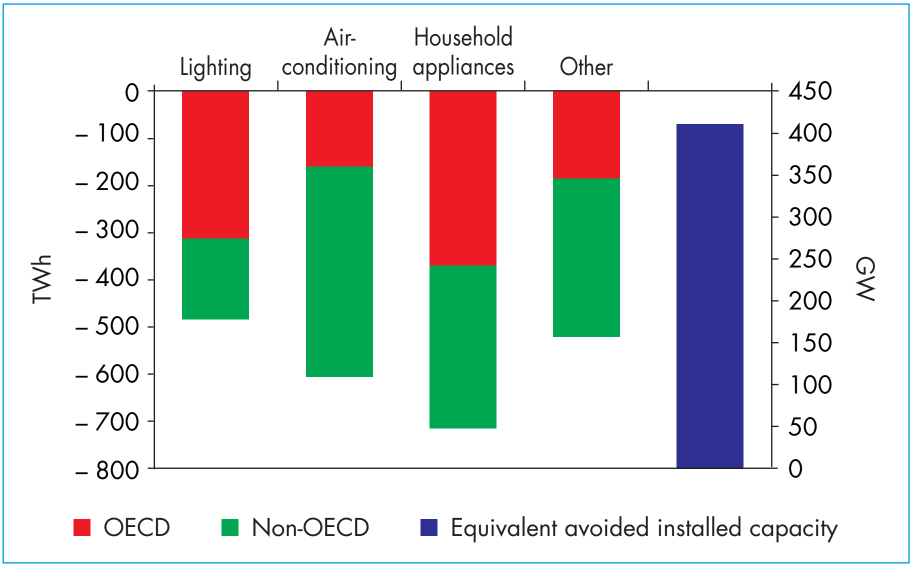


* Compared with the Reference Scenario.

Electricity Savings

The main driver of energy demand growth in the residential and services sectors is the increasing importance of electrically-powered equipment and appliances used in buildings. For example, the number of electric appliances per European household has increased tenfold over the last three decades. Electricity use in buildings today accounts for 53% of total world electricity demand, up from 38% in 1971. In the Reference Scenario, this share rises slightly to 55% by 2030. The introduction of new policies in the Alternative Policy Scenario tempers the growth in electricity demand in buildings, so that its share in total demand is slightly lower, at 53%. The electricity savings in the residential and services sectors, compared with the Reference Scenario, are 2 320 TWh in 2030 (using a conversion of 1 Mtoe to 11.63 TWh), equivalent to 412 GW of installed capacity, slightly less than the total installed capacity of

Figure 9.17: **Change in Electricity Demand in the Residential and Services Sectors in the Alternative Policy Scenario* by Use, 2030**



China in 2004. These savings would avoid the need to build some 400 large coal-fired power plants that would otherwise be needed in 2030.

More efficient household appliances cut electricity use by 714 TWh in 2030, compared with the Reference Scenario, accounting for 31% of the total electricity savings in the residential and services sectors. There is considerable scope even within OECD countries to save electricity through measures that stimulate the deployment of more efficient equipment. Electricity savings in 2030 in OECD are 88 Mtoe, slightly smaller then the 112 Mtoe savings in non-OECD. About half of these savings are produced by a tightening of between 10% and 30% in standards for appliance efficiency compared with the Reference Scenario. However, potential savings are greater still. The cost-effective savings potential[13] in household appliances amounts to 36% of total residential electricity demand in the OECD.[14] Developing countries,

13. This potential is defined as the savings that could be achieved without any increase in the overall cost of buying and running the appliance over its lifetime (IEA, 2003).

14. The IEA has launched initiatives to reduce electricity consumption in the residential and services sectors. Noteworthy proposals include the IEA 1 Watt Plan and setting efficiency standards for television "set-top" boxes and digital television adaptors. The IEA 1 Watt Plan proposes that all countries harmonise energy policies to reduce standby power use to no more than one watt per electronic appliance. Standby power is the electricity consumed by appliances while switched off or not performing their primary functions. The potential savings in the IEA countries would be 20 GW by 2020. Similarly, establishing efficiency standards for television "set-top" boxes and digital television adaptors would save a further 8 GW by 2020 (IEA, 2006b).

which have much lower equipment ownership and use than in the OECD, are poised for a boom in the sale of electrical equipment and appliances. The efficiency of the equipment on offer in developing countries is frequently low, so even greater relative savings can be attained by measures to improve the energy efficiency of the products on offer.

More efficient air-conditioning, mainly in non-OECD countries, accounts for another quarter of electricity savings in buildings in the Alternative Policy Scenario. In OECD countries, the proportion of building floor area that is space-conditioned (*i.e.* heated and/or cooled) has grown dramatically over the last three decades. Coupled with the continuing increase in total building floor area, this would have increased building energy demand exponentially had there not also been an almost equally large fall in the amount of energy needed to heat or cool a given amount of building space. Better insulation and more efficient heating, ventilating and air-conditioning equipment has enabled the average amount of energy used to space-condition a unit area to remain relatively constant over this time frame despite the considerable increase in thermal comfort. Non-OECD countries are expected to experience similar growth in diffusion of air-conditioning, so this is where the greatest potential for savings lies.

More efficient lighting also offers considerable potential for electricity savings, and exploiting these saves 483 TWh, or 21%, in 2030 compared with the Reference Scenario (Box 9.3). Savings from more efficient lighting are estimated at 38% of total lighting energy use in the Alternative Policy Scenario, assuming only cost-effective investment (IEA, 2006b).

Box 9.3: **Opportunities to Save Energy Through More Efficient Lighting**

Lighting accounts for an estimated 19% of global electricity demand. World lighting demand is greater than all the power generated from either the world's hydroelectric or nuclear power plants. Three-quarters of all electric light is consumed in the residential and services sectors. It results in almost 1.9 Gt of CO_2 emissions. Enormous amounts of electricity are wasted in lighting. Light is routinely supplied to spaces where no one is present. There are very large differences in the efficiency of competing lighting sources and in the way lighting systems are designed to deliver light where it is needed. Moreover, architecture often makes poor use of abundant daylight, which could contribute more to lighting needs.

The IEA estimates that were end-users to install only efficient lamps[15], ballasts and controls whose efficiency would save money over the life cycle of the lighting service, global lighting electricity demand in 2030 would be just 2 618 TWh. This is almost unchanged from 2005 levels and the level is actually lower in the years between 2010 and 2030. In the intervening years, staggering cumulative savings of almost 28 000 TWh of final electricity and over 16 000 Mt of CO_2 emissions would be realised, as compared with the Reference Scenario, with its assumption of the continuation of current policies (IEA, 2006c).

Savings in Other Fuels

The energy used in buildings can be divided into that used to provide thermal comfort, ventilation, lighting, water heating and the services supplied by various appliances. Buildings in most OECD regions are generally nearing saturation in demand for heating per unit area. To further cut total space-heating demand in absolute terms will require improving the efficiency of the building stock at a faster rate than the growth in total building floor area. In the Alternative Policy Scenario, oil and gas consumption in the OECD falls by 142 Mtoe, or 10%, compared with the Reference Scenario, as a result of an assumed strengthening of building codes. Non-OECD regions are far from reaching saturation, so demand is driven less by the efficiency of the delivered service and more by trends in total building floor area, comfort requirements and the affordability of space heating and cooling. Savings of oil and gas in 2030 in developing countries are 75 Mtoe, or 12%, below those in the Reference Scenario. Once again, the potential for improvement is even larger than that achieved in the Alternative Policy Scenario.

Several countries have adopted policies to encourage solar energy, mainly for water heating. In the Alternative Policy Scenario, solar energy use in buildings reaches 87 Mtoe in 2030, an increase of over 50% compared with the Reference Scenario. A comprehensive programme of research, development and demonstration is still needed to generate competitive solar heating and cooling systems that could account for up to 10% of low temperature heat demand in OECD countries (IEA, 2006d).

15. For example, using compact fluorescent lamps in place of incandescent lamps, the most efficient linear fluorescent lamps in place of standard ones, and not using inefficient halogen torchiere uplighters and mercury vapour.

Policy Overview

Policies taken into account in estimating the figures for the residential sector in the Alternative Policy Scenario cover lighting, electric appliances, space heating, water heating, cooking and air-conditioning. In the services sector, lighting, space heating, air-conditioning and ventilation are assessed, as well as miscellaneous electrical equipment. In the OECD, equipment standards, building codes, building energy certification and voluntary measures are analysed. In some cases, mandatory labelling schemes are also considered. Voluntary measures include voluntary targets, financing schemes for efficiency investments, endorsement labelling and "whole-building" programmes. Financing schemes include direct consumer rebates, low-interest loans and energy-saving performance contracting. Accelerated research and development efforts by governments are also taken into account.

Since 2004, there have been some important developments in the implementation of national, regional and local equipment and building energy efficiency measures. The nature of new measures under discussion has also changed. For example Europe has implemented three major new energy-efficiency directives: the Eco-Design, Energy Services and Energy Performance in Buildings directives. They reduce energy use in the Reference Scenario. In the Alternative Policy Scenario, these directives are assumed to be implemented in a more rigorous manner. As a result, the savings projected in the European Union in the Alternative Policy Scenario are bigger than in *WEO-2004*.

In recent years, many non-OECD countries have also adopted policies aimed at improving the energy efficiency of new equipment and buildings. They are assumed to achieve efficiencies that approach those of the OECD in the Alternative Policy Scenario. China has increased both the scope and number of the efficiency policies it has implemented. Accordingly, the ambition of the policies now under consideration has grown, increasing the savings in the Alternative Policy Scenario as these policies are assumed to be put into effect. Several OECD and developing countries have adopted policies to encourage solar energy – mainly solar water heaters – but further government action will be necessary to boost solar markets and is assumed here.

The rate of electrification and access to gas networks are assumed to be the same in both scenarios. But measures aimed at promoting a faster transition from traditional biomass to modern commercial energy sources in equipment and buildings are assumed in the Alternative Policy Scenario. As in the OECD region, the most important results in non-OECD countries come from measures to encourage energy labelling and setting of mandatory minimum energy-efficiency standards. For buildings, stricter mandatory codes, building certification and energy-rating schemes are assumed.

Many non-OECD countries have already established energy labelling and minimum efficiency standards. Other countries are planning to implement such programmes. In the Alternative Policy Scenario, it is assumed that existing programmes are broadened to cover more equipment types. Standards for new equipment sold between 2010 and 2030 are also raised to levels closer to those found in the OECD today. However, efficiency standards and labels are not assumed to reach life-cycle least-cost efficiency levels, which would bring even greater efficiency gains. Where there is a large spread in the level of efficiency attained by a specific category of products in OECD countries, we have assumed that the lower levels are attained in non-OECD countries.

Few non-OECD countries have adopted measures to improve the energy performance of buildings. In the Alternative Policy Scenario, it is assumed that building codes are adopted for new commercial and residential buildings. It is also assumed that certain policy measures are implemented to encourage higher efficiency in existing commercial buildings. These include energy-performance certification and energy-rating schemes for buildings. Solar water heating in houses is also assumed to expand more quickly than it does in the Reference Scenario.

The range of policy instruments to encourage greater energy efficiency in the residential and services sectors includes:

- **Energy labelling of energy-using equipment:** Labels can be voluntary or mandatory; they can contain information on the relative energy performance of the product in question compared to similar products, or simply be awarded to the most efficient products. The primary purpose of energy labels is to render the energy performance of products visible to consumers at the point of sale.

- **Energy efficiency performance requirements for new equipment and building codes:** These can also exist in multiple forms, such as mandatory minimum energy-efficiency standards, fleet average-efficiency requirements (mandatory or voluntary), voluntary target agreements, or requirements specifying the efficiency of installed equipment. Building codes also often specify minimum energy performance requirements for energy-using equipment systems. Mandatory minimum energy performance requirements are increasingly being specified in building codes which address all energy flows within a building and hence are known as "whole-building" requirements.

- **Building energy performance certification:** This involves issuing a certificate to increase awareness in the market of building energy performance – a practice that is becoming increasingly common in OECD countries.

- **Utility energy efficiency schemes:** The creation of incentives for energy utilities to implement or promote certified energy-saving measures among their client base, or the imposition of obligations on them to do so.
- **Fiscal and financial incentives:** These aim to improve building energy efficiency, for example through tax credits for building owners who invest in energy-efficient equipment and materials.

Other policies and measures to raise building energy efficiency taken into account in the Alternative Policy Scenario include: procurement programmes; information, awareness and capacity building programmes; voluntary and long-term agreements; building energy auditing and related measures; the establishment of energy service companies and third-party finance schemes.

GETTING TO AND GOING BEYOND THE ALTERNATIVE POLICY SCENARIO

HIGHLIGHTS

- Achieving the results of the Alternative Policy Scenario depends upon a strong commitment on the part of governments urgently to adopt and implement the policies under consideration. Considerable hurdles need to be overcome, not least policy inertia, opposition from some quarters and lack of information and understanding about the effectiveness of the opportunities which are open.
- The policies and measures in the Alternative Policy Scenario would avoid the release into the atmosphere of some 70 Gt of CO_2 over the period 2005-2030. If action were delayed by ten years, with implementation starting only in 2015, energy trends would deviate from the Reference Scenario much less by 2030. One result would be that the cumulative saving in emissions by 2030 would be 2%, rather than 8%.
- The implementation of only a dozen policies would result in nearly 40% of avoided CO_2 emissions by 2030. Giving priority to energy security would result in an almost identical choice of policies. Both objectives require a cut in demand for fossil fuels. The policies that, cumulatively, would yield the greatest reduction in that demand are those that achieve big gains in the efficiency of electricity generation and transport and the use of renewable energy and nuclear power.
- Public understanding, private-sector support and international co-operation are needed to enable governments to adopt and implement the more stringent policies required to make the Alternative Policy Scenario a reality. The conditions have to be created that will enable developing countries to adopt efficient equipment, technologies and practices.
- A still more ambitious goal – capping CO_2 emissions in 2030 at today's levels – could be met through a set of technological breakthroughs, stimulated by yet stronger government policies and measures. A Beyond Alternative Policy Scenario (BAPS) Case shows how CO_2 emissions could be cut by 8 Gt more than in the Alternative Policy Scenario. But the scale and the speed of the necessary technological change represent a new order of challenge.

- Four-fifths of the energy and emissions savings in the BAPS Case come from three main categories of effort: demand-side policies, fuel switching to nuclear and renewables in the power sector, and the introduction of CO_2 capture and storage technology. Almost all the measures considered also serve to enhance energy security.

Making the Alternative Policy Scenario a Reality

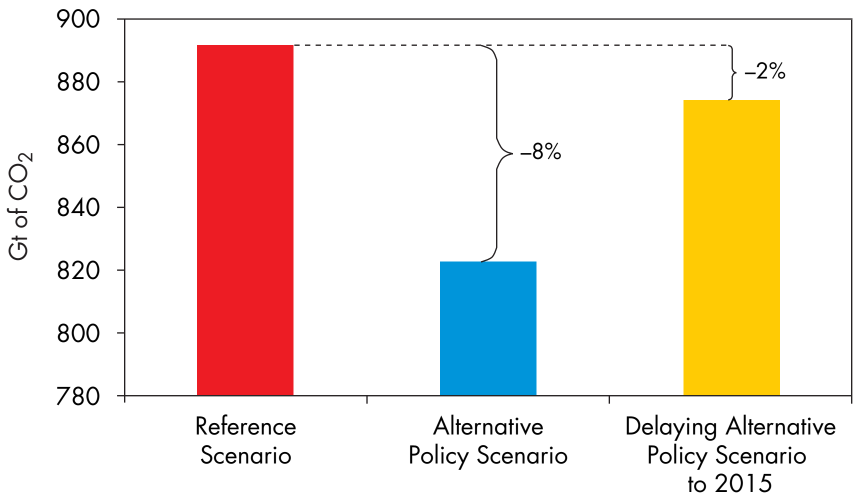
Identifying Policy Priorities

The adoption and implementation of the set of policies and measures analysed in the Alternative Policy Scenario would be a major step on the road to a more sustainable global energy system. They would begin to steer the world onto a markedly different energy path from that depicted in the Reference Scenario – a path that could lead, well beyond 2030, to a truly sustainable energy future in which energy supplies are secured and climate change is arrested. But adoption and implementation of those policies needs to begin immediately.

A wide range of policies needs to be adopted urgently, including the sensitive and progressive removal of subsidies that encourage the wasteful use of energy, more programmes on technology research, development, demonstration and deployment, and additional economic incentives to encourage energy users and producers to switch to low-carbon technologies. To accelerate energy-efficiency gains, governments need to enforce standards and implement new regulatory and legislative measures to improve demand-side management, building codes, industrial energy efficiency and new vehicle fuel economy. Any delays would compound the problems associated with rising energy use and emissions by extending the legacy of inefficient energy systems, increasing the costs of meeting targets and generating greenhouse-gas emissions that will reside in the atmosphere for decades or centuries to come.

To take the example of CO_2 emissions, cumulative energy-related emissions in the Reference Scenario over the period 2005-2030 are 890 Gt. The policies and measures of the Alternative Policy Scenario would avoid the release into the atmosphere of some 70 Gt, or 8% of CO_2 emissions in the Reference Scenario. Each year of delay in implementing the assumed policies would have a disproportionately large effect. A ten-year delay, for example, with implementation starting only in 2015, would reduce emissions much less by 2030. As a result, the saving in cumulative emissions in 2005-2030 would be only 2%, compared to the Reference Scenario (Figure 10.1).

Figure 10.1: **Cumulative Energy-Related CO_2 Emissions in the Reference and Alternative Policy Scenarios, 2005-2030**



The Alternative Policy Scenario incorporates 1 400 different policies and measures, all of which contribute to the energy and CO_2 emissions savings over the projection period. However, some policies contribute more than others, by yielding a greater change in energy consumption, imports or emission intensity. Some are also more cost-effective than others. Almost 40% of the savings in emissions by 2030 are achieved through the implementation of only a dozen policies (Table 10.1). Unsurprisingly, the policies with the greatest impact are found in countries where energy demand and CO_2 emissions are high, notably the United States, the European Union and China. In these countries, a focus on demand-side efficiency improvements (especially stricter vehicle fuel economy standards, building codes and appliance standards) and increased use of renewable energy sources and nuclear power in electricity generation contribute the bulk of the energy and emissions savings. An almost identical list of policies would emerge if the dominant concern was energy security. In other words, the policies of greatest significance are those that, cumulatively, produce the biggest switch away from fossil fuels: efficiency gains in both electricity generation and transport, and greater use of renewable energy and nuclear power. Collectively, both sets of policies yield significant economic benefits (see Chapter 8).

Table 10.1: **Most Effective Policies for Reducing Cumulative CO_2 Emissions in 2030 in the Alternative Policy Scenario Compared with the Reference Scenario**

Country/ region	**Policy**	**Avoided CO_2 emissions** (Mt)	**Share in global avoided CO_2 emissions** (%)	**Avoided oil imports** (kb/d)
Demand-side energy efficiency measures				
United States	Increased CAFE standards	252	5%	1 520
China	Improved efficiency in electricity use in the industrial sector	216	4%	<50
China	Improved efficiency in electricity use in the residential sector	189	3%	<50
US	Improved efficiency in electricity use in the residential sector	161	3%	<50
China	Improved efficiency in electricity use in the commercial sector	158	3%	<50
European Union	Increased vehicle fuel economy	99	2%	590
United States	Improved efficiency in electricity use in the commercial sector	96	2%	<50
European Union	Improved efficiency in electricity use in the commercial sector	68	1%	<50
Renewables				
China	Increased renewables use in power generation	230	4%	<50
United States	Increased renewables use in power generation	150	3%	<50
European Union	Increased renewables use in power generation	141	3%	<50
Nuclear				
China	Increased nuclear use in power generation	160	3%	<50
European Union	Extension of the life of nuclear plants	148	3%	<50
Total		**2 068**	**37%**	**2 240**

Hurdles to Policy Adoption and Implementation

The economic, energy-security and environmental benefits of the policies of the Alternative Policy Scenario are elaborated in the previous chapters. Why, then, have these policies not already been adopted and what might continue to prevent them from being rapidly adopted and implemented? The barriers are various.

Improving Energy Efficiency

Improving energy efficiency is often the cheapest, fastest and most environment-friendly way to bring energy needs and supplies into balance. Raising energy efficiency also reduces the need to invest in energy-supply infrastructure. Many energy-efficiency measures are economic: they will pay for themselves over the lifetime of the equipment through reduced energy costs (see Chapter 8). Widespread dissemination of best practice and technologies also helps reduce local and regional air pollutants, as well as greenhouse-gas emissions.

Several different policies have been proposed to increase efficiency. Two of the most effective seek to reduce energy demand in the transport sector: an increase in average fuel efficiency in the US light-duty vehicle fleet, and a vehicle efficiency programme in Europe. Both face considerable obstacles. In the case of the United States, some car manufacturers judge that, on the basis of present incentives and penalties, a switch from large vehicles to smaller and more efficient alternatives will mean smaller margins. The public, while supporting in principle the idea of increased efficiency – especially in the current price context – and lower pollution, allows these considerations to be outweighed by arguments that smaller cars are inherently less safe, are less comfortable and offer inferior performance. The new measures assumed in the Alternative Policy Scenario would impose a new fuel-economy standard but not the technology to achieve it, thereby giving car manufacturers some flexibility, while capitalising on public support for improved efficiency.

In the European Union, fuel-efficiency agreements were initially developed with the car manufacturers on a voluntary basis. The manufacturers are not on track to meet the target of 120g CO_2/km in 2012. The European Commission is therefore considering mandatory standards, coupled with differentiated excise-tax rates according to fuel efficiency.

The Japanese "Top Runner" approach for light-duty vehicles identifies the most fuel-efficient models in each vehicle class and requires future models to meet a level of fuel consumption close to the current (or expected future) best. Top Runner improves average fuel efficiency by encouraging improvements in the worst vehicles (or their elimination), and encouraging continuous improvements in the best.

These examples reflect differences of perception in Europe, North America and Japan over the impact and acceptability of different approaches, such as increases in fuel prices or additional regulation. Overcoming barriers requires such a tailored approach. But, in many cases, a regulatory approach will be needed to reinforce market mechanisms, such as the fuel taxes or carbon penalties that have been widely proposed and increasingly adopted in other sectors. This may be because the near-term effects of market options alone are too limited, making increasingly aggressive fuel-efficiency regulations necessary to achieve sufficiently rapid change in the transport sector. In developing and implementing such policies, policy-makers need to, and invariably do, take into account the consequences for national car makers. The result can be more politically palatable, though at same cost in terms of macroeconomic efficiency.

A different story emerges on closer examination of the policies proposed for saving electricity in the residential and services sectors. End users buying electrical equipment or appliances face problems of inadequate information (see Chapter 8). Changes in the price of electricity, as a result of government decisions on tax policy or the costs of CO_2 permits, could be expected to make considerable inroads in demand.

Enhancing the Role of Renewable Energy

Each of the world's major economies has proposed policies to promote the development and penetration of renewable energy and many already have policies in place. As with efficiency policies, there are similarities and differences in the policy approaches – and the barriers to their full implementation. New policies to promote renewables can be expected to have considerable implications for investment in this source of electricity. Indeed, policies already under consideration are projected to achieve a 27% share of renewables by 2030, compared with 22% in the Reference Scenario. In the Alternative Policy Scenario, investment in renewables-based electricity plants reaches $2.3 trillion, amounting to half the total investment in new generating plant.

To achieve this level of investment in renewables, governments will have to introduce vigorous incentives. A number of countries have already achieved much by using feed-in tariff mechanisms.[1] Another approach is to impose a requirement that a given proportion of electricity be produced from renewables – a portfolio quota – with or without accompanying tradable certificates, which increase the market orientation of the policy. A third approach is to offer a tax incentive, such as the US production tax credit. Green

1. A feed-in tariff is the price per unit of electricity that a utility or supplier has to pay for renewables-based electricity from private generators. The government regulates the tariff.

pricing, a voluntary measure, has not so far proven to have a significant impact. Increasing public funding of research, development and deployment can help speed up the decline in the capital costs of renewables as they enter the market.[2] But all these incentives are costly, either to governments themselves (through increased public spending) or to consumers (through higher taxes or prices). Pursuing such policies with the vigour assumed in the Alternative Policy Scenario depends on their being demonstrated to be cost-effective.

Other constraints will also apply. Planning periods are long for some types of renewables projects, particularly wind farms and hydropower. To facilitate investment in renewables, a clear and effective planning system is essential. The integration of intermittent renewables in the electricity grid has also to be planned with care.

Enhancing the Role of Nuclear Power

In many parts of the world, barriers to the adoption of policies encouraging the construction of nuclear reactors are particularly high. Public attitudes vary widely. In several countries in the European Union, there is vocal public opposition to nuclear power and, in some cases, governments have even fallen over the issue of plant lifetime extension or expansion of nuclear capacity. Opposition is based on concerns over reactor safety, the safety and cost of long-term waste disposal and proliferation of nuclear weapons. In developing countries, obtaining financing for large-scale initial investment is another major hurdle. Chapter 13 examines in detail the economics, prospects and current policy framework for nuclear power.

Overcoming Hurdles to Government Action

It will take considerable political will to push through the policies and measures in the Alternative Policy Scenario, many of which are bound to encounter considerable resistance from industry and consumer interests. This is largely because of the way costs fall under present conventions. Much effort needs to be expanded in communicating clearly to the general public the benefits of change to the economy and to society as a whole. In many countries, the public is becoming increasingly familiar with the energy-security and environmental advantages of action to encourage more efficient energy use and to boost the role of non-fossil fuels. The high oil prices experienced over the past few years have helped to increase the awareness of the benefits of change.

To make the Alternative Policy Scenario a reality, private-sector support for more stringent government policy initiatives would be essential, together with a strong degree of co-operation between industry and government and between

2. The share of renewable energy technologies in total government energy R&D spending has remained relatively stable over the past two decades (IEA, 2006a).

countries (for example in relation to emissions charges for aviation fuel use). Multilateral lending institutions and other international organisations can support non-OECD countries in devising and implementing new policies. Governments can also facilitate access to advice and expertise on energy policy-making and implementation and can improve conditions for technology transfer.

Access to capital is a particular problem for smaller developing countries, which, unlike China and India, are not besieged by investors seeking opportunities. Programmes are required to promote technology transfer, to help build the capacity to implement change and to offer opportunities for collaborative research and development. Developing countries need to make complementary changes to facilitate exchanges.

Going Beyond the Alternative Policy Scenario

Although the policies and measures in the Alternative Policy Scenario would substantially improve energy security and reduce energy-related CO_2 emissions relative to the Reference Scenario, fossil fuels would still account for 77% of primary energy demand. Global CO_2 emissions would still be 8 Gt higher in 2030 than they are today. Oil and gas imports into the OECD and developing Asia would be even higher than they are today and would come increasingly from politically unstable regions, through channels prone to disruption.

In this section, we explore how greater energy savings and emissions reductions than in the Alternative Policy Scenario might be achieved by 2030. This Beyond the Alternative Policy Scenario (BAPS) Case responds to requests by policy-makers to illustrate the potential for achieving still more ambitious emissions reductions through stronger policies and more favourable technological development, and the obstacles and implications for energy security. The goal adopted in this Case, as a proxy for more diverse energy objectives, is to ensure that global energy-related CO_2 emissions in 2030 are no higher than the 2004 level of 26.1 Gt.

The BAPS Case is not constrained by the criterion that only policies already under consideration by governments are adopted. Accordingly, this case assumes even faster and more widespread deployment of the most efficient and cleanest technologies, thanks to more aggressive policies and measures and the adoption of new technologies, beyond those which have already been applied commercially today.

Achieving the BAPS Goal

Achieving the BAPS goal means reducing emissions in 2030 by 8 Gt more than in the Alternative Policy Scenario and by 14.3 Gt compared with the

Reference Scenario. This would require major changes in energy supply and use. Demand and supply efficiency would need to be further improved and increased use be made of nuclear and renewables, to levels well beyond those in the Alternative Policy Scenario. Technologies exist today that could permit such radical changes over the *Outlook* period, but there are many barriers to their deployment, including the following:

- The life span of the existing capital stock limits commercial opportunities for new plant construction – particularly in OECD countries.
- Even existing highly-efficient technologies have yet to be widely adopted.
- The costs are, in some cases, likely to be considerably higher than those of established technologies.

Achieving the BAPS goal will, therefore, almost certainly call for new technologies as well as improvements to those that exist. Of the existing technologies that are currently under development but not yet commercially available, CO_2 capture and storage (CCS)[3] and second-generation biofuels seem the most promising.

There are many different possible paths leading to this more sustainable future, involving a myriad of technology options and fuel choices. A policy approach that promotes a portfolio of technologies would greatly reduce the risk and potentially the cost of accelerating technological solutions, because one or more technologies might fail to make the expected progress. The mix of options presented here is not necessarily the cheapest, nor the easiest to implement politically or technically.

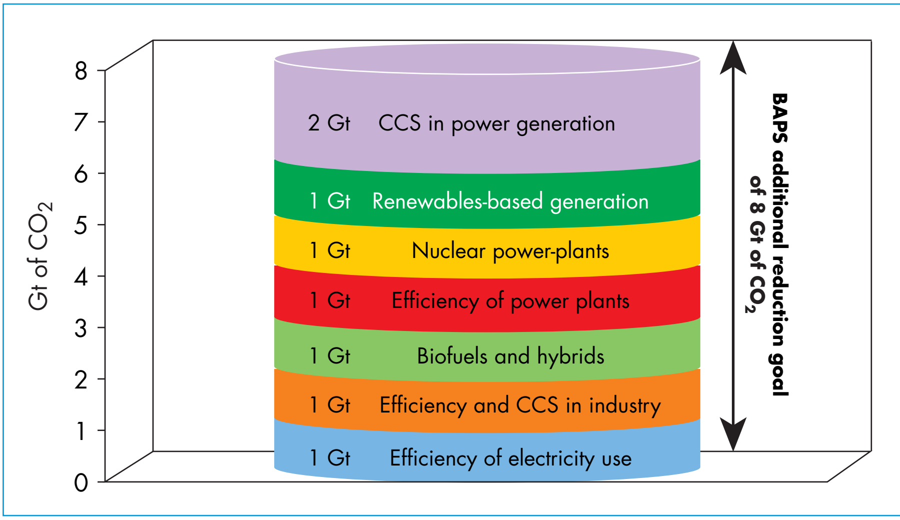
10

So far as emissions reductions are concerned, Pacala and Socolow suggest that a useful indicator of the value of technical options for emissions reduction is their capacity to yield 1 Gt of cumulative emissions reductions over the next 50 years (Pacala and Socolow, 2004). A variant of that framework is used here. We identify six different initiatives, each of which can yield a saving of 1 Gt of CO_2 emissions in 2030. We add a seventh, CO_2 capture and storage in power generation, which we count upon to save 2 Gt, in order to arrive at savings of 8 Gt beyond those made in the Alternative Policy Scenario in 2030 (Figure 10.2). The initiatives are as follows:

- **Increasing savings in electricity demand:** This involves increasing the average efficiency of electricity use by an additional 50% over and above the level achieved in the Alternative Policy Scenario. Electricity savings would total 1 815 TWh compared with the Alternative Policy Scenario and 5 730 TWh compared with the Reference Scenario. Those savings would avoid building close to 200 GW of coal-fired power plants, emitting 1 Gt of CO_2. Two-thirds of these savings could be achieved in electricity use in the

3. See Box 7.2 and IEA (2004) for a detailed assessment of the status and prospects for CCS.

Figure 10.2: **Reduction in Energy-Related CO_2 Emissions in the BAPS Case Compared with the Alternative Policy Scenario by Option**



residential and services sectors, where the untapped technical potential for energy efficiency measures is still very high. Additional savings could come from industry, mainly through more efficient motor-drive systems. Incentives would be required for early capital retirement, together with other pricing policies and regulations.

- **Measures in the industrial sector:** Increasing the efficiency of fossil fuels used in industry, by an additional 7% over and above the gains achieved in the Alternative Policy Scenario, could avoid the burning of fossil fuels emitting 0.5 Gt of CO_2. Pricing policies might achieve such a change. Other types of policy might focus on reducing the capital cost of more efficient equipment. Another promising option that could bring about an additional reduction of 0.5 Gt is equipping boilers and furnaces with CCS. Policies would be required to provide incentives for small-scale CCS technologies. These could include regulatory requirements or subsidies for installation.
- **More efficient and cleaner vehicles:** Sales of hybrid vehicles would make up 60% of new light-duty vehicles sales (18% in the Alternative Policy Scenario), plug-in hybrids would enter the LDV market and biofuels use in road transport would double compared to the Alternative Policy Scenario. Those measures combined would avoid the combustion of more than 7 mb/d of oil, saving 1 Gt of CO_2 in 2030. Policies to promote hybrids technology could include vehicle-purchase subsidies, regulatory standards and higher taxes on the least efficient vehicles. Plug-in hybrids, which allow a portion of

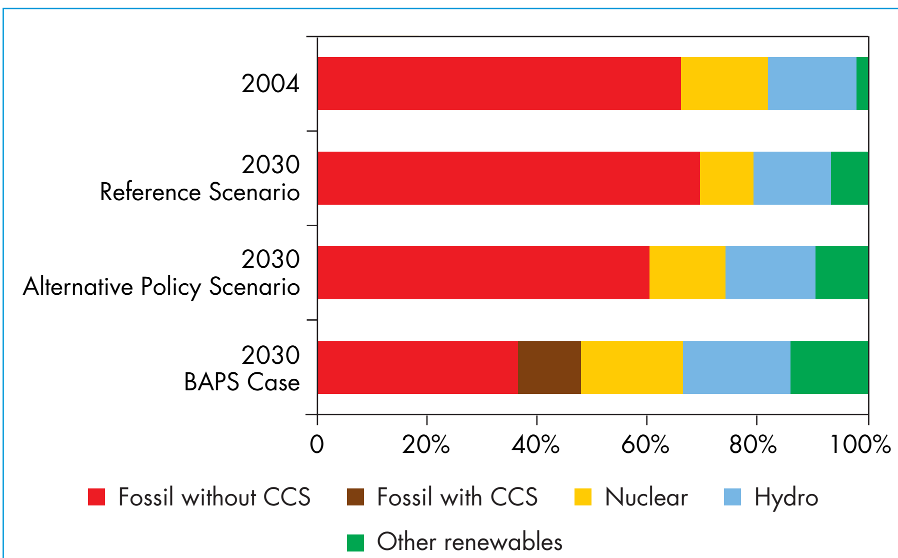
road-transport oil demand to be saved by using electricity from the grid, can yield significant benefits provided the grid becomes less carbon-intensive (see below). Policies to promote the further development of battery technology would be essential for these vehicles to be widely deployed. Given the constraints on land and biomass availability, the level of penetration of biofuels could only be achieved through the large-scale introduction of second-generation biofuels based on ligno-cellulosic feedstock (see Chapter 14). Policies to encourage this could include increased research and development, incentives for construction and operation of biorefineries and minimum requirements for biofuels in conventional fuel blends.

- **Increasing the efficiency of power generation:** Inefficient coal-fired power plants would be retired early and replaced with more efficient coal plants and hydrogen fuel cells. Retirement of an additional 125 GW of old coal-fired plants could be involved (in addition to the 412 GW retired in the Alternative Policy Scenario) between 2004 and 2030. The new coal-fired power plants would achieve an average efficiency of 48%, compared with 46% in the Alternative Policy Scenario. The equivalent savings in CO_2 are 0.5 Gt. Policies to drive such early retirements could include changes in capital depreciation rates, incentives for the installation of advanced technology and efficiency standards for coal installations. If hydrogen fuel cells were to supply 550 TWh of electricity more than in the Alternative Policy Scenario, this could yield another 0.5 Gt of CO_2 savings. Policies to bring this about could include intensified research and development (to drive down costs), subsidies for building new power plants and policies to reduce the lending risk of capital for such investments.
- **Increased nuclear power generation:** An additional 140 GW of nuclear capacity would need to be installed by 2030, replacing coal-fired plants. This would bring the total installed nuclear capacity in 2030 to 660 GW, as compared with 519 GW in the Alternative Policy Scenario and 416 GW in the Reference Scenario. Policies to promote such additions might include more intensive effort to improve waste management, loan guarantees to reduce the cost of capital and measures to garner public support for nuclear power.
- **Increased use of renewables-based power generation:** An additional 550 TWh of hydropower and 550 TWh of other renewables-based generation would need to be commissioned, each saving 0.5 Gt of CO_2 emissions. With such additions, renewables-based generation represents a 32% share of electricity generated in 2030, as compared with 27% in the Alternative Policy Scenario and 22% in the Reference Scenario. Policies could include research and development to bring down costs, renewables portfolio standards or feed-in tariffs, and loan guarantees to reduce the cost of capital.

- **Introduction of CO_2 capture and storage in power generation:** The introduction of CCS in the power sector would reduce emissions by 2 Gt in 2030. Approximately 3 100 TWh of electricity would then be generated from coal and natural gas plants equipped with CCS. Some 70% of new coal-fired capacity and 35% of new gas-fired plants would be equipped with CCS over the projection period. CCS in coal plants would account for more than 80% of the captured emissions. Such a solution would be particularly productive in China and India. Potential policies to implement this strategy are diverse: funding for research and development, incentives for large-scale demonstration plants, loan guarantees for new plants, performance standards for emissions from new plants, international cooperation to facilitate the building of new plants in the developing world and the wider introduction of financial penalties on carbon emissions (taxes or cap-and-trade arrangements).

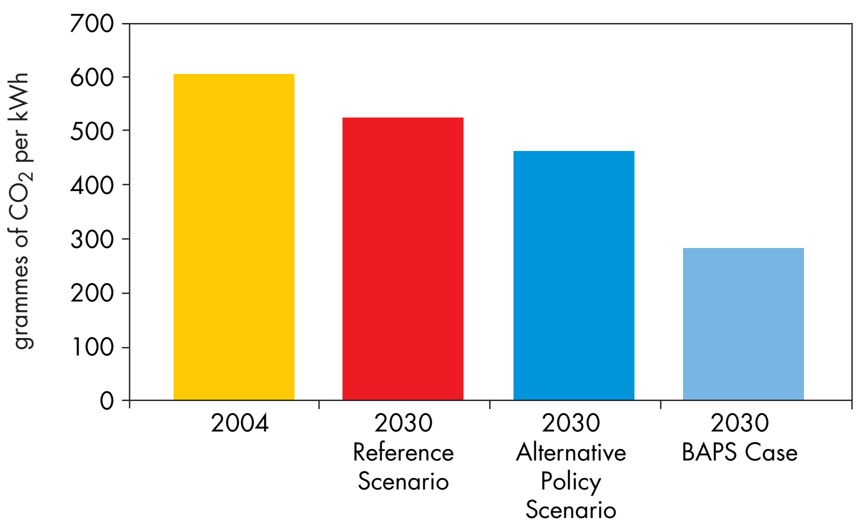
If all approaches were adopted in the manner described, the power-generation mix would change radically (Figure 10.3). The share of nuclear power in total generation in 2030 would reach 19%, compared with 14% in the Alternative Policy Scenario and 10% in the Reference Scenario. The share of coal would remain large – but the share of generation from coal-fired plants equipped with CCS equipment would reach 8%, compared with zero in the Alternative Policy and Reference Scenarios. The share of renewable energy would also increase sharply.

Figure 10.3: **Fuel Mix in Power Generation in Different Scenarios**



A large proportion of the emissions reductions would occur later in the projection period as the incremental capacity of renewables, nuclear and more efficient fossil fuels-based power generation comes into service and current (less efficient and higher emitting) electricity-generating plants are retired. The improvement in the CO_2-emissions intensity of electricity generation in 2030 is illustrated in Figure 10.4.

Figure 10.4: **CO_2 Intensity of Electricity Generation**



The policies required to achieve the BAPS reductions are clearly aggressive. No single policy would suffice. In some cases, there would be synergies between policies, for example a price on carbon will help incentivise CCS, nuclear power and renewable energy. However, other policies may be more divisive. R&D efforts need to be technology-specific and there would be competition for a limited pot of money. Furthermore, there are many companies and actors in the energy sector; policies that give advantage to one part of that community may damage another. Thus, a requirement that new coal plants install CCS technologies imposes a burden on power companies and increases electricity prices, while bringing considerable additional revenue to the CCS technology providers. Interventions by policy-makers to allocate the costs and the benefits may be necessary to maximise the effectiveness of the policies and, even, to make them politically feasible.

Implications for Energy Security

The analysis of the BAPS Case is based on the goal of returning energy-related CO_2 emissions in 2030 to 2004 levels to mitigate climate change. But many of the measures and technologies that would enable this goal to be met would also enhance energy security. Greater diversity in the fuel mix serves a diversity of purposes.

Meeting the BAPS Case CO_2 goal would reduce oil demand in 2030 to 95 mb/d – around 8 mb/d less than in the Alternative Policy Scenario, 21 mb/d less than in the Reference Scenario and only 10 mb/d more than today. This implies that the average oil intensity – the amount of oil consumed per unit of GDP – of the world economy would more than halve between 2004 and 2030. For comparison, oil intensity fell by 46% over the past three decades worldwide. But global oil demand still increased from 58 mb/d in 1974 to 82.5 mb/d in 2004. The BAPS Case would therefore represent a significant break with past trends.

Natural gas demand is also reduced. By 2030, it is 6% below the level of the Alternative Policy Scenario. Most of this reduction comes from lower demand in the power-generation sector which, with fuel switching to nuclear power and renewable sources of energy, becomes less reliant on gas. The volume of gas trade in this case is, therefore, smaller than in the Alternative Policy Scenario.

Lower oil and gas demand and imports in developing countries would boost the disposable incomes of households and businesses and the potential for more rapid economic and human development. This would benefit all importing nations. Recognition of the mutual energy-security benefits of such policies would facilitate the establishment of co-operative arrangements between developing and OECD countries.

Beyond 2030: the Need for a Technology Shift

The above discussion describes some of the policy tools that might be used to reduce CO_2 emissions by an additional 8 Gt beyond those attained in the Alternative Policy Scenario. It is clear that achieving this result will be contingent on the development and deployment of new technologies. The technology shifts outlined in the BAPS Case would represent a very severe challenge in terms of their speed of deployment.

Technology development is typically a slow process: decades often elapse between the initial invention and mass application. In fact, all of the new technologies analysed in the Alternative Policy Scenario and some in the BAPS Case are already commercially available and operational. This is important, because policies to encourage their faster penetration are less speculative than backing unproven technologies. This does not mean that large-scale application of these technologies is imminent. Without sustained research and development efforts, many of these technologies will remain too expensive to be used outside niche applications (IEA, 2006b). But this level of achievement will also need technologies which are, as yet, far from commercial application.

A number of technologies are listed in Table 10.2, with an eye to developments beyond 2030. Some of these (solar PV, CCS and plug-in hybrids) are assumed to be deployed in the BAPS Case – albeit at low levels, in some cases. However, nearly all of them could make a significant contribution to energy supply after 2030. But they are unlikely to be commercialised and deployed rapidly in the absence of determined policy intervention. For example, for many forms of renewables-based power generation, the variability of the resource quality and the intermittency of supply will impede deployment (IEA, 2006a). Such constraints impose limits on their wide-ranging deployment, even if their costs are competitive on some bases of comparison. Long-distance transmission of electricity could play a significant

Table 10.2: **Options for Emissions Reductions beyond 2030**

Power generation	Solar PV and concentrating solar power in combination with long-distance electricity transportation Ocean energy Deep-water wind turbines Hot dry rock geothermal Generation IV nuclear reactors Large-scale storage systems for intermittent power sources Advanced network design Low-cost CCS for gas-fired power plants Distributed generation Low-cost unconventional gas
Transport	Hydrogen fuel-cell vehicles Plug-in hybrids Transmodal transportation systems Intermodal shift
Industry	CCS Biomass feedstocks/biorefineries
Buildings	Advanced urban planning Zero-energy buildings

role in power supply, if its costs could be brought down. Better integration of national and regional electricity systems could also dampen the effects of intermittency and allow the higher share of renewables to grow. Large-scale electricity-storage systems could serve a similar purpose.

Some technologies are inhibited by a combination of institutional and technical barriers. As discussed above, nuclear power offers considerable advantages in terms of avoiding greenhouse-gas emissions and of energy security. The development of fourth-generation nuclear reactors and new fuel-cycle facilities aims to address waste disposal and nuclear proliferation concerns – central to the anxieties of the public about this electricity source (see Chapter 13). However, fourth-generation reactors are not yet commercial. It will take considerable additional resource commitments, as well as policy intervention, to bring this generation into widespread use. Its broad penetration is likely only after 2030 (IEA, 2002).

The building sector is highly significant in terms of its longer-term potential. While some retrofitting of the existing building stock is both technically and economically feasible today, a considerably greater opportunity will emerge as the existing stock is replaced. Achieving better insulated building shells, improved ventilation systems and the necessary urban planning measures requires patience. But action as opportunity permits would reduce the demand for space heating and cooling and, possibly, for transportation. This would affect not only demand for electricity but also for fossil fuels. New technologies are emerging that may lead to major changes in this sector, including small-scale combined heat and power generation systems for heating and cooling of buildings, improved condensing gas boilers, and gas-fired heat pumps. Of special importance are the construction programmes in new cities in the developing world, especially in temperate climates; taking advantage of modern technologies can significantly reduce their energy demand.

Indeed, in many countries, new buildings could, on average, be made 70% more efficient than existing buildings. In Europe today there are over 6 000 passive solar buildings, mainly in Germany and northern Europe. While these houses are not yet zero-energy, their heating energy needs are typically 75% lower than normal. A combination of good insulation and ventilation heat-exchange is sufficient to achieve this. A further step will be required to achieve zero-energy buildings (designed to use no net energy from the utility grid).

In the period from 2030 to 2050, the production of hydrogen from low-carbon and zero-carbon sources could expand and the consumption of hydrogen, in distributed uses, could grow substantially. However, this will require huge infrastructure investments (IEA, 2005). Hydrogen-powered fuel-cell vehicles could make a significant contribution, even by 2030, if there are breakthroughs in hydrogen storage and the infrastructure develops. The use in fuel-cell vehicles of hydrogen from low-carbon or zero-carbon sources could ultimately largely de-carbonise oil use in transport.

Looking beyond 2050, other options, like nuclear fusion, might emerge. Fusion is a nuclear process that releases energy by joining together light elements, as distinct from fission, produced by breaking apart heavy elements. Its proponents believe it holds the promise of virtually inexhaustible, safe and emission-free energy. Over the past two decades, the operation of a series of experimental devices has considerably advanced the technology. Fusion power generation as a commercial undertaking remains a long-term objective which requires sustained research and development efforts, including materials and system optimisation. Because of the potential benefits, very high shares of IEA countries' energy research and development budgets are allocated to investigating its feasibility and potential. It is not likely to be deployed until at least 2050.

PART C

FOCUS ON KEY TOPICS

THE IMPACT OF HIGHER ENERGY PRICES

HIGHLIGHTS

- The price of crude oil imported into IEA countries averaged just over $50 per barrel in 2005, almost four times the nominal price in 1998 and twice the 2002 level. Prices continued to rise strongly through to mid-2006. Real prices paid by most final energy consumers have increased far less than international prices in percentage terms, because of the cushioning effect of taxes and distribution margins and, in some countries, subsidies and a fall in the value of the dollar. We estimate that consumption subsidies in non-OECD countries amount to over $250 billion per year.
- Strong demand for energy, driven by exceptionally fast economic growth, has helped drive up oil and other energy prices since 1999, but there are signs that higher prices are now beginning to curb demand growth. All the same, oil demand is becoming less sensitive to changes in final prices as consumption is increasingly concentrated in transport, where demand is least price-elastic. Income remains the primary driver of demand for oil, gas, coal, and electricity, demand for all of which has continued to grow strongly, with incomes, in most regions.
- Oil prices still matter to the health of the world economy. Although most oil-importing countries around the world have continued to grow strongly, the world economy would have grown even more rapidly had oil prices and other energy prices not increased – by 0.3 percentage points per year more on average since 2002. The loss of real income and the adverse impact on the budget deficits and current account balances of importing countries were proportionately greatest for the most heavily indebted poor countries.
- The eventual impact of higher energy prices on macroeconomic prospects remains uncertain, partly because the effects of recent price increases have not fully worked their way through the economic system. There are growing signs of inflationary pressures, leading to higher interest rates. The longer prices remain at current levels or the more they rise, the greater the threat to economic growth in importing countries.
- There are major benefits for importing countries, in terms of price, security and economic welfare, of reducing reliance on imported oil and gas. This requires policies to stimulate indigenous production of hydrocarbons and alternative sources of energy and improve energy efficiency. The removal of energy subsidies and economically efficient pricing and taxation policies can play a major role in achieving this goal.

Introduction

Since the first oil shock in 1973-1974, some fluctuations in global economic performance have been clearly associated with sharp changes in the international price of oil and other forms of energy. But the causality is not always obvious, largely because of the complex linkages between energy demand, supply and prices, and economic activity in general. Economic activity is the primary determinant of energy demand and thereby influences energy prices. Yet energy prices, in turn, influence energy demand and economic performance. The feedback links between the three variables are complex and involve varying time-lags, which can lead to cyclical movements in prices. The economic downturn in the wake of the 1997-1998 Asian financial crisis drove down oil prices, while the economic rebound in 1999-2000 and 2002-2004 pushed them up again. The first oil shock and the second in 1979-1980 led to recessions in the major oil-importing countries.

This chapter analyses quantitatively the consequences for energy markets and the economy at large of high energy prices, both historically and in the future. It looks at the role of price subsidies in dampening the impact on demand of higher international energy prices[1] and their implications for macroeconomic indicators. It also considers which regions, sectors and social groups are most vulnerable to persistently higher prices.

The chapter is organised into four sections. The first reviews recent trends in international energy prices and analyses price relationships between fuels and regions. The following section considers the sensitivity of energy demand to changes in price, through a review of the many studies that have been conducted in recent years on that subject, our own analysis of price/demand relationships (which underpins the demand modules of the IEA's World Energy Model) and simulations of higher price assumptions than those used in the Reference Scenario. A third section assesses the overall macroeconomic impact of higher energy prices. A final section briefly assesses the implications of this analysis for energy policy-making.

Energy Price Trends and Relationships

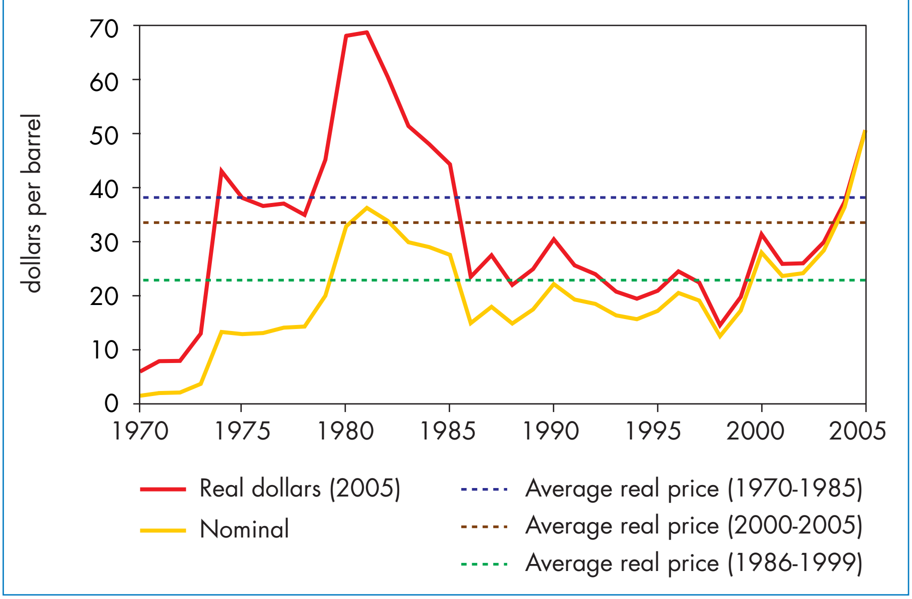
International Prices

Oil prices have been extremely volatile in recent years. The average IEA crude oil import price rebounded sharply from lows of around $12/barrel (in real 2005 prices) reached at the end of 1998 to well over $30 in 2000, before falling back to $26 on average in 2001 and 2002 – only slightly above the average of

1. The impact of higher prices on supply is assessed in Chapter 3 (Implications of Deferred Upstream Investment). A more detailed analysis can be found in IEA (2005).

the period from 1986 to 1999 (Figure 11.1). Prices rose on average again in 2003, surging to new highs in 2004 and 2005. Prices peaked at well over $70 (almost $80 for West Texas Intermediate, or WTI) in July 2006 – a record at the time in nominal terms.[2] In 2005, the average IEA crude oil import price was almost four times the nominal price in 1998. As a result, the average IEA oil price in real terms has been above that of the 1970s since the start of the current decade, but still below that of the period from 1970 to 1985. International oil-product prices (before local taxes and subsidies) have generally increased in line with crude oil prices. Prices have risen in response to a decline in spare supply capacity, as demand for oil products has outpaced increases in crude oil production and refining capacity, as well as to supply disruptions and geopolitical tensions (see Chapter 3).

Figure 11.1: **Average IEA Crude Oil Import Price**

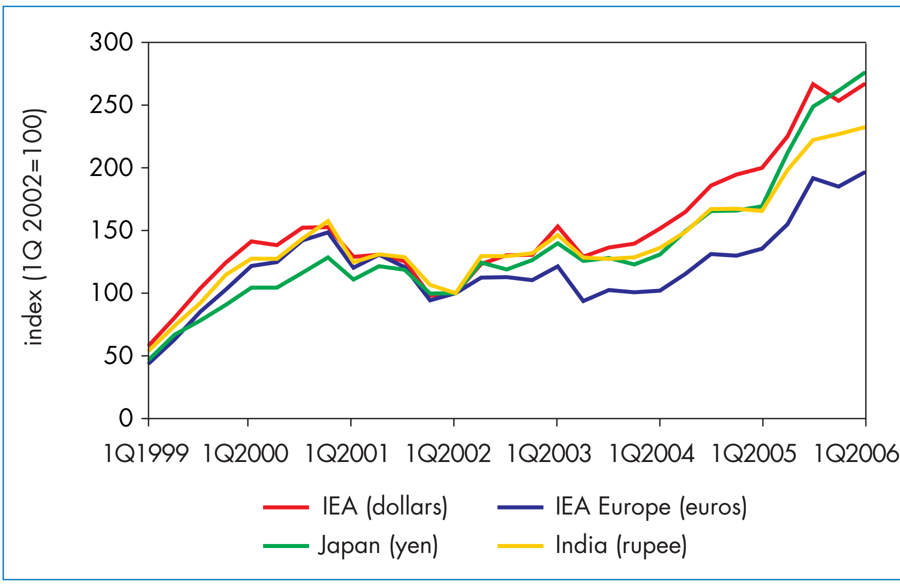


Regional oil-import prices expressed in local currency terms have differed markedly since the end of the 1990s, due to fluctuations in dollar exchange rates (Figure 11.2). The average European crude oil import price expressed in euros rose faster than dollar prices in 1999-2000, but then fell – in both absolute and relative terms. Indexed to the first quarter of 2002, the euro price in real terms (nominal prices adjusted using the gross domestic product, or GDP, deflator) rose

2. In 2005, the average IEA crude oil import price averaged $5.97 less than WTI and $3.90 less than Brent.

by about 60% of the increase in the dollar price. In contrast, the Japanese oil-import price in yen rose slightly more than the dollar price over 2002-2005. Chinese oil-import prices followed dollar prices up to July 2005, as the yuan was pegged to the dollar – a system that had been in place since 1994. With the adoption of new arrangements, under which the yuan is now tied to a basket of currencies, the Chinese currency was then revalued upward against the dollar by 2.1%, reducing import prices marginally in yuan terms. In several other developing countries, currency revaluations have dampened the impact of higher dollar oil prices to a larger extent. For example, since 2002, the real price of crude oil imports into India has risen by only about 80% as much as dollar prices.

Figure 11.2: **Average Crude Oil Import Prices by Region in Real Terms and Local Currencies**



Wholesale and import prices of natural gas have generally risen in line with crude oil prices since 1999, reflecting competition between gas and oil products and contractual links. Proportionately, gas prices increased more or less at the same rate as oil prices in North America between the first quarter of 1999 and the last quarter of 2005, actually increasing faster between 2002 and early 2005 due to supply constraints and a surge in demand as several new gas-fired power stations came on line. US gas prices have since fallen relative to oil prices. In Europe and Asia, gas prices increased less rapidly than oil prices, and with a time-lag. Almost all the gas consumed in continental Europe and Japan is traded under long-term contracts with oil-price indexation (Box 11.1), but price caps – contractual clauses that

Box 11.1: **Contractual Links between Oil and Gas Prices**

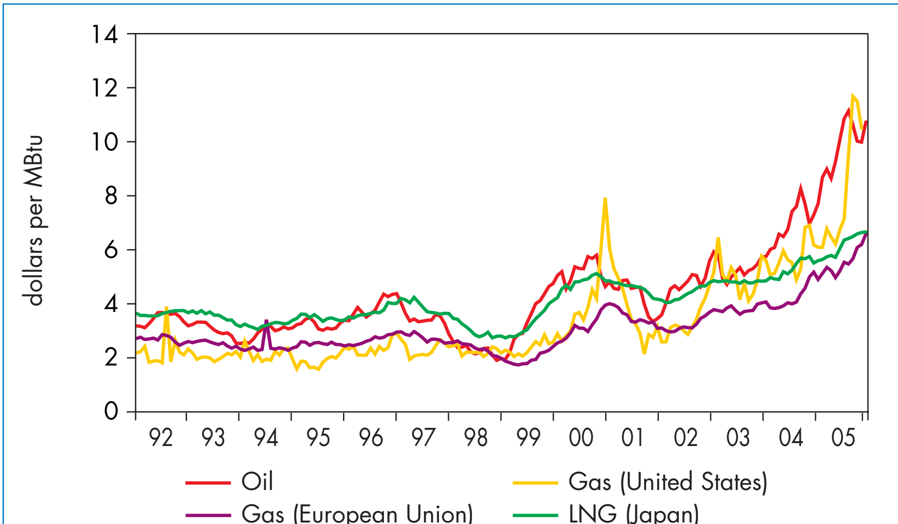
The share of term contracts (as opposed to spot deals) in wholesale or bulk gas supply varies considerably across regions. Although spot trade has been growing, it remains small in most regions. The share is highest in North America, Great Britain and Australia. In other regions, almost all gas is traded under term contracts of varying lengths. Precise figures are not available, as the terms of such transactions are confidential. Gas traded under term contracts (covering supply over several months or years) can be indexed against spot or futures prices for gas, crude oil, oil products, coal and/or electricity. Indexation against general price inflation is also incorporated into some contracts. Some contracts include indexation against just one price parameter; others include two or more (for example, crude oil and heavy fuel oil, or oil and electricity). Many term contracts – especially in non-OECD regions – have no indexation at all.

Gas prices in term contracts are most commonly indexed on oil prices. Indexation to other gas prices is confined mainly to North America, Britain and Australia, because spot gas trade elsewhere is limited and reliable price quotations are not available. Oil indexation is thought to be used in only a small proportion of contracts in the United States and Canada, accounting for well under 10% of the total amount of gas traded in bulk. In continental Europe, term contracts – often covering very long terms of twenty or more years – account for well over 95% of bulk gas trade (almost 100% outside Belgium and the Netherlands). Virtually all of these contracts include oil-price indexation. In Britain, term contracts – which are generally much shorter in duration than in the rest of Europe – account for 90% of all bulk trade. In contrast to the rest of Europe, they almost always price the gas on the basis of spot or futures gas prices, usually at the National Balancing Point (a notional location on the grid where gas demand and supply are assumed to balance). A small number of contracts may have some limited degree of oil-price indexation. Of total OECD European supply of 534 bcm in 2004, perhaps 80% – or well over 400 bcm – is priced in whole or in part against oil. It is thought that gas prices are indexed against oil prices in one way or another in all the long-term LNG supply contracts to Japan, Korea, Chinese Taipei, China and India. In some contracts, there are limits on how high or low prices can go. Spot trade, however, is increasing, especially to Japan.

In other OECD countries, gas prices are usually indexed against oil prices (solely or in combination with other prices) in import and other bulk supply contracts. In non-OECD countries, gas consumed domestically is not usually traded commercially and any contracts that exist typically do not involve any form of indexation. For example, in Russia – the world's second-largest consumer of gas – gas is sold under regulated, subsidised prices, with no explicit oil-price indexation. Non-OECD gas exports, when commercial, are most often priced against oil. We estimate that the share of global gas supply that is traded in bulk under contracts with explicit oil-price indexation clauses is probably at least one-third and may be as high as half. Focusing solely on cross-border trade, contracts with oil-price indexation probably account for around 90% of the world total.

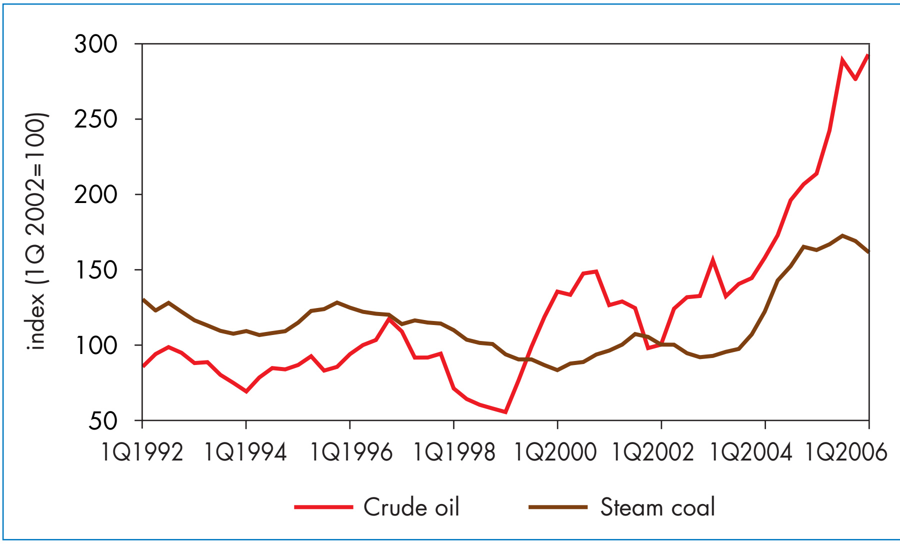
place a ceiling on how high gas prices can go in absolute terms – have insulated gas prices from part of the recent increase in oil prices, especially since 2003 (Figure 11.3). In Japan, for example, the price of imported LNG at the end of 2002 was the same as that of crude oil in calorific value terms; by the end of 2005, gas cost more than 40% *less*.

Figure 11.3: **Average IEA Crude Oil and Natural Gas Import Prices**



Wholesale coal prices have generally increased much less than the prices of oil and gas since 2002. The average price paid by OECD countries for imports of steam and coking coal rose steadily in 2000 and 2001, but then fell back. By the beginning of 2003, coal prices were well below the level of the 1990s. Coal prices rebounded sharply in 2003 and 2004 – by proportionately more than oil prices – but stabilised in 2005 (Figure 11.4). By the first quarter of 2006, the price of steam coal was about 51% above the average level of 1992-2002.

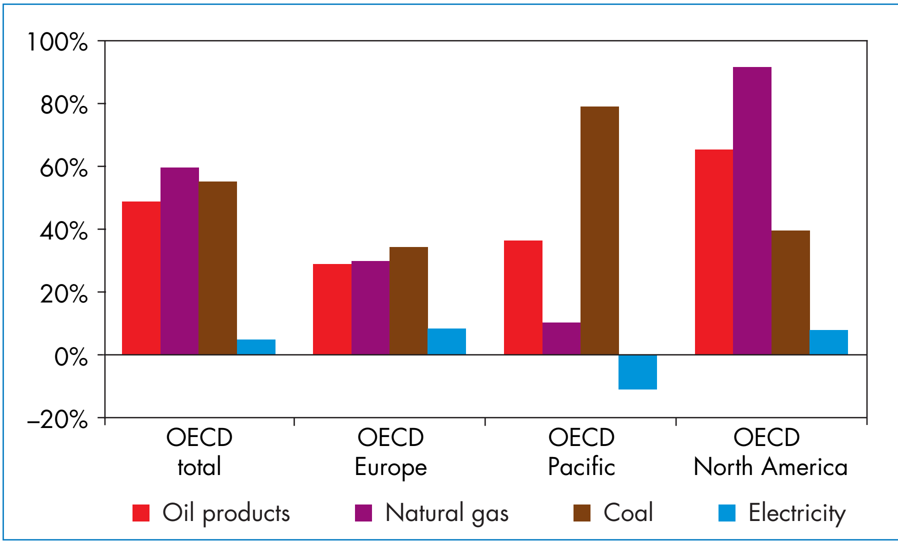
Figure 11.4: **Average IEA Crude Oil and Coal Import Prices**



Final Prices to End Users

In general, the prices paid by final energy consumers have increased as much as international or wholesale prices in absolute terms, but far less in percentage terms. In the case of oil products, this is mainly because of the dampening impact of taxes and subsidies. Excise duties, which are levied at a flat rate per volume, cushion the impact on the final prices of oil products of increases in international prices. The higher the level of duty on a given fuel, the less the final price will increase proportionately relative to the international price. Subsidies – often in the form of price controls – can also prevent higher international market prices from feeding through fully into local energy prices. In addition, distribution costs and margins – which make up a significant part of the final price – have increased much less than bulk prices. As non-fuel costs account for a significant share of the total cost of electricity supply, increases in generation fuel costs lead to much smaller increases in final electricity prices – even where all of the cost increases are passed through. In the OECD, for which good price information is available, final coal and gas prices have increased more in percentage terms than the prices of oil products and electricity (Figure 11.5).

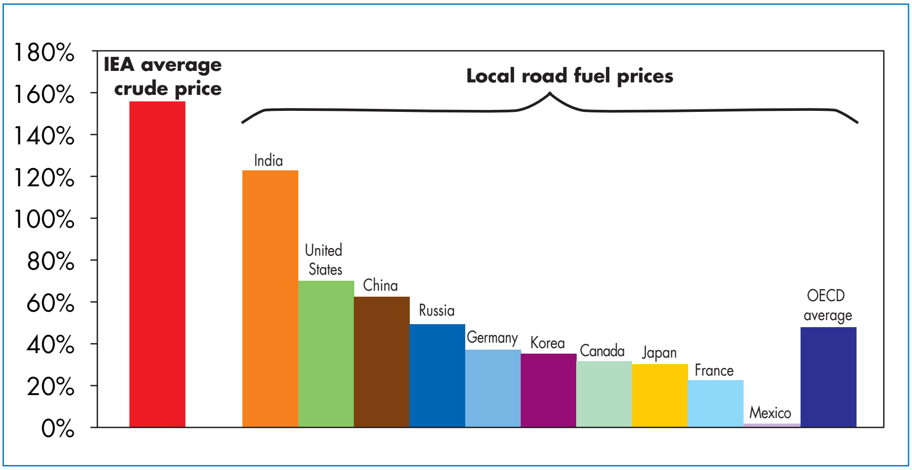
Figure 11.5: **Change in Real Energy End-Use Prices by Region and Fuel, 1999-2005**



In most countries, taxes are the main reason why local oil-product prices have increased proportionately less than import prices and less than the prices of other end-use fuels. Road-transport fuels are typically the most heavily taxed products in all regions. In OECD countries, taxes on gasoline currently range from 13% to 70% of the price at the pump, while diesel taxes range from 11% to 68%. Taxes account for more than half of the gasoline pump price in 22 of the 29 OECD countries surveyed by the IEA. Road fuel tax rates are highest in Europe and lowest in the United States. In non-OECD countries, rates are generally lower, so that pump prices have often risen more in percentage terms than in the OECD (Figure 11.6). In no country have pump prices increased as much in percentage terms as crude oil prices. Some non-OECD countries, including China, have limited increases in final prices, shielding consumers from higher import costs. Other oil products and other forms of energy, such as coal, are generally taxed at much lower rates or, in some cases, not at all.

Natural gas prices to end users have also increased to varying degrees across countries, mainly because of differences in pricing practice and regional market conditions. Gas prices to end users fluctuate much less than import or well-head prices because regulated transportation costs, which are usually relatively stable, account for a significant share of the final price. In the OECD, gas prices have increased most in recent years in North America because of particularly tight gas supplies in the region. In Japan, they actually fell slightly

Figure 11.6: **Change in Average Annual IEA Crude Oil Import Price and Road Fuel Prices in Ten Largest Oil-Consuming Countries, 1999-2005**



Note: All prices are in real terms.

between 1999 and 2005 in real terms. In many non-OECD countries, local gas prices have not increased significantly, because prices are set independently of international market conditions. In China, for example, where gas prices until recently have been set with little regard for international price movements, final prices to industry and households have risen only modestly since a new pricing structure was introduced in 1997. The price for end users of coal, which is rarely taxed at all, has risen more in percentage terms than any other final fuel on average in the OECD countries – even though international prices have increased less than those of oil and gas.

Movements in electricity prices in recent years vary considerably among countries, according to the fuel mix in power generation, government policies and regulations, and other local factors. On average, final pre-tax electricity prices (in nominal terms) in OECD countries were broadly flat through the 1990s and have increased only modestly since 2001. Between the first quarter of 2001 and the first quarter of 2006, industrial prices rose by less than a third and household prices by less than a fifth.

Quantifying Energy Subsidies

Energy consumption subsidies – government measures that result in an end-user price that is below the price that would prevail in a truly competitive market including all the costs of supply – are large in some countries. Energy is most commonly subsidised through price controls, often through state-owned companies. Consumption subsidies have been largely eliminated in the

OECD, but remain large in some non-OECD countries, both in gross terms and net of any taxes. Electricity and household heating and cooking fuels are usually most heavily subsidised, though several countries still subsidise road-transport fuels. Remaining energy subsidies in OECD countries are mainly directed to production and do not necessarily reduce end-user prices below market levels.[3]

Analysis carried out for this *Outlook* confirms the prevalence of consumption subsidies in non-OECD countries. Total subsidies (net of taxes on each fuel) in the 20 countries assessed, which collectively make up 81% of total non-OECD primary energy use, amount to around $220 billion per year, according to 2005 data. On the assumption that subsidies per unit of energy consumed are of the same magnitude in other non-OECD countries, world subsidies might amount to well over $250 billion per year. That is equal to all the investment needed in the power sector every year on average in non-OECD countries in the Reference Scenario. Total subsidies to oil products amount to over $90 billion. Box 11.2 describes the methodology used to quantify subsidies.

Box 11.2: **Quantifying Global Energy Subsidies**

Energy subsidies were calculated using a price-gap approach, which compares final consumer prices with reference prices that correspond to the full cost of supply or, where available, the international market price, adjusted for the costs of transportation and distribution.[4] This approach captures all subsidies that reduce final prices below those that would prevail in a competitive market. Such subsidies can take the form of direct financial interventions by government, such as grants, tax rebates or deductions and soft loans, and indirect interventions, such as price ceilings and free provision of energy infrastructure and services.

Simple as the approach may be conceptually, calculating the size of subsidies in practice requires a considerable effort in compiling price data for different fuels and consumer categories and computing reference prices. For traded forms of energy such as oil products, the reference price corresponds to the export or import border price (depending on whether

3. IEA analysis, the results of which were reported in Von Moltke *et al.* (2003), puts total OECD energy production subsidies at $20-30 billion per year.
4. See IEA (1999) for a detailed discussion of the price-gap approach and practical issues relating to its use in calculating subsidies and their effects.

the country is an exporter or importer) plus internal distribution. For non-traded energy, such as electricity, the reference price is the estimated long-run marginal cost of supply. VAT is added to the reference price where the tax is levied on final energy sales, as a proxy for the normal rate of taxation to cover the cost of governing a country. Other taxes, including excise duties, are not included in the reference price. So, even if the pre-tax pump price of gasoline in a given country is set by the government below the reference level, there would be no *net* subsidy if an excise duty large enough to make up the difference is levied.

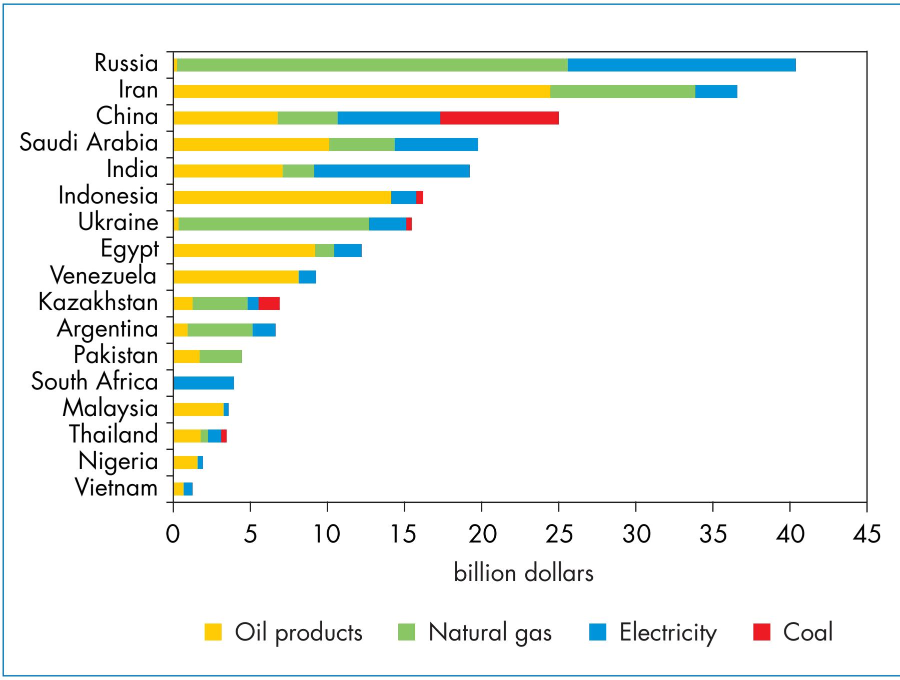
The aggregated results are based on net subsidies only for each country, fuel and sector. Any negative subsidies, *i.e.* where the final price exceeds the reference price, were not taken into account. In practice, part of the subsidy in one sector or for one fuel might be offset by net taxes in another. Subsidies were calculated only for final consumption, to avoid the risk of double counting: any subsidies on fuels used in power generation would normally be reflected at least partly in the final price of electricity. All the calculations for each country were carried out using local prices, and the results were converted to US dollars at market exchange rates.

Russia has the largest subsidies in dollar terms, amounting to about $40 billion per year (Figure 11.7). Most of these subsidies go to natural gas and the rest to electricity (which includes the underpricing of gas delivered to power stations). Subsidies of $25 billion per year to final consumption of gas are alone more than twice the annual investment projected for the entire Russian gas industry. Iranian energy subsidies are almost as large, at an estimated $37 billion per year. Six other countries – China, Saudi Arabia, India, Indonesia, Ukraine and Egypt – have subsidies in excess of $10 billion per year each.

In terms of fuels, the biggest subsidies overall go to oil products. Most of the countries included in this analysis were found to subsidise at least one oil product. Industrial and residential fuels other than gasoline and automotive diesel[5] – notably kerosene and liquefied petroleum gas – and other forms of

5. Other products make up about two-thirds of total oil consumption in non-OECD countries as a whole.

Figure 11.7: **Economic Value of Energy Subsidies in non-OECD Countries, 2005**



Note: Subsidies in Brazil, the Philippines and Chinese Taipei are not shown, as they amount to less than $1 billion in each case.

energy are generally subsidised more than road fuels. Subsidies to gasoline and diesel have fallen sharply in percentage terms in recent years in many countries – despite rising international prices. This has not been the case in Iran, which continues to subsidise transport fuels heavily. In fact, Iran had the highest rate of oil subsidisation in 2005. Oil subsidies were also large in Indonesia, but have since fallen sharply following a government decision to double the pump price of road fuels in October 2005. Several other developing Asian countries have announced their intention to bring domestic prices more into line with international prices in 2006 and 2007, partly because of the rising fiscal cost of subsidies or, as in the case of China and India, losses incurred by refiners. China, Indonesia and Malaysia raised oil-product prices in March 2006.

Underpricing is biggest for natural gas (Table 11.1). On average, consumers in the countries analysed pay less than half the true economic value of the gas they use. Gas subsidies are biggest in the transition economies, Saudi Arabia and Egypt. Electricity subsidies are less prevalent, but are large in some countries, including Saudi Arabia.

Table 11.1: **Consumption Subsidy as Percentage of Reference Energy Price in non-OECD Countries, 2005**

	Gasoline	Diesel	Kerosene	LPG	Light fuel oil	Heavy fuel oil	Natural gas	Coal	Electricity
China	5	13	3	18	0	0	45	17	0
Chinese Taipei	0	0	0	9	27	6	0	5	0
India	0	0	47	26	0	0	70	0	5
Indonesia	24	54	58	30	35	n.a.	0	58	13
Malaysia	26	37	0	33	9	0	n.a.	n.a.	5
Thailand	0	16	0	35	0	0	65	57	10
Pakistan	0	28	19	n.a.	21	n.a.	59	0	n.a.
Philippines	0	0	5	0	34	n.a.	n.a.	n.a.	0
Vietnam	6	26	5	0	n.a.	n.a.	n.a.	n.a.	14
Iran	82	96	76	67	32	73	66	0	30
Saudi Arabia	51	81	6	n.a.	81	n.a.	89	n.a.	54
Egypt	65	80	88	94	80	71	76	0	4
South Africa	0	0	0	0	0	0	n.a.	0	41
Nigeria	19	17	42	6	n.a.	n.a.	n.a.	n.a.	24
Brazil	0	0	n.a.	0	0	n.a.	n.a.	n.a.	0
Argentina	20	5	0	0	0	0	58	n.a.	27
Venezuela	90	96	0	82	94	84	n.a.	n.a.	25
Russia	0	0	0	0	0	16	57	0	34
Kazakhstan	28	20	n.a.	n.a.	49	48	83	86	24
Ukraine	0	23	n.a.	n.a.	n.a.	n.a.	83	36	27
Weighted average	1	15	27	19	6	10	57	12	8

n.a.: not available.
Note: Based on weighted average subsidies and prices across final sectors for each fuel. Cross-subsidies between sectors are, therefore, not included.
Source: IEA analysis.

Impact of Higher Energy Prices on Demand

Energy Demand Trends since Prices Started Rising

Global primary energy demand[6] grew rapidly between 2000 and 2004, averaging 2.7% per year (Table 11.2).[7] Demand grew by only 1.3% on average in the 1990s. Demand grew about six times faster in non-OECD countries than in the OECD. In developing Asia it grew faster than in any other major world region. In most regions, demand growth slowed in 2001 and then accelerated in 2002 and 2003, with the 4.6% increase in global energy demand in 2004 representing the fastest rate since 1976. Much of the growth came from China and other developing countries. Partial data suggest that energy demand growth may have slowed in 2005, partly in response to higher prices.

Global oil demand has grown on average more slowly than energy demand in total since 2000. The cumulative increase in global oil use between 2000 and 2004 was 8%, compared to 11% for energy demand as a whole. On average, oil demand grew by 1.8% per year in the five years to 2005, the same rate as during the second half of the 1990s (Figure 11.8). Developing Asian countries accounted for 46% of the total increase in oil demand between 2000 and 2005, with 29% coming from China alone. China and North America together contributed more than half of the exceptional increase of more than 3 mb/d, or 4%, in 2004 – the fastest rate of increase since 1977. Other non-OECD regions have contributed most of the rest of the increase in oil demand since 2000, especially in 2004 and 2005.

Other fuels have followed markedly different trends. Globally, primary demand for gas has grown strongly, averaging 2.4% per year since 2000. It surged in 2003, by almost 100 billion cubic metres – despite weaker North American demand – and continued to grow strongly in 2004 and 2005, contributing to the overall strength of energy prices (Figure 11.9). North American gas demand fluctuated between 2000 and 2005. European demand grew without pause, but at varying rates. Demand in non-OECD regions, including developing Asia, grew steadily at an average rate of more than 4% between 2000 and 2005. On average, non-OECD regions accounted for more than 80% of the total increase in global gas demand between 2000 and 2005.

World coal use has followed a more erratic path. It rose strongly in the three years to 2004, driven mainly by a surge in demand for power generation in China and the rest of developing Asia. World demand surged by 7% in 2003 and 9% in 2004. In 2001, coal use fell slightly. Chinese coal demand grew by about 20% in both 2003 and 2004. World electricity consumption grew at just over 3% per year over 2000-2004.

6. Demand and consumption are used interchangeably throughout this chapter and the rest of the *Outlook*.

7. We do not have a complete picture of energy demand beyond 2004 because of data gaps. Preliminary data on aggregate demand in some large countries are available for 2005, notably for oil and gas.

Table 11.2: **Change in Energy Demand by Fuel and Region**
(%, year-on-year)

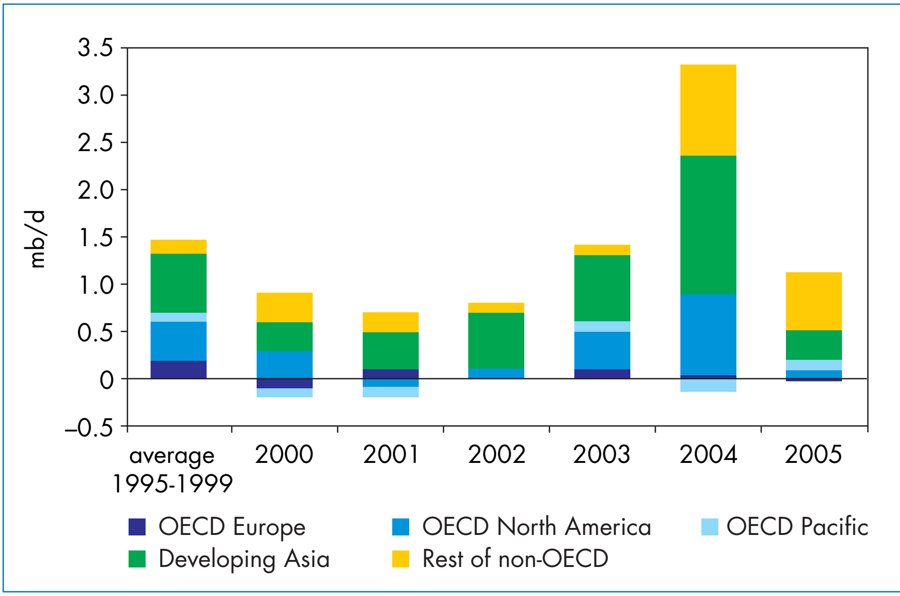
	2000	2001	2002	2003	2004	2005*	2000-2004**
OECD							
Total primary demand	2.0	–0.4	0.8	1.0	2.0	n.a.	0.9
Coal	*3.7*	*–0.5*	*1.2*	*0.4*	*2.3*	*n.a.*	*0.8*
Oil	*0.1*	*0.4*	*–0.2*	*1.5*	*1.7*	*0.4*	*0.8*
Gas	*4.2*	*–1.6*	*2.7*	*1.9*	*0.7*	*–0.1*	*0.9*
Total final consumption	2.4	–0.5	0.6	1.8	2.0	n.a.	1.0
Oil	*0.9*	*0.7*	*0.3*	*1.2*	*2.1*	*n.a.*	*1.1*
Gas	*6.1*	*–3.0*	*1.5*	*2.2*	*–0.4*	*n.a.*	*0.1*
Electricity	*3.7*	*0.4*	*1.3*	*2.5*	*2.1*	*n.a.*	*1.6*
Non-OECD							
Total primary demand	2.5	1.9	3.7	6.1	7.3	n.a.	4.7
Coal	*2.0*	*–0.2*	*6.4*	*12.8*	*13.9*	*n.a.*	*8.1*
Oil	*2.0*	*2.9*	*2.6*	*2.6*	*6.7*	*2.8*	*3.7*
Gas	*3.9*	*2.9*	*3.4*	*6.2*	*4.1*	*4.9*	*4.2*
Total final consumption	2.1	2.4	2.8	4.4	6.7	n.a.	4.1
Oil	*3.6*	*2.8*	*3.0*	*2.9*	*8.1*	*n.a.*	*4.2*
Gas	*3.1*	*1.6*	*3.5*	*6.4*	*6.3*	*n.a.*	*4.4*
Electricity	*5.7*	*3.7*	*5.7*	*8.4*	*8.1*	*n.a.*	*6.4*
World							
Total primary demand	2.2	0.7	2.2	3.4	4.6	n.a.	2.7
Coal	*2.8*	*–0.3*	*3.9*	*7.1*	*8.9*	*n.a.*	*4.8*
Oil	*0.8*	*1.4*	*0.9*	*1.9*	*3.7*	*1.3*	*2.0*
Gas	*4.1*	*0.4*	*3.0*	*3.9*	*2.3*	*2.3*	*2.4*
Total final consumption	2.3	0.9	1.7	3.1	4.3	n.a.	2.5
Oil	*1.8*	*1.4*	*1.3*	*1.8*	*4.3*	*n.a.*	*2.2*
Gas	*5.0*	*–1.4*	*2.2*	*3.7*	*2.1*	*n.a.*	*1.7*
Electricity	*4.4*	*1.6*	*2.8*	*4.6*	*4.4*	*n.a.*	*3.3*

n.a.: not available.
* Preliminary estimates.
** Average annual growth rate.

Responsiveness of Energy Demand to Price Changes

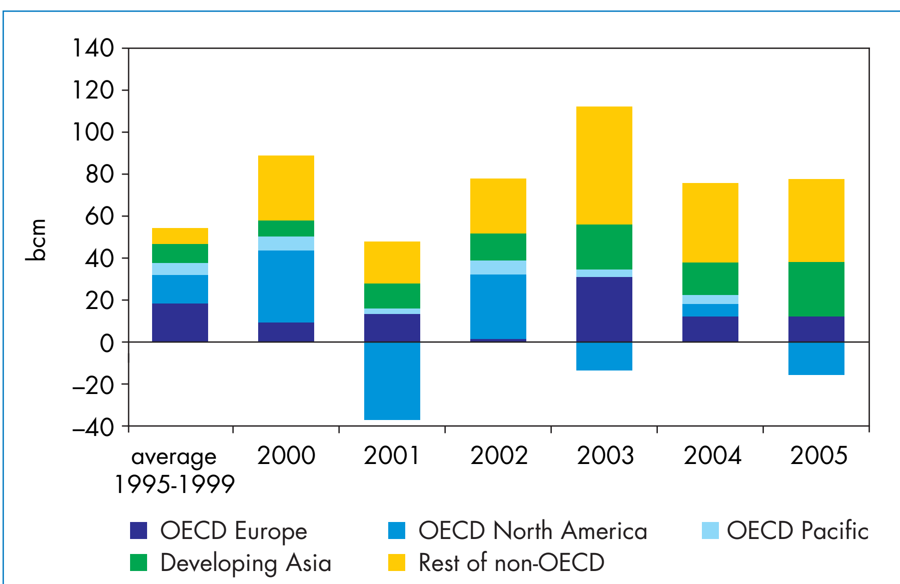
Energy is always consumed for the services it can provide, rather than as an end in itself. Demand for any kind of energy service is determined by a number of factors. In most instances, the two most important factors are real incomes and

Figure 11.8: **Increase in World Primary Oil Demand by Region** (year-on-year)



Note: Preliminary estimates for 2005.

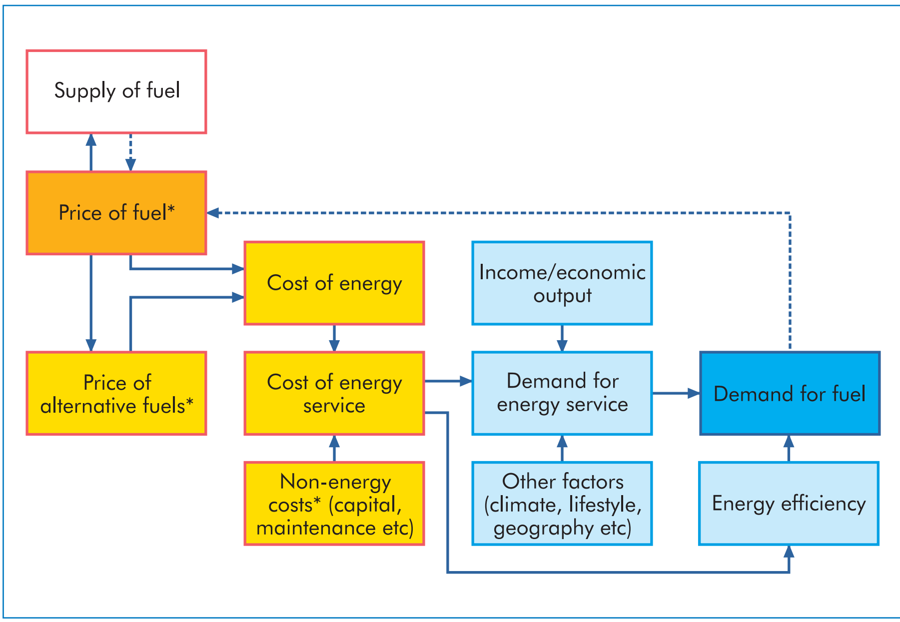
Figure 11.9: **Increase in Natural Gas Demand by Region** (year-on-year)



Note: Preliminary estimates for 2005.

the overall price of that service, a key component of which is the cost of the fuel used to provide it (Figure 11.10). How sensitive the demand for a given fuel is to changes in its effective price to the consumer (including taxes) depends, therefore, partly on the ease with which the consumer can forgo the service or switch to a cheaper fuel, and the share of the price of the fuel in the total cost of providing the energy service. The larger the share of fuel in the overall cost of providing an energy service, the more sensitive the demand for that service – and, therefore, the fuel itself – will be to fuel prices.

Figure 11.10: **The Link between Fuel Price and Demand**



* Including taxes and subsidies.

In economists' parlance, the sensitivity of demand to changes in price is known as the price elasticity of demand. Under normal conditions, demand for an energy service and the fuel used to provide it will be higher as the price of that fuel falls; in other words, the *own-price* elasticity of demand is negative. Where it is possible to switch fuels, demand will also be affected by the prices of other fuels. The sensitivity of fuel demand to changes in other fuel prices, known as the *cross-price* elasticity of demand, is typically positive, as demand for a given fuel will rise as the price of a competing fuel increases. Assessing the sensitivity of demand to price changes in the short and long term is complicated by the role played by other factors, notably income, climate, lifestyles, investment cycles, technology, price expectations and government policies.

Energy price elasticities vary widely by fuel, sector and region. In all cases, demand responds in a gradual fashion to a shift in price, as changes in behaviour occur and new investment is made in energy-using equipment in response to the new price environment. Thus, elasticities are generally much higher in the long term than the short term: the impact of a permanent shift in price is typically greater the longer the period examined.

Movements in price often have little immediate effect on demand, because consumers may not expect the price change to persist or because it is difficult or expensive for consumers to switch to other fuels or change their energy equipment. This is especially true for transport fuels. Few practical substitutes are yet available for oil-based fuels for cars and trucks, so demand for these energy services tends to be relatively price-inelastic in the short term. However, if fuel prices have risen and are expected to remain high in the longer term, end users have a strong incentive to opt for more fuel-efficient models when replacing an existing vehicle. Similarly, only electricity can power electrical devices, so demand for electricity is highly price-inelastic in the short term. End users may nonetheless change their behaviour so as to use less of a particular energy service in response to higher prices. Different fuels – gas, coal and oil products – can provide non-electricity stationary services (such as fuel for heating boilers), so demand for these fuels in these sectors is generally more sensitive to changes in price, especially where multi-firing equipment is widespread. Power generators may also be able to switch more quickly to cheaper fuels if they have dual-firing capability or spare capacity.

Oil demand is relatively insensitive to movements in crude oil prices, especially in the short term. As the last section demonstrated, this is in large part because changes in crude oil prices lead to smaller percentage changes in local prices to end users – particularly for road-transport fuels. The weighted average crude oil price elasticity of total oil demand across all regions is –0.03 in the short term and –0.15 in the long term, based on econometric analysis of historical demand trends (Table 11.3). In other words, a permanent doubling of the crude oil price would be expected to cut oil demand by about 3% in the same year and 15% after more than ten years, were these elasticities to remain constant and all other factors to remain equal.

Elasticities are even lower for transport fuels, because fuel accounts for a smaller part of the total cost of using a vehicle. Fuel-price elasticities are generally highest in countries with low taxes, as final prices respond more in percentage terms to changes in crude oil prices (Figure 11.11). As a result, overall crude oil price elasticity is generally lowest for regions where the share of transport in total oil use is relatively high because transport fuels are usually taxed more than other oil products. This is the case for most European countries, as well as India among developing Asian countries. Income elasticities of oil demand are higher than price elasticities: the weighted average income elasticity worldwide is 0.09 in the short term and 0.48 in the long term. In other words, a sustained one-off 10% increase in income would ultimately drive up oil demand by about 5%.[8]

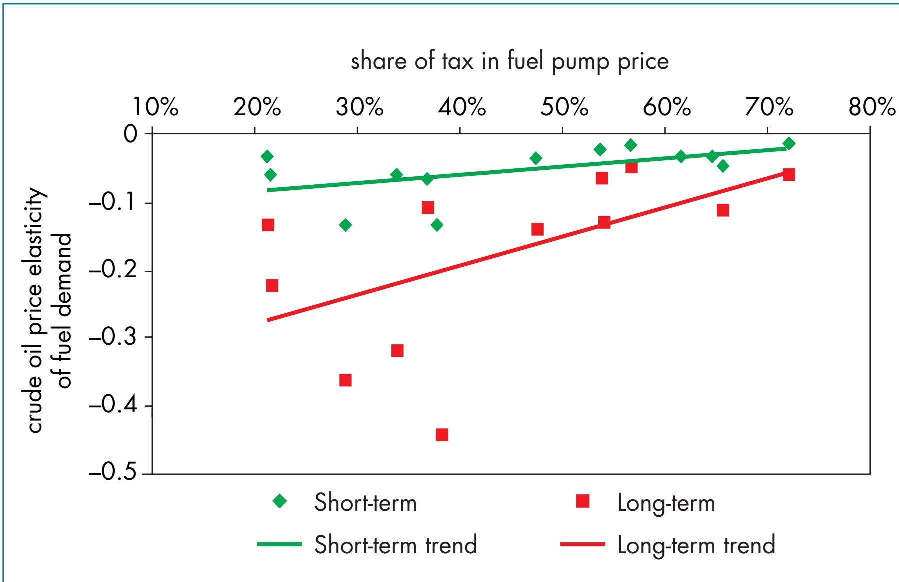
Table 11.3: **Crude Oil Price and Income Elasticities of Oil Demand Per Capita by Region**

	Oil consumption in 2005 (Mt)		**Price elasticity**		**Income elasticity**	
	Million tonnes	**Share of transport**	**Short-term**	**Long-term**	**Short-term**	**Long-term**
OECD N. America	1 143	63%	–0.02	–0.12	0.04	0.22
OECD Europe	737	53%	–0.03	–0.11	0.14	0.49
OECD Pacific	396	40%	–0.05	–0.25	0.08	0.39
Developing Asia	717	36%	–0.03	–0.21	0.09	0.73
Middle East	281	38%	–0.01	–0.07	0.07	0.67
Latin America	237	48%	–0.03	–0.28	0.09	0.94
Africa	134	53%	–0.01	–0.01	0.27	0.33
World*			**–0.03**	**–0.15**	**0.09**	**0.48**
*Top 20 countries**			*–0.05*	*-0.16*	*0.24*	*0.59*

*Weighted average.
Note: Short-term is the current year; long-term is when the full effects of price or income changes on demand have been felt, typically within 10-15 years. Elasticities are derived from regression analysis based on annual data from 1979 to 2005. The average IEA import price is used as a proxy for crude oil prices.
Source: IEA analysis.

8. These estimates are broadly in line with estimated income elasticities of demand from several other studies based on time series data. Estimates vary among studies according to the time period and countries analysed and the methodology used. In addition, there is some evidence of asymmetric effects of changes in both price and income on oil demand: the percentage increase in demand that results from a rise in income or drop in price is bigger than the fall in demand when income falls or price rises (see, for example, Gately and Huntington, 2002). Other factors than price and income, including the introduction of non-oil sources of energy, partly explain the divergence in estimated price and income elasticities across regions. For example, the development of gas infrastructure and nuclear power has allowed power generators and consumers to switch away from oil in some countries, disguising the effects of price and income on demand.

Figure 11.11: **Crude Oil Price Elasticities of Road Transport Oil Demand versus the Share of Tax in the Pump Price**



Note: Estimates are for the world's 20 largest oil-consuming countries.
Source: IEA analysis.

The price elasticity of demand for road-transport fuel based on *final* prices (including taxes) is significantly higher and more homogeneous, as the impact of differences in tax and subsidy policies is stripped out. It is, nonetheless, still somewhat lower than income elasticity, both in the short and in the long term. We estimate that a permanent doubling of the final price would cut demand by 15% in the short term and 44% in the long term in the world's 20 largest oil-consuming countries (weighted average price elasticities of –0.15 and –0.44). These estimates are somewhat lower than those produced by other studies in recent years. A study by Goodwin *et al.* (2004), for example, estimates elasticities at –0.25 in the short term and –0.6 in the long term, based on a survey of 69 studies of demand in various countries published since 1990. Their study found that the impact of a change in price on fuel demand resulted mostly from a change in the number of vehicles on the road and the number of kilometres driven per vehicle. The amount of fuel used per kilometre by each individual vehicle is only marginally affected by a change in the pump price. A parallel survey by Graham and Glaister (2004) yielded average fuel-price elasticities of road-transport demand of –0.25 in the short term and –0.77 in the long term. Median estimates were lower, at –0.21 and –0.55.

The own-price elasticity of electricity demand is also very low. For the WEO regions (see Annex C), long-term price elasticities range from –0.01 to –0.14. Short-term elasticities are even lower on average. Economic activity is the main driver of electricity demand in all regions. Average income elasticities of demand across all end-use sectors, using per-capita GDP as a proxy for income, range from 0.4 to 1.3. Elasticities are generally highest in non-OECD regions: on average, their electricity demand rises faster than income. OECD electricity demand is income-*inelastic*. This difference reflects saturation effects in the OECD and catching-up by the poorer developing countries. It also reflects changes in the structure of economic activities. Heavy electricity-intensive industry has contributed more of the increase in GDP in non-OECD countries than in the OECD. The energy efficiency of electrical equipment and appliances in non-OECD countries is also generally lower, boosting electricity intensity.

The aggregate demand for non-electrical energy for final stationary uses – which, together with electrical services and transport, makes up final energy demand – is also price-inelastic. However, demand for different fuels is more sensitive to changes in *relative* fuel prices, because of the possibility of substitution in many end uses. For this reason, a rise in the price of oil products can lead to a significant amount of switching to natural gas or coal if the prices of those fuels do not increase. Similarly, the fuel mix in power generation can shift markedly in response to changes in relative prices, even in the short term, as fuel-switching or reserve capacity is generally far more extensive than in final sectors.

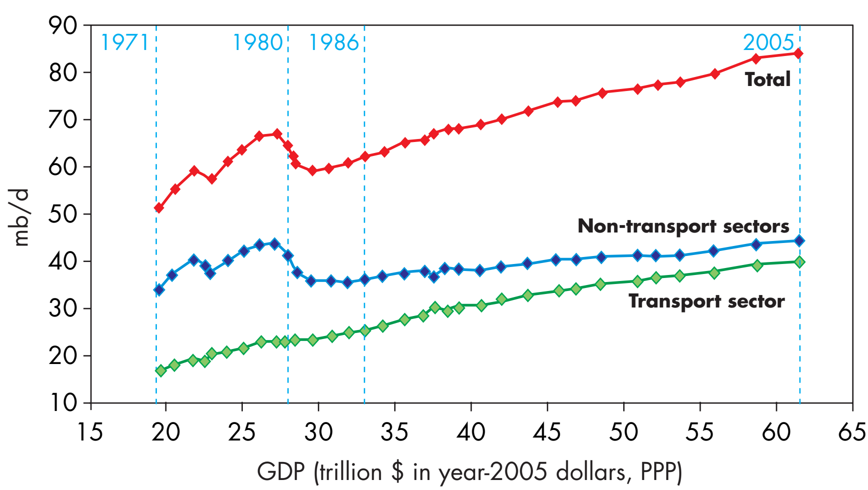
Explaining Recent Trends in Energy Demand

Trends in global energy demand since the end of the 1990s appear to be broadly consistent with established relationships between demand on the one hand and real GDP and prices on the other. The relatively rapid growth in primary energy demand is almost entirely explained by exceptionally strong world GDP growth, which peaked at more than 5.3% in 2004 – the highest annual rate since the 1970s – and remained strong at an estimated 4.3% in 2005. In effect, economic expansion, which partly explains the strength of energy prices, has overshadowed the adverse impact of higher prices on demand and more than outweighed it. We estimate that, *had prices not risen since 2002, global primary energy demand would have grown on average by 4.1% in the two years to 2004 – a mere 0.1 percentage point more than it actually did* – on the assumption that nothing else was different.

Global **oil** demand has been most affected by higher prices, mainly because oil prices have risen more than those of other fuels in most regions. Primary oil demand grew on average by only 1.2% per year between 1998 and 2004, compared with 2.5% for energy use generally. Strong economic growth nonetheless drove up oil demand by more than the loss of demand due to higher oil prices. Exceptional factors, including a surge in Chinese demand for heavy fuel oil and distillate for power generation due to delays in commissioning new coal-fired power stations, added to the strength of global oil demand in 2004 (CBO, 2006). A slowdown in the world economy was the main cause of the deceleration of oil demand in 2005, though much higher prices probably also contributed.

Non-transport oil use, which is most sensitive to price changes, explains most of the recent fluctuations in total oil demand. Between 1998 and 2004 – the last year for which we have a detailed sectoral breakdown – non-transport demand increased by 1.3%, little more than half the rate of increase in transport oil use. Non-transport demand actually fell in absolute terms in 2002, largely owing to the lagged effect of the surge in prices in 1999 and 2000. According to preliminary estimates, the slowdown in total oil demand in 2005 was also largely due to a levelling-off of non-transport demand – especially in China (where oil use in power generation is thought to have fallen sharply) and the rest of developing Asia. As the analysis of the previous section has shown, transport demand is relatively price-inelastic. In fact, transport demand has generally risen with real GDP in an almost constant linear fashion since the late 1980s (Figure 11.12).

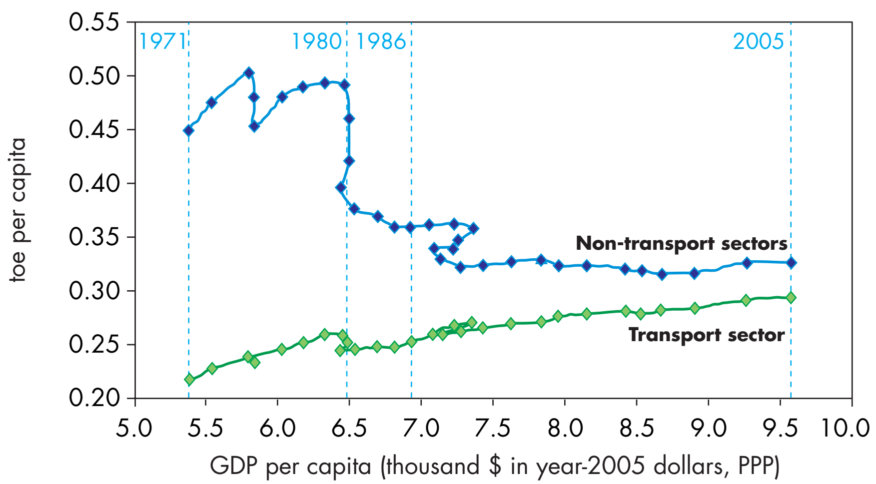
Figure 11.12: **World Oil Demand and Real GDP**



Note: 2005 data are estimated.
Source: IEA analysis.

The different effects of higher prices on oil demand by sector are more evident when demand is expressed in per-capita terms, as the effect of changes in population is stripped out (Figure 11.13). Total per-capita oil consumption fell in 2001-2002 and levelled off in 2005, following sharp increases in oil prices in the previous years. Most of the recent fluctuations in oil use per capita have been explained by shifts in non-transport demand, which has been trending downwards in a rather erratic manner since the 1980s and reached a low point in 2002. The lagged impact of price increases since 2002 is clearly apparent. In particular, the estimated plateauing of demand in 2005 was due to higher prices. In contrast, per-capita oil use for transport has been rising with income in an almost perfect linear relationship since the early 1990s, with fluctuations in prices having only a very limited effect on demand trends. In only one year since then has demand fallen relative to GDP: in 2001, and then only marginally, largely because of the temporary adverse impact on personal travel of the events of 11 September.

Figure 11.13: **World Oil Demand and Real GDP Per Capita**

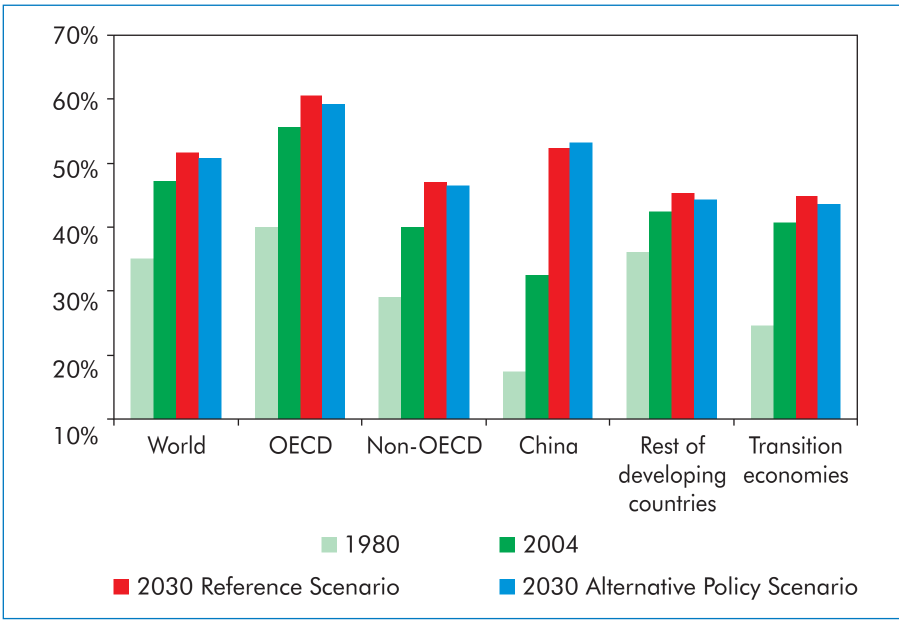


Note: 2005 data are estimated.
Source: IEA analysis.

The share of transport – the demand for which is price-inelastic relative to other services – in total primary oil consumption is increasing steadily in most countries. For the world as a whole, it has risen from 35% in 1980 to 47% in

2004. It is projected to increase further, to 52% in 2030 in the Reference Scenario and 51% in the Alternative Policy Scenario (Figure 11.14). This factor is expected to outweigh the effect of the growing share in global oil demand of developing countries, where overall price elasticity is generally higher. In this case, oil demand would continue to become less and less responsive to movements in crude oil prices. This means that crude oil prices can be expected to fluctuate more than in the past in response to short-term shifts in demand and supply.

Figure 11.14: **Share of Transport Sector in Primary Oil Consumption in the Reference and Alternative Policy Scenarios**



Note: 2005 data are estimated.
Source: IEA analysis.

Demand for non-oil forms of energy has generally been less affected by higher price.[9] Demand for **natural gas** has been depressed by rising prices in some regions, most clearly in North America, where higher bulk prices quickly feed through into final prices and where there is still substantial fuel-switching

9. It is difficult to assess fully the impact of higher prices since 2003 on demand for other forms of energy as comprehensive data are generally available only up to 2004.

capability in power generation and heavy industry. In addition, some productive activities have stopped or been shifted overseas, where gas prices and overall production costs are lower. The US chemicals industry, which relies heavily on natural gas feedstock, has contracted sharply in recent years.[10] For example, more than a fifth of ammonia capacity has been shut and production has fallen by more than a third since 2000. North American gas demand rebounded in 2002 as prices fell back from the highs reached in 2001 and then slumped again over 2003-2005 as prices rose strongly. US gas demand dropped by 2.3% in 2005, partly because of the damage to industry and households caused by hurricanes. European gas demand rose moderately in 2004 and 2005, even though some industrial consumers and power generators have been able to switch to cheaper coal or heavy fuel oil. Demand in non-OECD regions, including developing Asia, was particularly strong, reflecting rapid economic growth. Final prices in many non-OECD countries have increased much less than in the OECD, because of price controls or because their gas markets are physically unconnected to international markets.

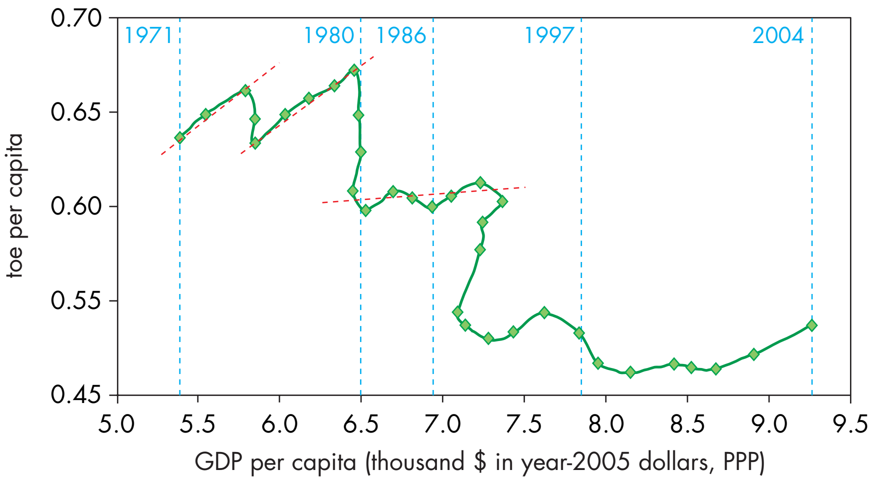
The surge in **coal** demand in 2002-2004 was at least partly driven by higher oil and gas prices, as coal became more competitive in power generation. The price of coal delivered to power generators – the main market for coal – has risen sharply in most major coal-consuming countries, but generally less in percentage terms than heavy fuel oil, distillate and natural gas. The use of coal in power generation is set to remain strong in the coming years as a growing share of new power plants ordered in the last few years has been coal-fired, partly because of relatively higher gas prices. Gas-fired plants had been the favoured option at the beginning of the decade in many parts of the world, though coal continued to account for the bulk of new capacity in China and India.

Taking in aggregate natural gas, coal and oil demand used in stationary final uses, there is little evidence of price having any significant impact on per-capita demand since the 1980s. In fact, the reverse appears to be the case, with shifts in per-capita demand altering prices. The impact of the first two oil-price shocks on demand in per-capita terms is clearly apparent, but the drop in prices in 1986 and 1998 did not induce a rise in demand (Figure 11.15). In contrast, a slump in per-capita demand in 1997-1998, in the wake of the Asian financial crisis, certainly contributed to the fall in oil prices at that time. Similarly, a recovery in demand in 2000 and again in 2003 helped

10. Testimony of the American Chemistry Council on the Impact of High Energy Costs on Consumers and Public, presented to the US Congressional Energy and Mineral Resources Subcommittee, 19 May 2005.

to drive prices up. Demand appears to have become less sensitive to increases in income than in the past. Partly, this reflects improvements in end-use efficiency and a shift towards electricity in stationary energy uses in industry, services and households.

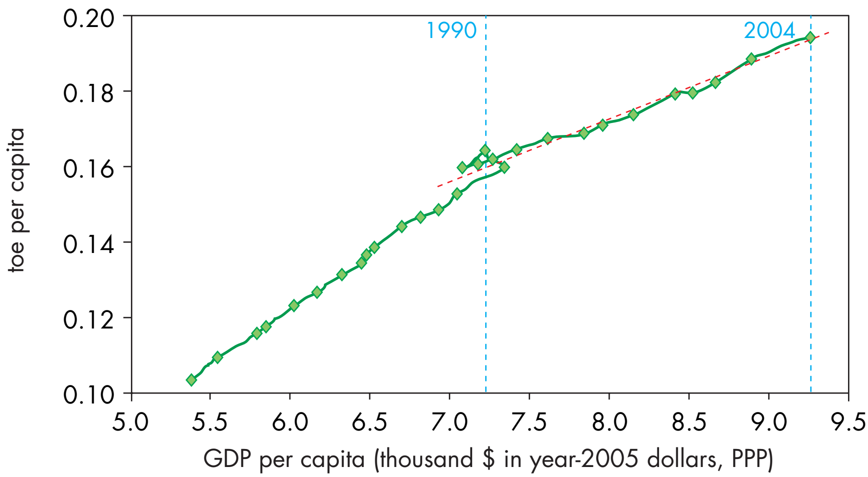
Figure 11.15: **World Stationary Final Fossil Fuel Demand and Real GDP Per Capita**



Source: IEA analysis.

Electricity demand has continued to rise in almost constant proportion to income in recent years (Figure 11.16). There was a temporary decoupling of electricity demand from per-capita income at the beginning of the 1990s following the break-up of the former Soviet Union, but the linear relationship quickly re-established itself. Each thousand-dollar increase in per-capita GDP (in 2005 dollars and PPP terms) has added 0.02 tonnes of oil equivalent to per-capita electricity demand. The rate of increase in demand relative to GDP in 2002 to 2004 was slightly above this average and closer to the average of the period 1971-1990. Large changes in energy prices, including recent increases, have had only a limited impact on electricity prices, and no discernible effect on electricity use during the period 1971-2004.

Figure 11.16: **World Electricity Demand and Real GDP Per Capita**



Source: IEA analysis.

Price Sensitivity Analysis

Real oil and gas prices are assumed to remain high in 2006 and 2007 and then to fall back gradually over the next five years or so, before resuming a modestly rising trajectory through to 2030. But several factors could combine to change this price path. For example, lower investment in exploration and development of oil and gas reserves could cause crude oil markets to tighten further, forcing up prices (see Chapter 3). Alternatively, slower economic growth could depress energy demand growth and, therefore, prices.

11

In view of the uncertainty surrounding near-term price prospects, we have carried out a separate analysis using the World Energy Model (WEM)[11] – the primary tool used to produce the energy-demand projections contained in the *Outlook* – to examine the effects of higher price assumptions on energy demand by fuel and sector. In this exercise, the average IEA crude oil import price is assumed to be $20 per barrel (in year-2005 dollars), or 39%, higher than in the Reference Scenario in each year from 2007 through to the end of the projection period. Natural gas and coal prices are also assumed to change, with approximately 90% of the percentage change in the oil price reflected in the gas price and 20% in the coal price in each region. This sensitivity analysis takes into account the impact on GDP of changes in energy prices, based

11. The WEM incorporates estimates of own-price and cross-price elasticities of demand, derived largely from detailed sector-by-sector and fuel-by-fuel econometric analysis of demand. These estimates are constantly updated.

on the results of our assessment of the macroeconomic impact (see the next section). Real GDP in the OECD is assumed to be 0.4% lower in 2007 and 0.6% lower from 2010 through to the end of the projection period. On balance, world GDP is 0.6% lower in 2007 and 0.8% lower from 2010 onward relative to the Reference Scenario.

In this High Energy Prices Case, global primary energy demand is reduced by 465 Mtoe in 2015 and 561 Mtoe in 2030 – or 3.3% in both years – relative to the Reference Scenario (Table 11.4). Higher demand for biomass and other renewables partially offsets the reduction in demand for fossil fuels. The average rate of global energy demand growth is 0.1 percentage points lower, at 1.5%. The non-OECD regions account for most of the reduction in demand, because they contribute most of the incremental demand in the Reference Scenario and because end-user prices there increase proportionately more than in the OECD as their tax rates are generally lower. Of the cumulative reduction in global energy demand, more than 80% results from the direct price effect alone and the rest from the loss of GDP. Oil accounts for the bulk of the reduction in demand, largely because end-user prices increase most. Oil use is 7.2 mb/d, or 6.2%, lower in 2030. The proportional reduction in oil demand is biggest in non-OECD regions, because

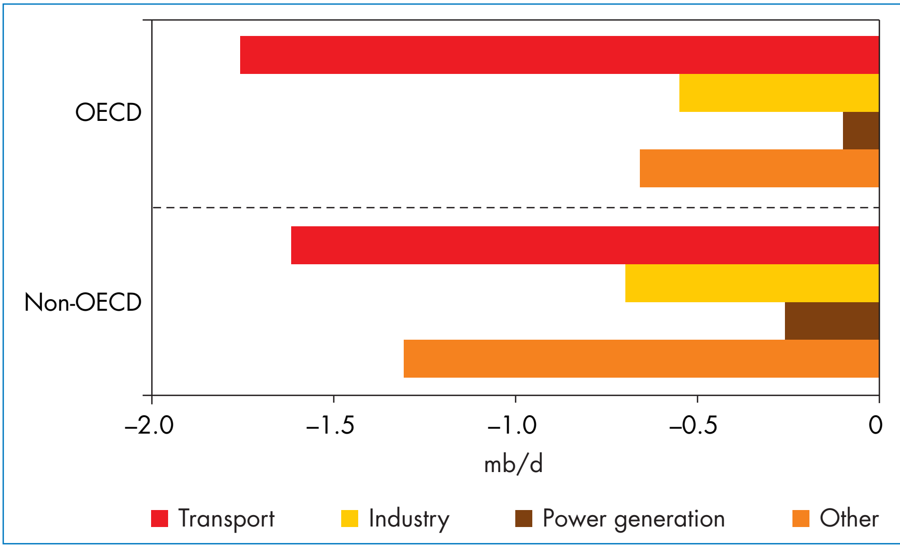
Table 11.4: **Change in Primary Energy Demand by Fuel and Region in the High Energy Prices Case Compared with the Reference Scenario**

	2015		2030	
	Mtoe	%	Mtoe	%
OECD	**–201**	**–3.2**	**–216**	**–3.2**
Oil	–137	–5.5	–147	–5.7
Gas	–55	–3.8	–61	–3.7
Coal	–15	–1.3	–16	–1.3
Other	7	1.8	8	1.4
Non-OECD	**–253**	**–3.3**	**–332**	**–3.3**
Oil	–151	–7.2	–187	–6.7
Gas	–55	–3.4	–88	–4.0
Coal	–60	–2.5	–69	–2.2
Other	12	1.1	12	0.9
World	**–465**	**–3.3**	**–561**	**–3.3**
Oil*	–299	–6.3	–346	–6.2
Gas	–110	–3.6	–149	–3.8
Coal	–76	–2.1	–86	–1.9
Other	19	1.3	20	1.0

* Includes international marine bunkers.

non-transport demand – which is more sensitive to price – accounts for a larger share of total oil use there and because income elasticities of oil demand are generally higher than in OECD countries. Nonetheless, the transport sector accounts for most of the reduction in demand in all regions (Figure 11.17).

Figure 11.17: **Change in Primary Oil Demand in the High Energy Prices Case by Region and Sector Compared with the Reference Scenario, 2030**



Macroeconomic Impact of Higher Energy Prices

How Higher Energy Prices Affect the Macroeconomy

An increase in the price of oil and other traded forms of energy leads to a transfer of income from importing to exporting countries through a shift in the terms of trade. For oil-importing countries, the immediate magnitude of the direct effect of a given oil-price increase on national income depends on the ratio of oil imports to GDP. This, in turn, is a function of the amount of oil consumed for a given level of national income (oil intensity) and the degree of dependence on imported oil (import dependence). It also depends on the extent to which gas and other energy prices rise in response to an oil-price increase and the gas-import intensity of the economy. Naturally, the bigger the initial oil-price increase and the longer higher prices are sustained, the bigger the macroeconomic impact. In the longer term, however, the impact will be reduced according to how much end users reduce their energy consumption and switch away from oil and how much domestic production of oil and other fuels increases in response to sustained higher prices. For net oil-exporting countries, a price increase directly increases real national income through higher export earnings. However, part of this gain would be later offset by losses from lower demand for their exports, generally due to the decline in GDP suffered by trading partners and possibly to a fall in non-oil exports caused by a rise in the exchange rate – a phenomenon known as "Dutch disease".

An oil-price increase leads to a reduction in the purchasing power of the export earnings of importing countries. If an importer continues to import the same value of non-oil goods and services while the cost of oil imports increases, the balance of payments will deteriorate, putting downward pressure on exchange rates. As a result, imports become more expensive, leading to a drop in real national income and lower domestic consumption. The dollar will also tend to rise, if oil-producing countries' demand for dollar-denominated international reserve assets grows, aggravating the downward adjustment in real income for economies other than the United States and others with a currency linked to the US dollar.

Domestic output is not directly affected by higher oil prices. But adjustment, or second-round effects, which result from nominal wage, price and structural rigidities in the economy, typically lead to a fall in GDP in practice in net oil-importing countries. Higher oil prices push up inflation, increasing input costs for businesses, reducing non-oil demand and lowering investment. Unless firms are able to pass through all of the increase in energy costs to higher prices for their final goods and services, profits fall, dragging down investment further. Tax revenues fall and the budget deficit increases, due to rigidities in government expenditure. If oil-product prices are directly subsidised by the government such that not all of the increase in bulk prices feeds through into final prices, as in many Asian countries, spending on subsidies rises. This leads either to a reduction in other forms of government spending, cutting overall demand, or a deterioration in the fiscal balance. Because of resistance to any real decline in wages, an oil-price increase may lead to upward pressure on nominal wage levels, which, together with reduced demand, tends to lead to higher unemployment. These effects are greater if the price increase is sudden (for example, if it results from a serious supply disruption) and sustained, and are magnified by the negative impact of higher prices on consumer and business confidence.

The fiscal and monetary policy measures chosen in response to higher energy prices also affect the overall impact on the economy over the longer term. Government policy cannot eliminate the adverse effects described above but it can minimise them; inappropriate policies can worsen them. The reaction of the monetary authorities to the threat of inflation and, perhaps more importantly, their *ex-ante* credibility in fighting inflationary pressures are critical. The quicker the authorities respond to inflation by raising interest rates, the bigger the short-term dip in GDP growth will be but the more likely it is that inflationary pressures will be squeezed out of the economy before expectations of higher rates of price and wage increases become entrenched. In practice, the monetary authorities need to strike a balance between dampening inflationary expectations and limiting the fall in GDP growth. Contractionary monetary and fiscal policies which are too severe could exacerbate the recessionary effects on income and employment. But unduly expansionary policies may simply delay the fall in real income necessitated by the increase in oil prices, stoke up inflationary pressures and worsen the impact of higher prices in the long run.

A fall in oil prices affects the macroeconomy of oil-importing countries in a reverse manner, but as in the case of a price rise, the magnitude of the impact does not match the full extent of the price change because of the offsetting costs of structural change. Similarly, the boost to economic growth in oil-*exporting* countries provided by higher oil prices has, in the past, always been less than the loss of economic growth in importing countries, such that the net global effect has always been negative. This is explained both by the cost of structural change and by the fact that the fall in spending in net importing countries is typically bigger than the stimulus to spending in the exporting countries in the first few years following a price increase. Demand in the latter countries tends to rise only gradually, so that net global demand tends to fall in the short term.

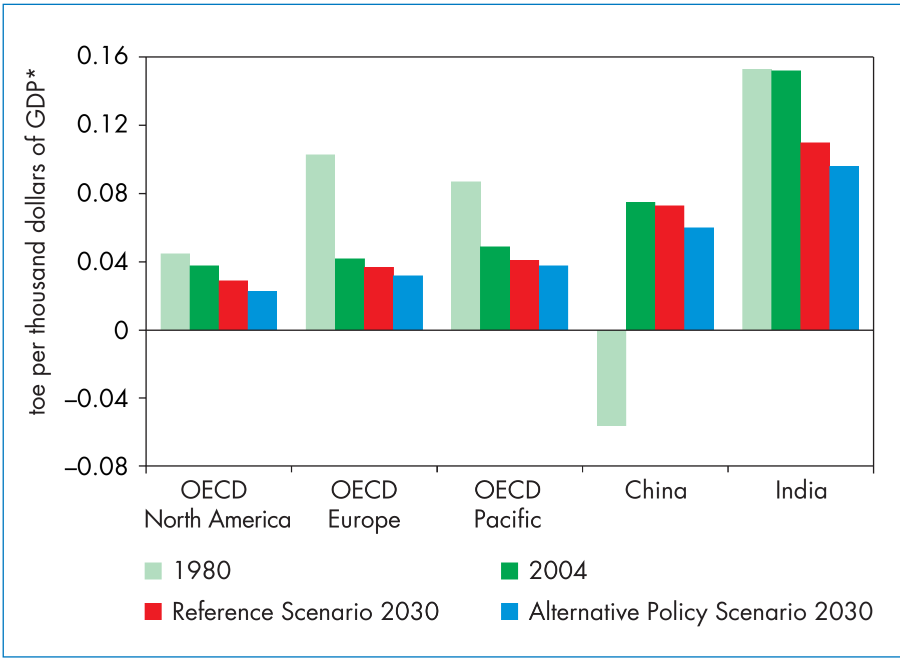
Quantifying the Recent Shift in the Terms of Trade

The impact of a given change in energy prices on the economy is linked to the size of the shift in the terms of trade. That shift, in turn, depends on energy-import intensity. Levels of and historical trends in intensity vary among countries and regions. Some regions have seen a substantial decline in oil-import intensity since the 1980s, notably Europe and the Pacific region (Figure 11.18).[12] Import intensity has risen in some developing countries, including China and India. This is mainly because improvements in the oil intensity of their economies have been outweighed by the rapid increase in their dependence on oil imports.[13] High net oil-import intensity – due to both high import dependence and high oil intensity – renders developing countries economically more vulnerable to increases in oil and gas prices than most other

12. Measured using market exchange rates. Intensity is much lower when GDP is measured using PPP-adjusted GDP rather than market exchange rates.

13. Several factors affect oil intensity, notably climate, the structure of the economy, the stage of economic development, the efficiency of energy-consuming processes and the availability and cost of oil products relative to other forms of energy.

Figure 11.18: **Oil-Import Intensity by Region**

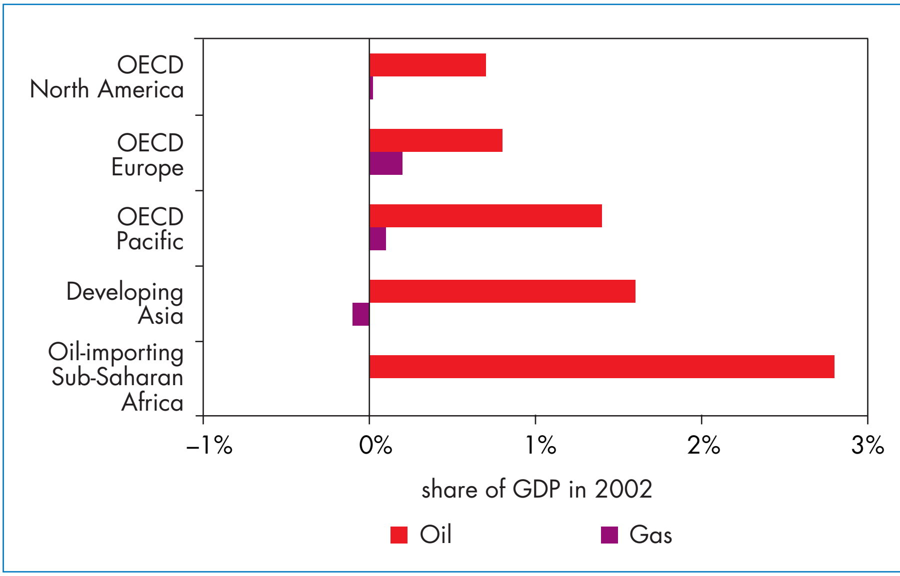


* GDP in year-2000 dollars and at market exchange rates.

importing regions. On average, oil-importing developing countries use twice as much energy to produce a dollar of output as OECD countries. Among the five largest non-OECD countries, India has by far the highest oil-import intensity.

Higher prices since the late 1990s have had a large impact on the terms of trade. For example, the increase in international prices in 2002-2005 raised the cost of net oil and gas imports in developing Asia as a whole by about $49 billion compared with 2002 – equal to 1.5% of GDP (Figure 11.19). The increase was 1.1% of GDP in China and 3.1% in India. Oil accounted for all of the increase in the total oil and gas import bill in the region as a whole: the increase in the value of gas exports more than offset the higher cost of gas imports. The increase in the import bill was equal to about 7% of total exports for developing Asia, 5% for China and 22% for India. The estimated $7 billion increase in import costs for oil-importing sub-Saharan African countries is about seven times the total annual saving in debt payments received by the 14 African countries included in the 2005 G8 debt agreement. OECD regions fared better. The cost of net oil and gas imports grew by $86 billion (0.8% of GDP) in OECD North America, $91 billion (1%) in OECD Europe and $85 billion (1.5%) in OECD Pacific.

Figure 11.19: **Increase in the Net Oil and Gas Import Bill in 2005 over 2002**



Note: The analysis is based on actual net imports and exports. Negative numbers indicate an increase in the value of net exports.
Source: IEA analysis.

Simulating the Macroeconomic Effects of Higher Energy Prices

Energy-import intensity provides a useful gauge of the vulnerability of a country's economy to an increase in oil and other energy prices. But, in practice, the overall consequences of higher prices for growth, the trade balance, inflation, employment and other economic indicators also depend on economic structures and conditions, and behavioural and policy responses. For these reasons, understanding and predicting the actual impact of higher energy prices requires a quantitative framework or model that attempts to capture the various economic inter-relationships within and between national economies, thus allowing the effects of price increases to be assessed in a consistent manner.

While the mechanism by which oil prices affect economic performance is generally well understood, the precise dynamics and magnitude of these effects – especially the adjustments to the shift in the terms of trade – are very uncertain. Quantitative estimates of the overall macroeconomic damage caused to the economies of oil-importing countries by the oil-price shocks of 1973-1974, 1979-1980 and 1990-1991, as well as the gains from the 1986 price collapse, vary substantially. This is partly due to differences in the models used to examine the issue, reflecting the difficulty of capturing all the interacting effects. Nonetheless, there is no doubt about the direction or significance of the effects: economic growth fell sharply in most oil-importing countries in the year or two following each price shock. Indeed, most of the major economic downturns in the United States, Europe and the Pacific since the 1970s were preceded by a sudden increase in the price of crude oil, although other factors were also important in some cases. Several studies involving simulations of higher energy prices have been carried out since 2000, using integrated macroeconomic models to gauge the impact of recent price rises and to predict the effects of further increases. The results of these simulations are not strictly comparable, as they are based on different assumptions about the starting point for prices and the extent and duration of the price increase, as well as the policy responses. Most such studies focus on the industrialised countries.

A 2004 IEA study, carried out in collaboration with the OECD Economics Department and with the assistance of the IMF Research Department, estimated the impact of a $10 per barrel rise from $25 to $35 in the international oil price on importing regions and for the world as a whole. It found that OECD countries would lose up to 0.4% of GDP in the first and second years of higher prices compared to the base case. Inflation would rise by half a percentage point and unemployment would increase by 0.1 percentage points. Euro-zone countries, which are highly dependent on oil imports, would suffer most in the short term, their GDP dropping by as much as 0.5% and inflation rising by 0.5 percentage points in the first year. The United States would suffer least, with GDP falling by 0.3%, largely because indigenous production meets a bigger share of its oil needs. Japan's GDP would fall by 0.4%, with its relatively low oil intensity compensating to some extent for its almost total dependence on imported oil. In all OECD regions, these losses start to diminish in the following three years as global trade in non-oil goods and services recovers.

The adverse economic impact of higher oil prices on oil-importing developing countries is generally more severe than for OECD countries, because their economies are more dependent on imported oil and are more energy-intensive. Heavily indebted poor countries on average would lose 1.6% of GDP and sub-Saharan African countries as a whole more than 3% in the year following a $10 oil-price increase. GDP in oil-importing developing Asian countries would be 0.8% lower. Overall, world GDP would be at least 0.5% lower – equivalent to $255 billion – in the year following a $10 oil price increase. This is because the economic stimulus provided by higher oil-export earnings in exporting countries would be more than outweighed by the depressive effect of higher prices on economic activity in the importing countries.

Other recent studies also report significant macroeconomic effects from higher prices.[14] A 2005 analysis by the International Monetary Fund quantifies the macroeconomic effects of a short-lived sharp spike in oil prices on the global economy.[15] International oil prices are assumed to average \$80 in 2005 – an increase of about \$37 compared with the base case – falling back to the base case level by 2009. In that first year, GDP growth in the industrialised countries is projected to fall by 0.6 percentage points and by 0.8 points in developing Asia and other net oil-importing developing and emerging market economies (Table 11.5). Inflation would be one percentage point higher in the industrialised countries. If the price increase is perceived to persist, the GDP and inflation effects would be much more pronounced, with GDP falling by as much as 1% in the industrialised countries and 1.3% in the oil-importing developing countries. These estimates do not take account of the impact of a sudden jump in prices on business and consumer confidence. The IMF estimates that a severe fall in confidence could reduce US GDP growth by a further 0.8 percentage points in the first year relative to the base case.

The US Department of Energy's Energy Information Administration, at the request of the IEA, also carried out a high oil price simulation, using the Global Insight Global Scenario Model.[16] In the base case, the average international crude oil price follows the same trajectory as in the Reference Scenario set out in Part A of this *Outlook*. In the high oil price case, oil prices are assumed to be 40% higher in every year from 2007 through to 2025, equal to an average of around \$20 per barrel in real terms. Natural gas prices, which are endogenously determined, rise more or less in line with oil prices; coal prices rise by only half as much as oil prices. Real exchange rates were held constant in the high oil price case. It was also assumed that governments do not make discretionary changes to their fiscal policies to counter the effect of higher energy prices. Central banks are assumed to adjust monetary policy to counter part of the impact of higher prices on inflation.

For the world as a whole, the sensitivity of real GDP to oil prices in the high price case is slightly less than that reported in the IEA's 2004 study and other recent studies that looked at the effects of a permanent increase in oil prices. In addition, the period over which higher prices affect macroeconomic

14. See, for example, Barrell and Pomerantz (2004), Huntington (2005), Hunt *et al.* (2001 and 2002) and Jimenez-Rodriguez and Sanchez (2004).

15. See IMF (2005). The IMF provided the IEA with additional information on the results of this analysis.

16. The model covers 22 major countries and regions, including China, India and the rest of developing Asia.

Table 11.5: **IMF Analysis of the Macroeconomic Impact of an Increase in the International Crude Oil Price to $80 per Barrel***
(Percentage point deviation from baseline in the first year)

	Base case		Higher persistence case – real GDP growth
	Real GDP growth	CPI inflation	
Industrialised countries	**–0.6**	**1.0**	**–1.0**
United States	–0.8	1.3	–
Euro area	–0.6	0.9	–
Japan	–0.7	0.9	–
United Kingdom	–0.4	0.9	–
Developing and emerging market oil importers	**–0.8**	**–**	**–1.3**
Africa	–0.9	–	–1.4
Central and eastern Europe	–0.8	–	–1.2
CIS and Mongolia	–1.0	–	–1.7
Developing Asia	–0.8	–	–1.3
Newly industrialised Asia	–0.8	–	–1.4
Western hemisphere	–0.7	–	–1.2
Heavily indebted poor countries	–1.7	–	–2.7

* From a starting price of $43/barrel.
Source: IMF (2005).

variables is typically longer in this analysis. World real GDP falls by about 0.9% relative to the base case on average in the first four years of higher prices (Table 11.6). Most of the impact occurs within the first three years; thereafter, GDP growth returns roughly to the same path as in the baseline. In general, the overall GDP impact in oil-importing developing countries is significantly greater than that in the industrialised countries. Among the large developing countries, the impact on GDP is greatest for China, where it falls by 0.6%. The impact of higher prices on inflation is generally more marked. Most industrialised countries see their consumer price inflation rates rise by between 0.2 and 1.1 percentage points. Inflation rises more in the developing countries, partly because taxes on energy are lower. It is 0.9 percentage points higher in China and 1.5 points higher in India than in the base case. The unemployment rate is also slightly higher in most oil-importing countries.

Table 11.6: **Macroeconomic Effects in EIA/IEA High Oil Price Case, 2007-2010**
(average percentage point deviation from baseline)

	Real GDP	Consumer price index
Industrialised countries	**–0.5**	**–**
United States	–0.6	0.5
Germany	–0.5	0.6
France	–0.5	0.7
Italy	–0.3	0.6
United Kingdom	–0.4	0.4
Japan	–0.2	0.7
Korea	–1.0	0.9
Non-industrialised countries	**–0.9**	**–**
China	–0.6	0.9
India	–0.3	1.5
Brazil	–0.5	0.6
World	**–0.9**	**–**

Source: EIA/IEA analysis.

The studies described above were carried out at different times and were based on different energy-price and other assumptions. Therefore, the results are not strictly comparable. Deriving a rule of thumb from these studies, we estimate that a sustained $10 per barrel increase in international crude oil prices would cut average real GDP by around 0.3% in the OECD and by about 0.5% in non-OECD countries as a whole compared with the baseline. Overall world GDP would thus be reduced by about 0.4%. Oil-exporting countries would receive a boost to their GDP, offsetting part of the losses in importing countries. Oil-importing developing Asian countries would incur bigger GDP losses, averaging about 0.6%. Most of these effects would be felt within one to two years, with GDP returning broadly to its baseline growth rate thereafter. Critically, these estimates assume that all other economic factors remain unchanged. In practice, changes in other factors may outweigh the impact of higher oil prices, limiting or increasing GDP losses. The estimates are slightly lower than those of IEA (2004), in line with the results of more recent quantitative analyses carried out by the IEA and other organisations.

Using these estimates, we have calculated how fast GDP would have increased had oil prices not risen since 2002. All other factors are assumed to remain unchanged and no constraints on productive capacity are considered, which may not be realistic (see below). This analysis suggests that the world economy might have grown on average by 0.3 percentage points per year more than it actually did since 2002.[17] The average loss of GDP for oil-importing developing Asian countries was around 0.6% (Table 11.7). Heavily indebted poor countries, mostly in sub-Saharan Africa, suffered the biggest loss of GDP.

Table 11.7: **Estimated Impact of Higher Oil Prices since 2002 on Real GDP**

	2002	2003	2004	2005	2002-2005*
Actual GDP growth (%)					
OECD	1.6	2.0	3.3	2.8	2.7
Oil-importing developing Asia	7.3	8.7	9.1	9.2	9.0
Heavily indebted poor countries	3.6	4.2	6.4	5.8	5.5
World	3.1	4.1	5.3	4.9	4.8
Simulated GDP growth at 2002 price levels (%)					
OECD	1.6	2.1	3.5	3.2	3.0
Oil-importing developing Asia	7.3	9.0	9.6	10.1	9.6
Heavily indebted poor countries	3.6	4.7	7.4	7.5	6.5
World	3.1	4.3	5.6	5.5	5.1
Difference, percentage points					
OECD	0.0	0.1	0.2	0.4	0.3
Oil-importing developing Asia	0.0	0.3	0.5	0.9	0.6
Heavily indebted poor countries	0.0	0.5	1.0	1.7	1.0
World	0.0	0.2	0.3	0.6	0.3

* Average annual rate.
Source: IEA analysis.

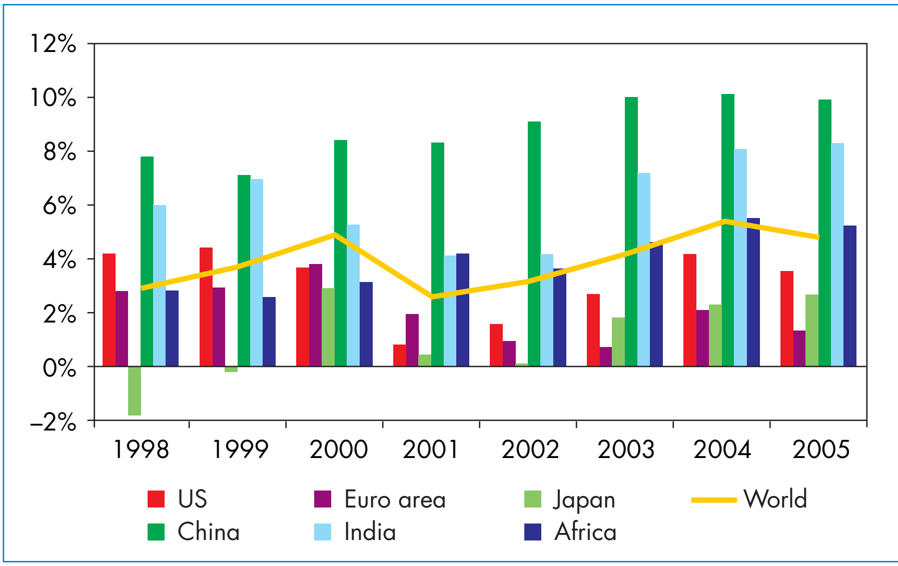
Explaining Macroeconomic Resilience to Higher Energy Prices

The analysis described above indicates that oil prices still matter to the economic health of the world in general and of oil-importing developing countries in particular. This would suggest that the recent substantial increase in oil prices ought to have resulted in a significant economic loss in oil-importing countries. In fact, most countries around the world have continued to grow strongly. According to the IMF, the world economy grew by 5.3% in 2004 – the fastest rate since the 1970s – and by a still brisk 4.9% in 2005 (IMF, 2006a). All major regions saw faster growth in 2003 and 2004, though most countries – including the United States and Europe – have slowed into 2005. The industrialised countries grew by 2.6% in 2005, down from a peak of 3.2% in 2004. Other emerging market and developing countries grew on

17. In this case, oil demand would have grown even faster than it did.

average by 7.7% in 2004 and 7.4% in 2005 – well above the rates of the early 2000s and 1990s. China's GDP surged by about 10% in both 2004 and 2005, while India notched up growth of over 8% (Figure 11.20). The resilience of the developing countries' economies to surging oil prices is all the more remarkable given that most of them are large net importers of oil and have relatively oil-intensive economies. Growth in the Middle East accelerated in 2005 to 5.7%, thanks to higher oil-export revenues.

Figure 11.20: **Real GDP Growth by Region**



Source: IMF (2006b).

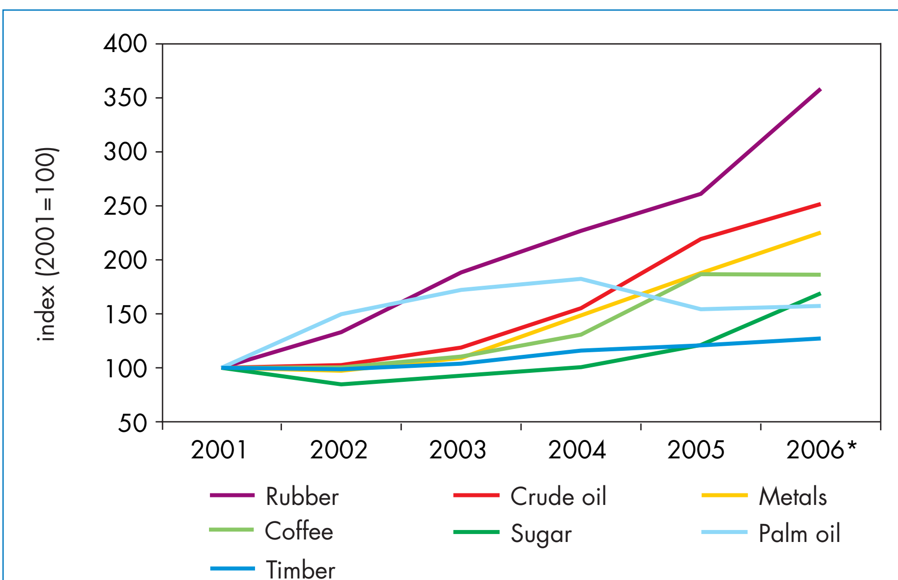
11

So, given the magnitude of recent oil-price increases, why has the adverse macroeconomic impact been so obscure? There are several reasons why economic growth has remained high and current account balances have been less affected than might have been expected, chief among which is the remarkable underlying strength of the world economy. This is reflected in high rates of growth in production and income, coupled with low inflation. In fact, rising oil prices are at least partly the *result* of strong economic growth in many parts of the world, especially Asia. This growth has certainly tempered the adverse impact of higher energy prices on importing countries. Some countries would have grown even more rapidly had oil prices not risen, though constraints on productive capacity might have capped economic growth. For example, GDP growth in the oil-importing developing Asian countries, which averaged 9.2% in 2005, may not necessarily have been as much as

0.9 percentage points higher in 2005 had oil prices not increased by $25 per barrel, as the rule of thumb described in the previous section would suggest. The first two oil-price shocks had more pronounced adverse effects on GDP growth partly because the world economy at that time was in a less healthy state and oil-import intensities were also much higher. In those episodes, prices rose much faster as a result of a supply shock, which contrasts with the trajectory of the demand-led price increases since 1999.

Strong global economic growth has also contributed to higher prices for non-oil exports, offsetting to varying degrees the impact of higher energy import prices on the terms of trade. The prices for most non-oil commodities have also risen since the beginning of the decade – sharply in some cases (Figure 11.21). In effect, the upturn in economic growth and the rise in energy prices are interlinked in both directions. As many developing countries are major net exporters of non-oil commodities, the impact of higher energy prices has, in many cases, been partially compensated or even more than offset by the increase in the value of exports. In effect, higher export prices provided additional foreign currency to pay for the higher cost of oil imports. In some cases, the appreciation of local currencies against the dollar has also boosted the dollar value of exports (while limiting the impact of higher prices on the oil-import bill). Better agricultural harvests in some countries in 2005 also helped.

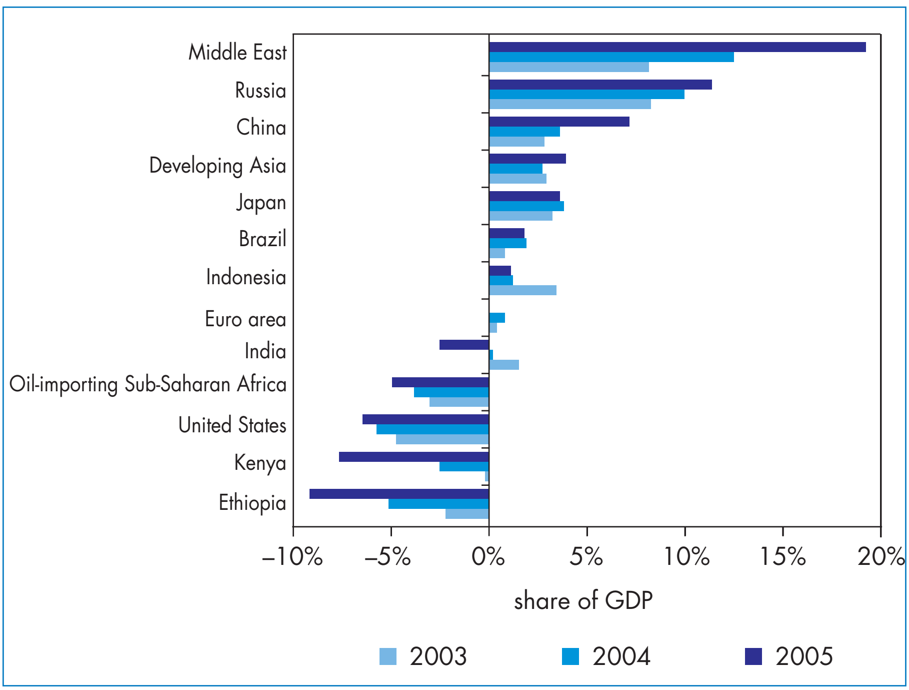
Figure 11.21: **Commodity Price Indices**



* Projection.
Source: IMF (2006b).

These factors explain why the current account balance in some net oil-importing countries, particularly in the developing world, has actually improved in the last three years, though the improvement would have been still greater in the absence of the oil-price increase (Figure 11.22). Some countries, particularly those that rely most heavily on imported oil, such as India, have seen a significant deterioration in their current account balance. But because these countries enjoyed current-account surpluses before the price increases of 2003-2005, they have been able to cope with this deterioration without running up against foreign exchange constraints,[18] thereby averting a sudden slump in domestic demand. Some other countries that rely increasingly on imported oil, such as China, have been able to increase their trade surpluses because of strong growth in the exports of intermediate and finished goods or non-fuel commodities.

Figure 11.22: **Current Account Balance in Selected Countries/Regions**

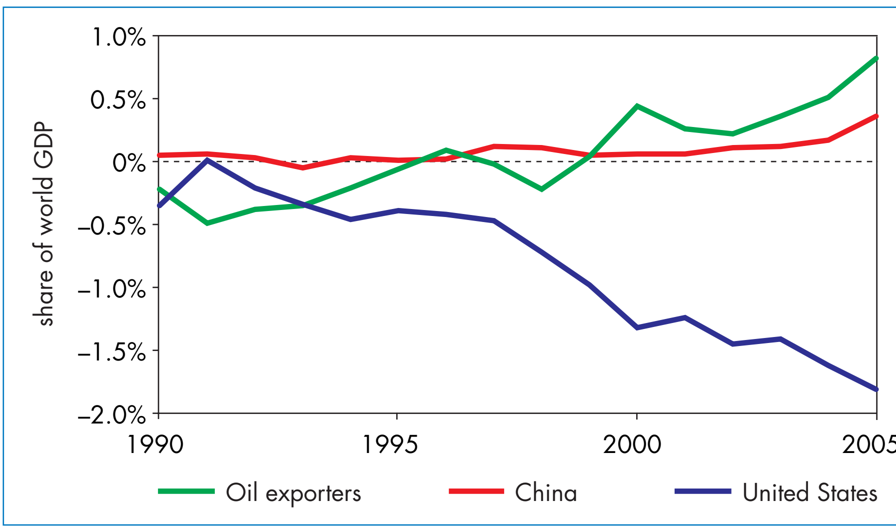


Source: IMF (2006b).

18. For example, India has financed its current-account deficit in 2004 and 2005 largely through increased external borrowing.

Most OECD countries have experienced a worsening of their current account balances, most obviously the United States. In fact, the deepening of the US trade deficit since the mid-1990s has been mirrored by the improvement in the trade balances of oil-exporters and China (Figure 11.23). Higher oil prices explain most of the increase in that deficit, which has been matched by increased borrowing by households. In effect, oil-exporters, China and other countries running trade surpluses are temporarily making good the loss of purchasing power of American consumers by buying dollar-denominated financial assets. The recycling of petro-dollars may have helped to mitigate the rise in long-term interest rates, offsetting the adverse impact of higher energy prices on real incomes and GDP. These factors are delaying, but not eradicating, the impact of higher energy prices on US income and output.

Figure 11.23: **Current Account Balances of the United States, China and Oil Exporters**



Source: IMF (2006b).

The stage of the economic cycle has probably also played a significant role in mitigating the impact of higher energy prices. With accelerating economic activity and expanding investment and production, companies have found it easier to absorb higher input costs – especially as profits have also been improving. Developing Asian countries, in particular, have benefited from particularly strong exports of electronic and other goods, global demand for which is highly sensitive to cyclical economic trends. In addition, there has been no oil-supply shock comparable to those in 1973-1974, 1979-1980 and 1990-1991 to undermine consumer and business confidence.

Increased flexibility in labour markets and more intense competition in product markets have also helped to limit the second-round effects of higher energy prices. Higher input costs and energy prices to consumers have generally not led to a wage spiral. In some cases, price controls and subsidies have limited or delayed the impact on final prices and inflation. In other cases, high taxes on oil products have reduced the direct impact on the consumer price index in percentage terms. Firms have found it harder than in the past to pass through higher costs into the final prices of their goods and services because of increasing global market competition.

There is also evidence that the monetary response to higher energy-import costs has been more appropriate during the recent surge in prices than was the case during past oil shocks (IMF, 2005). Central banks in many countries, especially in the OECD, have been granted formal independence from government in setting interest rates and controlling the money supply. Most central banks now operate under inflation targets, rather than output targets, and act more promptly than in the past in dampening inflationary pressures. This has boosted their credibility and helped them establish a climate of low inflationary expectations. Interest rates were raised in most major economies in 2005 in response to the threat of rising inflation caused by energy prices.

Although most oil-importing countries have so far coped well with higher energy prices, some particularly energy-intensive sectors have suffered disproportionately. Those most vulnerable to higher energy prices are heavy manufacturing industry, including aluminium, petrochemicals and iron and steel, and freight. Though booming demand has allowed producers to pass through a considerable part of higher input costs to final prices, limiting the impact on output, there are nonetheless signs that petrochemical producers are struggling to maintain profit margins in the face of competition from Middle East producers with access to cheaper feedstock. Higher aviation costs have held back the growth of the tourist industry in some countries.

Poor households generally have also endured a relatively large drop in their real disposable incomes where commercial energy costs have been allowed to rise in line with international prices. This is because energy represents a larger share of their expenditure than it does for wealthier households. The lowest-income households in the poorest oil-importing developing countries are not always the most vulnerable to higher prices, because they consume little commercial energy. But real incomes can be reduced significantly as a result of slower economic growth, limiting the ability of governments to fund welfare payments (UNDP/ESMAP, 2005a and 2005b). The World Bank estimates that the number of people in poverty in developing countries has risen by 4% to 6% since 2002 as a result of higher energy costs.[19] The social impact of higher oil prices has been particularly marked in several sub-Saharan African countries that have passed through to consumers most or all of the increase in international oil prices, including Burkina Faso, Burundi, Comoros, Côte d'Ivoire, Ethiopia, Guinea, Malawi, Mali, Mozambique, Niger and Tanzania. In some countries, subsidies have limited the impact of higher prices on real incomes, especially so, rather perversely, for the richest households for whom commercial energy represents a particularly large share of total expenditures. Elsewhere, higher prices threaten to hold back the transition to modern fuels (see Chapter 15).

The eventual impact on short- and medium-term macroeconomic prospects of recent increases in energy prices remains uncertain. This is partly because their effects have not fully worked their way through the economic system and the full impact on economic activity and inflation will take more time to materialise. There are growing signs that inflation is starting to rise, causing interest rates to rise. Clearly, the longer prices remain at current levels or the more they rise, the greater the threat to the economic health of importing countries, although further increases in non-oil commodity prices and depreciation of the US dollar may continue to dampen the impact in some countries.

How quickly the oil-exporting countries spend their windfall revenues is a critical factor. The exporters have accumulated large trade and budget surpluses, which they are wary of drawing down, partly because they fear prices and revenues may fall back in the near future. A number of countries have created oil stabilisation funds, aimed at smoothing out the impact of fluctuations in revenues on government spending, providing a fiscal cushion for periods when revenues are lower and encouraging macroeconomic stability. However, these surpluses slow down the process of global adjustment to the new conditions.

In its September 2006 edition of the *World Economic Outlook*, the IMF forecasts that global real GDP will grow by 5.1% in 2006 and 4.9% in 2007, on the assumption that oil prices average $69.20 per barrel in 2006 and $75.50 in 2007[20] (IMF, 2006a). Growth is projected to be slightly lower than in the past two years in the industrialised countries, the transition economies and the developing countries. The OECD forecasts that GDP growth, on average in its

19. Information communicated privately to the IEA.
20. Arithmetic average of the spot prices of Brent, Dubai and WTI.

Member countries, will rise from 2.8% in 2005 to 3.1% in 2006, and then fall back to 2.9% in 2007 (OECD, 2006). But both the IMF and the OECD suggest that a renewed surge in oil prices, together with ever-worsening current account imbalances and abrupt exchange rate realignments, long-term interest rate rises and a slump in asset prices, represents the biggest risk to near-term global macroeconomic prospects. Global imbalances will need to be resolved at some point. The question is when and how quickly. One possibility, even without fiscal policy action, is an orderly adjustment in imbalances led by the private sector, involving an increase in private US savings, higher interest rates, a slowdown in house prices and a substantial real exchange rate adjustment. But another is a much more abrupt and disorderly adjustment, characterised by a substantial overshooting of exchange rates and a big jump in interest rates, and resulting in a sharp contraction of global activity. An increase in wage inflation cannot be ruled out, particularly if real incomes stall for a prolonged period.

Energy Policy Implications

Higher energy prices have important implications for energy policy. They reinforce the economic and energy-security benefits of diversifying away from imported oil and gas – a major policy objective of IEA Member countries as well as other oil-importing countries. This can be achieved through efforts to stimulate indigenous production of hydrocarbons and alternative sources of energy, such as biofuels, other renewable energy technologies and nuclear power, as well as through energy efficiency measures. Market and regulatory reform can contribute to lowering supply costs, thereby offsetting at least part of the effect of higher primary energy prices.

Most countries are considering anew stronger policies and measures to reduce oil-import intensity for economic, security and/or climate-change reasons. Such policies are of particular importance to countries with relatively high oil-import intensities. There is a large potential to improve the efficiency of energy use in developing regions, given the relatively inefficient energy capital stock currently deployed and the extent of the new investment in energy which is required there. Faster deployment of the most efficient technologies will be needed for this potential to be realised. All oil-importing countries would benefit from reduced imports in developing countries, as this would relieve upward pressure on international oil prices. The economic benefits from reduced oil-import intensity could be substantial in the longer term. In the Alternative Policy Scenario, new energy policies aimed at reducing energy-import dependence and greenhouse-gas emissions reduce the annual oil-import bill by \$0.9 trillion for OECD countries and \$1 trillion for developing Asian countries by 2030. China alone would save \$0.5 trillion and India

$0.2 trillion (see Chapter 8). The $1.9 trillion of cumulative savings for the OECD and developing Asia are roughly equal to all the capital needed for gas-supply infrastructure in those regions. Most of the benefits accrue after 2015.

The single most important area of policy action is energy pricing (see the earlier section, Quantifying Energy Subsidies). Many developing countries, especially in Asia and Africa, continue to subsidise implicitly or explicitly the consumption of energy services. In many cases, price controls prevent the full cost of higher imported energy from being passed through to end users. As a result, consumption does not respond to increases in the prices of imported fuels, so import costs remain unnecessarily high. They can also place a heavy direct burden on government finances and weaken the potential for economic growth. In addition, by encouraging higher consumption and waste, subsidies exacerbate the harmful effects of energy use on the environment. They also impede the development of more environmentally benign energy technologies. Although usually meant to help the poor, subsidies often benefit better-off households. Targeted and transparent social welfare programmes are a more efficient and effective way of compensating the poor for higher fuel prices. They could be funded by the budget savings from lower energy subsidies (IEA/UNEP, 2002).

CURRENT TRENDS IN OIL AND GAS INVESTMENT

HIGHLIGHTS

- Oil and gas industry investment has surged in recent years. In 2005, investment by the industry reached $340 billion dollars, 70% more than in the year 2000 in nominal terms. However, most of the increase was due to rising materials, equipment and labour costs, especially since 2004. Expressed in cost inflation-adjusted terms, investment in 2005 was only 5% above that in 2000.
- Major oil and gas company plans point to an investment increase of over 57% in 2006-2010 compared to 2001-2005. If those plans are fully implemented and their spending forecasts prove accurate, oil and gas investment would rise from $340 billion in 2005 to $470 billion in 2010. In real terms, however, investment is 40% higher in the second half of the decade than in the first. The upstream sector will absorb almost two-thirds of total capital spending of which two-thirds will go to maintaining or enhancing production from existing fields.
- Upstream investment is planned to add close to 21 mb/d of new crude oil production capacity during 2006-2010. However, project slippage and a decline in the production capacity of existing wells mean that the net increase in capacity could be only about 9 mb/d. This is about 1.3 mb/d more than the projected growth in world oil demand to 2010 in the Reference Scenario and 3.3 mb/d more than in the Alternative Policy Scenario. However, capacity additions could be smaller on account of shortages of skilled personnel and equipment, regulatory delays, cost inflation and geopolitics.
- Refinery investment has also risen, from $34 billion in 2000 to an estimated $51 billion in 2005. Industry spending plans point to more modest increases in the next five years, with investment reaching $62 billion in 2010. As in the upstream, much of this increase is explained by higher unit costs. Around 7.8 mb/d of throughput capacity will be added by 2010.

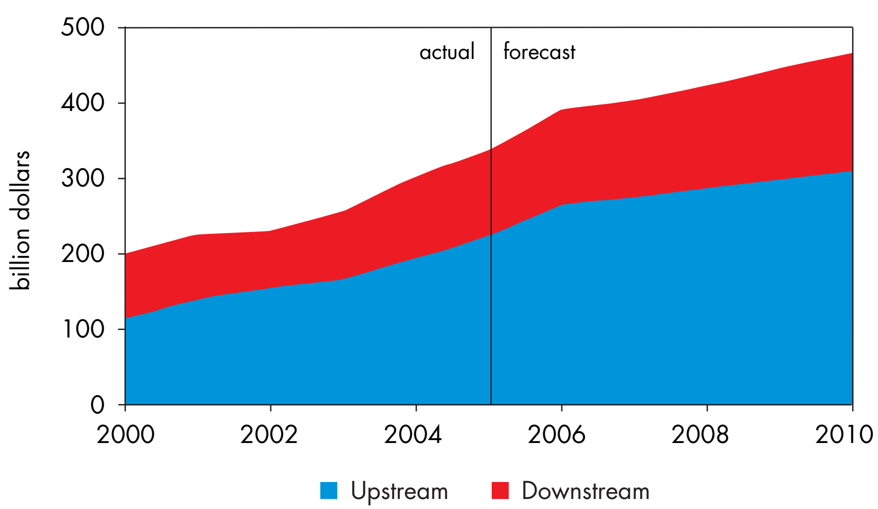
- The five years to 2010 will see an unprecedented increase in capital spending on new LNG projects. A massive 167 million tonnes (226 bcm) per year of new liquefaction capacity is under construction or planned to come on stream by 2010 at a cost of about $73 billion. World LNG capacity will almost double to 345 Mt/year if these projects are all completed on time.
- Beyond the current decade, higher investment in real terms will be needed to maintain growth in production capacity. Future projects are likely to be smaller, more complex and remote, involving higher unit costs. Slowing production declines at mature giant fields will require increased investment in enhanced recovery.

Overview

Capital spending by the world's leading oil and gas companies increased sharply in nominal terms over the course of the first half of the current decade and is planned to rise further to 2010 – the end of the period analysed in this chapter.[1] Between 2000 and 2005, capital spending grew at an average rate of 11% per year. In 2005, total investment by the industry reached $340 billion, up from $200 billion in the year 2000 – an increase of 70%.[2] The increase was particularly strong in 2004 and 2005, with most of the increase going to the upstream sector (Figure 12.1). The increase in spending was due to sharp increases in costs, caused largely by higher international prices for cement, steel and other materials used in building production, processing and transportation facilities, as well as increased charges for oilfield equipment and services, plus increased energy-input costs. In cost inflation-adjusted terms, the capital investment in 2005 was only 5% higher than that of 2000. In 2001-2004, real spending was, on average, 10% higher than in 2000. Box 12.1 provides a description of the methodology used to analyse near-term investment trends.

1. Because of data deficiencies, downstream oil and gas investment in this chapter primarily covers oil refining, oil pipelines, oil tankers, LNG chains and gas-to-liquids (GTL) plants. The long-term projections in Chapters 3 (oil) and 4 (gas) also include bulk gas-storage facilities, gas-transmission pipelines (cross-border and national systems) and gas-distribution networks.
2. All the investment figures in this chapter are expressed in nominal terms, unless otherwise specified. Where the figures have been adjusted for changes in cost inflation in the oil and gas industry, the qualifying terms "cost inflation-adjusted" or "real" are used.

Figure 12.1: **Total Oil and Gas Industry Investment, 2000-2010**



Source: IEA databases and analysis; part of the historical company data collated using Evaluate Energy *Petrocompanies* online database (www.evaluateenergy.com).

Box 12.1: **Analysis of Current Oil and Gas Investment Plans**

In addition to the long-term analysis of energy investment in the Reference and Alternative Policy Scenarios (described in Parts A and B of this *Outlook*), a detailed analysis has been made of oil and gas industry investment over the period 2000 to 2010. The objective was first, to assess whether the industry is planning to invest more in response to higher prices and the need for more capacity in the upstream and downstream, and second, to quantify the resulting additions to oil production and refining capacity. This involved four main tasks:

- A survey of the capital spending programmes of 40 major oil and gas companies, covering actual capital spending from 2000 to 2005 and their own forecasts of spending through to 2010. These companies included the major international oil and gas companies, independent producers and national oil companies (Table 12.1). The selection of the companies was based on their size as measured by their production and reserves, though geographical spread and data availability also played a role. The surveyed companies account for about three-quarters of world oil production and reserves, 65% of gas production and 55% of gas reserves. Total industry investment was calculated by adjusting upwards the

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spending of the 40 companies, according to their share of world oil and gas production for each year.[3] Downstream investment was also adjusted using project databases.

- A review of all major upstream projects worldwide that are due to be on stream by 2010. The sanctioned (approved by the company board) and planned projects covered total over 120. They include conventional oil and gas production and non-conventional oil sands. For each project, data were compiled on the amount and timing of capital spending and the amount of capacity to be added per year from 2006 to 2010.
- A survey of 500 oil-refinery projects, including greenfield refineries, refinery expansions and additions to upgrading capacity.
- A survey of 45 sanctioned and planned LNG liquefaction and gas-to-liquids projects as well as LNG shipping and regasification-terminal investments worldwide.

For each task, data were obtained from the companies' annual and financial reports, corporate presentations, press reports, trade publications and direct contacts in the industry. The year 2010 was chosen as the end-date for this analysis, because almost all the capacity that will be brought on stream by then is already under construction or at an advanced stage of planning due to the long lead times for large-scale projects. As with all studies of this kind, our analysis may not be accurate enough to estimate total industry investment authoritatively. Underestimation can occur due to the difficulties in capturing every project and every dollar of planned spending. Overestimation can be due to unforeseen changes in company plans.

On the basis of trends in investment planned or forecast by the companies surveyed, total industry investment for 2006-2010 is expected to be 57% higher than in the first half of the current decade. If their plans are fully implemented and their spending forecast proves accurate, total oil and gas investment will rise from $340 billion in 2005 to $470 billion in 2010. On average, about 67% of total spending in 2006-2010 would go to the upstream sector, 14% to oil refining, 7% to LNG and 12% to other

3. For 2006-2010, the shares were held constant at 2005 levels.

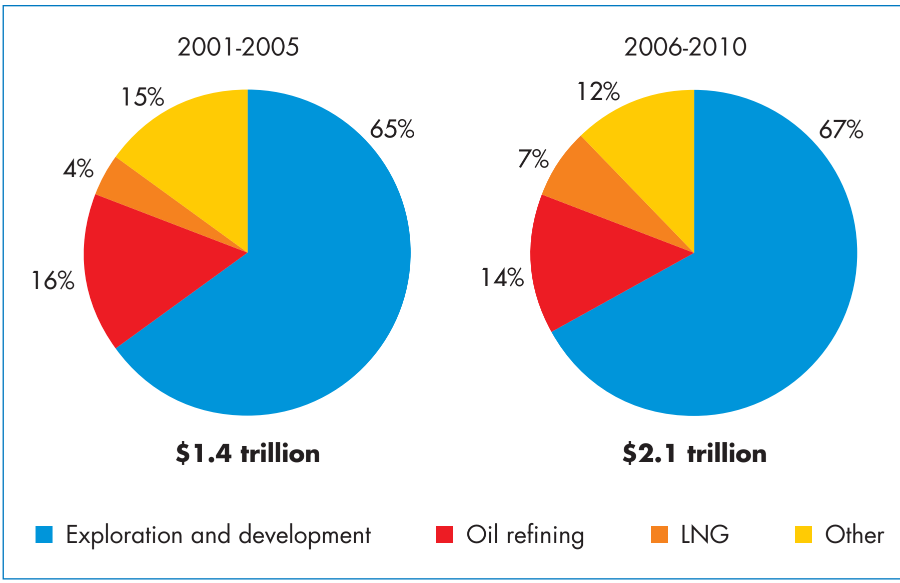
Table 12.1: **Oil and Gas Production of Surveyed Companies by Type, 2005**

	Oil (mb/d)	Gas (bcm/year)		Oil (mb/d)	Gas (bcm/year)
Independents			**National oil and gas companies**		
Apache	0.2	13.1	ADNOC	2.8	46.7
BG Group	0.1	21.5	CNOOC	0.4	4.4
CNRL	0.3	14.9	Gazprom	0.3	545.9
Encana	0.2	33.2	Iraq National Oil Company	1.5	88.9
Marathon	0.2	9.5	Kuwait Petroleum Company	2.6	10.6
Hydro	0.4	9.5	Libya National Oil Company	1.6	12.3
Occidental	0.5	6.9	National Iranian Oil Company	4.1	89.8
PetroCanada	0.2	8.3	NNPC	2.4	20.8
Repsol	0.5	35.3	ONGC	0.5	2.0
TNK-BP	1.6	11.0	PDVSA	2.4	30.5
Major international oil and gas companies			Pemex	3.5	50.0
BP	2.6	87.8	PetroChina	2.3	31.7
Chevron	1.7	43.7	Qatar Petroleum	0.8	34.3
ConocoPhillips	1.5	34.5	Rosneft	1.4	13.1
ENI	1.1	38.8	Saudi Aramco	11.0	65.9
ExxonMobil	2.5	95.6	Sinopec	0.8	6.3
Shell	2.0	85.4	Sonangol	1.2	–
Total	1.7	54.2	Sonatrach	0.5	56.2
Previously state-owned companies					
Lukoil	1.8	5.8	Petrobras	1.9	22.9
Petronas	0.7	47.9	Statoil	0.7	27.0
			Total	**62.5**	**1 816**

Note: Data obtained from company reports and press statements.

downstream activities, including GTL, pipelines, oil tankers, distribution and retailing (Figure 12.2). The shares of exploration and development and LNG projects are set to be higher in 2006-2010 than in the first half of the decade. Upstream spending would grow at an average annual rate of 6.7% between 2005 and 2010. In cost inflation-adjusted terms, spending is projected to grow by about 40% between 2005 and 2010 – on the assumption that unit costs level off in 2007 and begin to decline gradually towards the end of the decade. By 2010, cost inflation-adjusted spending is expected to be 46% higher than in 2000.

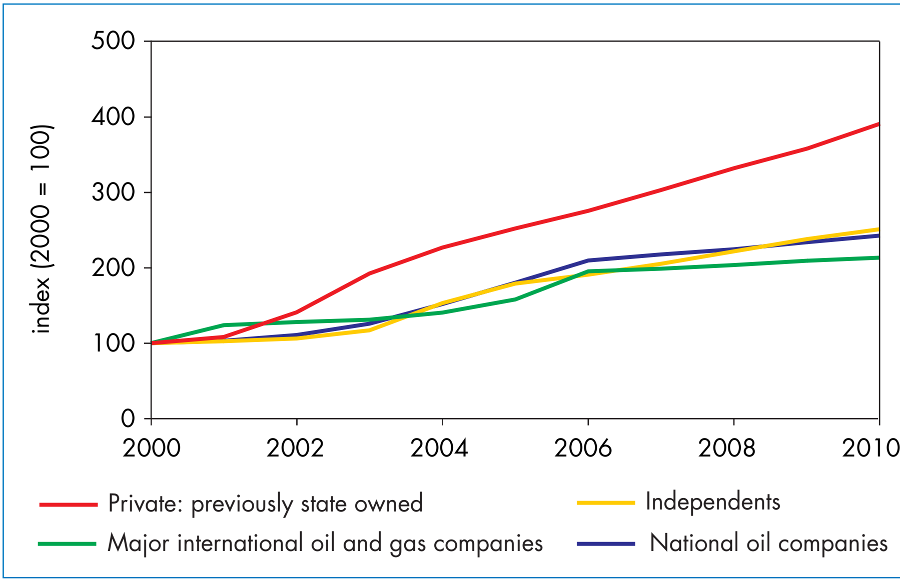
Figure 12.2: **Total Oil and Gas Industry Investment by Sector**



Source: IEA databases and analysis.

National oil and gas companies account for 35% of the total investment of all the companies surveyed from 2000 to 2010. Independents account for 15%, previously state-owned companies 11% and major internationals 38%. The share of the international oil companies falls between the first and second halves of the decade, while all others increase. The national oil companies' share of investment increases the most. While national, international and independent oil companies all more than double their investment between 2001 and 2010, the previously state-owned private companies quadruple theirs (Figure 12.3).

Figure 12.3: **Oil and Gas Industry Investment by Type of Company**



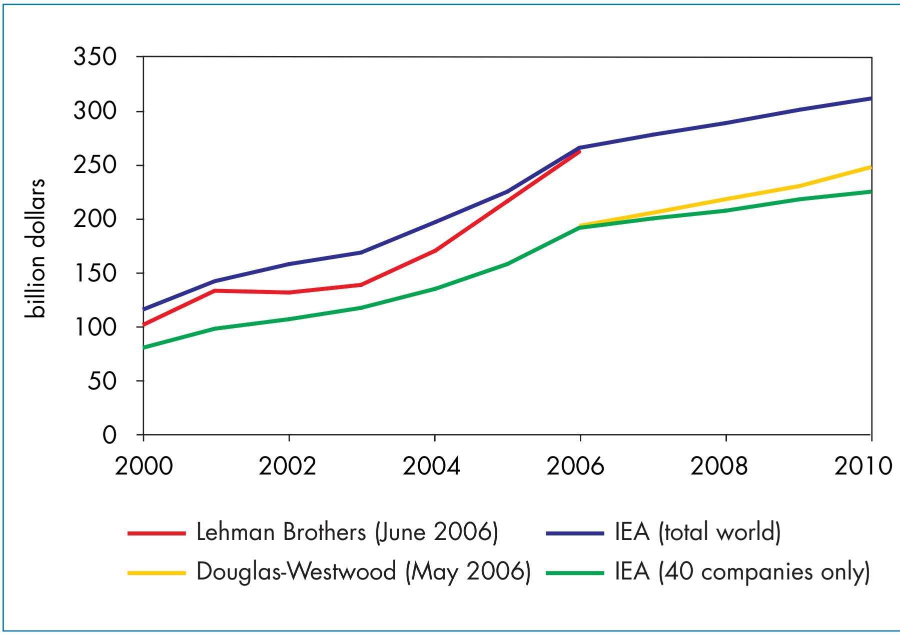
Note: See Table 12.1 for details of the breakdown by type of company.
Source: IEA databases and analysis.

Exploration and Development

Investment Trends

Capital spending on oil and gas exploration and development has risen sharply since the beginning of the current decade and, according to industry plans, will continue to rise through to 2010. Spending is estimated to have reached \$225 billion in nominal terms in 2005, twice the level of 2000. Much of this increase was due to cost inflation, an increase in the total number and size of projects under development, and a shift to more complex and costly projects in locations where no infrastructure exists. In real terms, spending rose steadily through to 2003, but levelled off in 2004 and in 2005 (see below). On current plans, spending is expected to increase by another 20% to \$265 billion in 2006 and then to rise further to about \$310 billion in 2010 (Figure 12.4). Cost inflation is expected to slow markedly by the end of the decade, partially driven by falling commodity prices and availability of new equipment to meet current sustained growth in activity. Total planned upstream spending in 2006-2010 amounts to \$1.4 trillion in nominal terms, compared with \$890 billion in the previous five years. These trends are broadly in line with those reported by other organisations, including Lehman Brothers and Douglas-Westwood, though the coverage of their surveys differed.

Figure 12.4: **Investment in Oil and Gas Exploration and Development**

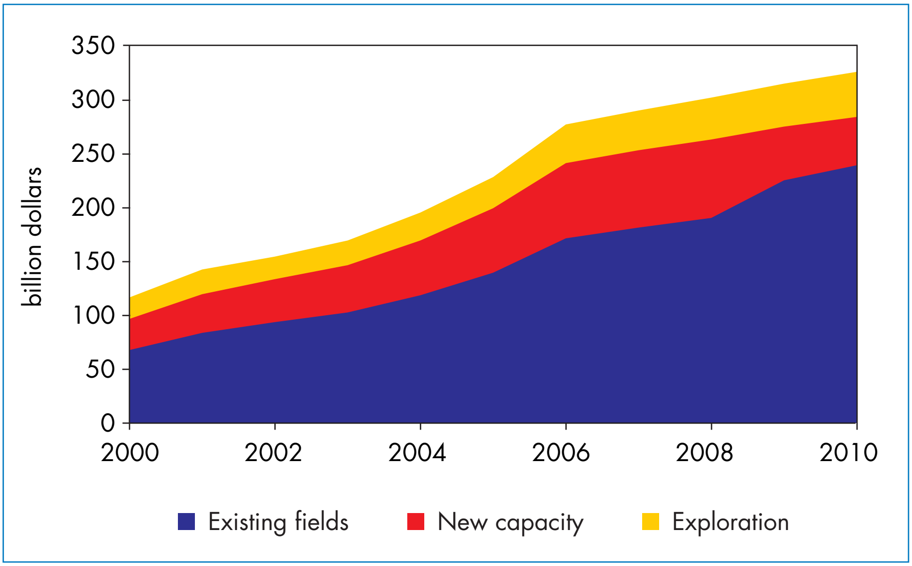


Source: IEA database and analysis; Lehman Brothers (2005); Douglas-Westwood (2006).

Over the period 2006-2010, spending on exploration is expected to amount to about \$194 billion, or 14% of total upstream oil and gas spending. The balance of almost \$1.2 trillion, or 86% of upstream spending, will go to development and production. We estimate that projects to develop new fields will absorb \$306 billion, of which the twenty largest will absorb over 50% (Table 12.2). Therefore, the remaining \$900 billion, or almost two-thirds of total upstream spending, is destined to enhance or maintain output at existing fields (Figure 12.5).

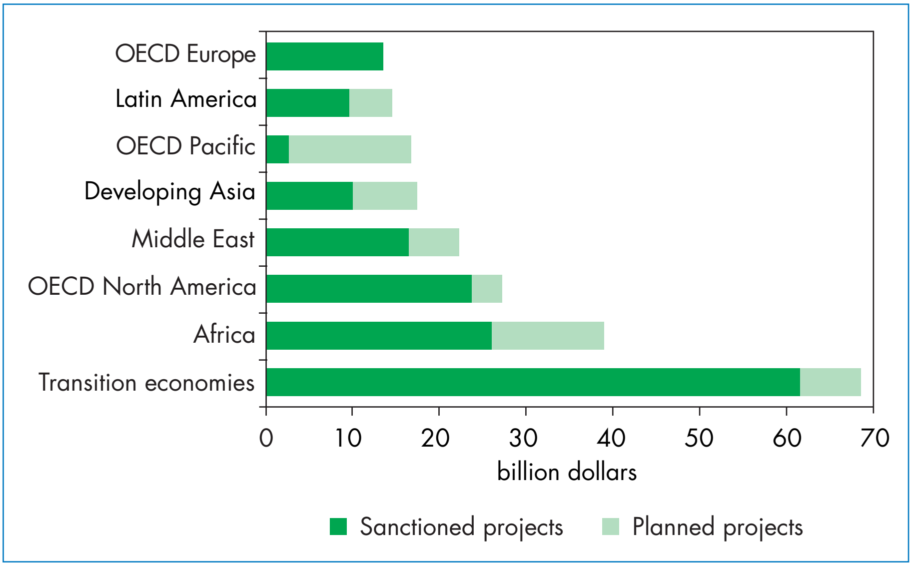
Almost all spending on new projects due to be on stream by 2010 has already been sanctioned, with many such projects already under development (Figure 12.6). More than half of the spending on new projects is going to Africa and the transition economies. Many of these projects are very large, involving fields in Nigeria, Angola, the Caspian Sea and Sakhalin that were discovered in the last decade. Many were sanctioned several years ago. Developers are now struggling to complete these projects on time and within budget in the face of huge increases in costs and limited availability of equipment and manpower (see below).

Figure 12.5: **Upstream Investment by Activity, 2000-2010**



Source: IEA database and analysis.

Figure 12.6: **Sanctioned and Planned Project Investment on New Oil and Gas Fields by Region, 2006-2010**



Note: Covers spending on the development of new fields only. Planned spending covers only those projects that have reached the front-end engineering design stage of the project.

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Table 12.2: **Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010**

Project	Location	Operator	Completion date	Capacity addition Oil (kb/d)	Capacity addition Gas (bcm/year)	Total estimated capital cost ($ million)
Sakhalin 2	Sakhalin	Shell	2009	120	10	20 000
Sakhalin 1 (Chayvo)	Sakhalin	ExxonMobil	2006	250	10	17 000
Qatar GTL Pearl 1	GTL Qatar	Shell	2009	70	8.3	12 000
Kashagan Phase 1	Kazakhstan	ENI	2009	75	16	10 000
Athabasca Muskeg	Canada	Shell	2007	90	–	10 000
Ormen Lange	Norway	Shell	2008	–	25	8 850
Syncrude Phase 3	Canada	Canadian Oil Sands	2006	350	–	8 400
Qatar GTL	GTL Qatar	ExxonMobil	2009	80	–	7 000
Karachaganak 3 & 4	Kazakhstan	ENI, BG	2009	200	–	7 000
ACG 1 (West Azeri)	Azerbaijan	BP	2006	300	–	6 000
ACG 2 (East Azeri)	Azerbaijan	BP	2007	450	–	6 000
ACG 3 (Gunesli)	Azerbaijan	BP	2008	320	–	6 000
Snohvit	Norway	Statoil	2007	–	5.5	5 300
Khurais	Saudi Arabia	Saudi Aramco	2009	1 200	–	5 000
Prirazlomnoye	Arctic	Gazprom,Statoil	2010	155	–	5 000
Puguang	China	Sinopec	2008	–	4.0	4 500
Vankorskoye 2	Siberia	Rosneft	2008	328	–	4 500
Agbami	Nigeria	Chevron	2008	230	–	4 000
Thunder Horse	GOM	BP	2008	250	2.1	4 000
Akpo	Nigeria	Total	2008	175	–	3 560
Tahiti	GOM	Chevron	2008	125	0.7	3 500
Dalia	Angola	Total	2006	240	–	3 400
Long Lake	Canada	Nexen	2008	60	–	3 120

Table 12.2: **Sanctioned and Planned Upstream Oil and Gas Developments for Completion in 2006-2010** *(Continued)*

Project	Location	Operator	Completion date	Capacity addition		Total estimated capital cost
				Oil (kb/d)	Gas (bcm/year)	($ million)
Atlantis	GOM	BP	2006	120	1.5	3 250
Shah Deniz	Azerbaijan	BP	2006	–	9.3	3 000
Tengiz expansion	Kazakhstan	Chevron	2006	250	1.0	3 000
Bonga South	Nigeria	Shell, Chevron	2007	150	–	3 000
Greater Plutonio	Angola	BP	2007	240	–	3 000
Escravos EGTL	GTL Nigeria	Chevron, Sasol	2008	95	–	3 000
Bayu Undan	Australia	Santos	2006	69	2.2	2 700
Kristin	Norway	Statoil	2006	126	5.5	2 600
Banyu Urip (Cepu)	Indonesia	ExxonMobil	2008	170	0.2	2 600
Shaybah & Central	Saudi Arabia	Saudi Aramco	2008	380	–	2 500
Kizomba C	Angola	ExxonMobil	2008	80	–	2 500
Tombua Landana	Angola	Chevron	2009	100	1.8	2 300
Shenzi	GOM	BHP Billiton	2008	80	–	2 200
Tyrihans	Norway	Statoil, Total	2009	70	–	2 200
White Rose	Canada	Husky	2006	100	1.5	2 000
Buzzard	UK	Nexen	2007	200	–	2 000
Demianskiy	Siberia	TNK-BP	2008	220	–	1 800
Moho-Bidondo	Congo	Total	2008	75	0.5	1 800
Others				**5 073**	**30**	**40 920**
Sanctioned			**By 2010**	**12 666**	**135**	**250 500**
Planned			**By 2010**	**2 748**	**53**	**55 500**
Total sanctioned and planned			**By 2010**	**15 414**	**188**	**306 000**

Note: Covers spending on the development of new fields only. Planned spending covers projects that have reached the front-end engineering design stage of the project-development process. GOM is Gulf of Mexico. Source: IEA database of 120 projects and analysis.

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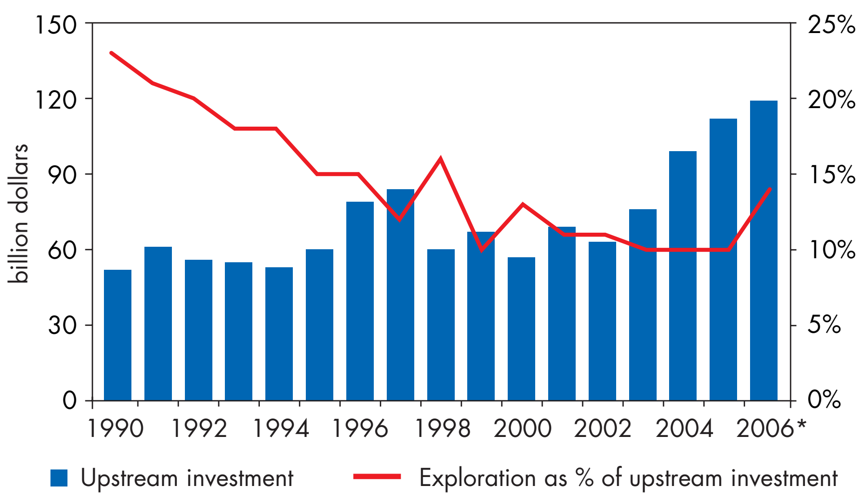
While most upstream investment continues to go to development of fields already in production, the *increase* in spending since the start of the current decade has been focused on development of new fields that were already discovered by 2000. Spending on exploration has risen in absolute terms since the beginning of the current decade, but has continued to decline as a share of total upstream investment (Figure 12.7). Although oil company exploration budget forecasts for 2006 indicate a reversal of this trend, putting exploration plans into effect will be hampered by the shortages of rigs and manpower over the next one to two years. If this is the case, there may be a shortage of new projects awaiting development when the current wave of upstream developments is completed early in the next decade.

Figure 12.7: **Oil and Gas Exploration Investment**



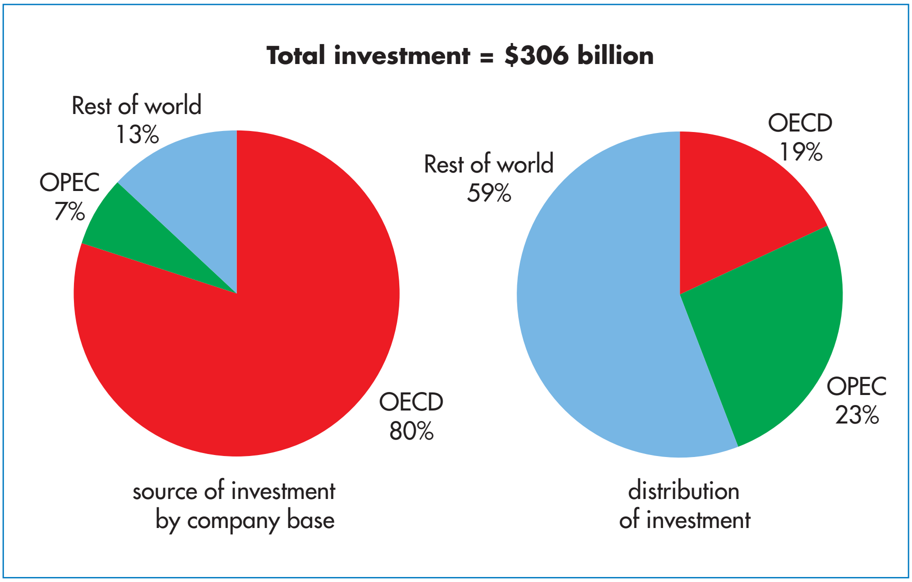
* Planned.

Note: Includes Apache Corporation, BG Group, BP, Chevron, CNOOC, ConocoPhillips, ExxonMobil, Lukoil, Occidental, ONGC, PDVSA, Petrobras, Petro-Canada, PetroChina, Repsol-YPF, Sinopec, Statoil and Total.

Source: IEA databases and analysis.

Oil and gas companies based in OECD countries continue to dominate global upstream investment. We estimate that they are responsible for about 60% of total investment over 2000-2010 and 80% of new project investment over 2006-2010. Although the share of total investment made by national oil companies in the Middle East is projected to be higher in the second half of the decade than in the first, it is still remarkably small, at less than 10% of both types of investment. Development costs per barrel are significantly lower there than in other regions. Nonetheless, most of the new investment made over the five years to 2010 will go to projects in non-OECD countries: only 19% of the capital that will be spent will be on projects in OECD countries, while under a quarter will go to projects in OPEC countries and nearly 60% to projects in other non-OECD countries (Figure 12.8).

Figure 12.8: **New Oil and Gas Project Investment by Source and Destination, 2006-2010**



Note: Based on upstream projects surveyed. Includes GTL and LNG.
Source: IEA databases and analysis.

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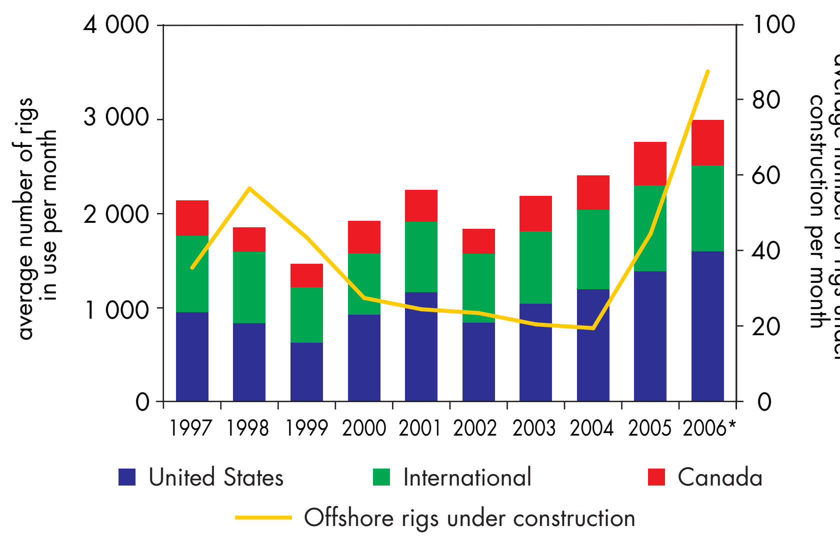
Impact of Cost Inflation on Upstream Investment

Exploration and development costs have increased sharply in recent years. In part, rising upstream costs have resulted from higher basic material costs, such as steel and cement. They have also been driven up by a sharp increase in demand for equipment and manpower as companies have sought to boost output in response to higher oil prices. An increase in the number of large-scale projects being developed at the same time, their remoteness and greater complexity and the increasing need for costly production enhancement at large mature fields have added to the upward pressure on cost. Drilling remains the single most expensive component of upstream activity. Since 2002, drilling-rig rates have risen more than any other cost component, with daily rates increasing by as much as 100% for a North Sea jack-up rig to over 400% for a rig in the Gulf of Mexico. The main reason is a surge in demand for rigs which has driven effective utilisation rates up to 100% in most regions (Figure 12.9).[4] Increases in equipment prices range from 20% for mechanical pumps to up to 50% for special fabrications of oil and gas production equipment. Construction labour now costs 25% more than in 2002, while at the top end of the labour market, rates for specialised expertise such as project management consultancy have increased by up to 80%.[5] Rising oil prices have encouraged the oil and gas service industry to invest in new equipment and technology at a rate not seen since the late 1970s. In particular, the number of offshore rigs under construction has increased dramatically, holding out the prospect of lower rates in the future. Although nominal upstream investment has doubled between 2000 and 2005, we estimate that much of this increase has been absorbed by cost inflation (Figure 12.10). In 2005, upstream spending in cost inflation-adjusted terms was only about a fifth higher than in 2000. On the assumption that costs level off in 2006-2007, real spending is expected to rise by around a quarter between 2005 and 2010.

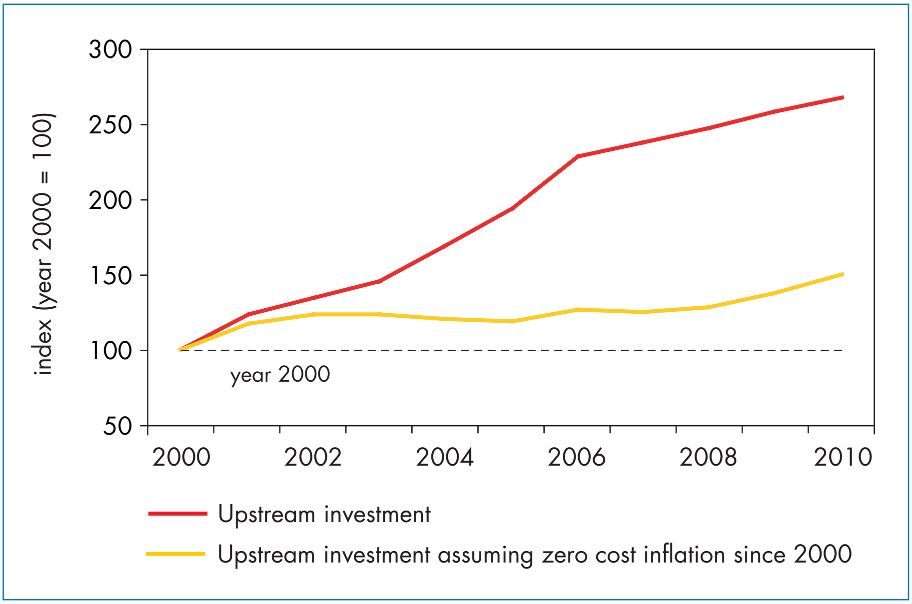
Figure 12.9: **Active Drilling Rigs and Offshore Drilling Rigs under Construction, 1997-2006**



* To July.
Sources: Baker Hughes rig count (available at www.bakerhughes.com); ODS Petrodata.

4. See ODS Petrodata website (www.ods-petrodata.com).
5. Information obtained in communications with oil and gas industry.

Figure 12.10: **Upstream Oil and Gas Industry Investment in Nominal Terms and Adjusted for Cost Inflation**

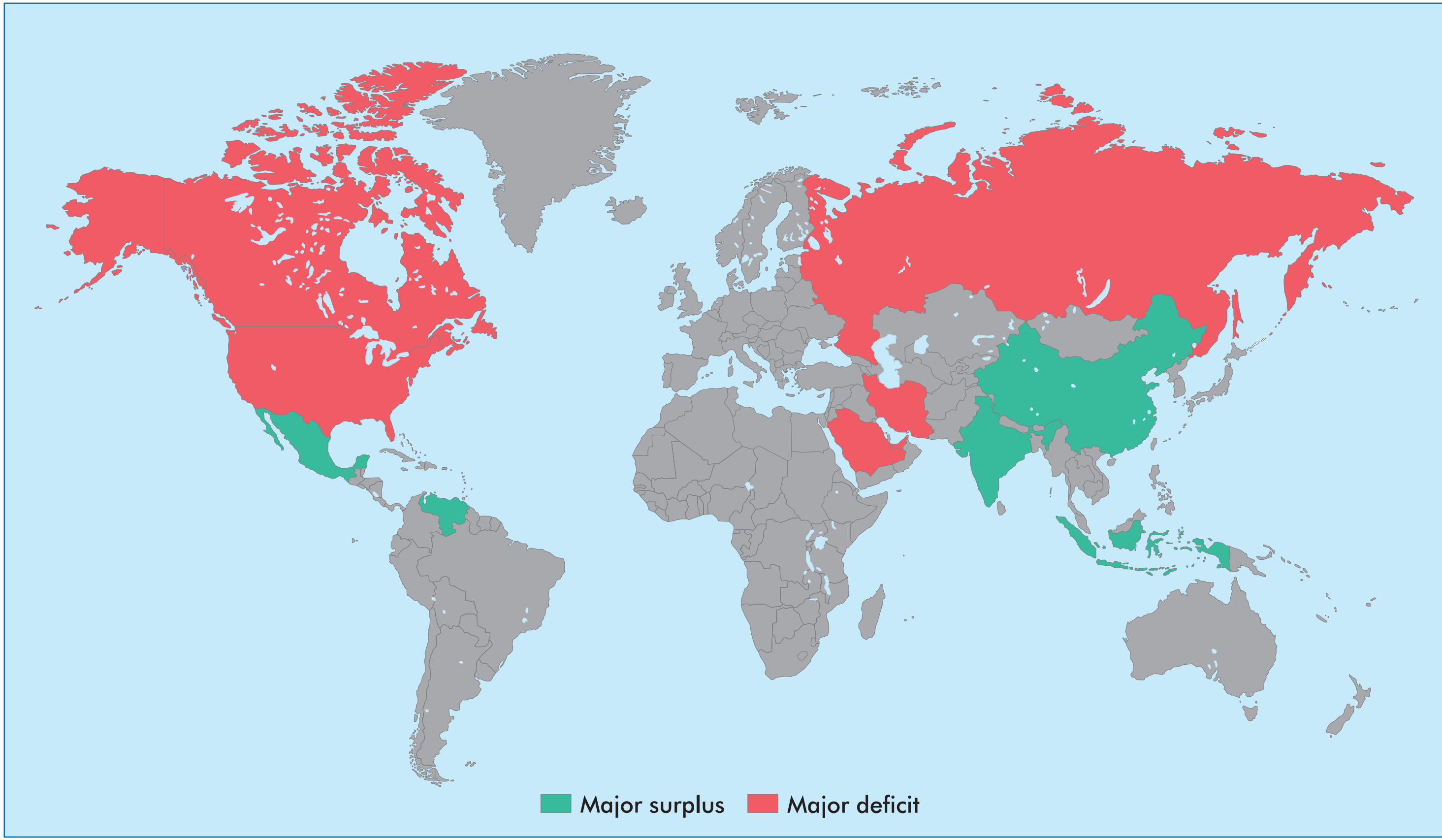


Source: IEA database and analysis.

Increased exploration and development activity is stretching the industry labour force to its limits. A 2005 benchmarking survey of 30 oil and gas companies and 115 universities estimates that the demand for petroleum-industry personnel will increase by around 7% per year for the next ten years.[6] Demand for experienced, qualified personnel far outstrips current availability and there are regional shortages of petroleum geology and engineering university graduates. The biggest shortages of local graduates are in North America, the Middle East, Russia and other transition economies (Figure 12.11). Venezuela, Mexico, India, China and Indonesia are among the few countries with excess graduates in petroleum disciplines. Globally the supply should meet demand if all petro-technical graduates were to join the industry. A historically low intake of suitably qualified graduates into the industry is pushing up the average age of the workforce across all disciplines: it currently ranges from 40 to 50 years (Deloitte, 2005). A significant gap also exists between the supply of, and demand for, mid-career experienced oil industry personnel.

6. Private survey carried out by Schlumberger Business Consulting, the results of which were communicated to the IEA Secretariat.

Figure 12.11: **Availability of Petroleum-Industry Graduates by Region**

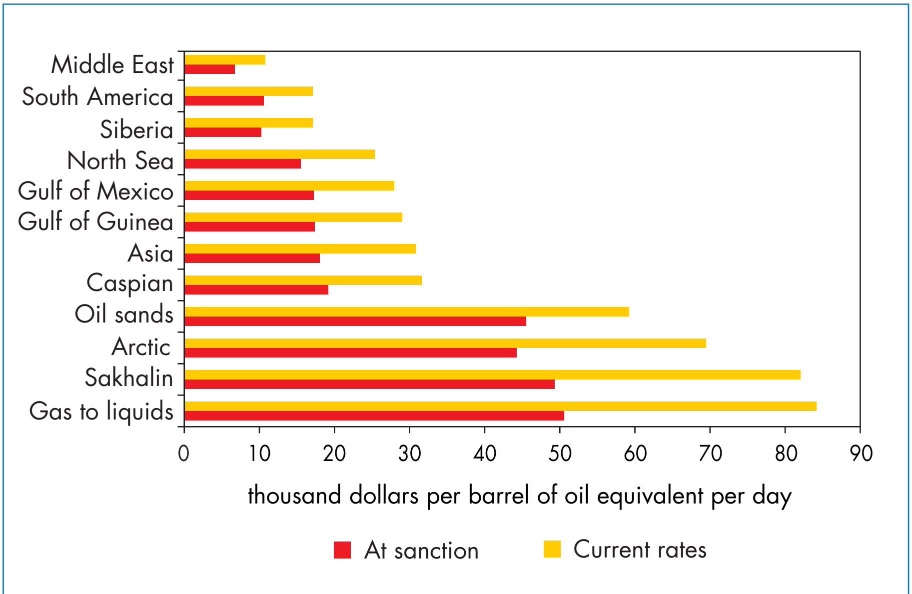


The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Information provided to the IEA by Schlumberger Business Consulting.

The average capital cost of the capacity to produce each new barrel of oil equivalent per day due to come on stream in the period 2006-2010 is estimated at $31 000. Costs vary considerably across regions. The most expensive are over $60 000 and include oil sands (bitumen mining) and gas to liquids projects as well as projects based in Sakhalin and Arctic regions. By far the cheapest are in the Middle East, at a little over $10 000 (Figure 12.12). In most cases, costs have risen sharply since the projects were sanctioned – especially in the Arctic regions and for the development of oil sands in Canada, where significant new infrastructure is needed.

Figure 12.12: **Estimated Capital Intensity of Upstream Development Projects by Region, 2006-2010**



Source: IEA database and analysis.

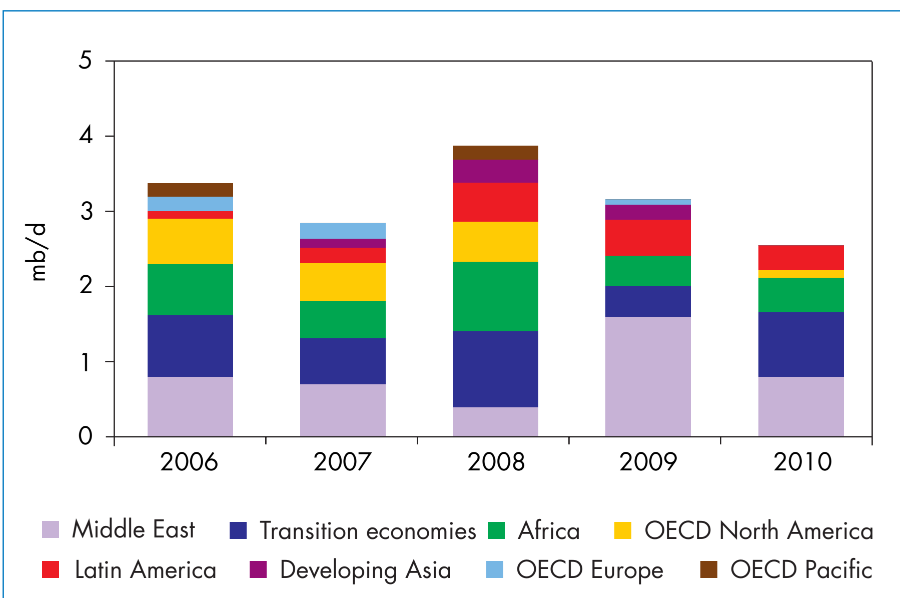
Implications for Oil and Gas Production Capacity

Of the more than 120 major upstream projects we analysed, 89 have been sanctioned, creating a minimum expected gross addition to oil production capacity of 12.7 mb/d by 2010. This increases to 15.4 mb/d with the addition of 23 planned projects (Table 12.2). Almost two-thirds of this capacity is expected to come on stream by 2008. The Middle East, transition economies and Africa account for 70% of total additions to 2010 (Figure 12.13). Our separate review of the 40 oil and gas companies' production growth plans points to additional oil-production capacity of 15.9 mb/d by 2010.

Historically, slippage in the completion of projects is quite common and typically ranges from 5% to 20%. The probability of slippage is even more likely today due to shortages of equipment, materials and personnel. Of the 22 recently launched projects, 15 are currently encountering delays, averaging one-and-a-half years, while seven were ahead of schedule, by an average of four months. Two examples of major projects that are slipping behind schedule are Sakhalin-2 in Russia, which is delayed by at least a year because of the complexity of the project, the need for regulatory approvals and the environment, and Thunder Horse in the Gulf of Mexico, which is expected to be two-and-a-half years late, because of technical problems, notably faulty valves, which almost led to the capsize of the de-manned floating platform when hit by Hurricane Dennis in 2005.

The biggest gross oil-production capacity additions between 2006 and 2010 will occur in the Middle East, totalling about 4.2 mb/d. Saudi Arabia accounts for most of this. Three major projects are currently under way there, which together will add approximately 2 mb/d of capacity. The Haradh development

Figure 12.13: **Gross Oil Capacity Additions from New Sanctioned and Planned Projects by Region**



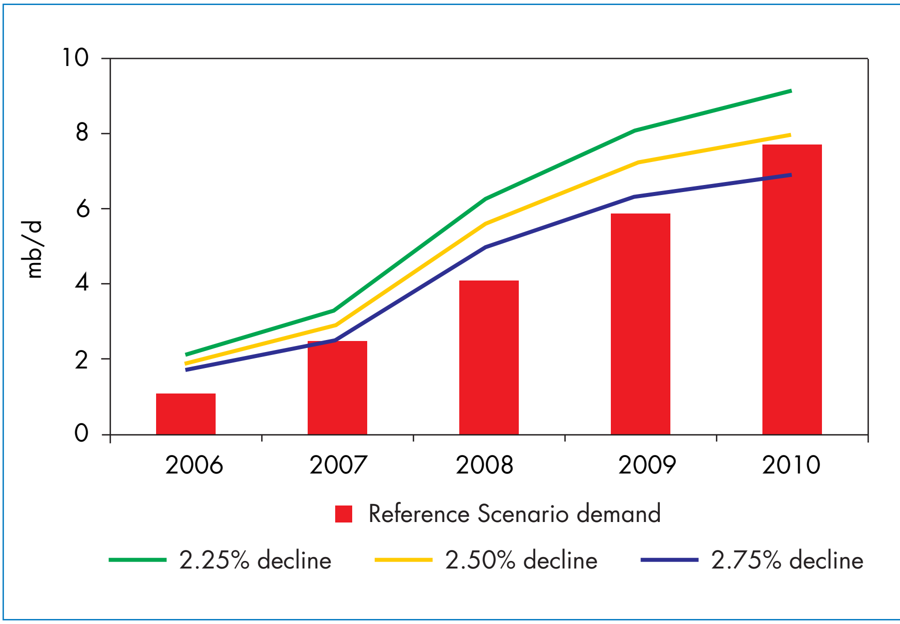
Source: IEA upstream project database.

was commissioned at the beginning of 2006, adding 300 kb/d. The de-mothballing of the light crude Khursaniyah field and the nearby Fahdili and Abu Hadriya fields are expected to be completed in 2007 and the expansion of the extra light crude Shaybah field is due on stream in 2008. The largest increment, of 1.2 mb/d, will come from the Khurais field – one of five onshore fields mothballed by Saudi Aramco in the early 1990s. Khurais, a satellite of Ghawar, will be developed in parallel with the offshore heavy crude Manifa field. Outside the Middle East, the largest increment in gross capacity will occur in Azerbaijan, where 1.2 mb/d will be added over the next four years to feed the recently opened Baku-Tbilisi-Ceyhan pipeline. Gross capacity additions in the three OECD regions will be small and will be significantly impacted by declines in production at existing fields, resulting in a low net capacity increase. A drop in crude oil capacity will be compensated by a rise in NGL and non-conventional capacity (in Canada).

While both our project-based projections and oil companies' production forecasts are of similar magnitude, they are not exhaustive and account for only a proportion of all the projects that will be implemented worldwide. To arrive at a world figure, we have analysed both data sets, to cross-check, calibrate and scale up our estimate of production-capacity additions by 2010. Using the share of the 40 companies surveyed in the upstream projects and their relative share of world oil production, an estimated world gross capacity addition of 21 mb/d was derived. This figure includes an extrapolation of capacity additions for the projects not involving the 40 companies surveyed. Assuming an average slippage rate of 10% compared with current estimated project completion times, which may be conservative in the current market environment, gross adjusted additions are over 2 mb/d lower, at under 19 mb/d.

These planned gross additions will be offset by declines in production from existing fields as reserves are depleted – even with continuous large-scale investments in those fields. Based on a global observed decline rate of 2.5% per year, the reduction in capacity at existing fields amounts to 10 mb/d between 2005 and 2010. The *net* increase in production capacity is, therefore, estimated at around 9 mb/d. The projected increase in oil demand in the Reference Scenario is 7.7 mb/d. So, if these projections prove accurate, spare crude oil production capacity, currently estimated at about 2 mb/d, would increase by 1.3 mb/d to 3.3 mb/d in the Reference Scenario. This increase might help to ease the tightness of crude oil markets over the next few years. However, an increase of just one-quarter of a per cent in the decline rate of existing fields would offset almost all of this additional spare capacity (Figure 12.14). A higher slippage rate than assumed here would also reduce the increase in spare capacity. In the Alternative Policy Scenario, world oil demand is projected to grow by 5.6 mb/d by 2010, which would have the effect of increasing spare capacity by 3.3 mb/d to 5.4 mb/d.

Figure 12.14: **Cumulative Additions to Global Oil Demand and Net Oil Production Capacity Based on Observed Rates of Decline of Existing Production**



Source: IEA database and analysis.

The spare capacity estimate of 3.3 mb/d to 5.4 mb/d is lower than the 4.9 mb/d to 6.8 mb/d range for 2010 published in the IEA's *Mid-Term Oil Market Report (MTOMR)* of July 2006. Differences in the approaches in this *Outlook* and the *MTOMR* result in these slightly different outcomes. While both methodologies produce similar results for firmly committed crude oil projects, the *MTOMR* accounts for exploration activity through 2010, to factor in any as yet unidentified projects. It allows for this by looking at reserves to production (RP) ratios in individual countries, adding small increments to countries where RP levels move to unusually high levels, while subtracting capacity where production profiles (based on firm projects) look unsustainable. On the other hand, this *Outlook* assumes that tightness in the oil-services sector and equipment and labour markets will prove a further constraint to existing or new projects in the period to 2010.

OPEC NGLs have also been modelled differently. The *MTOMR* looks closely at the firmly-committed liquids-extraction plans for OPEC countries alongside the gas-output projections in *WEO-2005*. Production of natural gas, and therefore NGLs, in *WEO-2006* has been revised downwards, reflecting slower growth in global gas demand and the difficult investment and political climate in key countries. The next update of the *MTOMR* will assess whether, considering the current underutilisation of liquids in the gas stream, these changes to the gas flows will affect NGL extraction.

Gas production capacity is expected to rise even more rapidly than oil capacity, with just over 710 billion cubic metres per year of gas capacity due to be added worldwide in the five years to 2010.[7] This figure should be considered a gross increase as it includes company plans for both the addition of production from new projects and increases from existing fields. Subtracting the estimated natural decline in production yields a net increase in capacity of 380 bcm/year. Our upstream project analysis suggests that at least 230 bcm/year of this increase will come from new fields currently under development (Table 12.2). Global gas demand is projected to increase by just over 400 bcm in the Reference Scenario between 2005 and 2010. This might suggest a tightening of gas markets to 2010. However, gas markets remain highly regionalised, so a global estimate gives little indication of the gas supply/demand balance in the main consuming markets. In addition, it is difficult to predict how much associated gas will be marketed, rather than reinjected or flared. In most OECD countries, indigenous production is close to plateau or already in decline, so that they will need to rely increasingly on imports to meet their gas needs (see Chapter 4 and IEA, 2006b).

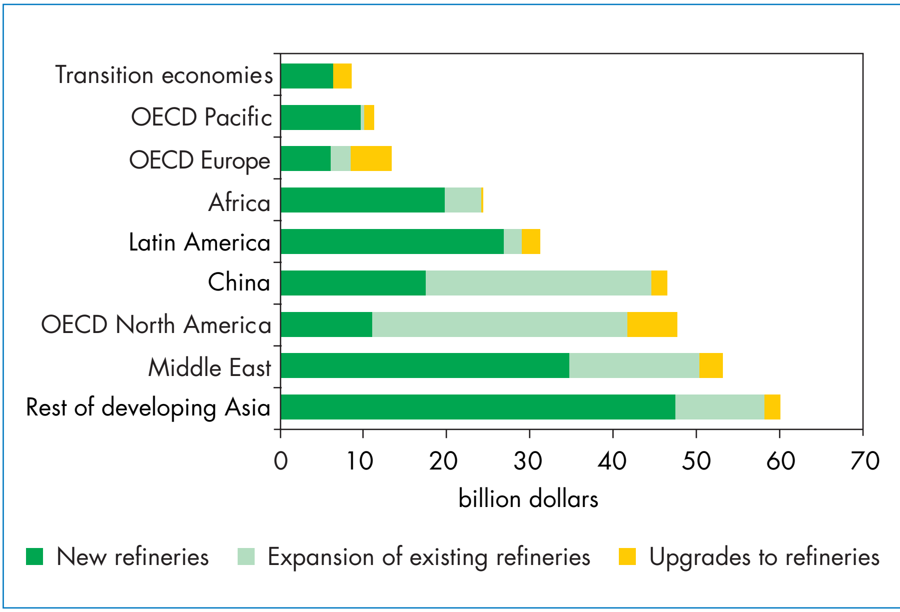
Oil Refining

Total refining industry investment has risen strongly since the start of the current decade. Capital spending reached an estimated $51 billion in 2005 – up from $34 billion in 2000. Industry spending plans point to continuing, but slightly more modest increases in the next five years, reaching $62 billion in 2010. On average, spending will be $60 billion per year in 2006-2010, compared with $43 billion in 2001-2005. Just over 60%, or $180 billion, of the total investment of $298 billion during the five years to 2010 will be in new greenfield refineries, with the rest going to expansion projects ($95 billion) and upgrading only ($24 billion) at existing refineries (Figure 12.15).

The bulk of investment in both new and existing refineries will go to secondary processing units to improve the quality of finished products and increase the yield of light products and middle distillates. This will enable refiners to meet changes in the pattern of demand towards lighter products and to meet tighter product specifications, including lower maximum permitted sulphur content. Most new distillation capacity will be at greenfield refineries being built mainly

7. World gas production extrapolated from surveyed companies' gas production growth plans based on their share of world gas production.

Figure 12.15: **World Oil Refinery Investment by Type, 2006-2010**



Source: IEA database and analysis.

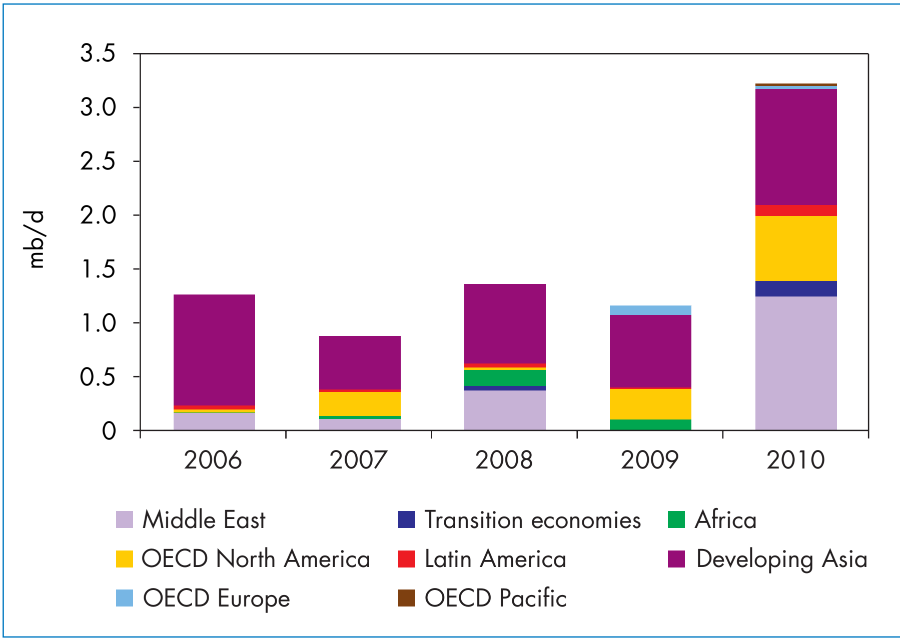
in developing countries. The Middle East and developing Asia will account for the lion's share of global investment in refining in 2006-2010.

We estimate that sanctioned and planned projects will add 7.8 mb/d of new distillation and upgrading capacity by 2010. The additions come on stream particularly at the end of the period and just after; a further 2.5 mb/d will be added in 2011 bringing the total distillation increase to 10.3 mb/d (IEA, 2006a). The biggest increases in capacity are planned for developing Asia – mainly China and India – and the Middle East (Figure 12.16). Virtually no new capacity will be added in OECD Europe or OECD Pacific, while there will be only a relatively modest increase in OECD North America.

Liquefied Natural Gas Facilities

There will be an unprecedented increase in capital spending on new LNG projects in the five years to 2010 and the biggest increase in capacity ever. A massive 167 million tonnes (226 bcm) per year of new liquefaction capacity is under construction or is planned to come on stream by 2010, involving about $73 billion of investment If all these projects come to fruition, capacity would almost double to 345 Mt/year. A further 60 million tonnes (82 bcm) of

Figure 12.16: **World Oil Refinery Capacity Additions by Region, 2006-2010**



Sources: IEA database and analysis; information obtained from Purvin and Gertz.

capacity, costing an additional $26 billion, is proposed to come on stream by 2010 (Table 12.3). New LNG tankers on order exceed $32 billion. Regasification plants will require another $31 billion and are expected to add 328 bcm per year regasification capacity by 2010.

Close to half of the sanctioned and planned projects to increase liquefaction capacity in 2006-2010 will occur in the Middle East and North Africa. Qatar, already the world's largest LNG producer and exporter after Indonesia, will add more capacity than any other country, tripling capacity to 77 Mt/year by 2010. Australia and Nigeria are also planning to substantially increase their existing capacity. Angola, Equatorial Guinea, Norway and Yemen are expected to join the ranks of the LNG-exporting countries by the end of the decade. Iran, Peru, Russia and Venezuela have proposed LNG projects, but they are less likely to be completed before 2010.

The bulk of the planned increase in LNG production is destined for markets in Europe and North America. In the United States, fifteen regasification terminals had received planning approval from the Federal Energy Regulatory Commission as of 30 August 2006 and a further two terminals had been

Table 12.3: **Natural Gas Liquefaction Plants to be Commissioned by 2010**

Country	Operator	Project name	Status	Online	Capacity (Mt/year)	Cost ($ million)
Algeria	Repsol & Gas Natural	Gassi Touil Arzew	Engineering	2009	4.0	2 100
Algeria	Sonatrach	Skikda Replacement	Engineering	2010	5.9	800
Angola	Sonangol, Chevron	Soyo	Engineering	2010	5.1	5 000
Australia	NW Shelf LNG	Karratha T5 NWS	Construction	2008	4.3	1 100
Australia	Chevron	Gorgon	Engineering	2009	10.1	1 100
Australia	Pluto LNG	Karratha	Proposed	2010	6.0	1 200
Australia	Woodside	Greater Sunrise	Proposed	2010	5.4	2 800
Australia	Inpex	Ichthys	Proposed	2010	4.0	1 200
Brunei	Brunei LNG (Shell)	Lumut (Brunei LNG)	Planned	2009	4.0	1 000
Egypt	ELNG	Idku T3 ELNG	Planned	2008	3.7	750
Equatorial Guinea	Marathon & GE Petrol	Bioko Island	Construction	2007	3.5	1 700
Indonesia	BP	Tangguh	Construction	2008	8.1	1 000
Indonesia	BP & Pertamina	Donggi	Planned	2009	7.1	1 000
Iran	NIGEC, Total	Assalayeh Pars LNG	Proposed	2009	8.9	2 000
Iran	NIGEC, Repsol Shell	Assalayeh Persian LNG	Proposed	2010	10.7	2 500
Nigeria	NNPC, ENI & Conoco	Brass River	Engineering	2009	10.1	2 000
Nigeria	NLNG (Shell, Agip & Elf)	Bonny Train 7	Engineering	2010	8.0	4 000
Nigeria	ExxonMobil, Chevron & ConocoPhillips	West Niger Delta	Planned	2010	20.0	4 000
Norway	Statoil	Snohvit	Construction	2007	5.5	2 700
Peru	Total, Repsol, BG & Sempra	Pacific LNG	Proposed	2009	5.9	5 000
Peru	Hunt Oil & SK	Pampa Melchorita LNG	Proposed	2010	4.0	2 000

Table 12.3: **Natural Gas Liquefaction Plants to be Commissioned by 2010** *(Continued)*

Country	Operator	Project name	Status	Online	Capacity (Mt/year)	Cost ($ million)
Qatar	Qatargas II (QPC, ExxonMobil & Total)	Ras Laffan (T1 & T2)	Construction	2008	15.6	7 600
Qatar	RasGas (QPC & ExxonMobil)	Ras Laffan (T5)	Construction	2008	4.8	2 000
Qatar	Qatargas III (QPC & ConocoPhillips)	Ras Laffan (T3)	Engineering	2009	7.5	6 500
Qatar	Qatargas IV (QPC & Shell)	Ras Laffan (T4)	Engineering	2010	7.9	7 000
Qatar	RasGas (QPC & ExxonMobil)	Ras Laffan (T6 & T7)	Construction	2010	15.8	7 000
Russia	Shell Mitsubishi Mitsui	Sakhalin II	Construction	2008	9.6	12 000
Russia	Tambei LNG	Yamal	Proposed	2010	3.5	1500
Trinidad & Tobago	Atlantic LNG	Pomit Fortin (T5 &T6)	Proposed	2010	6.0	5 000
Venezuela	PDVSA Shell	Mariscal Sucre LNG	Proposed	2010	4.8	2 700
Yemen	Yemen LNG	Bal Haf Yemen LNG	Construction	2009	6.2	3 000
Planned, engineering and construction					**166.8**	**73 350**
Proposed					**59.2**	**25 900**
World					**226.0**	**99 250**

Note: Proposed projects could slip beyond 2010 but are included here for the sake of completeness.
Source: IEA database and analysis.

approved by the US Maritime Administration.[8] However, construction work has begun on only five of them. Another three projects have been approved in Canada and three in Mexico. Terminals now being built will add about 65 bcm/year of capacity by 2010 to the 60 bcm/year of capacity at the five existing terminals, all of which are located in the United States (IEA, 2006b). If all the approved projects go ahead, capacity could exceed 200 bcm/year. In Europe, 16 new terminals are under construction or planned at a total cost of $10 billion. Capacity is expected to increase by 110 bcm per year by 2010.

Investment in the LNG chain has been stimulated by high gas prices in the main consuming regions, dwindling indigenous production and rising demand. Despite the very large amounts of capital needed for each project, the interval between LNG project approval and completion has generally been short compared to pipeline projects of comparable size, which generally take a decade. In part, this is explained by the fact that most projects have been led by international oil companies with access to ample finance, strong credit ratings and extensive experience of managing large-scale energy projects. Falling costs relative to pipelines have boosted interest in new LNG projects. However, rising engineering, procurement and contracting costs – caused in part by the recent surge in demand for related services and materials – are already leading to delays in sanctioning and completing some projects, and to decisions not to proceed with others. Nonetheless, even with escalating costs, the number of proposed LNG projects continues to grow more rapidly than the number of long-distance pipeline projects.

Gas-to-Liquids Plants

A small but growing proportion of total oil and gas industry investment is going to gas-to-liquids plants, which convert natural gas into high-quality oil products. There are three existing GTL plants in operation: Shell's 15-kb/d plant in Bintulu Malaysia, PetroSA's 25-kb/d plant in Mossel, South Africa and the joint venture 34-kb/d Oryx plant built by Qatar Petroleum (QP), Chevron and Sasol in Qatar, which was commissioned in early 2006. Another 34-kb/d plant is being built by Chevron and the Nigerian National Petroleum Corporation at Escarvos in Nigeria. Two further GTL plants are at an advanced planning stage: the Shell/QP Pearl plant in Qatar, with a final capacity of 140 kb/d, and Sonatrach's 36-kb/d plant at Tinhert in Algeria. Other GTL plants planned for Qatar are on hold pending a review of the optimal extraction policy for the giant North Field. The GTL projects currently under

8. Information on the status of North American LNG projects is available from the FERC website (www.ferc.gov).

construction or just recently completed involve investment of $24 billion and promise to add 280 kb/d by 2010. This makes GTL the most capital-intensive of all the oil production projects, at almost $84 000 per barrel of capacity.

Oil Sands and Extra-Heavy Oil

Of the 120 largest upstream projects under development or planned for completion between 2006 and 2010, ten involve the development of non-conventional oil reserves. Eight are based on oil sands in Canada and two on extra-heavy oil in Venezuela. In Canada, oil is extracted by opencast mining of bitumen when the oil sands are close to surface and by *in-situ* recovery using steam injection and production wells when the oil sands are too deep to mine. Combined investment amounts to $35 billion and will add just over 1 mb/d of oil production capacity by 2010. There are a further 17 projects under consideration, with the potential to add another 2 mb/d by 2015 at an estimated cost of $44 billion. The investment required for oil-sands mining operations amounts to some $45 000 to $60 000 per barrel, while *in-situ* projects cost roughly half that (see Chapter 3). Several projects in Canada may be delayed because of a lack of manpower and of road and rail infrastructure to provide access to the remote oil-sand deposits. The plans of some operators include air strips to fly workers to and from the mines. The refining industry in the two countries is estimated to be investing a total of $200 million in 50 separate upgrading projects to process the additional volumes of extra-heavy crude oil and bitumen feedstock that will flow from the new upstream projects.

Investment Beyond the Current Decade

Unlike our longer-term analysis of the production and investment outlook presented in Chapter 3 (oil) and Chapter 4 (gas), the analysis of near-term investment prospects set out in this chapter has been limited to the period to 2010 (for reasons described in Box 12.1). However, this analysis has provided us with several observations about investment challenges in the next decade, which we present below for completeness.

In summary, our near-term analysis points to a significant increase in investment through to 2010, though a significant part of this is the result of cost inflation across the industry. Companies based in the OECD countries are expected to continue to provide the bulk of capital spending, with most of it going to countries outside both the OECD and OPEC. We estimate that, unless project-slippage rates or production-decline rates worsen significantly, global crude oil production capacity is likely to outstrip the growth in oil demand in the Reference Scenario as well as in the Alternative Policy Scenario. However, any spare production capacity the industry builds up in the next five years could be quickly offset if real capital spending is not raised further into the next decade and beyond.

The prospects for investment and production-capacity additions beyond the present decade are more challenging and will require further increases in investment. Increased exploration investment is required to appraise reserves for the next wave of development projects. The future projects in the "golden triangle" of deep-water basins, encompassing the Gulf of Mexico, Nigeria and Angola, are likely to be more numerous but smaller. Such fields will have higher development costs per barrel, requiring higher investment than current large projects, which benefit from economies of scale. Existing drilling rigs and 90 others under construction are expected to be kept busy well into the next decade, as exploration activity and the number of development projects increase.

On the other hand, there are a number of new large unexplored basins, notably in the Russian Arctic, deep-water Caspian and offshore Greenland, that could yield significant new discoveries and underpin a new wave of large-scale developments. The harsh climate and the lack of existing infrastructure will mean higher capital investment and, assuming successful exploration and appraisal, production of oil or gas in these areas is unlikely to start much before 2020, given their remoteness.

In the Middle East, Iraq is under-explored, but security would have to improve greatly to permit the large-scale involvement of international companies. Even when the safety of company personnel can be assured, investment is likely to be focused initially on the re-development of existing fields, rather than exploration and the development of new fields. The international oil and gas companies are uniquely equipped to undertake complex, large-scale projects, thanks to their project-management skills, their access to advanced technology and their financial resources. But opportunities for them to invest remain limited because of government policy, civil conflict or geopolitical risks – especially in the Middle East, Russia, Africa and South America. The willingness and ability of national oil companies to develop reserves are in many cases very uncertain.[9]

Combating production decline at existing fields remains a top priority for the industry. Production from some of the super-giant oilfields that have been in production for decades, including Ghawar, the world's largest field, will plateau within the next decade or so. Increasingly large investments in enhanced oil recovery will be needed here, as elsewhere in mature basins, raising production costs. Fields developed more recently using advanced technology to maximise output and recovery are expected to remain at plateau for shorter periods and then decline more rapidly than earlier fields.

9. See Chapter 3 for a discussion of the main uncertainties surrounding oil investment in the longer term, including the Deferred Investment Case in OPEC countries.

PROSPECTS FOR NUCLEAR POWER

HIGHLIGHTS

- Concerns over energy security, surging fossil-fuel prices and rising CO_2 emissions have revived discussions about the role of nuclear power. Nuclear power is a proven technology for large-scale baseload electricity generation that can reduce dependence on imported gas and CO_2 emissions.
- In the Reference Scenario, world nuclear power generating capacity increases from 368 GW in 2005 to 416 GW in 2030. In the Alternative Policy Scenario, greater use of nuclear power contributes significantly to lowering emissions. Additional investment in nuclear power raises nuclear power generating capacity to 519 GW by 2030 in this scenario.
- New nuclear power plants can produce electricity at a cost of between 4.9 and 5.7 cents per kWh, if construction and operating risks are mitigated. Nuclear power is cheaper than gas-based electricity if gas prices are above $4.70 to $5.70 per MBtu. It is more expensive than conventional coal, unless coal prices are above $70 per tonne or nuclear investment costs are less than $2 000 per kW. Nuclear would be more competitive if a financial penalty on CO_2 emissions were introduced.
- Nuclear power generating costs are less vulnerable to fuel-price changes than coal- or gas-fired generation. Moreover, uranium resources are abundant and widely distributed around the globe. These two advantages make nuclear power a valuable option for enhancing security of electricity supply.
- Nuclear power plants are capital-intensive, requiring initial investment between $2 billion and $3.5 billion per reactor. For the private sector to invest in such projects, governments may need to reduce the investment risk.
- Economics is not the only factor determining the construction of new nuclear power plants. Safety, nuclear waste disposal and the risk of proliferation are real challenges which have to be solved to the satisfaction of the public, or they will hinder the development of new nuclear power plants.
- Uranium resources are not expected to constrain the development of new nuclear power capacity. Proven resources are sufficient to meet world requirements well beyond 2030, even in the Alternative Policy Scenario. Investment in uranium mining capacity and nuclear fuel manufacture production capacity must, however, increase sharply to meet projected needs.

Current Status of Nuclear Power

Renewed Interest in Nuclear Power

Concerns over energy security, surging fossil-fuel prices and rising CO_2 emissions have revived discussion about the role of nuclear power. Over the past two years, several governments have made statements favouring an increased role of nuclear power in the future energy mix and a few have taken concrete steps towards the construction of a new generation of safe and cost-effective reactors.

Not all countries see nuclear power as an attractive option, considering that the risks associated with the use of nuclear power – reactor safety, waste and proliferation – outweigh the benefits. For those countries open to the nuclear-power option, this chapter looks at the possible place of nuclear power in the total generation mix to 2030 and beyond, focusing particularly on the adequacy of uranium resources and the competitiveness of nuclear power in electricity markets.

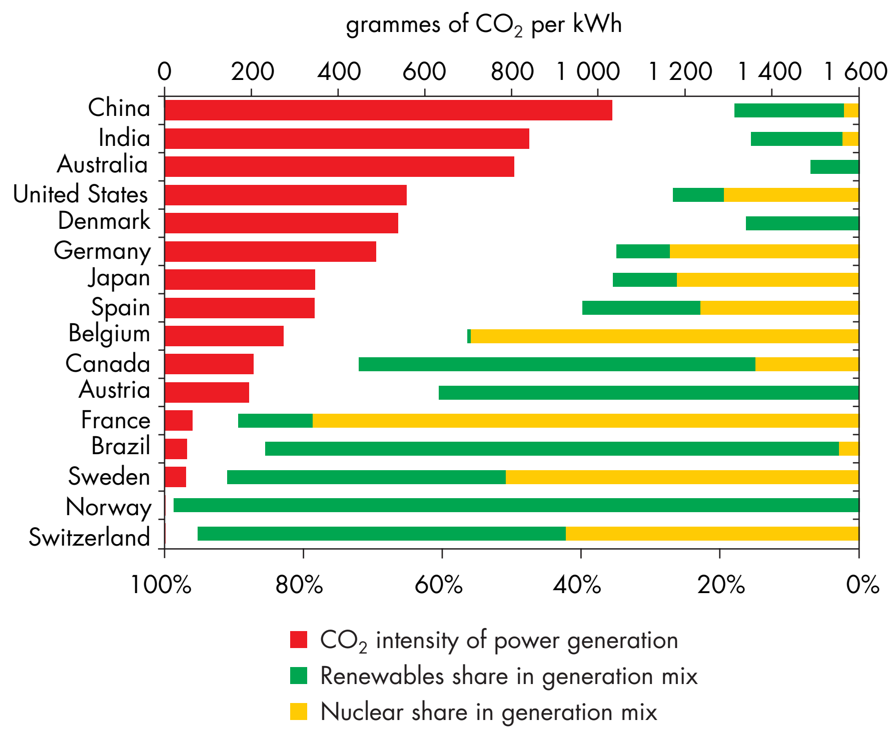
Along with energy efficiency, both on the demand and supply sides, renewable energy and – in the longer term – CO_2 capture and storage, nuclear power could help address concerns about over-reliance on fossil-fuelled electricity generation, especially worries about climate change and increasing dependence on gas imports:

- Nuclear power is a low-carbon source of electricity. Figure 13.1 shows the low CO_2 emissions per kWh of electricity produced in those countries with a high share of nuclear power and renewables in their electricity generation mix. Operation of one gigawatt of nuclear power generating capacity, if replacing coal-fired generation, avoids the emission of 5 to 6 million tonnes of CO_2 per year. Nuclear power plants do not emit any airborne pollutants such as sulphur dioxide, nitrogen oxides or particulate matter.
- Nuclear power plants can help reduce dependence on imported gas; and unlike gas, uranium resources are widely distributed around the world. The Reference Scenario shows that, under current policies, gas-import dependence will rise in most OECD regions and in key developing countries by 2030, an increase driven mainly by the power sector.
- Nuclear plants produce electricity at relatively stable costs, because the cost of the fuel represents a small part of the total production cost; the raw uranium accounts for about 5% and uranium fuel after treatment for about 15%. In gas-fired power plants, fuel accounts for about 75% of the total production cost.

Over the past few years, oil, gas and power prices have been high and volatile. The price of West Texas Intermediate crude oil in the United States hit $78 per barrel in July 2006. International gas prices averaged $6.13 per MBtu in 2005. The increase in power prices in most markets arose primarily from these high fuel prices. As described later in the chapter, new nuclear power plants can produce electricity at 4.9 to 5.7 cents per kWh. They can compete with gas-fired generation when gas costs more than $4.70 to $5.70 per MBtu (in the case, respectively, of a low and high capital cost estimate for the nuclear plant), corresponding to a crude oil price in the range of approximately $40 to $45 per barrel.[1]

A price of about $10 per tonne of CO_2 emitted makes nuclear competitive with coal-fired power stations, even under the higher construction cost assumption. Actual prices for carbon permits may turn out to be higher. The average CO_2 price seen in the European Union Emissions Trading Scheme in 2005 was €18.3 (about $23) per tonne.

Figure 13.1: **Power Sector CO_2 Emissions per kWh and Shares of Nuclear Power and Renewables in Selected Countries, 2004**



1. Gas prices are generally linked to oil prices. See also Box 11.1 in Chapter 11.

Nuclear Power Today

Nuclear power plants supplied 15% of the world's electricity in 2005, producing 2 742 TWh. A total of 31 countries around the world operated 443 nuclear reactors, with an installed capacity of 368 GW in 2005.[2] Four new reactors were connected to the grid in 2005 and one reactor in Canada, which had been refurbished after being shut down, was re-started. Two reactors were shut down: one in Germany and another in Sweden.

Most nuclear power plants are located in OECD countries, accounting for 84% of world total nuclear output and 308 GW of installed capacity (Table 13.1). Three OECD countries, the United States, France and Japan, operate over two-thirds of total OECD nuclear generating capacity and 57% of world nuclear capacity. The transition economies had 40 GW of installed capacity in 2005 and developing countries 19 GW.

Of the 31 countries in the world operating commercial nuclear power plants today, 17 are members of the OECD, seven are economies in transition and seven are in the developing world. Nuclear power is the largest source of electricity in eight countries: Lithuania, France, the Slovak Republic, Belgium, Sweden, Ukraine, Slovenia and Armenia. In four countries – Lithuania, France, the Slovak Republic and Belgium – more than half of all the electricity generated is nuclear. However, Lithuania and the Slovak Republic have agreements with the European Union to shut down nuclear plants.[3] Belgium plans to phase out nuclear power.

Worldwide, there were 86 companies operating nuclear power plants in 2005. In the OECD, they are mostly privately owned. Depending on the country, there may be one or more operators. In France, EDF – the world's largest nuclear operator – owns and operates 58 out of a total of 59 reactors (Table 13.2). The United States has the largest number of operators, 26 in total, despite significant industry consolidation in recent years. Operators are state-controlled in the transition economies and the developing countries. In most of these countries there is only one operator.

2. The reactor data used in this chapter are from the IAEA's Power Reactor Information System (PRIS) database.

3. The agreement concerns two out of six reactors in the Slovak Republic. In Lithuania, one reactor was shut down in 2004 as a result of this agreement, with the second unit expected to be shut down by 2009.

Table 13.1: **Key Nuclear Statistics, 2005**

Country	Number of reactors	Installed capacity (GW)	Gross nuclear electricity generation (TWh)	Share of nuclear power in total generation (%)	Number of nuclear operators
OECD	**351**	**308.4**	**2 333**	**22.4**	**68**
Belgium	7	5.8	48	55.2	1
Canada	18	12.6	92	14.6	4
Czech Republic	6	3.5	25	29.9	1
Finland	4	2.7	23	33.0	2
France	59	63.1	452	78.5	1
Germany	17	20.3	163	26.3	4
Hungary	4	1.8	14	38.7	1
Japan	56	47.8	293	27.7	10
Republic of Korea	20	16.8	147	37.4	1
Mexico	2	1.3	11	4.6	1
Netherlands	1	0.5	4	4.0	1
Slovak Republic	6	2.4	18	57.5	2
Spain	9	7.6	58	19.5	5
Sweden	10	8.9	72	45.4	3
Switzerland	5	3.2	23	39.1	4
United Kingdom	23	11.9	82	20.4	2
United States	104	98.3	809	18.9	26
Transition economies	**54**	**40.5**	**274**	**17.0**	**7**
Armenia	1	0.4	3	42.7	1
Bulgaria	4	2.7	17	39.2	1
Lithuania	1	1.2	10	68.2	1
Romania	1	0.7	5	8.6	1
Russia	31	21.7	149	15.7	1
Slovenia	1	0.7	6	39.6	1
Ukraine	15	13.1	84	45.1	1
Developing countries	**38**	**19.0**	**135**	**2.1**	**11**
Argentina	2	0.9	6	6.3	1
Brazil	2	1.9	10	2.2	1
China	9	6.0	50	2.0	5
India	15	3.0	16	2.2	1
Pakistan	2	0.4	2	2.8	1
South Africa	2	1.8	12	5.0	1
Chinese Taipei	6	4.9	38	16.9	1
World	**443**	**367.8**	**2 742**	**14.9**	**86**

Sources: IAEA PRIS and IEA databases.

Table 13.2: **The Ten Largest Nuclear Operators in the World, 2005**

Company	Country	Installed capacity (GW)	Share of nuclear in total company capacity
Electricité de France (EDF)*	France	65.8	50%
Rosenergoatom	Russia	21.7	100%
Exelon	United States	17.4	33%
Korea Hydro & Nuclear Power (KHNP)	Republic of Korea	16.8	97%
Tokyo Electric Power Co. (TEPCO)	Japan	16.8	28%
NNEGC Energoatom	Ukraine	13.1	100%
E.ON**	Germany	11.1	21%
British Energy	United Kingdom	9.6	83%
Kansai Electric Power Co. (KEPCO)	Japan	9.3	25%
Entergy	United States	9.1	31%

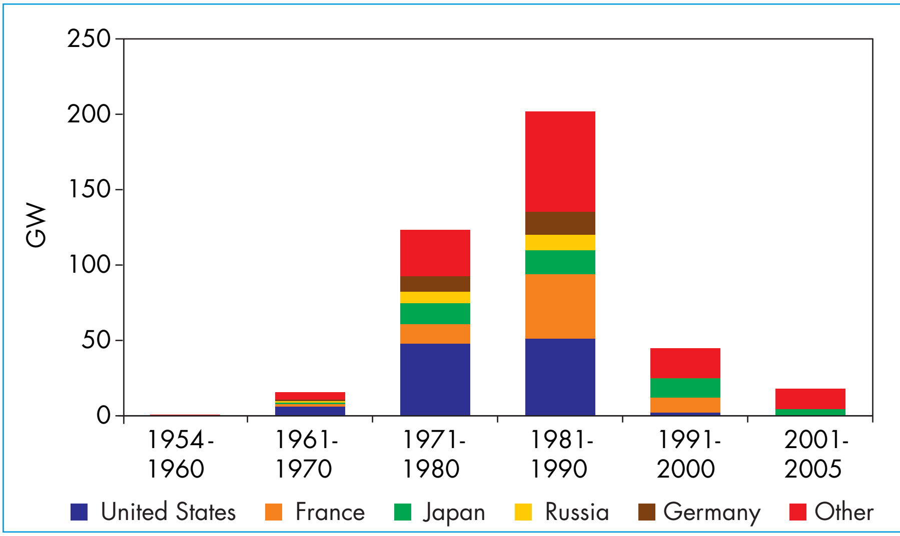
* Figures based on total capacity in France and other countries.
** Figures include partial ownership of reactors in Sweden (2.6 GW).
Source: Company data.

Historical Development

The development of commercial nuclear power plants started over half a century ago. Construction of nuclear power plants accelerated after the first oil shock and reached its historical peak in the 1980s (Figure 13.2). About 80% of the current nuclear capacity in the world was built in just two decades, before electricity market deregulation was launched. After the Three Mile Island accident in 1979 in the United States, there were significant delays in the construction of the nuclear power plants that were being built at the time of the accident. There were no nuclear plant orders in the United States after that date and many plans to build new reactors there were cancelled. Following the Chernobyl accident in 1986, several countries imposed restrictions on existing and/or new nuclear power plants.

The liberalisation of gas and electricity markets in the OECD during the 1990s, when natural gas prices were low and were expected to remain low, and before carbon-dioxide emissions became a major policy issue, made investment in new nuclear power plants less competitive than investment in the alternatives, particularly gas-fired combined-cycle gas turbines (CCGTs). Moreover, many countries had excess capacity in that period as a result of overbuild in the previous decade. The economic collapse of the transition

Figure 13.2: **Historical World Nuclear Capacity Additions**



Note: Includes reactors that have been shut down (about 36 GW in total).
Source: IEA analysis based on data from IAEA PRIS database.

economies resulted in a slower than anticipated development of nuclear power. Many of these countries had several projects under construction or had been planning significant capacity increases at the time. Most of those projects were cancelled or suspended.

Globally, nuclear capacity additions in the 1990s were less than a quarter of the additions of a decade earlier. But, despite the limiting factors, OECD countries have added about three times more capacity than non-OECD since 1990. This increase was led by Japan, France and the Republic of Korea.

The share of nuclear power in world electricity generation reached its highest point in 1996, at 18% (Figure 13.3) falling to 15% by 2005. The global decrease can be explained by a small decline in the OECD as well as by the increasing weight in global electricity generation of developing countries, where the share of nuclear power was around 2.5% during that period.

Nuclear electricity generation increased by 36% between 1990 and 2005. This increase reflects greater installed capacity and increases in the availability and capacity factors of nuclear power plants. Nuclear capacity increased by about 14% both because of the addition of new plants and plant uprates. Improved performance was a more important influence with improved capacity factors making an important contribution to competitiveness in many cases (Figure 13.4).

Figure 13.3: **Shares of Nuclear Power in Electricity Generation by Region**

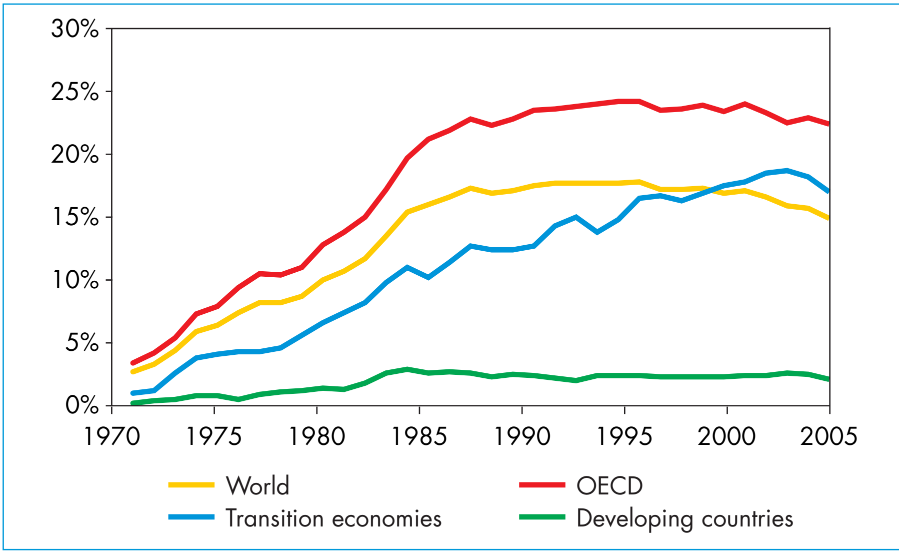
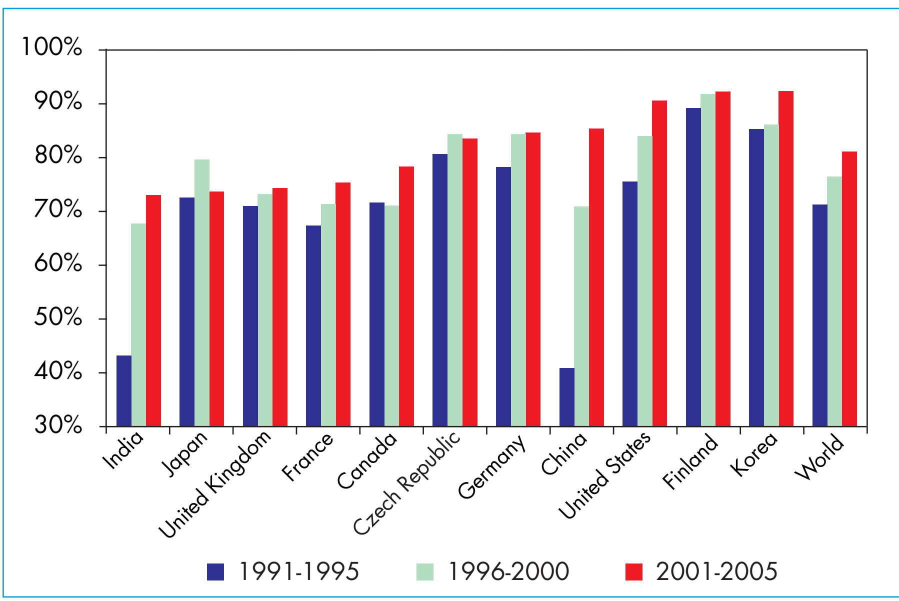


Figure 13.4: **Increases in Average Nuclear Capacity Factors, 1991-2005**



Sources: IAEA PRIS database (capacity data) and IEA (electricity generation data).

Major changes to the way nuclear reactors around the world are operated had stemmed from the Chernobyl accident in 1986. The World Association of Nuclear Operators (WANO) was created and the International Atomic Energy

Agency (IAEA) created the International Nuclear Safety Advisory Group, both of which helped to spread best practice, to tighten safety standards and to infuse a safety culture in nuclear power plants around the world. Regular meetings of the IAEA–OECD/NEA Incident Reporting System, where recent incidents are discussed and analysed in detail, are part of this global exchange process. Countries have been brought together through the Convention on Nuclear Safety to report on how they are living up to their safety obligations and to critique each other's reports. Safety indicators, such as those published by the WANO, improved dramatically in the 1990s. However, in some areas improvement has stalled in recent years and the gap between the best and worst performers is still large, providing substantial room for continuing improvement.

Policy Overview

Nuclear Power Generation

The most significant policy developments towards a resurgence of investment in new nuclear power plants have occurred in the United States (Table 13.3). The Nuclear Power 2010 programme, launched in 2002, aims at streamlining the regulatory process for building and operating new nuclear power plants through the Early Site Permit (ESP) and the combined Construction and

Table 13.3: **Timeline Leading to the Construction of New Nuclear Reactors in the United States**

Date	Outcome
2002	Launch of Nuclear Power 2010 programme.
2003	The Department of Energy (DOE) invites proposals to demonstrate COL and receives two ESP applications.
2004	DOE receives third ESP application. Issues guidelines for COL application.
2005	EPACT 2005 passed in summer.
2006	By mid-2006, ten firms had announced their intention to submit a COL. Further specification of EPACT 2005 provisions.
2007-2008	Expected time for the submission of COL to the Nuclear Regulatory Commission (NRC).
After 2007-2008	Final decision to proceed with construction.
2014-2020	Expected commissioning of the first 6 GW, most likely on existing sites.

Source: Based on information from the US Department of Energy.

Operating Licence (COL). The Energy Policy Act (EPACT) of 2005 includes additional incentives for new nuclear power plants: the extension for a period of 20 years of the Price-Anderson Act, which limits liability to third parties to about $10 billion; a production tax credit of 1.8 cents per kWh for up to 6 000 MW of generating capacity from new nuclear power plants for a period of eight years; standby support in the event of certain nuclear plant delays; and loan guarantees for up to 80% of the total cost of the project.

Finland is the only country in OECD Europe and one of the three OECD countries (with Japan and the Republic of Korea) having a nuclear power plant under construction as of September 2006.[4] Construction of a European Pressurised Reactor (EPR) started in Finland in August 2005. The reactor will be the third at the Olkiluoto site of the power company TVO. The process that led to a decision to build a reactor started in 1999 (Table 13.4).

Table 13.4: **Timeline Leading to the Construction of a New Nuclear Reactor in Finland**

Date	Outcome
1998-1999	TVO conducts and submits environmental impact assessment report to Ministry of Trade and Industry (MTI).
2000	TVO submits application for decision-in-principle.
2001	Preliminary safety assessment. Statements by the municipalities where the plant is expected to be built. Public hearings.
2002	Favourable decision-in principle by the government. Parliament vote approves the decision.
2003	TVO selects its Olkiluoto site to build a third reactor.
2004	TVO applies for construction licence.
2005	MTI grants licence. First concrete in August.
2010	Expected start-up (planned for end 2009 – project now running 12 months late).

Source: Based on information provided by the Ministry of Trade and Industry, Finland.

In May 2006, France's EDF announced its decision to build an EPR at its Flamanville site, where there are two other reactors in operation. Construction of the reactor is due to start in 2007 and it is expected to be completed by 2012 (Table 13.5).

4. Based on IAEA's definition of "under construction" and included in PRIS database.

Table 13.5: **Timeline Leading to the Construction of a New Nuclear Reactor in France**

Date	Outcome
2003	National debate on energy. White paper on energy published in November.
2004	EDF embarks on planning process towards the construction of an EPR, following debate in Parliament. EDF decides new reactor will be built at its Flamanville site.
2005	Energy policy law passed in July with the objective of keeping open the nuclear option. Launch of public debate on the EPR in October.
2006	Public debate completed in February. EDF announces in May its decision to go ahead with a third reactor at the Flamanville site.
2007	Beginning of construction (first concrete) at the end of the year.
2012	Estimated reactor start-up.

Source: Based on information by the French Ministry of Economy, Finance and Industry (available at www.industrie.gouv.fr).

A number of other countries are addressing the role of nuclear energy but do not have policies in place to promote the construction of new nuclear plants. Some do not have a meaningful licensing process in place. A number of OECD countries have passed laws that phase out nuclear power or ban the construction of new plants (Table 13.6). The phase-out policies of Sweden, Germany and Belgium are subject to continuing debate.

Outside the OECD, Russia, China and India have the most ambitious nuclear power programmes. In Russia, the development of nuclear power has become a government priority. In June 2006, the Russian President formally approved a new Federal Targeted Programme, which calls for an increase of the share of nuclear power in electricity generation from 16% now to 25% by 2030. This target appears ambitious, given the size of the necessary investment.

China has set a target to build 40 GW of nuclear capacity by 2020. Though an earlier target to reach 20 GW in 2010 will not be met, over the past few years, the Chinese government has stepped up efforts to promote the development of nuclear power.

In May 2006, India announced a new target for its nuclear generating capacity to reach 40 GW in 2030. India's record of meeting targets is poor, including the target set in the 1984 Nuclear Power Profile of 10 GW by 2000. Installed capacity in 2000 was only a quarter of the target. The programme seems to have accelerated now, as India has 3.6 GW under construction, as much as the installed capacity in mid-2006.

Table 13.6: **Main Policies Related to Nuclear Power Plants in OECD Countries**

Country	Comments
Countries where government has taken steps to support new build	
Finland	New reactor being built by the private sector.
France	EDF will start building a new reactor in 2007.
Japan	The new national energy strategy (May 2006) indicates a target share for nuclear power of more than 30-40% to 2030 and beyond.
Republic of Korea	Indicative target for nuclear power generating capacity to reach 27 GW in 2017 compared to 17 GW now.
United States	Incentives for new nuclear power plants in EPACT 2005.
Government in favour of new nuclear but no concrete measures	
Canada	Ontario and New Brunswick in support of refurbishing and/or replacing nuclear facilities.
Czech Republic	Government considers that new nuclear plants will be needed by 2030. CEZ – the main power company –to decide on new nuclear power by end 2006.
Slovak Republic	Considering new reactors to replace the negotiated shutdowns.
Turkey	Plans to build 5 GW of nuclear capacity. Details of the plan not known yet.
United Kingdom	Energy review (July 2006) in favour of nuclear power. Government to streamline the regulatory process. White Paper by the end of 2006 to set out policy more explicitly.

Sources: IEA (2001), NEA (2004), IAEA (2005) and national administrations.

Table 13.6: **Main Policies Related to Nuclear Power Plants in OECD Countries** *(continued)*

Country	Comments
Countries with restrictions in nuclear power in the past	
Italy	Shut down nuclear power plants in 1990 and halted ongoing construction following a referendum in 1987. Role of nuclear power is being discussed.
Netherlands	Decision to shut down the Borssele plant in 2003 overturned in 2000. In 2003, government decided to shut it down in 2013, after 40 years of operation. Plant lifetime extended to 60 years in 2006.
Spain	A moratorium in the 1980s led to the cancellation of three plants under construction. In 2006, government set up a "table of dialogue" to discuss the role of nuclear power in Spain.
Switzerland	A 10-year moratorium on nuclear plant construction, decided in 1990, was not renewed.
Poland	Construction of a nuclear power plant suspended in 1990. Recent government statements call for a new nuclear power plant in operation around 2021.
Countries with legal restrictions	
Australia	Restrictions under section 140A of the 1999 Environment Protection and Biodiversity Conservation Act prohibit most nuclear energy facilities.
Austria	Prohibits construction of nuclear plants on Austrian territory since 1978.
Belgium	Act of 31 January 2003 regulates the phase-out of nuclear power.
Denmark	Prohibits construction of nuclear plants since 1999.
Germany	Phase-out of nuclear power (Nuclear Exit Law passed in 2002).
Ireland	Prohibits the use of nuclear energy for the generation of electricity (since 1999).
Sweden	Phase-out of nuclear power (law passed in 1998).

Sources: IEA (2001), NEA (2004), IAEA (2005) and national administrations.

Lithuania and Bulgaria are considering new reactors to replace those shut down according to their respective EU accession agreements. The Slovak Republic is considering the completion of two light-water reactors (VVER) and Romania plans to add another two units at its Cernavoda plant (one unit is in operation now and one under construction). South Africa is pursuing the development of pebble-bed modular reactors and is also considering new nuclear power stations of conventional design. Some countries that do not have any nuclear power now (for example, Egypt, Indonesia, Malaysia, Morocco, Nigeria and Vietnam) have expressed interest in building nuclear power plants.

Nuclear Fuel and Waste Management

All the steps of the nuclear fuel cycle generate radioactive waste. Nuclear waste is classified according to the level of radioactivity into three broad categories: low-level waste (LLW), intermediate-level waste (ILW) and high-level waste (HLW). Most countries operating nuclear power plants have developed or continue to develop strategies to deal with waste. In many countries, disposal facilities are already available for LLW and, in some, for ILW.

More than 95% of the total radioactivity in radioactive wastes is contained in HLW (spent nuclear fuel or the most radioactive residues of reprocessing), even though HLW accounts for less than 5% of the total volume of waste. A typical 1 000-MW nuclear power plant produces 10 m^3 of spent fuel per year, when packaged for disposal. If this spent fuel is reprocessed, about 2.5 m^3 of vitrified waste is produced (IEA, 2001). Today, spent fuel and HLW are stored in special purpose interim storage facilities.

Large-scale reprocessing facilities are currently operational in France, Russia and the United Kingdom. The main Japanese reprocessing plant is still being commissioned, although a small plant is in operation (most Japanese reprocessing to date has taken place in France and the UK). Utilities in a few European countries (including Belgium, Germany, the Netherlands, Sweden and Switzerland) have had a significant amount of spent fuel reprocessed in France and the UK. In most cases these contracts have now ended, following changes in policy in these countries, but the power companies or countries concerned have a contractual obligation to take back the HLW produced for eventual disposal (as well as the separated plutonium and uranium). India has plans for commercial reprocessing as part of a thorium-uranium fuel cycle, but this is at the development stage. Other countries may reconsider the reprocessing option in future if alternative reprocessing technologies are developed or if reprocessing appears to be more economically attractive than direct disposal. New reactor designs and fuel cycles are being developed with this consideration in mind. There are relevant international cooperation programmes, with the United States taking a major role, as well as those countries which today reprocess.

HLW disposal is more contentious than disposal of lower-level wastes and no country today has an operating disposal site for high-level waste. Though wide technical consensus exists on the adequacy of geological disposal of HLW, it has not yet won general public consent. In some countries, however, there are volunteer communities to host repositories. Table 13.7 provides examples of strategies to deal with HLW. The search for politically acceptable solutions continues.

Proliferation and International Conventions

Effective safeguards against nuclear weapons proliferation are required as long as nuclear technologies generate, or can be used to generate, weapons-grade fissile material, irrespective of whether the material is designated for use in nuclear power plants, medical, agricultural or other peaceful applications. At the centre of the international non-proliferation regime is the Treaty on the Non-Proliferation of Nuclear Weapons (NPT), signed in 1970 and extended indefinitely in 1995. To advance the goal of non-proliferation, the Treaty established a system of safeguards under the responsibility of the IAEA.

Recent events have shown that the NPT needs to be further strengthened. Improvements required involve enhanced verification and inspection through the universal adoption of the so-called "Additional Protocol", and possibly restrictions on the use of weapon-usable material (plutonium and high enriched uranium) in civilian nuclear programmes. The processing of such material and the production of new material through reprocessing and enrichment could be limited to international centres, under appropriate rules of transparency, control and assurance of supply on a non-discriminatory basis, under strict IAEA control. The Global Nuclear Energy Partnership (GNEP), recently proposed by the United States, and the offer by the Russian Federation to set up a global network of nuclear fuel cycle services (supply of enriched fuel and recovery of used fuel) are concepts designed to enhance transparency and control over sensitive nuclear fuel cycle facilities and would go a long way towards strengthening the non-proliferation regime. The International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO) and the Generation IV International Forum (GIF) are technology-related efforts further to reduce nuclear proliferation risks and better to address the problem of radioactive waste.

Other components of the international non-proliferation regime include verification and development of proliferation-resistant technology, export controls on nuclear and nuclear-related material and equipment, the creation of nuclear weapons-free zones, controls against illicit trafficking of nuclear material and the physical protection of nuclear installations. Safeguards development will need to keep pace with the expansion of nuclear power.

Table 13.7: **Examples of High-Level Waste Disposal Strategies**

	Facilities and progress towards final repositories
Belgium	Underground laboratory in Boom Clay at Mol since 1984. Repository has not been selected yet.
Canada	Owners of used fuel required by law to develop strategy. Ultimate disposal in geological formation proposed but no sites have been selected.
Czech Republic	Decision for final HLW repository after 2010.
Finland	Construction of underground research laboratory. Resulting HLW repository expected to start operation in 2020.
France	HLW from spent fuel reprocessing vitrified and stored at La Hague and Marcoule (new waste stored at La Hague). Three research directions: partitioning/transmutation, reversible deep repository and storage. Studies under way for site selection and storage conception. Storage operational by 2025.
Germany	Used fuel storage at Ahaus and Gorleben. Expects to have a final HLW repository in operation around 2030.
Hungary	Site in Boda Claystone Formation selected. Surface exploration commenced in 2004. Underground research laboratory in 2010.
India	Research on deep geological disposal for HLW.
Japan	Vitrified HLW stored at Mutsu-Ogawara since 1995. Ongoing research for deep geological repository site. Operation expected in mid-2030s.
Netherlands	Temporarily surface storage is only allowed for existing plant. Study announced for final disposal of waste of existing plant and of any new plant. Decision expected in 2016.
Slovak Republic	Research for deep geological disposal started in 1996. Four areas have been proposed for detailed exploration.
Republic of Korea	Central interim HLW storage planned for 2016. Ongoing development of a repository concept.

Sources: NEA (2005) and national administrations.

Table 13.7: **Examples of High-Level Waste Disposal Strategies** *(continued)*

	Facilities and progress towards final repositories
Russia	Sites for final disposal under investigation.
Spain	Decision for final HLW repository after 2010.
Sweden	Site investigation in two locations. Final repository operation expected by 2020-2025.
Switzerland	Feasibility of HLW disposal proven and accepted by Federal goverment in June 2006 based on site near Zurich. Final site to be selected according to criteria which will be decided by Federal goverment in 2007. Repository expected operational by 2040.
United Kingdom	HLW vitrification and storage at Sellafield. Recent government-sponsored review has recommended deep disposal to government, but there is no decision yet.
United States	HLW repository at Yucca Mountain (2002 decision). Beginning of operation planned for 2017.

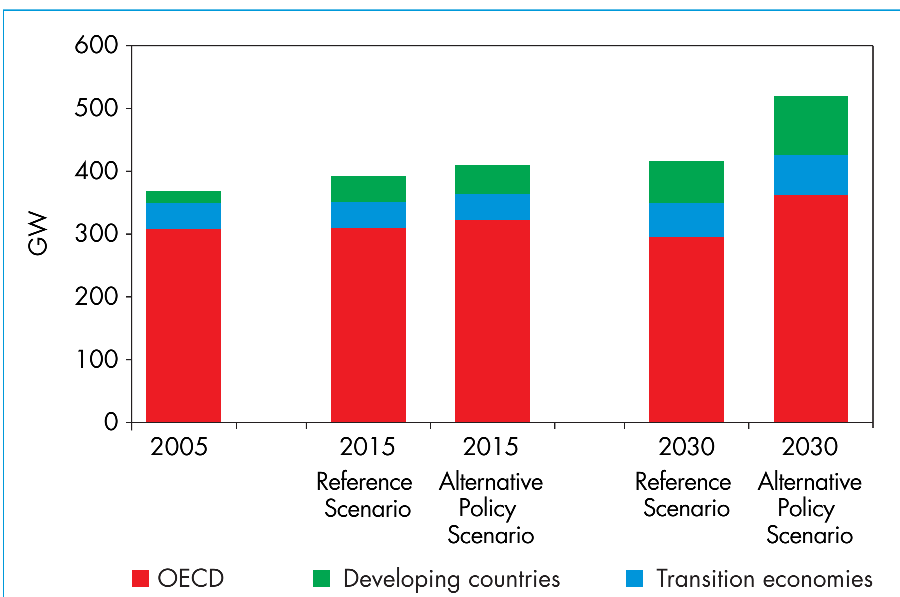
Sources: NEA (2005) and national administrations.

Outlook for Nuclear Power

In the Reference Scenario set out in this *Outlook*, world nuclear power capacity is projected to rise from 368 GW in 2005 to 416 GW in 2030 and to 519 GW in the Alternative Policy Scenario. The Reference Scenario assumes that current government policies remain broadly unchanged. Targets for nuclear power generation, if judged unrealistic, are assumed not to be achieved. The macroeconomic, technical and financial assumptions underlying many countries' targets are often different from those used in this *Outlook*. The Alternative Policy Scenario assumes additional policies will be put in place to combat global warming and to address security of supply, including measures to boost the role of nuclear power (see Chapter 7). Governments in countries that already have nuclear power plants are assumed to support lifetime extensions of existing reactors or the construction of new reactors. In all countries that have phase-out policies in place, it is assumed that reactors are shut down later than planned to hold down CO_2 emissions, to deal with concerns about security of supply and to postpone the need for new investment.

The expansion of nuclear capacity may, however, face several constraints, such as limits to global capacity to build major components of nuclear power plants, for example pressure vessels and valves, especially for very large reactors. Similar to

Figure 13.5: **World Nuclear Capacity in the Reference and Alternative Policy Scenarios**



other industries, short-term constraints that may limit new construction include the cost of raw materials, the difficulty of finding EPC (engineering, procurement and construction) contractors and the shortage of skilled personnel.[5]

Reference Scenario

In the Reference Scenario, world nuclear electricity generation is projected to increase from 2 742 TWh in 2005 to 3 304 TWh in 2030. This is an average annual growth rate of 0.7% per year, compared with 2.6% per year for total electricity generation. Installed capacity increases from 368 GW to 416 GW. Nuclear capacity factors are assumed to improve over time, mainly in those countries that are now below the world average. Overall, the average world capacity factor increases from 85% in 2005 to 91% in 2030.

The most significant increases in installed capacity are projected in China, Japan, India, the United States, Russia and the Republic of Korea. Nuclear capacity in OECD Europe decreases from 131 GW to 74 GW. Nuclear power phase-outs in Germany, Sweden and Belgium account for 35 GW. All nuclear power plants in these three countries are closed before 2030.

The share of nuclear power in world electricity generation drops from 15% to 10%. The most dramatic decrease in the share of nuclear power occurs in OECD Europe, where it drops from 28% in 2005 to 12% in 2030.

Alternative Policy Scenario

In the Alternative Policy Scenario, world nuclear electricity generation reaches 4 106 TWh in 2030, growing at an average rate of 1.6% per year. The share of nuclear power in total world electricity generation decreases slightly from the current 15%, hovering around 14% throughout the projection period. Installed nuclear capacity reaches 519 GW in 2030. The biggest difference between the two scenarios arises after 2020, because of the long lead times of nuclear power plants.

Installed capacity increases in all major regions except OECD Europe, where new build is not projected to be large enough to offset plant closures (Table 13.8). To change this picture in the competitive markets in Europe is likely to require strong market signals arising from long-term commitments to reduce carbon-dioxide emissions. At the moment, there are no clear targets about the size of CO_2 emissions cuts beyond 2012. Phase-out policies are assumed to remain in place, but they are delayed by about ten years. On this basis, Germany is left with one reactor by 2030 while Belgium's and Sweden's reactors are still operating in 2030. In the United Kingdom, all but one reactor are retired, without being replaced.

5. See also Chapter 12 for a discussion of these issues in the oil and gas industry.

Table 13.8: **Nuclear Capacity and Share of Nuclear Power in the Reference and Alternative Policy Scenarios**

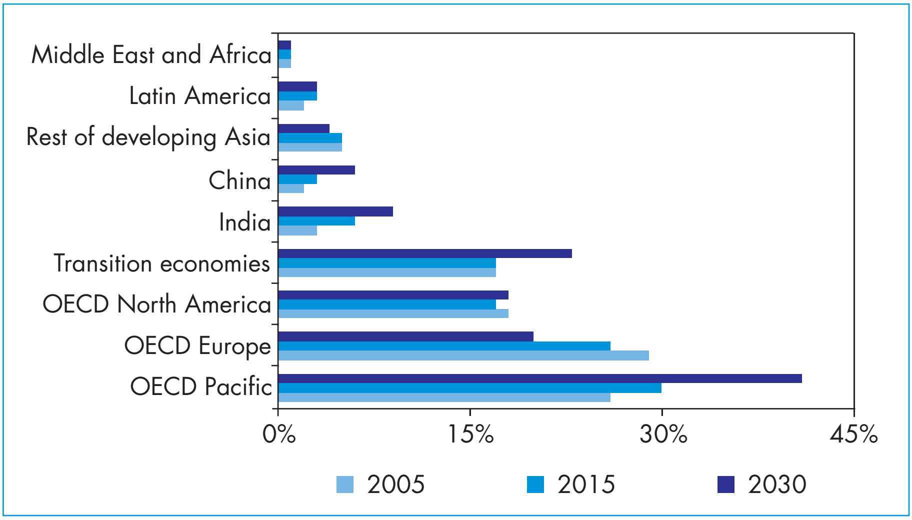
Region	Nuclear capacity (GW)			Share of nuclear in electricity generation (%)		
	2005	**2030 Reference Scenario**	**2030 Alternative Policy**	**2005**	**2030 Reference Scenario**	**2030 Alternative Policy**
OECD	**308**	**296**	**362**	**22%**	**16%**	**22%**
OECD North America	112	128	144	18%	15%	18%
OECD Europe	131	74	110	28%	12%	20%
OECD Pacific	65	94	108	25%	32%	41%
Transition economies	**40**	**54**	**64**	**17%**	**18%**	**23%**
Developing countries	**19**	**66**	**93**	**2%**	**3%**	**5%**
China	6	31	50	2%	3%	6%
India	3	19	25	2%	6%	9%
Other Asia	5	10	10	4%	3%	4%
Latin America	3	4	6	2%	2%	3%
Middle East and Africa	2	3	3	1%	1%	1%
World	**368**	**416**	**519**	**15%**	**10%**	**14%**

Note: The share of nuclear power in the Alternative Policy Scenario remains stable in the OECD, and increases in the transition economies and the developing countries, but the world share decreases because of the greater weight of developing countries in world demand in 2030.

The largest increases in nuclear power generating capacity are expected in China, the United States, Japan, the Republic of Korea, India and Russia. These six countries are projected to hold two-thirds of the world's nuclear capacity in 2030, compared with just over half today. Nuclear capacity factors are the same as in the Reference Scenario.

The largest increase in the share of nuclear power in electricity generation is expected to be in OECD Pacific, where it reaches 41% in 2030, up from 25% now (Figure 13.6). In OECD North America, nuclear power maintains its current share. In OECD Europe, the share of nuclear power falls to 20% by 2030. This share is higher than in the Reference Scenario, but still lower than the current share of 28%. In the transition economies, the share of nuclear power rises from 17% to 23%. In China and India, these shares reach 6% and 9% in 2030, up from 2% now.

Figure 13.6: **Share of Nuclear Power in Total Electricity Generation in the Alternative Policy Scenario**



Box 13.1: **Recent Trends and Outlook for Nuclear Reactor Technology**

The evolution in reactor technology can be characterised by generations, the next generation to be installed being Gen-III. The latest generation of reactors was developed in the 1990s, after the Chernobyl accident. It includes "passive safety" features, as well as improved economic and environmental characteristics, and is still evolving (Nuttall, 2004). The reactors expected to be built over the next 25 years will most likely be based on Gen-III designs or improved versions of current designs.[6] Several water-cooled Gen-III thermal reactors with evolutionary designs are already being marketed. The French company Areva is marketing the 1 600-MW European Pressurised Reactor (EPR). The target availability is 91% over a 60-year lifetime. Westinghouse has developed the AP600 reactor and a larger version, the AP1000, which is currently under consideration for use in China and the United States. General Electric has developed the Advanced Boiling Water Reactor (ABWR), which comes in different sizes, typically between 1 200 and 1 500 MW, and the 1 550 MW Economic Simplified Boiling Water Reactor (ESBWR). Three ABWR units have already been built in Japan. Canada's AECL has developed the Advanced CANDU Reactor (ACR), in two sizes: 700 MW and 1 000 MW. Russia plans to develop a new generation of

6. A new generation of reactors (Gen-IV) is currently under development and is expected to be deployed after 2030.

light-water reactors (VVER) in two sizes: 1 600 MW and 1 100 MW, and expects to have a licensed design in place over the next couple of years. Lying between Gen-III and Gen-IV are the small-scale gas-cooled reactors such as the Pebble Bed Modular Reactor (PBMR) developed by the South African utility ESKOM and General Atomics' Gas-Turbine Modular Helium Reactor (GT-MHR). A PBMR demonstration plant is planned to be operational in South Africa in 2011. PBMR and GT-MHR reactors may come on to the market after 2015.

Nuclear Power Economics in Competitive Markets

The electricity-supply industry has changed over the past 20 years in OECD countries, moving towards a more competitive structure, although there is wide difference between countries in the nature and extent of liberalisation. Most existing nuclear plants have performed well in competitive markets. They have achieved higher capacity factors and lower production costs. Modest capacity increases, particularly in the United States, have increased output at a relatively low cost, adding globally about 3 GW of capacity between 2000 and 2005.[7] Across the OECD, the industry is seeking plant life extensions, enhancing the value of nuclear assets.

While several OECD governments have stated their interest in pursuing the nuclear power option and seeing new nuclear plants built, the final economic decision about building new nuclear power plants lies in most cases with the private sector, subject to regulatory approval. In a competitive market, investors bear the risk of the uncertainties associated with obtaining construction and operating permits, construction costs and operating performance.

Generating Costs under Different Discount Rate Assumptions

This section examines the economics of new nuclear plants compared with competing mature technologies: gas-fired combined-cycle gas turbines (CCGT), steam coal, integrated gasification combined-cycle plants (IGCC) and onshore wind turbines. The main parameters used in the cost analysis are shown in Table 13.9.[8] The cost assumptions are based on expectations over the next ten to fifteen years. The construction cost of IGCC power plants and wind farms is lower than today by about 10% to 15%. The fossil-fuel starting prices and incremental annual increases are in line with the international price

7. Most uprates have been carried out in the United States, adding about 2.1 GW of capacity over 2000-2005. A few other countries like Sweden, Spain, Germany and Finland have also increased capacity through uprates. Further uprates are planned in Sweden. They can be a cost-effective way to increase nuclear power generating capacity.
8. All costs are expressed in real 2005 dollars.

Table 13.9: **Main Cost and Technology Parameters of Plants Starting Commercial Operation in 2015**

Parameter	Unit	Nuclear	CCGT	Coal steam	IGCC	Wind onshore
Capacity factor	%	85	85	85	85	28
Thermal efficiency (net, LHV)[1]	%	33	58	44	46	–
Investment cost[2]	$ per kW	2 000 - 2 500	650	1 400	1 600	900
Construction period	months	60	36	48	54	18
Plant life	years	40	25	40	40	20
Decommissioning[3]	$ million	350	0	0	0	0
Annual incremental capital cost	$ per kW	20	6	12	14	10
Unit cost of fuel[4]	$ per MBtu or tonne	0.50 per MBtu	6.00 per MBtu	55 per tonne	55 per tonne	–
Fuel escalation rate	annual, %	0.5	0.5	0.5	0.5	–
Waste management	cents per kWh	0.1	–	–	–	–
Total O&M[5]	$ per kW	65	25	50	55	20
O&M escalation rate	annual %	0.5	0.5	0.5	0.5	0.5
Carbon intensity of the fuel[6]	t CO_2 per toe	–	2.43	4.21	4.21	–

1. Lower heating value (LHV) is the heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapor and the heat is not recovered. For coal and oil, the difference between lower and higher calorific value is approximately 5%; for most natural gas and manufactured gas it is approximately 9-10%.
2. Total capital expenditure for the project, excluding the cost of finance.
3. Assumes a fund is accumulated over the first 20 years of operation.
4. Coal and gas prices are OECD import prices. They are increased by about 10% in the model to reflect the cost of delivery to power stations. A coal price of $55 per tonne corresponds to $2.20 per MBtu. Nuclear fuel cost includes uranium, enrichment, conversion, and fabrication.
5. Total non-fuel operating and maintenance costs are assumed to be fixed.
6. CO_2 intensity refers to electricity generation only. Life-cycle emissions are somewhat higher and are not zero for wind and nuclear power (but still negligible compared with coal or gas).
Sources: IEA databases and NEA/IEA (2005).

assumptions used throughout the *Outlook* and described in Chapter 1. Natural gas prices are assumed to be in the range of $6 to $7 per MBtu in the period to 2030. The coal price refers to the international market price for coal imported into the OECD, but some countries, including the United States and Canada, have access to cheaper indigenous coal, making coal-fired generation more competitive. For nuclear plants, a range of construction costs has been used to reflect the uncertainty in the cost estimates for reactors that would enter commercial operation in 2015. These construction costs are for nuclear reactors built on existing sites. Greenfield projects are likely to be more costly. Most new reactors in OECD countries are likely to be built on existing sites, at least over the next ten to fifteen years.

Depending on the extent of the risks borne by investors in the power plant, whether they are the shareholders of the operating company or outside financiers, they will seek different returns on investment. The two cases analysed here are:

- **A low discount rate** case, corresponding to a moderate risk investment environment, where construction, operating and price risks are shared between the plant purchaser, the plant vendor, outside financiers and electricity users, through arrangements such as long-term power-purchase agreements.
- **A high discount rate** case, representing a more risky investment framework in which the plant purchaser and financial investors and lenders bear a higher proportion of the construction and operating risks.

The financial parameters for the two cases are shown in Table 13.10. In the low discount rate case, the plant purchaser is assumed to have access to relatively cheap finance in the form of debt and to accept a relatively low return on equity, given that the construction and operating risks have been appropriately mitigated. In the high discount rate case, it is assumed that lenders will require higher debt interest rates and that there will need to be higher return on equity to compensate for the higher risks associated with the higher proportion of equity funding required to satisfy lenders' conditions. The financing parameters are therefore more demanding. The economic lifetime is assumed to be 40 years in the low discount rate and 25 years in the high discount rate cases.[9]

Figure 13.7 compares the generating costs of nuclear power with the main baseload alternatives in the low discount rate case. Under the high construction cost assumption ($2 500/kW) nuclear power is competitive with CCGT plants at gas prices around $6 per MBtu (which is close to the average

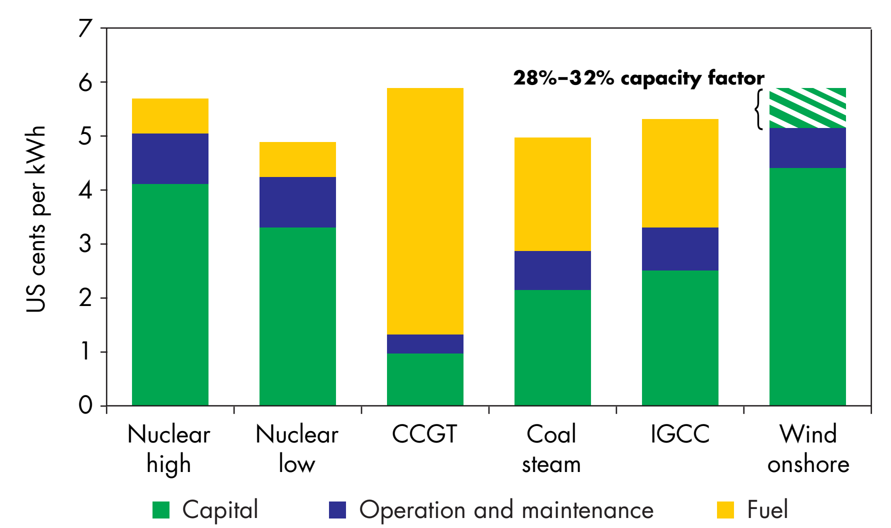
9. These two cases represent commercial discount rates. Publicly owned companies or private companies benefiting from government support might have access to cheaper financing and the use of a lower discount rate might be appropriate.

Table 13.10: **Summary of Financial Parameters**

Parameter	**Unit**	**Low discount rate**	**High discount rate**
Inflation rate	annual %	2.0	2.0
Cost of debt capital (nominal)	annual %	8.0	10.0
Required return on equity (nominal)	annual %	12.0	15.0
Debt fraction	%	50.0	40.0
Capital recovery period*	years	40	25
Marginal corporate tax rate	annual %	30.0	30.0
Tax depreciation schedule	-	straight line	straight line
Tax depreciation period	years	15	15
Real after-tax weighted average cost of capital	annual %	6.7	9.6

* In the low discount rate case, the capital recovery period corresponds to the plant's physical life (see Table 13.9), while it is 25 years for all technologies but wind in the high discount rate case.

Figure 13.7: **Electricity Generating Costs in the Low Discount Rate Case**



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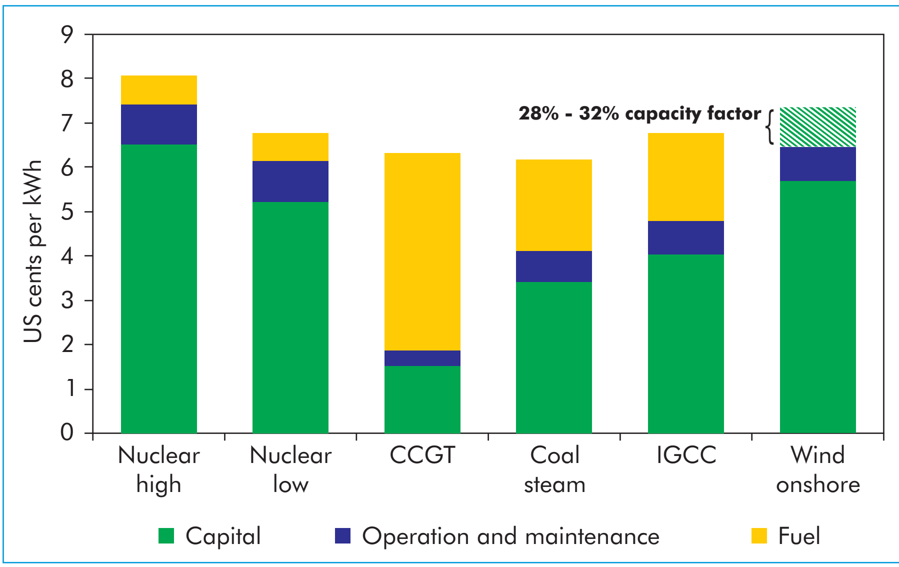
OECD price in 2005 and within the assumed range of prices of around \$6 to \$7 per MBtu over the entire projection period), but more expensive than steam coal at \$55 per tonne of coal. Under the lower construction cost assumption (\$2 000/kW), nuclear is competitive with coal. The generating costs of nuclear power for the high and low construction costs estimates are 5.7 cents and 4.9 cents per kWh. In the high discount rate case, capital-intensive technologies, such as nuclear and wind power, are not competitive with CCGT or coal plants (Figure 13.8). Nuclear power generation costs are between 6.8 cents per kWh and 8.1 cents per kWh in this case.

Figure 13.8: **Electricity Generating Costs in the High Discount Rate Case**



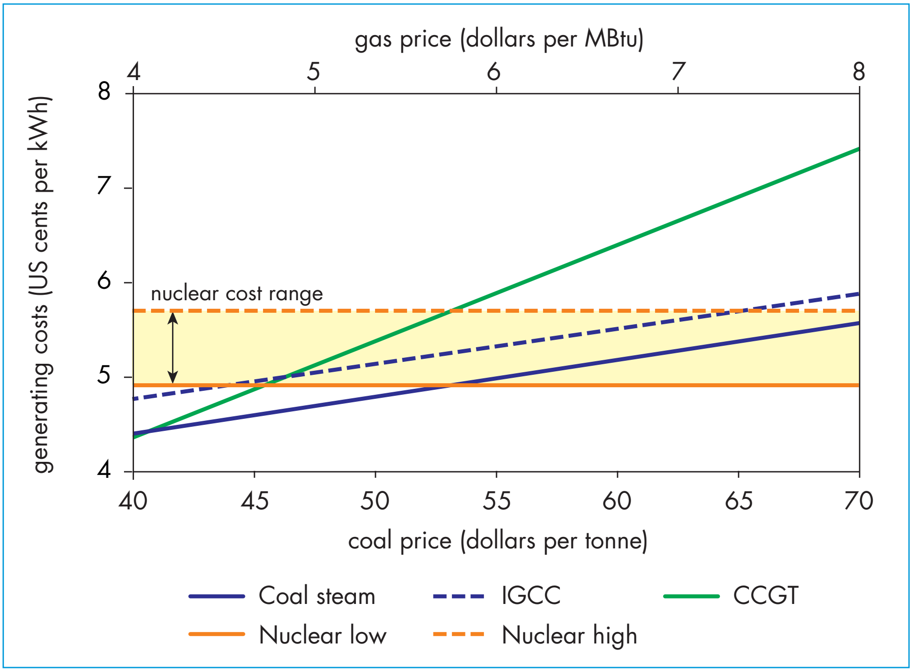
Sensitivity Analysis of Nuclear Power Generating Costs

There are many uncertainties about the magnitude of the parameters used in the cost estimates presented above. The most important factors affecting the competitiveness of nuclear power are the investment cost, the discount rate and the plant's economic life. Increases in gas and coal prices or the introduction of a carbon value improve the competitive position of nuclear power against the alternatives. Location and size also affect costs.

Impact of Changes in Coal and Gas Prices

Figure 13.9 shows the sensitivity of gas- and coal-fired plants to coal and gas price changes. The cross-over point between nuclear and CCGT generating costs occurs when the gas price reaches \$4.70 per MBtu in the low capital cost case and $5.70 in the high capital cost case, corresponding to an average IEA crude oil import price of $40 to $45 per barrel. Steam-coal plants are cheaper than nuclear plants for a coal price lower than $70 per tonne, while the cross-over between nuclear in the high capital cost estimate and IGCC plants occurs at a coal price of about $65 per tonne. In the high discount rate case, nuclear power generating costs are between 6.8 and 8.1 cents per kWh, requiring long-term gas prices above $6.60 per MBtu (corresponding to $65 per barrel of oil) in order to be competitive with gas-fired generation.

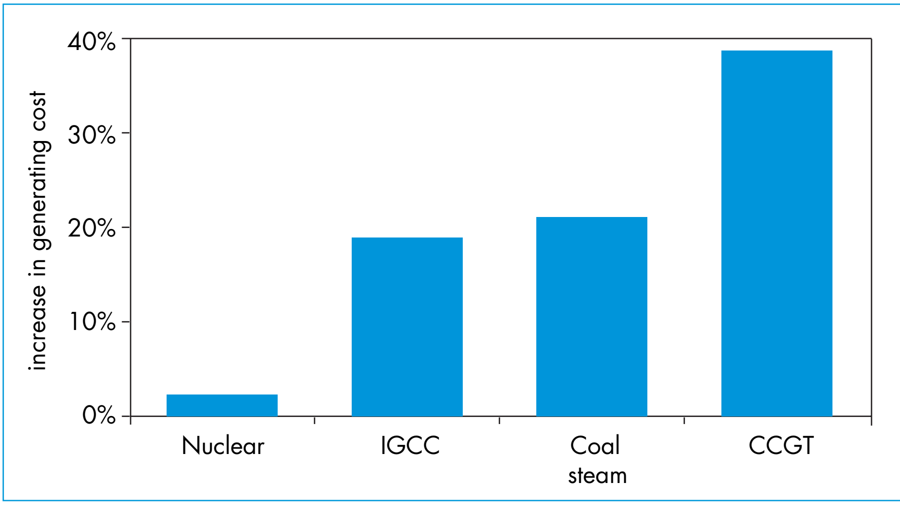
Figure 13.9: **Comparison of Nuclear, Coal and CCGT Generating Costs under Different Coal and Gas Prices** (low discount rate case)



Fuel costs are a small component of nuclear power generating costs. A 50% increase in uranium, gas and coal prices (compared with the base assumptions) would increase nuclear generating costs by about 3%, coal generating costs by around 20% and CCGT generating costs by 38%, demonstrating the greater resilience of nuclear generation to upside fuel price risks (Figure 13.10).

The greater stability and predictability of nuclear power generating costs could make this solution more attractive to heavy users of electricity. For example, consortia of electricity-intensive industrial users in Finland and France have expressed interest in long-term fixed price contracts for electricity, which could, in turn, be used to facilitate financing investments in new nuclear plants.

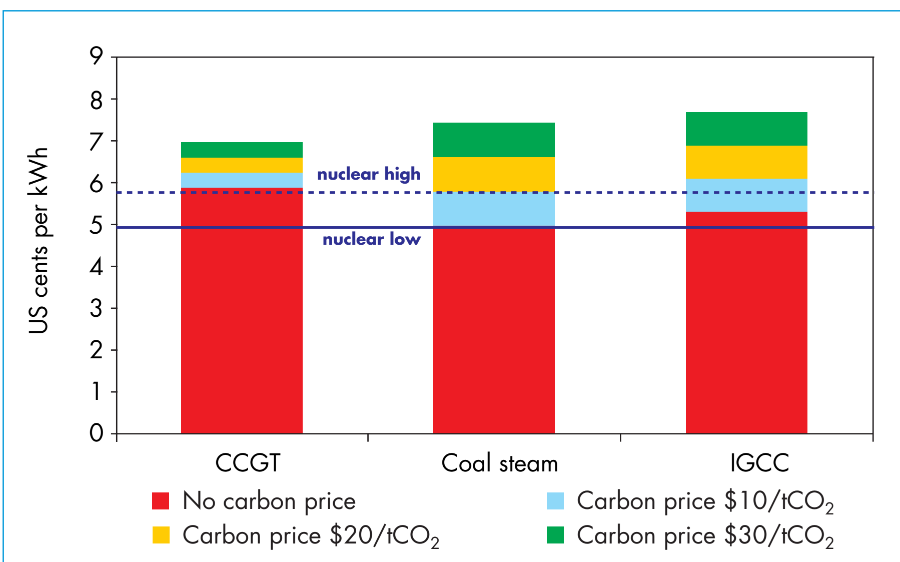
Figure 13.10: **Impact of a 50% Increase in Fuel Price on Generating Costs** (low discount rate case)



Impact of Carbon Prices

Figure 13.11 shows the impact of carbon prices on the costs of nuclear-, coal- and gas-fired generation in the low discount rate case. A price of about \$10 per tonne of CO_2 makes nuclear competitive with coal-fired power

Figure 13.11: **Impact of CO_2 Price on Generating Costs** (low discount rate case)



stations, even under the higher construction cost assumption. This low carbon price suggests that nuclear power is a cost-effective mitigation option. The average carbon price in the EU Emissions Trading Scheme has often been much higher. The average CO_2 price in 2005 was €18.3 per tonne (about $23), and it rose to €22.9 ($33) in 2006 until the end of April, when the price collapsed. From the price collapse in April 2006 to the end of August 2006, CO_2 prices have averaged €15.5 ($19). In the high discount rate case, a carbon price of about $10 to $25 is required to make nuclear competitive with coal respectively in the lower and higher capital cost assumptions and $15 to $50 to make it competitive with gas-fired plants.

Other Factors Influencing the Generating Cost of Nuclear Power

Initial Cost

Nuclear power is much more capital-intensive than alternative baseload fossil-fuel technologies such as gas-fired CCGT and coal-fired plants. Of the three major components of nuclear generation cost – capital, fuel and operation and maintenance – the capital cost component makes up approximately three-quarters of the total. It represents only about 20% of total costs for a CCGT. Construction costs for nuclear plant are three to four times greater than for a CCGT. In addition, a typical nuclear unit is much larger than a typical CCGT unit: recent nuclear technologies range from 1 000 MW (such as Westinghouse's AP1000) to 1 600 MW (Areva's EPR), while CCGTs units are typically in the range of 300 to 800 MW.[10] The greater unit size of nuclear power plants exposes investors to greater risks as compared to smaller unit technologies such as CCGT, which can be built faster and in series of smaller plants. Large upfront capital investment can be more difficult to finance. The environmental characteristics of CCGT plants make siting easier. Building large nuclear power plants is likely to require significant investment in transmission, particularly in areas where there is now congestion. In addition, a large increase in capacity may create excess capacity for a period.

In the past, nuclear power plant construction faced significant cost overruns in some countries, notably in the United States.[11] A 1986 study (EIA/US DOE, 1986) by the US Energy Information Administration showed that the actual costs of nuclear power plants substantially exceeded the original

10. See Box 13.1 for a description of recent reactor designs and sizes.

11. The United States is the only country to have published such detailed cost data. Some cost estimates exist for nuclear power plants in the United Kingdom. Information about past construction costs in other countries is not readily available.

estimates. Approximately three-quarters of the increase came from increases in the quantities of land, labour, material and equipment. The estimated and realised costs of these plants are shown in Table 13.11. In countries such as the United States, nuclear power will need to overcome this legacy of the past, rebuilding the confidence of investors that plants can be built on time and on budget.

Table 13.11: **Average Estimated and Realised Investment Costs of Nuclear Power Plants by Year of Construction Start, 1966-1977** ($2005 per kW)

Year of construction start	Number of plants	Initial estimate	Realised costs
1966-1967	11	530	1 109
1968-1969	26	643	1 062
1970-1971	12	719	1 407
1972-1973	7	1057	1 891
1974-1975	14	1095	2 346
1976-1977	5	1413	2 132

Note: Original data expressed in $1982.
Source: EIA/US DOE (1986).

Operating Flexibility

Because of their low marginal operating cost, nuclear plants are usually run as baseload units at high capacity factors. Nuclear power is competitive only when operated at high capacity factors. A change of the capacity factor from 90% to 80% hardly affects the cost of CCGT-generated electricity, while nuclear costs increase by nearly one cent per kWh.[12]

Planning and Construction Time

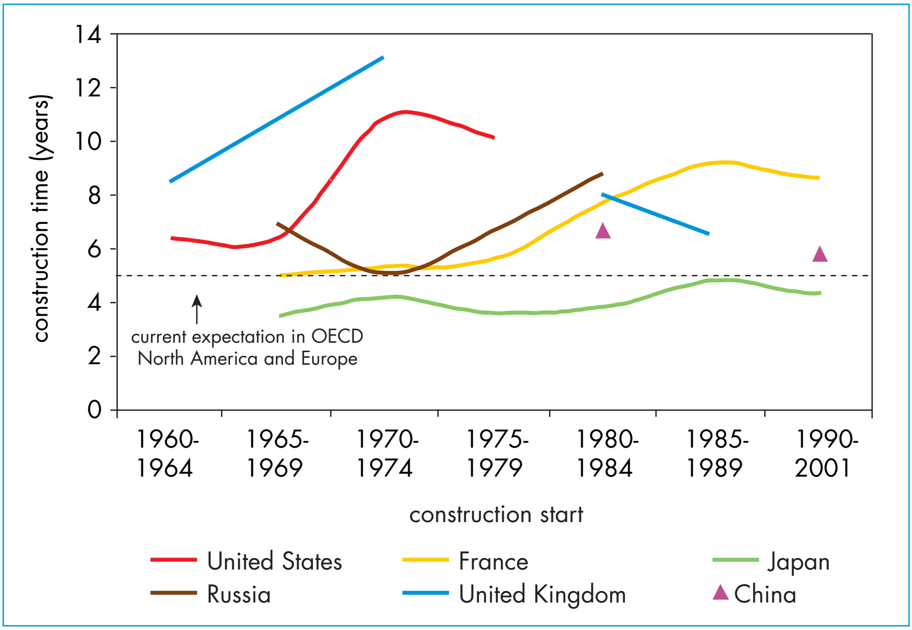
Nuclear power plants have long lead times, both in the planning and licensing phase and in the construction phase. Countries with the entire infrastructure in place can expect a total lead time, between the policy decision and commercial operation, of seven to 15 years. In countries with no previous experience in commercial use of nuclear power generation, developing the required institutional and regulatory framework and a skilled workforce generally requires longer lead times.

Nuclear power plant construction times are much longer than those for CCGT plants (typically two to three years), wind power plants (one to two years) and, to a lesser extent, coal-fired plants (four years). In the past, disputes about plant

12. Figure 6.8 in Chapter 6 shows the impact of the capacity factor on the generating costs of nuclear and other technologies.

licensing and siting due to local opposition, access to water for cooling and other issues, as well as technical or project management issues, have delayed the construction and completion of nuclear plants, notably in the United States and the United Kingdom. In Japan, nuclear power plants have been built in less than four years (Figure 13.12). In China and the Republic of Korea some nuclear power plants have been built ahead of schedule. Most new nuclear power reactors in the OECD are expected to be built on existing sites, either because the sites have been designed to accommodate additional units or because they will replace retired reactors. This reduces costs and makes public acceptance less of an issue.

Figure 13.12: **Construction Time of Existing Nuclear Power Plants**



Notes: The construction time has been calculated to the beginning of commercial operation of plants. The construction time to grid connection is lower by a few months. The dates on the horizontal axis show when the construction started (first pour of concrete). For example, power plants in France that started in the period 1975-1979 took 5.7 years (5 years and 8 months) on average to complete.
Source: IEA analysis based on IAEA PRIS database.

Fuel Cycle and Decommissioning Costs

Nuclear-fuel costs consist of front-end and back-end costs. The front-end costs are the cost of uranium (about 25% of the total fuel cost), its conversion (5%), enrichment in light water reactors (30%) and fabrication into fuel assemblies (15%). The back-end costs (roughly 25% of the total fuel cost) include direct disposal or reprocessing followed by recycling of the fissile material for reuse. The costs of direct disposal, as currently borne by utilities, consist of the cost of on-site storage plus the provision for ultimate waste disposal levied in some countries (for example, 0.1 cent per kWh in the United States).

At the end of 2005, eight power plants had been completely decommissioned and dismantled worldwide, with the sites released for unconditional use (UIC, 2006). The International Atomic Energy Agency has defined three options for decommissioning: *immediate dismantling, safe enclosure* – which postpones the final removal of controls for a longer period – and *entombment*, which places the facility into a condition that will allow the remaining radioactive material to remain on site indefinitely.

In countries with privately owned nuclear power plants, the owner is responsible for decommissioning costs. The total cost of decommissioning depends on the sequence and timing of the various stages of the programme. Decommissioning costs reported for existing plants range from \$200-500/kW for western PWRs, \$330 for Russian VVERs, \$300-550 for BWRs, \$270-430 for Canadian CANDU, and as much as \$2 600 for some UK gas-cooled Magnox reactors (in year-2001 dollars). Decommissioning costs for plants built today are estimated at 9% to 15% of the initial capital cost, but when discounted, they amount to only a small percentage of the investment cost. Overall, decommissioning accounts for only a small fraction of total electricity generating costs. In the United States, power companies are collecting 0.1 cents to 0.2 cents per kWh to fund decommissioning.

Financing Nuclear Power Plants

Past experience has shown that some of the risks faced by nuclear projects are larger than for other types of power plants or large industrial projects. Such risks include the extent of the initial capital investment at risk, the greater risks posed by technology-related issues and the greater risks posed by regulatory and political actions (IEA, 2001). Because of these risks and of negative experiences in the past, the financial community may still regard financing a new nuclear project as a high-risk undertaking. Some studies suggest that any new nuclear build is likely to carry a substantial risk premium over competing technologies, at least for the first units to be built. Two recent US studies estimated that the risk premium required by bond and equity holders for financing new nuclear plants would be around three percentage points (MIT, 2003 and University of Chicago, 2004).

The construction and operational risks of nuclear power plants can be managed through arrangements which clearly allocate the various risks and responsibilities to the appropriate industry stakeholders. A recent positive experience is TVO's innovative approach to financing its EPR project

(Box 13.2). In the United States, the firms buying existing nuclear power plants have generally obtained power purchase contracts from the companies selling the plants. There is a strong correlation between the agreed price in the purchase contract for the power and the selling price of the plant.

Box 13.2: **Financing Finland's New Nuclear Reactor**

In 2005, the Finnish power company TVO started building a new nuclear power reactor at its Olkiluoto site. The total cost of this plant was estimated at around €3 billion in 2003. The main financing arrangements are:

- TVO's shareholders will invest 25% of the total cost of the project and provide 5% as a shareholder loan. The remaining 75% will be covered by loans from financial institutions under commercial terms.
- The construction risk is borne by the plant vendor, Areva, under a turnkey contract. Any cost overruns and construction delays will be borne by the vendor, on defined terms.
- The most important aspect underlying the financing arrangement is that market risk will be mitigated by very long-term power-purchase agreements under which TVO will provide electricity to its shareholders at production cost over the lifetime of the plant. This unique arrangement has facilitated financing at low cost.

In today's markets, new nuclear power plants may be built as public-sector projects (probably in countries which have not liberalised their energy markets), public/private partnerships or private-sector undertakings (most likely in OECD countries). In the past, consumers in OECD countries carried the construction cost and performance risk. This will not be the case in liberalised markets or even in OECD markets that remain regulated.

The private sector may finance a large construction contract on the basis of corporate finance, on the balance sheet of the purchasing company (or a partnership of companies), or non-recourse project finance, where the project is established as a separate legal entity and investors can seek repayment only from the revenues generated by the project and from no other source. In either case, investor risk may be mitigated by widening the range of those who share the risk, for example by including the project contractor and purchaser of the ultimate output from the plant.

In liberalised markets, construction of a new nuclear plant is likely to be seen as too risky to support project financing. In the United States, for example, even divested nuclear power plants have been unable to raise project financing. Without government support, it seems likely that new nuclear power plants will be financed on the basis of corporate financing by a large power company or a consortium of companies with experience in mitigating the construction and performance risks associated with nuclear power. Experience in managing complex large industrial projects, as well as stakeholders who are accustomed to working together appear to be key elements for success. Some 1 100 subcontractors are currently involved in the construction of the Finnish EPR plant.

Governments may choose to play a role in facilitating such capital-intensive investments as nuclear power plants. Box 13.3 describes the impact on nuclear power generating costs of the incentives the US government provides for nuclear power.

Box 13.3: **Impact of Incentives in the US 2005 Energy Policy Act on Nuclear Power Generating Costs**

The Energy Policy Act 2005 provides a set of incentives for new nuclear power plants. The act provides a production tax credit of 1.8 cents per kWh for the first eight years of operation. This incentive reduces the lifetime generating cost of nuclear power by about 0.8 cents per kWh.

The act also provides for loan guarantees of up to 80% of the project cost. Loan guarantees enable lenders to offer lower interest rates and require less equity investment. The latter allows project leverage to increase up to 80% compared to 50% without guarantees. Assuming a nominal debt interest rate of 5% (instead of 8% in the analysis presented in the section discussing the economics of nuclear power) and 80% debt, the impact on the generating cost of nuclear power is 1.2 cents/kWh over the lifetime of the plant. It is equivalent to $125 million per year assuming a 20-year debt recovery period.

The standby guarantee, the third major incentive, provides guarantees in case of regulatory delays (up to $500 million per plant for the first two plants and up to $250 million for the next four). This translates into a payment of between about 0.1 cents per kWh for a six-month delay to 0.5 cents per kWh for a 24-month delay period.

Nuclear Fuel Outlook

Demand for Uranium

Annual reactor requirements for uranium are determined principally by the amount of electricity generated in operating nuclear plants. Based on the projections of nuclear power generation presented earlier in the chapter, annual demand for uranium is projected to increase from 68 thousand tonnes in 2005 to between 80 thousand and 100 thousand tonnes by 2030. This demand is expected to be satisfied mainly by newly-mined primary uranium, which over the past several years has met some 50% to 60% of world requirements. The remainder has been derived from secondary sources, including stockpiles of natural and enriched uranium, the reprocessing of spent fuel and the re-enrichment of depleted uranium tails – a waste product of uranium enrichment. The share of secondary sources is expected to decline, mainly because of the end of the "Megatons to Megawatts" programme, agreed by the US and Russian governments in 1993, which co-ordinates the blending of highly-enriched uranium from nuclear warheads with low-enriched uranium fuel for use in commercial nuclear power plants. The 275 tonnes converted to date could generate enough electricity to meet US demand for more than a year. Upon completion of the programme in 2013, 500 tonnes of highly-enriched uranium from Russian nuclear warheads will have been used. Russia and the United States plan to release 34 tonnes of plutonium each, which will be used in MOX fuel.[13]

Uranium Resources[14]

Uranium resources are reported by confidence level and production cost category. In 2005, 43 countries reported total resources in all confidence and cost categories of 14.8 million tonnes (Table 13.12). Uranium resources are widely distributed around the world, with significant known uranium resources found in Australia, Canada, Kazakhstan, Namibia, Niger, the Russian Federation, South Africa and the United States. The top fifteen countries, which account for 96% of the global resources, are shown in Figure 13.13.

Table 13.12: **Total World Uranium Resources** (tonnes U as of 1 January 2005)

Resource category by cost of production	< $40/kg	< $80/kg	< $130/kg	Total*
Reasonably assured	1 947 000	2 643 000	3 297 000	
Inferred	799 000	1 161 000	1 446 000	
Prognosticated	n.a.	1 700 000	2 519 000	
Speculative	n.a.	n.a.	4 557 000	
Total	**2 746 000**	**5 504 000**	**11 819 000**	**14 798 000**

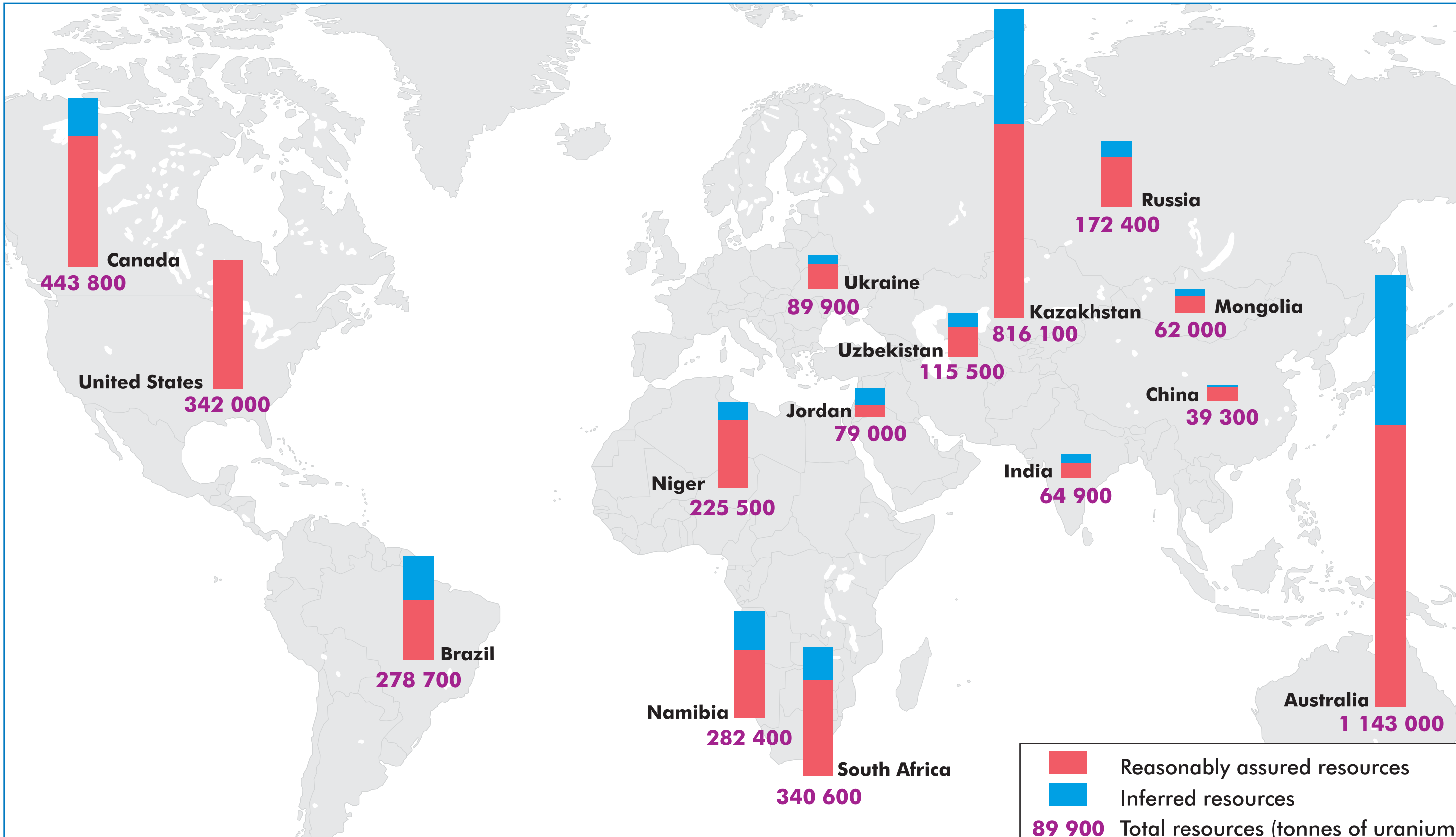
*Total across all categories includes 2 979 000 tonnes U of speculative resources with no recovery cost estimate assigned.
Source: NEA/IAEA (2006).

13

Identified conventional uranium resources are sufficient for several decades of operation at current usage rates. Figure 13.14 compares today's uranium resources with cumulative uranium requirements to 2030 for the lifetime of all the reactors that are operating today and the reactors that are expected to be

13. MOX fuel or mixed oxide is a blend of plutonium and uranium oxides.
14. The discussion of uranium resources, production capacity and uranium prices is based on NEA/IAEA (2006).

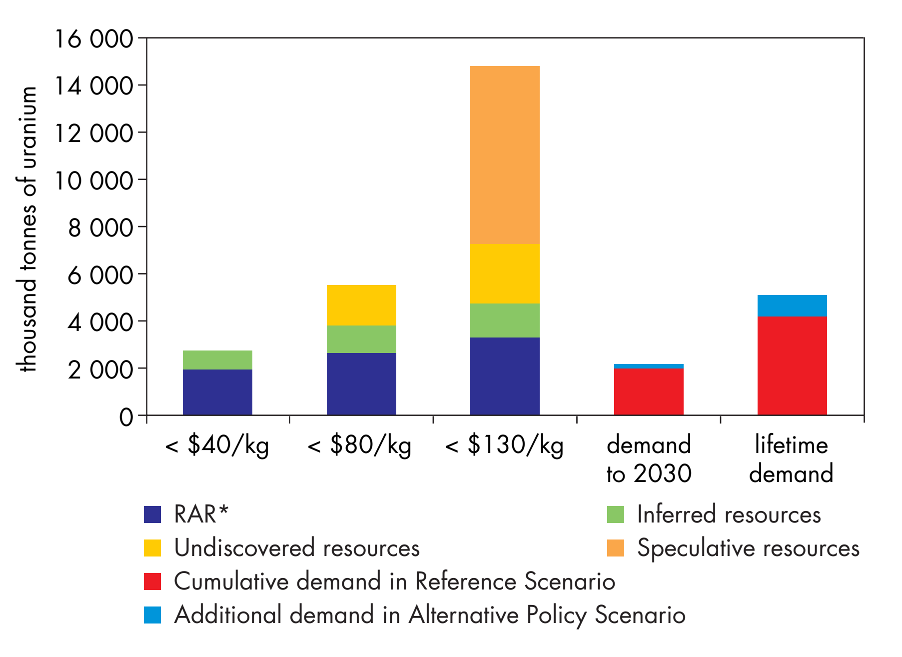
Figure 13.13: **Identified Uranium Resources in Top Fifteen Countries** (tonnes U as of January 2005)



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Based on NEA/IAEA (2006).

Figure 13.14: **Uranium Resources versus Cumulative Uranium Demand**



*RAR= reasonably assured resources (proven).
Source: IEA calculations using uranium resource data in NEA/IAEA (2006). The calculated cumulative uranium demand refers to uranium needed for nuclear plants built in the Reference and Alternative Policy Scenarios until 2030, assuming a 60-year lifetime (but not for plants built after 2030).

built between now and 2030. These requirements amount to just under 2 billion tonnes in the Reference Scenario and 2.2 billion tonnes in the Alternative Policy Scenario. The cumulative requirements over the lifetime of these reactors range between 4.2 billion tonnes and 5.1 billion tonnes. In both scenarios, all demand to 2030 can be met from reasonably assured resources at a production cost below $80 per kg. Beyond 2030, the additional demand can still be met, on the basis of current estimates of total uranium resources, including reasonably assured, inferred and undiscovered resources.

13

Exploitation of more geologically uncertain "undiscovered" resources could provide uranium supplies for several hundred years, but this would require significant exploration and development. The recent increases in exploration activity, driven by rising uranium prices, can be expected to result in new discoveries. Moreover, unconventional uranium resources in phosphates and seawater, as well as alternative fuel cycles based on thorium – an element much more abundant than uranium – hold promise as nuclear fuels in the long term, though this will require further technological development. There is a wide range of technologies under development to secure the future of nuclear power, including Generation IV technologies, fast neutron reactors and nuclear fusion. Such technologies, together with reprocessing and alternative nuclear fuel cycles, could contribute to long-term fuel needs.

Uranium Production

World primary uranium production reached 40 263 tonnes in 2004. The past decade has seen a continuing trend of concentration of uranium production in fewer and fewer countries. While there were 19 uranium-producing countries in 2004, just two of them – Canada and Australia – together produced over half of the total (Table 13.13).

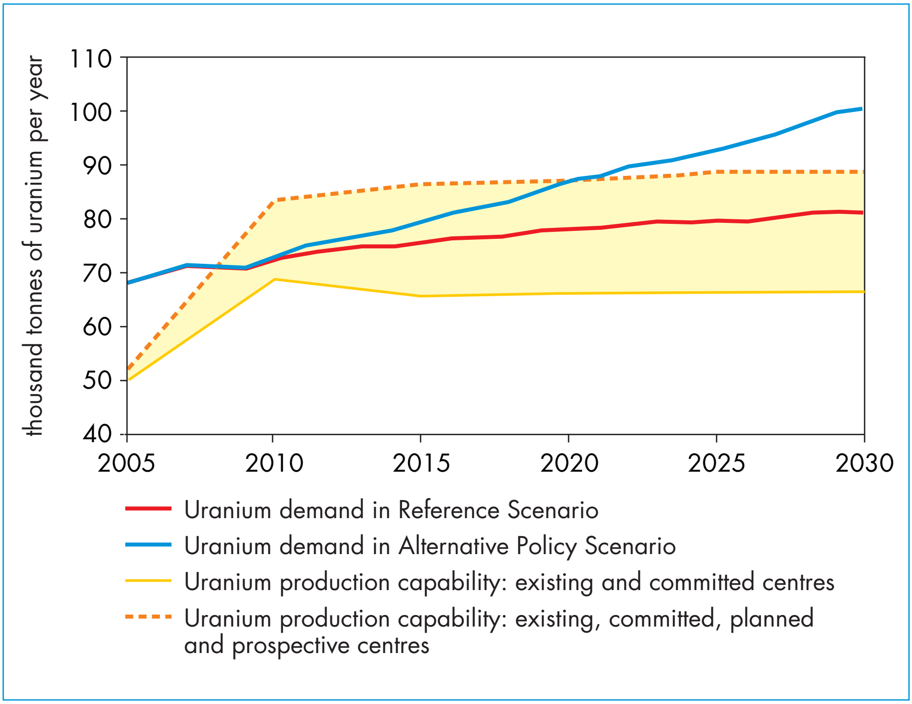
Table 13.13: **World Uranium Production in Selected Countries, 2004**

Country	**Production** (tonnes)	**Share in world uranium producion** (%)
Canada	11 597	28.8
Australia	8 982	22.3
Kazakhstan	3 719	9.2
Russia	3 280	8.2
Niger	3 245	8.1
Namibia	3 039	7.6
Uzbekistan	2 087	5.2
United States	878	2.2
South Africa	747	1.9
Other	2 689	6.7
World	**40 263**	**100**

Source: NEA/IAEA (2006).

Planned production capability from all reported *existing* and *committed* production centres, based on resources estimated to be recoverable at a cost of less than $80 per kg, is sufficient to satisfy about 80% of the Reference Scenario requirements and about 65% of the Alternative Policy Scenario requirements by 2030 (Figure 13.15). Adding *planned* and *prospective* production centres would allow primary production to satisfy demand in the Reference Scenario, but primary production would still fall short of needs in the Alternative Policy Scenario, meeting only about 86% of requirements in 2030. After 2015, the availability of secondary sources of uranium is expected to decline, meaning that reactor requirements will

Figure 13.15: **World Uranium Production Capability and Reactor Requirements in the Reference and Alternative Policy Scenarios** (tonnes per year)



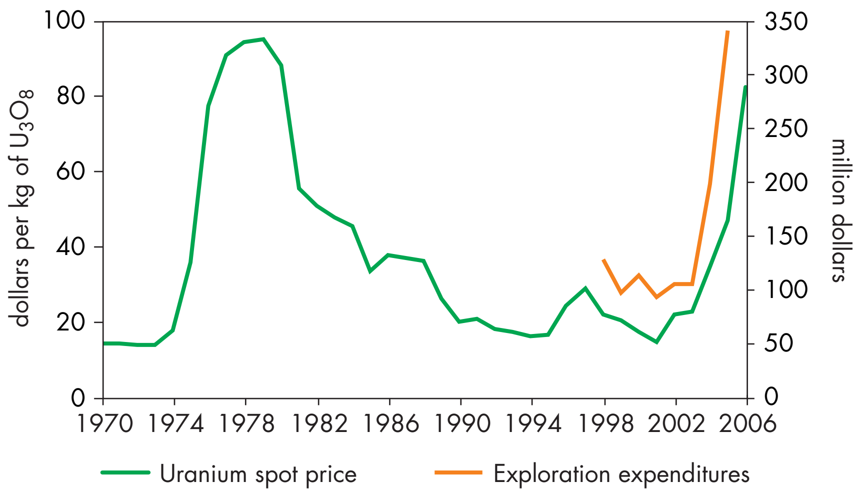
Source: IEA calculations for uranium demand and NEA/IAEA (2006) for production capability.

have to be met increasingly from primary production. Despite the significant additions reported here, primary production capability will require still further expansion, either at existing production centres or at new ones.

Uranium Prices and Investment in Exploration and Production

The overproduction of uranium, which lasted through the 1990s, combined with the availability of secondary sources, resulted in a fall in uranium prices from the early 1980s. The price of uranium rebounded from historic lows in 2001 to levels not seen since the 1980s. The spot price of uranium oxide (uranium ore) increased sixfold, from $13.1 per kg in January 2001 to $94.8 in May 2006 (Figure 13.16). The reasons for the rise include production problems at existing mines in Australia and Canada, uncertainties concerning continued operation of some mines, rising expectations of a nuclear renaissance, an increasing awareness that secondary sources are declining in availability, speculative elements in the

Figure 13.16: **Uranium Oxide (U_3O_8) Spot Prices and Exploration Expenditures**



Note: Prices are in current dollars.
Sources: TradeTech for uranium prices (www.uranium.info); NEA/IAEA (2006) for exploration expenditure.

market and the weakness of the US dollar, the currency used in many uranium transactions. Enrichment and conversion prices have also gone up slightly over the last few years.

Most uranium is traded under long-term contracts and consequently generators' costs have not increased to the same extent as spot prices. Because of the relatively moderate impact that these price increases will have on nuclear power generating costs, there appears to be little cause for concern at the moment.

The recent price increases and the expectation that prices will remain high have triggered significant new exploration and new production projects. Some countries, in particular Australia, Canada and Kazakhstan, have begun to report significant additions to planned future capacity.

Policy Issues

The analysis presented in this chapter shows that new nuclear power plants can produce electricity at competitive prices – if gas and coal prices are high enough and if nuclear construction and operating risks are appropriately handled by the plant vendor, the operating company and/or the regulatory authorities (where markets remain regulated), keeping the cost of capital or discount rate sufficiently low (Table 13.14). Nuclear power generating costs are in the range of 4.9 cents

Table 13.14: **Summary of Nuclear Power Economics**

	Low discount rate	**High discount rate**
Nuclear generating costs (construction costs \$2000 – \$2500 per kW)	4.9 - 5.7 cents per kWh	6.8 – 8.1 cents per kWh
Conditions for nuclear competitiveness		
Fuel costs*	Gas price > \$4.70 – \$5.70 per MBtu Coal price > \$55 – \$70 per tonne	Gas price > \$6.60 – \$8.40 per MBtu Coal price > \$70 – \$105 per tonne
CO_2 price that makes nuclear competitive	With CCGT: competitive without carbon price With coal plant: 0 - \$10 per tonne CO_2	With CCGT: \$15 – \$50 per tonne CO_2 With coal plant: \$10 – \$25 per tonne CO_2

* Fuel costs that correspond to the generating costs of nuclear power shown in the table.

to 5.7 cents per kWh in the lower discount rate estimate, making nuclear power a potentially cost-effective option for reducing carbon-dioxide emissions, diversifying the energy mix and reducing dependence on imported gas.

Economics is only one factor. Many other issues must be addressed to facilitate nuclear investment. The nature of the regulatory process that leads to obtaining a licence to construct and operate a nuclear power plant is a key factor. The uncertainty and costs of the siting and licensing process need to be minimised. A number of countries now discussing the role of nuclear power have not built a nuclear power plant in a long time. The US government has taken steps to review and streamline the regulatory process. It also provides economic incentives for new power plants. In the UK Energy Review, the government has stated its intention of streamlining the regulatory and planning process.

A sound and predictable regulatory framework is essential. In the case of nuclear power, there is a particular risk of retroactive changes, which increases investor uncertainty.

Safety, nuclear waste disposal and the risk of proliferation are all issues which test public acceptability and which must be convincingly addressed. In liberalised markets, private investors will carry the cost of decommissioning and waste from new nuclear build and will need to be able to evaluate the arrangements in place to manage these costs. International cooperation (for example, sharing waste disposal capacity and infrastructure) can help. Fear of proliferation arising from civil nuclear activities can be mitigated only by full participation in and demonstrated compliance with international conventions related to the use of nuclear power.

Based on the projections of the Reference and Alternative Policy Scenarios, the annual amount of spent fuel could reach 12 000 to 15 000 tonnes heavy metal by 2030. Cumulative spent fuel production over the *Outlook* period is likely to range between 470 000 and 620 000 tonnes. This exceeds by far the current storage capacity of 244 000 tonnes, indicating the need for new facilities and policies to manage waste, including reprocessing.[15] Permanent long-term storage facilities must be put in place.

Where governments are determined to enhance energy security, cut carbon emissions and mitigate undue pressure on fossil fuel prices, they may choose to play a role in tackling the obstacles on the path of nuclear power, facilitating the large initial investment required for nuclear plants – between $2 billion and $3.5 billion per unit – and in paving the way for the development of a new generation of reactors. These objectives have become more explicit in recent years and the economics have moved in nuclear power's favour; but concrete measures have so far been few.

15. Current spent fuel production and storage capacity are taken from Fukuda *et al.* (2003).

CHAPTER 14

THE OUTLOOK FOR BIOFUELS

HIGHLIGHTS

- Interest in biofuels – transport fuels derived from biomass – is soaring for energy-security, economic and environmental reasons. Biofuels hold out the prospect of replacing some imported oil by indigenously produced fuels and of diversifying sources. They can also help curb greenhouse-gas emissions, depending on how they are produced, and contribute to rural development. Higher oil prices have made biofuels more competitive with conventional oil-based fuels, but further cost reductions are needed for most biofuels to be able to compete effectively without subsidy.
- In the Reference Scenario, world output of biofuels is projected to climb from 20 Mtoe in 2005 to 54 Mtoe in 2015 and 92 Mtoe in 2030 – an average annual rate of growth of 7%. Biofuels meet 4% of world road-transport fuel demand by the end of the projection period, up from 1% today. In the Alternative Policy Scenario, production rises much faster (at 9% per year), reaching 73 Mtoe in 2015 and 147 Mtoe in 2030 – 7% of road-fuel use.
- In both scenarios, the biggest increases in biofuels consumption occur in the United States, already the world's biggest biofuel consumer, and Europe. Biofuels use outside the United States, Europe and Brazil remains modest. Ethanol is expected to account for most of the increase in biofuels use worldwide, as production costs are expected to fall faster than those of biodiesel – the other main biofuel. Trade grows, but its share of world supply remains small. Production is assumed to be based entirely on conventional crops and technology.
- About 14 million hectares of land are currently used for the production of biofuels – about 1% of the world's available arable land. This share rises to over 2.5% in 2030 in the Reference Scenario and 3.8% in the Alternative Policy Scenario. Rising food demand, which will compete with biofuels for existing arable and pasture land, will constrain the potential for biofuels output, but this may be at least partially offset by higher agricultural yields.
- New biofuels technologies being developed today, notably enzymatic hydrolysis and gasification of woody ligno-cellulosic feedstock, could allow biofuels to play a much bigger role than that foreseen in either scenario. Ligno-cellulosic crops, including trees and grasses, can be grown on poorer-quality land at much lower cost than crops used now to make biofuels. They may also be more environmentally benign. But significant technological challenges still need to be overcome for these second-generation technologies to become commercially viable.

Current Status of Biofuels Production and Use

Market Overview

Interest in biofuels – liquid transport fuels derived from biomass[1] – is soaring in many countries. Biofuels hold out the prospect of replacing substantial volumes of imported oil with indigenously produced renewable fuels and of diversifying the sources of energy supply in the coming decades. Such a development would bring energy-security benefits to importing countries. Produced in a sustainable way, it could also bring environmental benefits, including lower greenhouse-gas emissions, because the raw materials for producing biofuels are renewable. Biofuels can also contribute to rural development and job creation. Farm policy is an important driver of biofuels markets.

The recent surge in international oil prices – together with lower biofuels production costs – has made biofuels more competitive with conventional petroleum-based fuels. But, in most cases, further reductions in costs will be needed for biofuels to be able to compete effectively with gasoline and diesel without subsidy. Land availability and food needs will also limit the growth in conventional biofuels production based on sugar, cereals and seed crops. New biofuels technologies being developed today, notably enzymatic hydrolysis and gasification of ligno-cellulosic feedstock, could allow biofuels to play a much bigger role in the long term. Until recently, most biofuels programmes were conceived as part of farm-support policies, but a growing number of governments are now planning to expand or introduce such programmes for genuine energy-security, economic and environmental reasons.

There are several types of biofuels and many different ways of producing them. Today, almost all biofuels produced around the world are either ethanol or esters – commonly referred to as biodiesel. Ethanol is usually produced from sugar and starchy crops, such as cereals, while biodiesel is produced mainly from oil-seed crops, including rapeseed, palm and sunflowers. Other crops and organic wastes can also be used. Each fuel has its own unique characteristics, advantages and drawbacks. Ethanol, in an almost water-free form (anhydrous ethanol), is usually blended with gasoline (either pure or in a derivative form, known as ethyl-tertiary-butyl-ether, or ETBE).[2] Biodiesel can be used easily in most existing compression-ignition engines in its pure form or in virtually any blended ratio with conventional diesel fuel. Ethanol in a hydrous form

1. The term biofuels is used in this report to refer exclusively to liquid fuels derived from biomass that can be used for transport purposes. Some studies use the term more broadly to cover all types of fuels derived from biomass used in different sectors.

2. ETBE has lower volatility than ethanol, but there are health concerns about its use as a gasoline blending component.

(containing up to 5% water) and some types of biodiesel can be used unblended or in high-proportion blends only with modifications to the vehicle engine. Almost all biofuels are used in cars and trucks, though small quantities of ethanol are used for aviation purposes.

Global production of biofuels amounted to 20 Mtoe, or 643 thousand barrels per day (kb/d)[3] in 2005 – equal to about 1% of total road-transport fuel consumption in energy terms. Brazil and the United States together account for almost 80% of global supply (Table 14.1). The United States is thought to have overtaken Brazil in 2006 as the world's largest producer of biofuels. In both countries, ethanol accounts for almost all biofuels output. US output of ethanol, derived mainly from corn (maize), has surged in recent years as a result of tax incentives and rising demand for ethanol as a gasoline-blending component. In Brazil, production of ethanol, entirely based on sugar cane, peaked in the 1980s, but declined as international oil prices fell back.[4] Falling production costs, higher oil prices and the introduction of vehicles that allow switching between ethanol and conventional gasoline have led to a renewed surge in output. Production of biofuels in Europe is growing rapidly thanks to strong government incentives. The bulk of EU production is biodiesel, which, in turn, accounts for 87% of world biodiesel output. Elsewhere, China and India are the largest producers of biofuels, mostly in the form of ethanol. Only in Brazil, Cuba and Sweden did the share of biofuels in total transport-fuel demand exceed 2% in 2004 (Figure 14.1). This share is nonetheless growing rapidly in several countries as new capacity comes on stream.

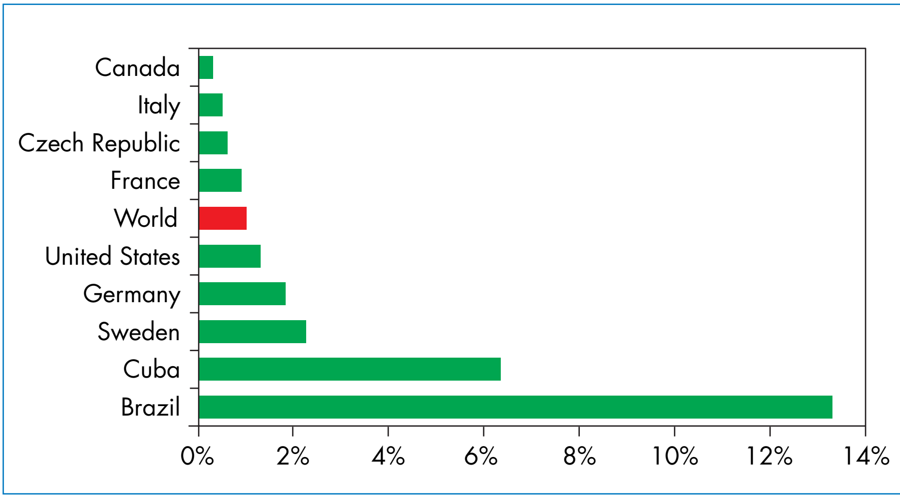
Table 14.1: **Biofuels Production by Country, 2005**

	Ethanol		Biodiesel		Total	
	Mtoe	kb/d	Mtoe	kb/d	Mtoe	kb/d
United States	7.50	254	0.22	5	7.72	259
Canada	0.12	4	0.00	0	0.12	4
European Union	0.48	16	2.53	56	3.01	72
Brazil	8.17	277	0.05	1	8.22	278
China	0.51	17		negligible	0.51	17
India	0.15	5		negligible	0.15	5
World	**17.07**	**579**	**2.91**	**64**	**19.98**	**643**

Source: IEA analysis based on F.O.Licht (2006).

3. Unless otherwise stated, volume equivalents are not adjusted to take account of differences in energy content, because the latter differ by type of fuel and because other characteristics affect fuel economy in practice.
4. See Chapter 16 for a detailed discussion of energy prospects generally in Brazil.

Figure 14.1: **Share of Biofuels in Total Road-Fuel Consumption in Energy Terms by Country, 2004**



Sources: F.O.Licht (2006) and IEA databases.

Ethanol

Conventional ethanol production technology involves fermenting sugar obtained directly from sugar cane or beet, or indirectly from the conversion of the starch contained in cereals. The ethanol produced is then distilled to produce a fuel-grade liquid. In OECD countries, most ethanol is produced from starchy crops like corn, wheat and barley, but ethanol can also be made from potatoes and cassava, or directly from sugar cane and sugar beet. In tropical countries like Brazil, ethanol is derived entirely from sugar cane. Starchy crops first have to be converted to sugar in a high-temperature enzymatic process. The sugar produced in this process or obtained directly from sugar crops is then fermented into alcohol using yeasts and other microbes. The grain-to-ethanol process yields several by-products, including protein-rich animal feed. By-products reduce the overall cost of ethanol, as well as the net greenhouse-gas emissions associated with its production, where crop residues such as straw or bagasse are used to provide heat and power for the ethanol production process.

Efforts to introduce ethanol into the market for road-transport fuels for spark-ignition engines have focused on low-percentage blends, such as ethanol E10, a 10% ethanol and 90% gasoline blend (known as gasohol in Brazil and the United States). Such blends, which are already marketed in many countries, do not require engine modifications and can be supplied in the same way as gasoline through existing retail outlets. Higher-percentage blends, with more than 30% ethanol, or pure ethanol can be used only with some modifications to the vehicle engine. Ethanol has a high octane value, which makes it an attractive gasoline-blending component. It has generally good performance characteristics, though its energy content by volume is only two-thirds that of gasoline. The higher volatility of ethanol can create problems, especially in the summer months. Demand for ethanol as an octane enhancer is rising in several countries, especially the United States, where methyl-tertiary-butyl-ether (MTBE) – the most commonly used oxygenate – is being phased out or discouraged for health and environmental reasons. The fuel economy of a vehicle with an engine modified to run on pure ethanol, measured by kilometres per litre, can approach that of a gasoline-only version of the same vehicle, despite ethanol's lower energy content.[5] In several countries, "flex-fuel" vehicles, which allow consumers to switch freely between high-proportion ethanol blends and gasoline, have recently become available. This insulates the consumer from any sudden jump in the price of ethanol relative to gasoline that might result from a supply shortage or a drop in gasoline prices.

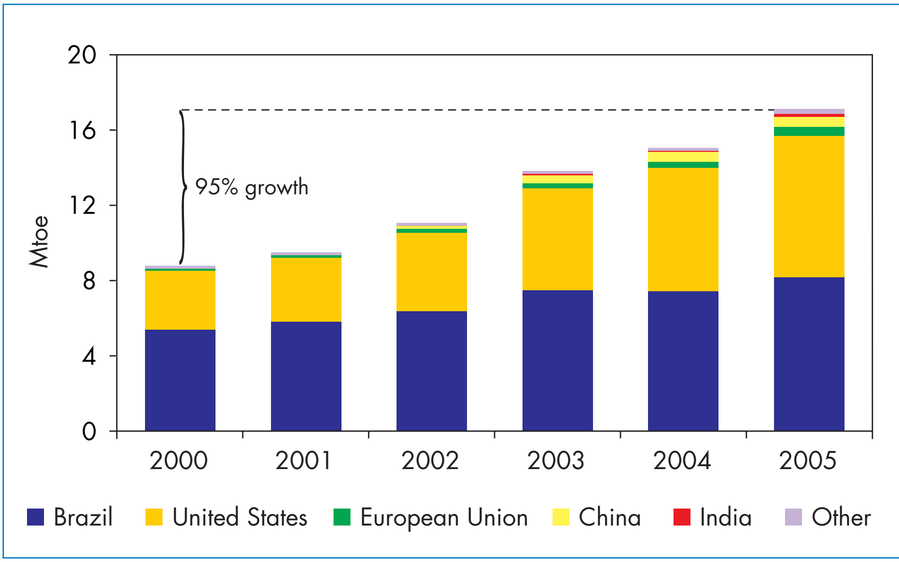
Ethanol production is rising rapidly in many parts of the world in response to higher oil prices, which are making ethanol more competitive, especially where reinforced by government incentives and rules on fuel specifications. Global production reached 17.1 Mtoe (579 kb/d) in 2005, almost double the level of 2000 (Figure 14.2). The United States accounted for much of the increase in output over that period. In most cases, virtually all the ethanol produced is consumed domestically, though trade is growing rapidly. Brazil accounts for half of global trade in ethanol (see below).

Biodiesel

The most well-established technology for biodiesel production is the *transesterification* of vegetable oils or animal fats. The process involves filtering the feedstock to remove water and contaminants, and then mixing it with an alcohol (usually methanol) and a catalyst (usually sodium hydroxide or potassium hydroxide). This causes the oil molecules (triglycerides) to break apart and reform into esters (biodiesel) and glycerol, which are then separated

5. This depends on whether the engine is optimised to run on ethanol. The high octane number of ethanol-rich blends, plus the cooling effect from ethanol's high latent heat of vaporisation, allows a higher compression ratio in engines designed for ethanol-rich blends. This is especially the case for vehicles using direct-injection systems. These characteristics result in increased horsepower and can partially offset the lower energy content of ethanol vis-à-vis gasoline.

Figure 14.2: **World Ethanol Production**



Source: IEA analysis based on F.O.Lichts (2006).

from each other and purified. The process also produces glycerine, which is used in many types of cosmetics, medicines and foods.[6]

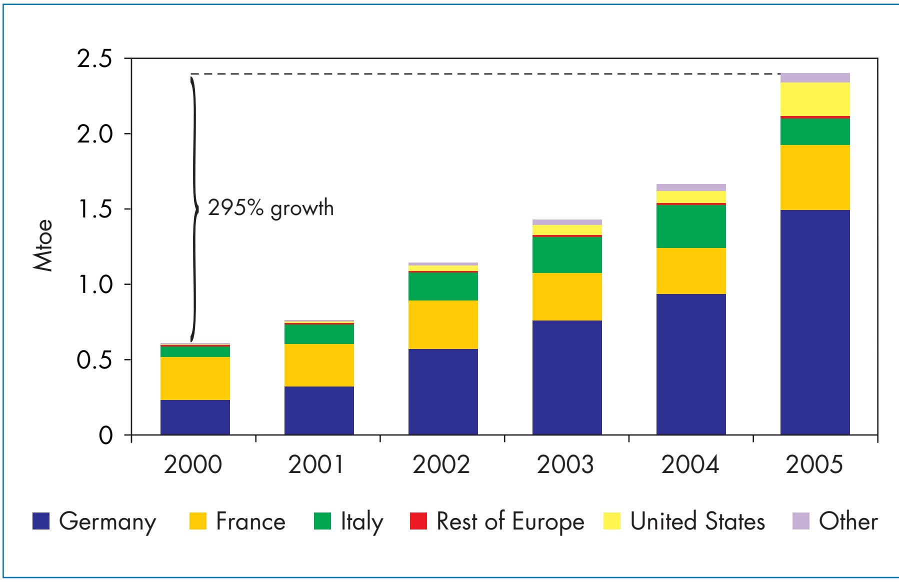
Total production of biodiesel worldwide remains small compared with that of ethanol, amounting to about 2.9 Mtoe (64 kb/d) in 2005. Close to 90% is produced and consumed in Europe. Germany and France are the biggest producers, followed by Italy, Austria, Belgium, the Czech Republic and Denmark. Production has risen sharply in recent years, surging in 2005 (Figure 14.3). Some countries outside Europe, including the United States, Brazil and Australia, have recently started producing biodiesel. Brazil opened its first biodiesel plant, using a mixture of vegetable oil and sewage, in March 2005. International trade in biodiesel is minimal as yet.

As with ethanol, most biodiesel is blended with conventional fuel, usually in a 5% blend (B5) for use in conventional vehicles. It is also marketed in some countries in blends up to 20% (B20) or in a pure form (B100) that some specially modified diesel vehicles can handle. In Germany, B100 has been available for several years at more than 700 service stations. Biodiesel's zero-

6. The co-production of glycerine improves the economics of making biodiesel, but the market value of glycerine is falling as biodiesel production rises because the commercial demand for non-energy uses is limited: it may increasingly be used as an energy input to the production process itself.

sulphur content and its solvent and lubricant properties, which improve engine performance and the life of engine parts, make it an attractive blending component. Biodiesel contains only about 90% as much energy as conventional diesel, but its lubricity and higher cetane number (a measure of the combustion quality of diesel under compression) mean that fuel economy is similar.

Figure 14.3: **World Biodiesel Production**



Source: F.O.Licht (2006).

The Environmental Impact of Biofuels

The net impact on greenhouse-gas emissions[7] of replacing conventional fuels with biofuels depends on several factors. These include the type of crop, the amount and type of energy embedded in the fertilizer used to grow the crop and in the water used, emissions from fertilizer production, the resulting crop yield, the energy used in gathering and transporting the feedstock to the biorefinery, alternative land uses, and the energy intensity of the conversion process. Calculating the energy and emissions balance of biofuel production

7. Tailpipe emissions from biofuels are not much different from those from gasoline and diesel for several toxic and noxious gases, but can be lower for some gases.

requires estimates of, or assumptions about, all these variables, as well as the energy or emissions credit that should be attributed to the various by-products. Carbon-dioxide emissions at the point of use are assumed to be zero, on the grounds that the biomass feedstock is a renewable resource (the carbon emitted is exactly equal to the carbon absorbed by the biomass).

In practice, the amount and type of primary energy consumed in producing biofuels and, therefore, the related emissions of greenhouse gases, vary enormously. A recent study compares several reports on corn-based ethanol production in the United States, in order to compile estimates of primary fossil-energy input/output ratios and net greenhouse-gas emissions using consistent parameters (Farrel *et al.*, 2006). It concludes that the "best point estimate" is that the primary energy input (excluding the biomass feedstock) is equal to about 80% of the energy contained in the ethanol output.[8] About 20% of the primary energy is petroleum and the rest is coal and natural gas. On this basis, greenhouse-gas emissions are only 13% lower per kilometre compared with petroleum-based fuels. Another recent study, published by the European Commission, shows that conventional ethanol production can result in a net saving of up to 23% of the fossil energy required for gasoline and a saving of over 30% in greenhouse-gas emissions (European Commision, 2006c).

The emission savings from ethanol production in Brazil are considerably higher. This is because sugar-cane yields are much higher than for corn-based ethanol, and because the fossil-fuel needs for processing are lower, as the sugar is fermented directly and the crushed stalk of the plant (known as bagasse) rather than fossil energy is used in the production process. For each unit of sugar-based ethanol produced there, only about 12% of a unit of fossil energy is required (IEA, 2004). As a result, CO_2 emissions calculated on a "well-to-wheels" basis are also very low, at about 10% of those of conventional gasoline. Studies also indicate that the conversion of sugar beet into ethanol in Europe can yield reductions in well-to-wheels emissions of typically between 40% and 60%, compared with gasoline.

Estimates for the net reduction in greenhouse-gas emissions that are obtained from rapeseed-derived biodiesel in Europe also range from about 40% to 60%, compared with conventional automotive diesel. As for ethanol, these results are sensitive to several factors, including crop yields and the use of the by-products. If more of the glycerine produced with the biodiesel is used for energy purposes, the net emission savings would be higher. Biodiesel yields vary widely

8. Previous studies suggest a range of 0.6 to 0.8 units of primary energy for each unit of corn-based ethanol produced (IEA, 2004).

according to the conversion process, the scale of production and region, and the type of crop used.

Biofuels production and use can have other important environmental effects. In particular, major changes in the use of farm land could profoundly affect local and regional ecosystems, with both positive and negative implications for flora and fauna. These effects depend on what land is used, which crops are grown for biofuels and farming techniques:

- Conventional agricultural crops, such as rapeseed, corn and cereals used to produce first-generation biofuels generally require high-quality farm land and substantial amounts of fertilizer and chemical pesticides. The production of such crops for biofuels would increase global competition for arable land, increase the pressure to turn more land over to crops, including rain forests, and drive up food and fodder prices.

- The environmental impact of sugar-cane cultivation, as practiced in Brazil, is generally smaller. Experience has shown that soil quality productivity can be maintained, over decades of production, by recycling the nutrients in the waste from the sugar mill and distillery back to the fields. However, using more bagasse as an energy input to ethanol production would reduce the amount of nutrients recycled. Most sugar-cane production in Brazil and other countries depends on rainfall and does not require irrigation.

- Palm oil is produced on plantations, typically on poor soils, but without the need for extensive use of fertilizers and pesticides. However, increases in the size of plantations can lead to the loss of rain forests, especially in southeast Asia.

Perennial ligno-cellulosic crops, such as eucalyptus, poplar or willow trees, can be harvested several times at intervals of three to seven years. Grasses can be harvested each year. Management is far less intensive compared to annual crops and fossil-energy inputs are generally low, with typical energy input/output ratios of between 1:10 and 1:20. Ligno-cellulosic crops can be grown on poor-quality land, requiring less fertilizer. In addition, most nutrients remain on the land because, for deciduous trees, the harvest takes place after the nutrient-rich leaves have dropped. As a result, soil carbon and quality tends to increase over time, especially when compared to conventional farming. Switching to the second-generation ligno-cellulosic ethanol technology, currently under development, could, therefore, greatly reduce the environmental drawbacks of biofuels production.

Prospects for Biofuels Production and Use

Summary of Projections to 2030

Demand for road-transport fuels is expected to increase strongly in the coming decades, especially in developing regions. By 2030, global energy use in that sector is expected to be 55% higher than in 2004 in the Reference Scenario and 38% higher in the Alternative Policy Scenario. Biofuels are expected to play an increasingly important role in meeting transport demand, though the rates of penetration differ substantially between the two main scenarios set out in this *Outlook* (Table 14.2):

- In the Reference Scenario, total world production of biofuels is projected to climb from 20 Mtoe in 2005 to 42 Mtoe in 2010, 54 Mtoe in 2015

Table 14.2: **World Biofuels Consumption by Scenario** (Mtoe)

	2004	2010		2015		2030	
		RS	APS	RS	APS	RS	APS
OECD	**8.9**	**30.5**	**34.7**	**39.0**	**51.6**	**51.8**	**84.2**
North America	7.0	15.4	17.4	20.5	28.8	24.2	45.7
United States	*6.8*	*14.9*	*16.4*	*19.8*	*27.5*	*22.8*	*42.9*
Canada	*0.1*	*0.6*	*1.0*	*0.7*	*1.3*	*1.3*	*2.8*
Europe	2.0	14.8	16.4	18.0	21.5	26.6	35.6
Pacific	0.0	0.3	0.8	0.4	1.4	1.0	2.9
Transition economies	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**	**0.5**
Russia	0.0	0.1	0.1	0.1	0.2	0.3	0.5
Developing countries	**6.5**	**10.9**	**14.0**	**15.3**	**21.1**	**40.4**	**62.0**
Developing Asia	0.0	1.9	4.6	3.7	8.5	16.1	32.8
China	*0.0*	*0.7*	*1.2*	*1.5*	*2.7*	*7.9*	*13.0*
India	*0.0*	*0.1*	*0.1*	*0.2*	*0.3*	*2.4*	*4.5*
Indonesia	*0.0*	*0.2*	*0.3*	*0.4*	*0.6*	*1.5*	*2.3*
Middle East	0.0	0.1	0.1	0.1	0.1	0.5	0.6
Africa	0.0	0.6	0.7	1.1	1.2	3.4	3.5
North Africa	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*0.6*	*0.5*
Latin America	6.4	8.4	8.6	10.4	11.2	20.3	25.1
Brazil	*6.4*	*8.3*	*8.6*	*10.4*	*11.0*	*20.3*	*23.0*
World	**15.5**	**41.5**	**48.8**	**54.4**	**73.0**	**92.4**	**146.7**
European Union	*2.0*	*14.8*	*16.4*	*18.0*	*21.5*	*26.6*	*35.6*

Note: RS = Reference Scenario; APS = Alternative Policy Scenario.

and 92 Mtoe in 2030. The average annual rate of growth is 6.3%. To meet this demand, cumulative investment in biorefineries of $160 billion (in year-2005 dollars) over 2005-2030 is needed.

- In the Alternative Policy Scenario, production rises much faster, at 8.3% per year, reaching 73 Mtoe in 2015 and 147 Mtoe in 2030. Cumulative investment totals $225 billion over the *Outlook* period.

In both scenarios, the biggest increases in biofuels consumption occur in the United States – already the world's largest biofuels market – and in Europe, which overtakes Brazil as the second-largest consuming (and producing) region before the end of the current decade. Biofuels use outside these regions remains modest, with the biggest increases occurring in developing Asia.

The costs of both ethanol and biodiesel production using conventional technologies are expected to fall in both scenarios in line with incremental efficiency improvements in the conversion processes and in agricultural productivity. In neither scenario are second-generation biofuels technologies, such as ligno-cellulosic ethanol or biomass gasification, assumed to penetrate the market. This is because important breakthroughs in developing these technologies will be necessary before they can be deployed commercially on a large scale. It is nonetheless possible that such breakthroughs could occur in the near future, which could pave the way for faster development of biofuels markets. Biofuel prices are expected to be attractive to blenders and consumers in the main growth markets, regardless of costs, as a result of fuel taxation and subsidy policies favouring biofuels.

Biofuels meet 4% of world road-transport fuel demand by the end of the projection period in the Reference Scenario, up from 1% today (Figure 14.4). In the Alternative Policy Scenario, the share reaches 7%, thanks to higher demand for biofuels but lower demand for road-transport fuels in total. The share remains highest in Brazil, though the pace of market penetration will be fastest in the European Union in both scenarios.

Ethanol is expected to account for most of the increase in biofuels use worldwide, as production costs are expected to fall faster than those of biodiesel. The share of biodiesel globally nonetheless grows in both scenarios, mainly because biodiesel production accelerates in the United States and Brazil (Figure 14.5). By 2030, biodiesel is expected to account for about 15% of total biofuels use in both countries and in both scenarios. By contrast, the biodiesel share of total biofuels consumption in the European Union is projected to drop from well over half today to under a third in 2030, as ethanol is expected to become a more attractive option for fuel suppliers.

The bulk of the biofuels consumed in each region will continue to be produced indigenously, as a result of protective farm and trade policies. The volume of biofuels traded internationally is nonetheless expected to grow significantly.

Figure 14.4: **Share of Biofuels in Road-Transport Fuel Consumption in Energy Terms**

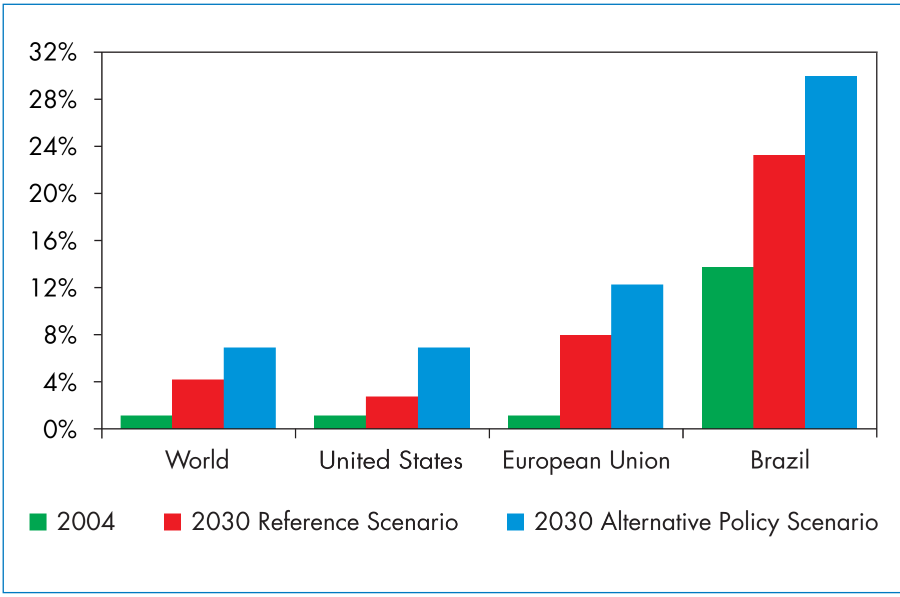
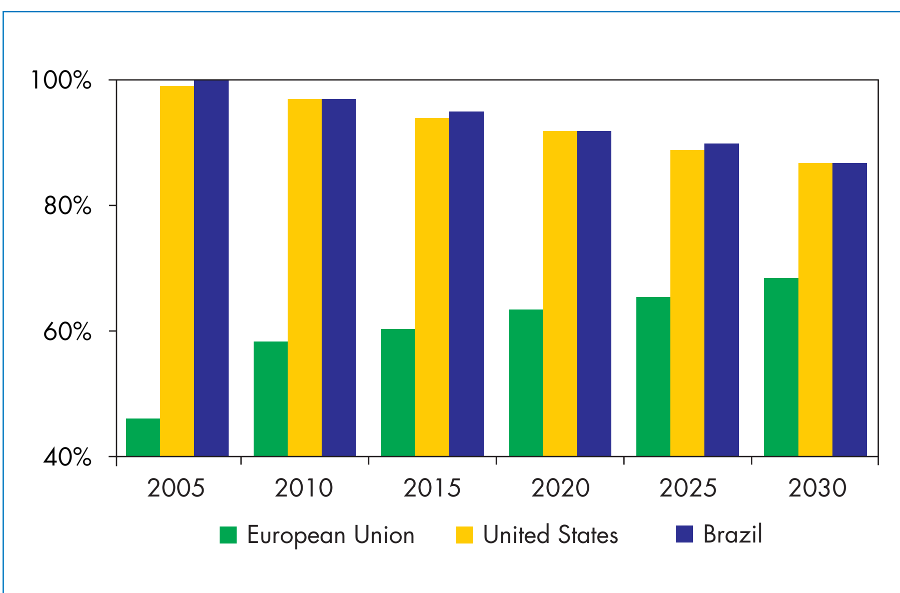


Figure 14.5: **Share of Ethanol in Total Biofuels Consumption in Energy Terms in Brazil, the European Union and the United States in the Reference Scenario**



Only those regions that have the potential to produce biofuels without subsidy are expected to export. Most exports will probably take the form of ethanol derived from sugar cane, because there will be less need to subsidise it, compared with biodiesel, and because countries that subsidise biodiesel are unlikely to permit producers to export that fuel. Brazil is expected to remain the largest ethanol exporter over the projection period. Some developing Asian and African countries have ethanol production costs close to those of Brazil and may emerge as significant exporters in the coming decades, depending on domestic requirements and trade policies. Malaysia, Indonesia and the Philippines could become exporters of biodiesel derived largely from palm oil. The European Union and the United States may become sizable net importers of biofuels, especially in the Alternative Policy Scenario, as demand outstrips domestic production. The way international trade in biofuels develops will depend on whether trade barriers are removed, on subsidy policies and on timely investment in production facilities.

In the Reference Scenario, existing biofuels policies are assumed to remain in place. A growing number of governments are actively supporting the development of the biofuels sector in recognition of the environmental benefits and energy-security benefits from reduced oil imports and from more diverse sources of energy supply. Although national circumstances vary markedly, in every country that has managed to develop a sizeable biofuels industry, strong government support has been required to kick-start the industry and bridge the gap between the market value of the fuel and its production cost. Government support can take various forms, including direct financial assistance to biorefiners and retailers in the form of grants, tax credits or cheap loans, subsidies to farmers, tax exemptions for flex-fuel vehicles and tax exemptions or rebates for biofuels. A number of countries have also set targets for the percentage and quantity of biofuels to be used in pure form or blended with conventional fuels. In some countries, fuel retailers are obliged to market particular blends, such as E20 in Brazil. A 2% biodiesel blend, which is currently voluntary, will become mandatory in that country from 2008. Mandatory fuel-mix requirements for oil companies are applied in 11 countries. Table 14.3 summarises the main measures currently in place in selected countries.

In the Alternative Policy Scenario, new policy measures to encourage the production and use of biofuels, which are now being considered by governments around the world, are taken into account (see Part B). These include larger subsidies to producers and consumers of biofuels and flex-fuel vehicles, more extensive vehicle-purchase mandates and increased spending on research and development. Trade barriers for agricultural products are also assumed to be reduced. Such barriers are restricting access in many industrialised countries to imported biofuels, which is holding back the growth of the industry in countries with the lowest production costs.

Table 14.3: **Summary of Current Government Support Measures for Biofuels in Selected Countries/Regions**

Country	Official targets*	Production incentives	Consumption incentives
Brazil	40% rise in production, 2005-2010 (ethanol)	Tax incentives for oil-seed production Loan assistance Reduced levels of industrial tax	Tax exemptions for vehicles able to use E blends, and flex-fuel vehicles Fuel tax advantage over petrol Price controls
US	2.78% for 2006 (ethanol)	Tax credits Producer payments Grant and loan programmes	Vehicle tax credits and fuel tax exemptions Subsidies on flex-fuel vehicles Government fleet requirement Loan assistance
Canada	3.5% by 2010 (ethanol)	Some provinces exempt ethanol from road tax	Exemption from excise tax (CA$ 0.085/litre)
Sweden	3% in 2005 (biofuels, by energy content)	Tax incentives for new plants Access to EU Common Agricultural Policy (CAP) provisions Capital grants	Exemption from fuel excise duty
France	5.75% in 2008; 7% in 2010; 10% in 2015 (biofuels)	Tax credits on equipment using renewable energy Tax penalty on refiners not using biofuels Access to EU CAP provisions Capital grants	Capped fuel tax exemptions Quotas

Table 14.3: **Summary of Current Government Support Measures for Biofuels in Selected Countries/Regions** *(Continued)*

Country	Official targets*	Production incentives	Consumption incentives
Germany	2% in 2005 (biofuels)	Access to EU CAP provisions Capital grants	Fuel tax exemptions for both pure and blended biofuels
UK	5% by 2020 (biofuels, by energy content)	Access to EU CAP provisions Capital grants	Part fuel excise exemption
India	5% "in near future" (biofuels)	Subsidies for inputs Tax credits and loans	Fuel tax exemptions Guaranteed prices
Japan	500 million litres by 2010	None (imports are expected to cover most ethanol needs)	None
China	15% by 2020 (total renewables)	$200 million research and development budget Loan assistance Various direct subsidies, including tax exemptions	
Thailand	2% by 2010 (biofuels)	Assistance to farmers Investment incentives for ethanol projects	50% road-tax discount for vehicles operating on biofuels Excise and fuel tax exemption

* Share of biofuels in total road-fuel consumption by volume (unless otherwise specified).
Sources: IEA databases; ACG (2005).

Regional Trends

Brazil

Biofuels consumption continues to grow in both scenarios. It more than triples over 2004-2030 in the Reference Scenario and grows by a factor of three-and-a-half in the Alternative Policy Scenario. Ethanol derived from sugar cane accounts for the bulk of the increase, but the share of biodiesel in total biofuels consumption rises from virtually zero in 2004 to about 15% in 2030 in both scenarios. Output of ethanol is expected to grow faster than consumption, allowing exports to expand – especially in the Alternative Policy Scenario. No significant trade in biodiesel is expected.

Thanks to a combination of climate, soil and relatively low labour and land costs, Brazil is currently the world's lowest-cost producer of sugar cane and, therefore, ethanol. In 2005, it produced one-quarter of the entire world's sugar cane. Roughly half of this output was used to make ethanol, the output of which reached 8.2 Mtoe (277 kb/d) – an increase of 51% over 2000. Until 2006, Brazil was the world's biggest ethanol producer. There are now about 300 ethanol refineries, most of which are located in the centre and south of the country, where sugar yields are highest. There are about 250 separate producers, but most of them are grouped in two associations that make up 70% of the market.

Brazil's ethanol programme dates back to the 1970s, when the government launched the ProAlcool programme in response to the first oil-price shock. The programme sought to encourage ethanol production and use through a combination of subsidies, tax incentives and regulatory measures. By the mid-1980s, some 90% of all new cars sold in Brazil were running on hydrous ethanol. A surge in sugar prices at the end of the 1980s, together with lower oil prices, caused a slump in ethanol production as sugar growers diverted their production to the export market. This resulted in a loss of public confidence in the security of ethanol supply. By the end of the 1990s, sales of dedicated ethanol-fuelled cars had almost dried up.

Interest in ethanol rebounded in the early 2000s, with higher oil prices and the introduction of the first flex-fuel cars, even though subsidies had been removed by then. Rising demand for oxygenates has driven up ethanol prices, boosting the profitability of ethanol production and stimulating investment in new sugar-cane plantations and biorefineries. Less than three years after they were introduced, flex-fuel vehicles now make up more than three-quarters of the vehicles sold in Brazil. Flex-fuel vehicle prices are no higher than those for conventional gasoline cars. All refuelling stations in Brazil sell near-pure hydrous ethanol (E95) and anhydrous gasohol (E10), and about a quarter also sell a 20% anhydrous ethanol blend (E20). In total, almost two-thirds of the ethanol currently consumed in Brazil is anhydrous. The price of ethanol has risen faster than that of gasoline in the past year, mainly due to high international sugar prices (in part, a result of the increasing amount of sugar used for ethanol production). This prompted the government to lower the minimum ethanol content in gasoline blends from 25% to 20% to prevent an ethanol shortage. Gasoline without ethanol can no longer be marketed in Brazil.

Exports of ethanol have increased sharply in recent years, from little more than 200 ktoe (7 kb/d) in 2000 to over 1.3 Mtoe (41 kb/d) in 2005. Buyers include the United States, India, Venezuela, Nigeria, China, Korea and Europe. Japan is negotiating a deal to import Brazilian ethanol to help meet its commitments to limit greenhouse-gas emissions under the Kyoto Protocol and to replace MTBE, which is being phased out.

The Brazilian government has set a goal of raising ethanol production by 40% between 2005 and 2010. Investment plans suggest that this target is likely to be met, though how much capacity is actually utilised will depend on the ratio of ethanol prices to both gasoline and sugar prices. Logistical constraints may also limit how quickly production can be raised. A major increase in exports will call for large-scale investments in new ports, storage and loading facilities, as well as railway and waterway links between the main producing regions and the ports (see Chapter 16).

United States

US biofuels consumption is projected to surge to more than three times its current level by 2030 in the Reference Scenario and over six times in the Alternative Policy Scenario. In these scenarios, biofuels meet respectively 3.4% and 7.3% of total road-transport fuel needs in 2030. In the Reference Scenario, the United States is the world's second-largest consumer of biofuels; in the Alternative Policy Scenario, it is the biggest.

US ethanol output, which is derived almost entirely from corn, reached 7.5 Mtoe (254 kb/d) in 2005, supplemented by a small volume of imported fuel. It has more than doubled since 2000. The United States is thought to have overtaken Brazil in 2006 to become the world's largest producer of ethanol, as a number of new plants have come on stream (Table 14.4). By mid-2006, 102 ethanol plants were in operation and another 43 were under construction. Most of them are dry mills, which produce ethanol as the primary output; wet mills are designed to produce a range of products alongside ethanol, including maize oil, syrup and animal feed. Most of the ethanol is used in low-percentage gasoline blends, but sales of high-percentage blends are rising. About 6 million flex-fuel vehicles are now running on E85. The United States also produces a small volume of biodiesel, mainly from soybeans; output totalled 220 ktoe (5 kb/d) in 2005 – less than half of one per cent of that of ethanol – though production capacity is growing rapidly.

Table 14.4: **US Biofuels Production Capacity**

	Available end-August 2006		Under construction or planned		Total	
	kb/d	Mtoe	kb/d	Mtoe	kb/d	Mtoe
Ethanol	319	9.4	193	5.7	512	15.1
Biodiesel	26	1.2	47	2.1	72	3.3
Total	**344**	**10.6**	**240**	**7.8**	**584**	**18.4**

Source: IEA analysis based on data from the Renewable Fuels Association website (www.ethanolrfa.org/industry/locations/) and the National Biodiesel Board website (www.biodiesel.org/).

The development of the corn-based ethanol industry has been boosted by a federal excise-tax credit on the sale of ethanol, currently amounting to $0.51 per gallon for all blends ($0.13 per litre). Some states also have partial tax exemptions and provide direct support to ethanol producers. To protect US corn growers, an import tariff of $0.54 per gallon ($0.14 per litre) is applied. Federal and state fleet alternative-fuel vehicle purchase mandates and voluntary programmes, such as Clean Cities, have also boosted ethanol use. Corn and soybean growers also receive generous federal subsidies. Roughly 10% of the corn crop is currently used for ethanol production. Support for biodiesel is much more recent. In 2005, Minnesota became the first state to introduce a requirement that diesel contain at least 2% biodiesel. A federal excise-tax credit of $0.01 per gallon of crop-based biodiesel for each percentage point share in the fuel blend was introduced in January 2005.

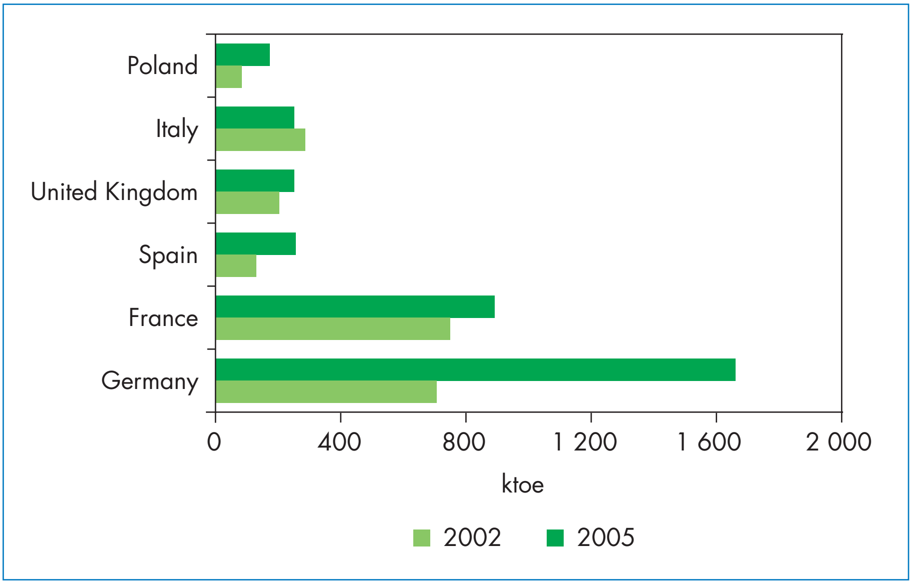
The phase-out of MTBE from the US gasoline pool is giving added impetus to ethanol demand and prices. Under the 2005 Energy Bill, refiners are no longer required to add any oxygenates, such as MTBE, to gasoline blends, though certain emission limits still apply. MTBE has been implicated in the contamination of groundwater wells in many areas around the nation and the compound is also believed to be a carcinogen. More than half of the states have now adopted legislation banning its use and refiners have decided to drop the additive altogether to avoid the threat of costly legal action where it is still allowed. The US Energy Information Administration estimates that the phase-out of MTBE could raise ethanol demand in 2006 by approximately 130 kb/d – an increase of almost 50% on 2005 (USDOE/EIA, 2006). US ethanol capacity is expected to jump by about a quarter in 2006, but even this may not be sufficient to meet all of the new demand. As a result, there are calls for fuel standards to be eased and for import tariffs to be removed to prevent domestic ethanol prices from rising further, which would, in turn, push up gasoline prices at the pump. The price of ethanol has risen sharply in recent years in absolute terms and relative to gasoline.

European Union

EU biofuels consumption is projected to soar over the projection period, by a factor of 13 in the Reference Scenario and 18 in the Alternative Policy Scenario. Ethanol contributes most of the increase, its share of total biofuels use rising from about a fifth today to over two-thirds in 2030 in both scenarios. The European Union nonetheless remains the leading region for biodiesel. Most biofuels will be produced within the region, but imports play an increasing role, especially in the Alternative Policy Scenario.

Biodiesel made up 84% of the 3 Mtoe of all biofuels produced and consumed in the European Union in 2005. Germany alone accounted for 62% of EU biodiesel output, with most of the rest coming from France, Italy and Spain (Figure 14.6). EU production trebled between 2000 and 2005, with the adoption of stronger national government incentives in an attempt to meet EU targets. Germany and Spain saw the biggest increases in output. Biodiesel use varies considerably across EU countries. In Germany, a significant share of biodiesel is sold in pure form (B100), whereas in France it is used exclusively in a B5 blend. In Italy, half of the biodiesel produced is used as heating fuel, with the rest blended into B5.

Figure 14.6: **Biofuels Consumption in Selected EU Countries**



Source: F.O.Lichts (2006).

EU biofuels production and use have been primarily driven by farm policy. Under the EU Common Agricultural Policy and a trade agreement with the United States, set-aside land – farm land left fallow, for which farmers are paid a per-hectare subsidy, to reduce surplus output – can be used to grow crops for biofuels up to a limit of 1 million tonnes of soybean equivalent per year. In addition, member states are permitted to levy lower excise taxes on biofuels than on conventional transport fuels. Some countries, including Germany, levy no excise tax at all on biodiesel. Several countries also provide financial incentives for investment in biorefineries. In 2003, the European Union adopted a directive requiring all member states to set non-binding national targets for a minimum share of biofuels in the road-transport-fuel market. The target was 2% for end-2005, rising to 5.75% by end-2010. Although the share reached only about 1.4% in 2005, it was well up on the level of 0.6% in 2003. The 2010 target is more or less achieved in the Alternative Policy Scenario, where the share reaches 5.6%, but not in the Reference Scenario, where the share is only 4.9%. The European Commission is reassessing its biofuels strategy (European Commission, 2005 and 2006a and b).

Other Regions

Biofuels use in other regions is expected to remain modest in both scenarios. Several Asian countries are planning to launch or expand biodiesel programmes. Malaysia is emerging as the leading producer, with 14 plants approved and a further 36 under consideration, all based on palm oil. Most are aimed at meeting domestic or regional demand, though exports to Europe are also envisaged. China is the main importer of Malaysian biodiesel. India has started producing ethanol and plans to begin producing biodiesel soon. China, Indonesia, Thailand and the Philippines are also planning new plants, though the volumes are relatively modest.

Chinese demand in the Reference Scenario is projected to rise from about 0.5 Mtoe today to 1.5 Mtoe in 2015 and just under 8 Mtoe in 2030. It rises to almost twice these levels in the Alternative Policy Scenario. Demand in the rest of developing Asia amounts to an additional 8 Mtoe in 2030 in the Reference Scenario and 20 Mtoe in the Alternative Policy Scenario. Consumption of biofuels in Japan is projected to grow strongly. Almost all the country's biofuels will need to be imported, with most expected to come from Brazil. Australia has good natural conditions for low-cost feedstock production of both sugar cane and wheat for ethanol and oil crops for biodiesel.

Several African countries currently have, or are planning to introduce, active biofuel policies, some of which date back to the 1970s. In South Africa, a pilot 500-kilolitre per year ethanol plant is being built and there are plans to adopt a national minimum requirement of between 1% and 3% biodiesel. South Africa, as well as the Democratic Republic of Congo, currently exports ethanol to the European Union. It is possible that future policies in Africa will be designed to meet not only domestic needs but also the growing international demand for biofuels. Total biofuels use in Africa is nonetheless expected to remain small in 2030, reaching 3.4 Mtoe in the Reference Scenario and 3.5 Mtoe in the Alternative Policy Scenario.

Key Drivers and Uncertainties

Technology and Production Costs

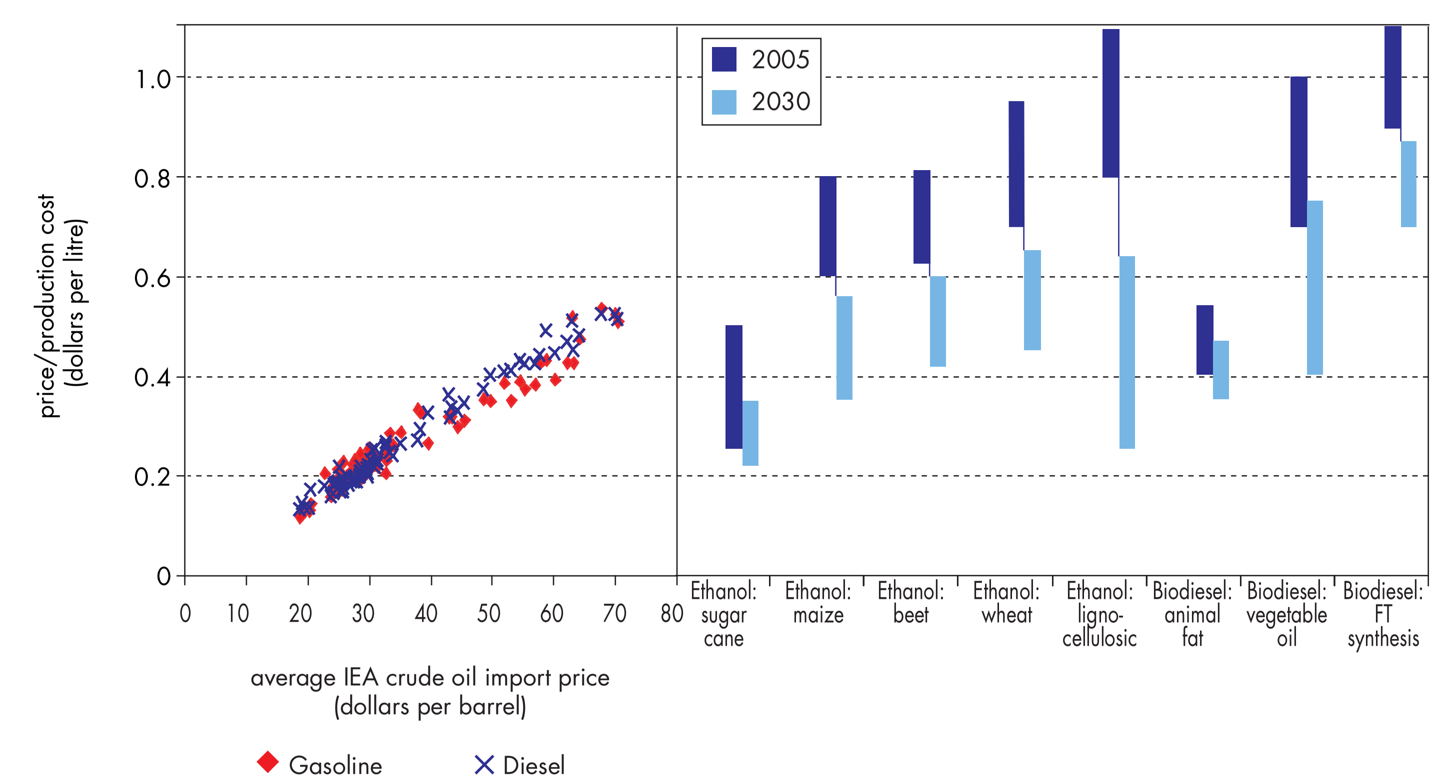
The growing interest in biofuels stems partly from the potential that is thought to exist for lowering the costs of production through technological advances. In most parts of the world outside Brazil, biofuels cost significantly more to produce than conventional gasoline or diesel, even with crude oil prices of over $70 per barrel. This is a critical barrier to commercial biofuel development. But costs have been declining over the last few years as the technology has improved and economies of scale have been exploited. Further cost reductions are achievable, even using existing technologies. Over time, the cost of producing second-generation biofuels, including enzymatic hydrolysis and gasification of ligno-cellulosic biomass, might eventually fall as low as $40 to $50 per barrel, which would make them competitive with conventional gasoline and diesel without subsidy at the crude oil prices assumed in the Reference Scenario (Figure 14.7). It may also be possible to produce better-quality biofuels, with more favourable performance characteristics. This would allow biofuels to be blended with gasoline and diesel in higher proportions than are currently feasible without engine modifications.

Conventional Ethanol and Biodiesel

Conventional production technologies for ethanol based on starchy and sugar crops are relatively mature. Further incremental cost reductions can be expected, particularly through large-scale processing plants, but no major breakthroughs in technology that would bring costs down dramatically are likely. Crop prices, which tend to be volatile, will remain a major factor in future production cost trends. Higher crop yields, through the use of better fertilizers, plant breeding and agricultural management, could help to lower prices (see below).

Bioethanol production costs today vary widely across countries, mainly due to climatic factors. Crop production costs are much lower in tropical countries. Brazil has the lowest unit costs in the world, at around $0.20 per litre ($0.30 per litre of gasoline equivalent) for new plants. Other developing countries in tropical zones may be able to achieve similar costs. In Europe and North America, farm subsidies distort production costs. Grain-based ethanol costs on average around $0.30/litre ($0.45/litre of gasoline equivalent) in the United

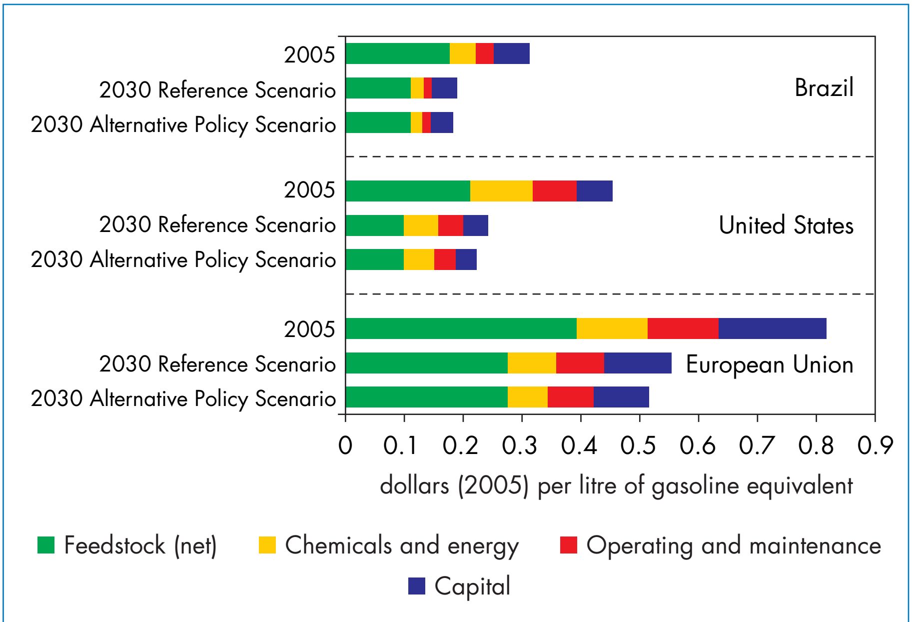
Figure 14.7: **Biofuel Production Costs versus Gasoline and Diesel Prices**



Note: Prices are monthly, from January 2000 to June 2006. Costs exclude subsidies to crops and biofuels production.
Source: IEA analysis.

States, after production subsidies, so that it is competitive with gasoline at an average crude oil price of between $65 and $70 per barrel.[9] In Europe, the ethanol production cost, including all subsidies, is about $0.55/litre ($0.80/litre of gasoline equivalent). Average production costs are projected to drop by around a third between 2005 and 2030 (Figure 14.8). Costs in Europe and the United States would be significantly higher without crop and ethanol subsidies.

Figure 14.8: **Production Costs of Ethanol in Brazil, the European Union and the United States**



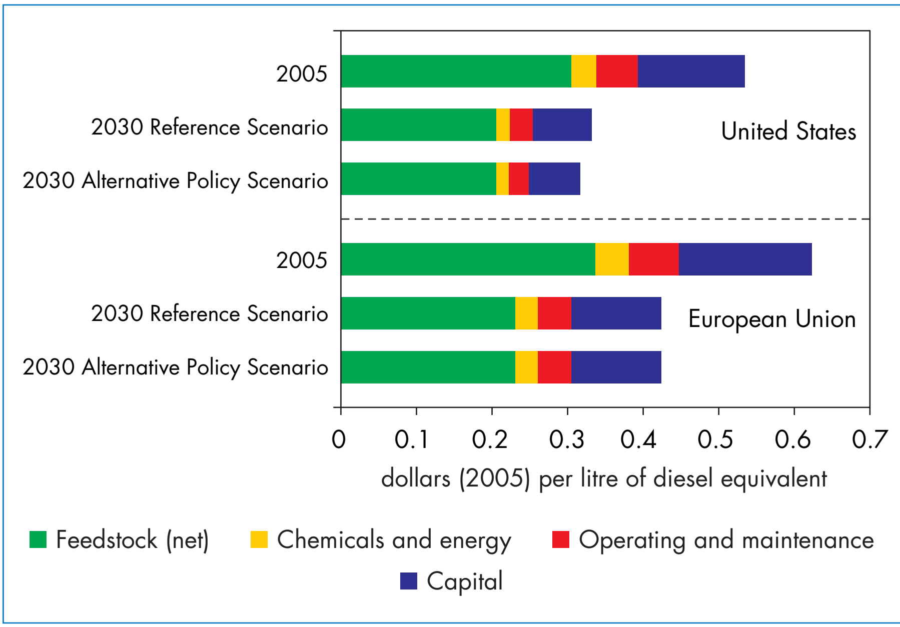
Note: In contrast to Figure 14.7, the costs shown in this chart include current rates of subsidy to crops and ethanol production.
Source: IEA analysis in conjunction with the Energy Economics Group of the Vienna University of Technology.

As with ethanol, the cost of producing biodiesel depends on the type of feedstock and the conversion technology. Costs also vary by region and depend on biomass yields, the cost of labour, land availability and access to capital. The current cost of conventional biodiesel production is estimated at just over $0.60 per litre of diesel equivalent in Europe (based on rapeseed) and about

9. As noted above, the price of ethanol has recently risen to well above its production cost because of strong demand for the fuel as a blending component.

$0.50/litre in the United States (based on soybean). There remains some scope for reducing the unit cost of conventional biodiesel production by building bigger plants. But technical breakthroughs on the standard transesterification process, leading to substantial cost reductions in the future, are unlikely. Production costs are projected to fall to just over $0.30/litre in the United States and $0.40/litre in Europe in 2030 (Figure 14.9).

Figure 14.9: **Production Costs of Biodiesel in the European Union and the United States**



Note: In contrast to Figure 14.7, the costs shown in this chart include current rates of subsidy to crops and ethanol production.
Source: IEA analysis in conjunction with the Energy Economics Group of the Vienna University of Technology.

Ligno-Cellulosic Ethanol Production

With conventional grain-to-ethanol processes, only the starchy part of the plant – which makes up a small percentage of the total mass – is used for the production of fuel. A considerable amount of research is currently being focused on new processes to extract fermentable sugar from the ligno-cellulosic material contained in the waste seed husks and stalks by means of biological enzymatic hydrolysis (IEA, 2004). In the case of corn, a much larger fraction of the plant could be used to produce fuel, thereby substantially increasing its ethanol yields and lowering unit costs.[10] Conversion efficiencies of 60% to 70% may ultimately be possible, yielding greenhouse-gas emission reductions of 90% or more compared with gasoline, assuming all the process energy is provided by the lignin component in the feedstock that cannot be converted to ethanol (Hamelinck *et al.*, 2004).

Succesful ligno-cellulosic ethanol technology would open the door to a much wider array of potential cellulosic feedstocks, including dedicated cellulosic crops, such as grasses and fast-growing trees. In North America, attention is being given to corn stover and switchgrass. In Europe, attention is focused on food-processing waste, miscanthus grass and short-rotation woody biomass. In Brazil, sugar cane stalks (bagasse) are already used to provide heat and electrical process energy for ethanol conversion, once the sugar is removed, but are not actually processed into ethanol itself. Much of the sugar-cane crop is still left in the field and burned. Advanced ligno-cellulosic conversion processes would allow the full use of the biomass available in the cane. Other forms of cellulosic feedstock could be grown on poorer quality soils than those currently used to grow crops for conventional ethanol production, requiring less fertilizer and water. Production costs could be considerably lower than for the cereal and seed crops currently used in Europe and the United States (Table 14.5)

For the production of ethanol from ligno-cellulosic feedstocks to become commercially viable, significant technological challenges still need to be overcome. Today, there is virtually no commercial production of ethanol from cellulosic biomass, but there is substantial research going on in this area in IEA countries, particularly the United States, Canada and Sweden. A key objective is to produce a fermented broth with a higher concentration of ethanol, in order to reduce the energy needs of the distillation process to fuel grade. A commercial scale plant is under construction in the United States and others are planned in Europe. The unit production cost is expected to be almost $1 per litre of gasoline equivalent, based on a biomass feedstock price of $3.60/GJ (Hamelinck *et al.*, 2005). Significantly lower costs are believed to be achievable in the next one or two decades, through optimised pre-treatment, higher ethanol concentrations before distillation, enhanced enzymes and improved separation techniques. Integration of biomass gasification and combined-cycle technology to improve the efficiency of use of the unused portion of lignin to power the process may also help lower costs and reduce greenhouse-gas emissions. Scaling up production facilities and better logistics

10. The financial cost of biomass from perennial crops such as trees and grasses is around $2/GJ (assuming each tonne of biomass contains 19 GJ) in many world regions, including Eastern Europe and the United States. It is lower in Latin America and sub-Saharan Africa. In temperate regions, the cost of producing cereals and seeds for ethanol production is typically five to ten times higher.

Table 14.5: **Performance Characteristics of Biofuel Crops in Europe**

Crop	**Period**	**Typical yield** (dry tonnes/ha/year)	**Primary energy input** (GJ/ha/yr)	**Typical net energy yield** (GJ/ha/yr)	**Production cost of biofuel** (euro/GJ)	**Status**
Rape	Current Long term	2.9 4	11 12	110 180	20 12	Widely deployed in Germany and France, to a lesser extent in Austria and Italy. Requires high-quality land. Needs large subsidies to compete, even in the long term.
Sugar beet	Current Long term	14 20	13 10	250 370	12 8	Annual crop, requiring high-quality land. High productivity but needs large amounts of energy-intensive fertilizers. Only surpluses are currently used for ethanol production.
Willow	Current Long term	10 15	5 5	180 280	3-6 <2	Perennial crop with typical rotation of 2 to 4 years. Suited to cold, wet climates. Commercial experience in Sweden, the UK and some other countries. Strong potential in Eastern Europe, where growing conditions and economics are good.
Poplar	Current Long term	9 13	4 4	150 250	3-4 <2	Perennial crop, currently grown for pulp production in several countries, with typical rotation of 8 to 10 years. Well-suited for biomass production. Economics depend on production region and market prices for competing biomass.

Table 14.5: **Performance Characteristics of Biofuel Crops in Europe** *(Continued)*

Crop	**Period**	**Typical yield** (dry tonnes/ ha/year)	**Primary energy input** (GJ/ha/yr)	**Typical net energy yield** (GJ/ha/yr)	**Production cost of biofuel** (euro/GJ)	**Status**
Miscanthus	Current	10	13-14	180	3-6	Perennial crop harvested each year. Limited commercial experience as yet in Europe. Production potential is uncertain. Suited to warm climates, where high yields are possible.
	Long term	20	13-14	350	<2	

Note: For woody and grassy crops (willow, poplar and miscanthus), transport, handling and storage costs add about 10% to the fuel-production cost when they are shipped by road to a local plant. The energy used in transportation is equal to 1% to 2% of that contained in the biomass. Long-distance intercontinental transport can add €0.50 to €1 per GJ and consume 6% to 10% of the energy in the biomass. The energy content of the biomass is assumed to be 19 GJ per dry tonne for wood, 28 GJ for rapeseed and 19 GJ for sugar beet.
Source: IEA analysis.

for supplying biomass residues would also help improve the cost competitiveness of the technology. Production costs could fall to close to \$0.25/litre (about \$0.40/litre of gasoline equivalent) in the long term (IEA, 2006).

Ligno-Cellulosic Biomass-to-Liquids Gasification Technologies

The other main route for converting ligno-cellulosic biomass into biofuels involves the gasification of the feedstock to produce synthetic gas (syngas) – a mixture of carbon monoxide, hydrogen and other compounds. The syngas can then be converted to diesel (via Fischer-Tropsch synthesis), methanol or dimethyl ether – a gaseous fuel similar to propane. Alternatively, the hydrogen can be separated and used as a fuel. Currently, most interest exists in production of diesel via FT-synthesis – the same technology used in gas-to-liquids and coal-to-liquids plants.

As yet, there is no commercial production of biofuels through gasification, because of the high cost compared with conventional technologies. However, a considerable amount of research and development is under way to devise commercially-viable processes. The main development challenges are improving the purity of the syngas, scaling up the various processes and integrating them efficiently. Technologies being developed today typically involve the use of heat and/or chemicals to break down the biomass into gas, with little or no microbial action involved. Effort is focused on maximising the hydrogen yield from such processes. To achieve economies of scale, very large plants will probably be needed, which will require extensive logistical systems for gathering and transporting the biomass feedstock (Hamelinck and Faaij, 2005). Demonstration plants have been built in Germany. The current production cost of FT diesel from biomass is about \$0.90 per litre, based on a woody biomass feedstock price of \$3.6/GJ. The cost could decline to \$0.70 to 0.80/litre in the long term (IEA, 2006).

Gasification technologies allow for co-gasification of biomass with coal, providing flexibility of feedstock – an attractive benefit in view of the uncertainties about future fuel prices and carbon-emission penalties. If combined with carbon capture and storage equipment to handle the carbon dioxide released during the syngas-production process, a biomass/coal feedstock mix could still yield significant net reductions in CO_2 emissions. There is extensive commercial experience with large-scale coal-to-liquids production, notably in South Africa.

Biomass and Land Needs for Biofuels Production

Producing biofuels on a large scale requires large areas of land. A substantial increase in conventional biofuels production is likely to depend on significant increases in the productivity of the land and increasing the area of arable land, especially in developing regions, given growing demand for food. However, if crop yields continue to increase, more set-aside land would result. About 14 million hectares of land are currently used for the production of biofuels and by-products, equal to about 1% of the world's available arable land. Given that 1% of global transportation fuels are currently derived from biomass, increasing that share to 100% is clearly impossible unless fuel demand is reduced, land productivity is dramatically increased, large areas of pasture are converted to arable land or production is shifted from conventional sources of biomass to new ones, such as crop residues or trees and grasses that can be grown on non-arable land. The conversion of pasture to arable land would require improvements in the efficiency of livestock-raising practices. Growing urban land needs, constraints on water availability, land degradation and changes in climate will limit potential crop yields. For these reasons, the large-scale use of biofuels will probably not be possible unless second-generation technologies based on ligno-cellulosic biomass that requires less arable land can be developed commercially.

On average, crop yields have doubled worldwide in the last four decades, mainly thanks to plant breeding, increased inputs and improved management and there is thought to be significant potential for boosting them further (IEA, 2004). Indeed, investment in biofuels in developing countries could be a powerful stimulus to improvements in those agricultural practices that can make land use more efficient generally, bringing additional benefits in the form of higher production of non-energy crops. This would reduce the competition for land use between biofuels and food production. How fast yields can be increased is very uncertain. The potential is undoubtedly highest in the poorest developing regions, notably sub-Saharan Africa, where yields are typically well below OECD averages, though water supply is a major constraint. Although traditional methods, such as selective breeding, may continue to play the main role in improving crop yields in the medium term, biotechnology, including genetically modified crops, may play a more important role in the longer term.

The commercial development of ligno-cellulosic ethanol would allow for a much larger potential supply of biomass, part of which could be used for biofuels production. At one extreme, it has been estimated that energy farming on current agricultural (arable and pasture) land could contribute up to 700 exajoules (16 700 Mtoe) per year of biomass energy by 2050 without jeopardising the world's food supply, forests or biodiversity – assuming very rapid technological progress (Table 14.6). That is slightly more than the world's entire energy needs in 2030 in the Reference Scenario.[11] Around

11. Biomass can, in principle, replace all forms of primary energy as a final fuel or as an input to power and heat production, conversion to gas (bagasse) or liquid fuels for use in transport (biofuels) or in other final uses.

200 EJ (4 800 Mtoe) of biomass production based on perennial crops could be developed at a cost of $2 per GJ (Hoogwijk *et al.*, 2005; Rogner *et al.*, 2000). In total, biomass potential from all sources could be as high as 1 100 EJ (over 26 000 Mtoe), though a more realistic assessment based on slower rates of improvement in yields is 250 EJ to 500 EJ (6 000 to 12 000 Mtoe). A mid-range estimate of 400 EJ would require about one-fifth of the world's existing agricultural land to be turned over to biomass energy production, equal to about 8% of the world's surface land area. World biomass energy production in 2004 amounted to about 50 EJ (1 170 Mtoe). Soil, water and nutrient constraints would reduce this potential.

These estimates are sensitive to assumptions about crop yields and the amount of land that could be made available for the production of biomass for energy uses, including biofuels. Critical issues include the following:

- **Competition for water resources:** Although the estimates cited above generally exclude irrigation for biomass production, it may be necessary in some countries where water is already scarce.
- **Use of fertilizers and pest control techniques:** Improved farm management and higher productivity depend on the availability of fertilizers and pest control. The heavy use of fertilizer and pesticides could harm the environment.
- **Land-use:** More intensive farming to produce energy crops on a large scale may result in losses of biodiversity. Perennial ligno-cellulosic crops are expected to be less pernicious than conventional crops such as cereals and seeds. More intensive cattle-raising could also be necessary to free up grassland currently used for grazing.
- **Competition with food production:** Increased biomass production for biofuels could drive up land and food prices, with potentially adverse consequences for poor households. On the other hand, rising prices could benefit poor farmers.

The share of the world's arable land used to grow biomass for biofuels is projected to rise from 1% at present to 2.5% in 2030 in the Reference Scenario and 3.8% in the Alternative Policy Scenario, on the assumption that biofuels are derived solely from conventional crops (Table 14.7). The amount of arable land needed in 2030 is equal to more than that of France and Spain in the Reference Scenario and to that of all the OECD Pacific countries – including Australia – in the Alternative Policy Scenario. If second-generation technologies based on ligno-cellulosic biomass were widely commercialised before 2030, arable land requirements could be much less per unit of biofuels output. In a Second-Generation Biofuels Case, ligno-cellulosic based technologies are assumed to be introduced on a large scale, pushing the share of biofuels in transport demand globally to 10% in 2030 compared with 5%

Table 14.6: **Global Potential Biomass Energy Supply to 2050**

Biomass category	Main assumptions and remarks	Potential bio-energy supply in 2050 in Mtoe
Bioenergy farming on current agricultural land	Potential land surplus: 0-4 Gha (average: 1-2 Gha). A large surplus requires adoption of intensive agricultural production systems. Higher yields are more likely where soil quality is good. Productivity of 8-12 dry tonnes/ha/year assumed.*	0 - 16 700 (average: 2 400 – 7 200)
Bioenergy production on marginal land	Maximum land surface of 1.7 Gha could be used. Low productivity of 2-5 dry tonnes/ha/year assumed* Poor economics or competition with food production could limit availability.	1 400 – 3 600
Residues from agriculture	Potential depends on yields and total agricultural land area in use as well as type of production system (extensive production systems require re-use of residues to maintain soil fertility).	400 – 1 700
Forest residues	The sustainable energy potential of the world's forests is uncertain. Low value corresponds to sustainable forest management and high value to technical potential. Estimates include processing residues.	700 – 3 600
Dung	Low estimate based on global current use, high estimate on technical potential. Collection rates are uncertain.	100 – 1 300
Organic wastes	Estimates dependent on assumed rates of economic development and consumption of biomass generally. Higher values correspond to more intensive use of biomass.	100 – 1 000
Total	Low estimate based on no land available for energy farming and use of residues only. High estimate based on intensive agriculture concentrated on high-quality soils.	1 000 – 26 200 (average: 6 000 – 11 900)

* Heat content of 19 GJ/tonne dry matter is assumed.

Sources: IEA analysis based on Hamelinck and Faaij *et al.* (2005), Smeets *et al.* (2006) and Hoogwijk *et al.* (2005).

in the Alternative Policy Scenario and 3% in the Reference Scenario. In this case, land requirements are only 0.4 percentage points higher than in the Alternative Policy Scenario. This is because a significant share of the additional biomass needed could come from regenerated and marginal land not currently used for crops or pasture, as well as from agricultural and forest residues and waste. In addition, the conversion efficiency of second-generation technologies is expected to be considerably higher.

Table 14.7: **Land Requirements for Biofuels Production**

	2004		2030 Reference Scenario		2030 Alternative Policy Scenario		2030 Second-Generation Biofuels Case	
	Million ha	% arable	Million ha	% arable	Million ha	% arable	Million ha	% arable
United States and Canada	8.4	1.9	12.0	5.4	20.4	9.2	22.6	10.2
European Union	2.6	1.2	12.6	11.6	15.7	14.5	17.1	15.7
OECD Pacific	neg.	neg.	0.3	0.7	1.0	2.1	1.0	2.0
Transition economies	neg.	neg.	0.1	0.1	0.2	0.1	0.2	0.1
Developing Asia	neg.	neg.	5.0	1.2	10.2	2.5	11.5	2.8
Latin America	2.7	0.9	3.5	2.4	4.3	2.9	5.0	3.4
Africa & Middle East	neg.	neg.	0.8	0.3	0.9	0.3	1.1	0.4
World	**13.8**	**1.0**	**34.5**	**2.5**	**52.8**	**3.8**	**58.5**	**4.2**

Note: neg. = negligible. In the Second-Generation Biofuels Case, some biomass for biofuels production comes from non-arable land and residues, reducing arable land requirements.
Sources: Farm land – Food and Agriculture Organization website, online database: www.fao.org; land requirements – IEA analysis.

International Trade in Biofuels

Current trade in biofuels and biomass feedstock is modest compared to total biomass energy production, but it is growing rapidly. Most trade is between neighbouring regions or countries, but long-distance trade – especially in finished biofuels – is becoming more important. Brazil dominates trade in ethanol, exporting to Japan, the European Union, the United States and elsewhere. Trade in biomass is more costly, because of its bulk and lower calorific value. Nonetheless, Malaysia exports palm kernel shells to the Netherlands, while Canada sells wood pellets to Sweden.

Biofuels produced in tropical regions from sugar cane and palm oil are already considerably cheaper than fuels derived from agricultural crops in temperate zones (excluding subsidies), providing strong incentives for trade. Biofuel shipping costs are small as a proportion of the total value of the fuel itself. But trade barriers and other forms of subsidy currently prevent large-scale shipments to Europe or the United States. It is very uncertain to what extent these regions and other major centres of biofuels demand will allow imports of biofuels in the future. This is a critical factor in determining where, and with what resources and technologies, biofuels will be produced in the coming decades, the overall burden of subsidy on taxpayers and the cost-effectiveness of biofuels as a means of reducing carbon-dioxide emissions and promoting energy diversity.

ENERGY FOR COOKING IN DEVELOPING COUNTRIES

HIGHLIGHTS

- In developing countries, especially in rural areas, 2.5 billion people rely on biomass, such as fuelwood, charcoal, agricultural waste and animal dung, to meet their energy needs for cooking. In many countries, these resources account for over 90% of household energy consumption.
- In the absence of new policies, the number of people relying on biomass will increase to over 2.6 billion by 2015 and to 2.7 billion by 2030 because of population growth. That is, one-third of the world's population will still be relying on these fuels. There is evidence that, in areas where local prices have adjusted to recent high international energy prices, the shift to cleaner, more efficient use of energy for cooking has actually slowed and even reversed.
- Use of biomass is not in itself a cause for concern. However, when resources are harvested unsustainably and energy conversion technologies are inefficient, there are serious adverse consequences for health, the environment and economic development. About 1.3 million people – mostly women and children – die prematurely every year because of exposure to indoor air pollution from biomass. Valuable time and effort is devoted to fuel collection instead of education or income generation. Environmental damage can also result, such as land degradation and regional air pollution.
- Two complementary approaches can improve this situation: promoting more efficient and sustainable use of traditional biomass; and encouraging people to switch to modern cooking fuels and technologies. The appropriate mix depends on local circumstances such as per-capita incomes and the availability of a sustainable biomass supply.
- Halving the number of households using traditional biomass for cooking by 2015 – a recommendation of the United Nations Millennium Project – would involve 1.3 billion people switching to other fuels. Alternative fuels and technologies are already available at reasonable cost. Providing LPG stoves and cylinders, for example, would cost at most $1.5 billion per year to 2015. Switching to oil-based fuels would not have a significant impact on world oil demand. Even when fuel costs and emissions are considered, the household energy choices of developing countries need not be limited by economic, climate-change or energy-security concerns.

- Vigorous and concerted government action is needed to achieve this target, together with increased funding from both public and private sources. Policies to promote cleaner, more efficient fuels and technologies for cooking need to address barriers to access, affordability and supply, and to form a central component of broader development strategies.

Household Energy Use in Developing Countries

According to the best available figures, household energy use in developing countries totalled 1 090 Mtoe in 2004, almost 10% of world primary energy demand.[1] Household use of biomass in developing countries alone accounts for almost 7% of world primary energy demand. In OECD countries, biomass demand comes mostly from the power generation and industry sectors, while in developing countries these sectors represent only 12%.

There are enormous variations in the level of consumption and the types of fuels used. While a precise breakdown is difficult, the main use of energy in households in developing countries is for cooking, followed by heating and lighting. Because of geography and climate, household space and water heating needs are small in many countries. This chapter concentrates on fuels for cooking. Households generally use a combination of energy sources for cooking that can be categorised as traditional (such as dung, agricultural residues and fuelwood), intermediate (such as charcoal and kerosene) or modern (such as LPG, biogas, ethanol gel, plant oils, dimethyl ether (DME) and electricity).[2] Electricity is mainly used for lighting and small appliances, rather than cooking, and represents a small share of total household consumption in energy terms.[3]

Supplies of biomass are abundant in many developing countries, although local scarcity exists. Indeed, they are the only affordable energy source for some households. The commercial production and distribution of fuelwood and

1. Collecting and processing biomass energy statistics is a complex process because of the diversity of consumption patterns, differences in units of measurement, the lack of regular surveys and the variation in heat content of the different types of biomass. The IEA and the Food and Agriculture Organization of the United Nations (FAO) are the main international organisations monitoring biomass energy data in developing countries. Some countries collect specific information on fuel use at the household level, while various regional organisations and independent researchers carry out *ad hoc* surveys.
2. The terms traditional, intermediate and modern relate to how well-established a fuel is and do not imply a ranking.
3. While electricity is not the focus of this chapter, it provides important benefits to households. The number of people without access to electricity is estimated to be 1.6 billion (Annex B).

charcoal generates significant employment and income in rural areas of developing countries, though a switch to alternative fuels would also create employment and business opportunities.

In OECD countries and in most transition economies, the technologies used to convert biomass to energy tend to be efficient and the resources are generally harvested in a sustainable way. But in developing countries, the technologies and practices are much less efficient. Many people use three-stone fires, cook without ventilation or harvest at an unsustainable rate. Reliance on biomass resources, important though they are to many communities, cannot be regarded as sustainable when it impairs health and has negative economic and environmental impacts.

Based on work done for *WEO-2002*, a database of the number of people relying on biomass as their primary fuel for cooking for each country in the *WEO* developing regions was built up using survey and census data, World Health Organization (WHO) data and direct correspondence with national administrations. We estimate that over 2.5 billion people, or 52% of the population in developing countries, depend on biomass as their primary fuel for cooking.[4] Over half of these people live in India, China and Indonesia (Table 15.1). However, the proportion of the population relying on biomass is highest in sub-Saharan Africa. In many parts of this region, more than 90% of the rural population relies on fuelwood and charcoal. The share is smaller in China, where a large proportion of households uses coal instead.[5] Poor households in Asia and Latin America are also very dependent on fuelwood (Figure 15.1).

Heavy dependence on biomass is concentrated in, but not confined to, rural areas. Almost half a billion people in urban areas also rely on these resources. Although urbanisation is associated with lower dependence, the use of fuels such as LPG[6] in towns and cities is not always widespread. In sub-Saharan Africa, well over half of all urban households rely on fuelwood, charcoal or wood waste to meet their cooking needs. Over a third of urban households in some Asian countries also rely on these fuels.

The share of biomass in household energy demand varies widely across countries and regions, primarily reflecting their resource endowments but also their levels of economic development and urbanisation. In Thailand, where per-capita income averages \$2 490, biomass accounts for 33% of household energy

4. Although households in developing countries use a combination of fuels for cooking and heating, this chapter focuses on the primary fuel used. This simplification is necessary in order to perform quantitative analysis.
5. Coal is excluded from the targets and projections in this chapter.
6. Liquefied petroleum gas (LPG) is a mixture of propane and butane pressurised in cylinders for storage and transport.

Table 15.1: **People Relying on Biomass Resources as their Primary Fuel for Cooking, 2004**

	Total population		Rural		Urban	
	%	million	%	million	%	million
Sub-Saharan Africa	76	575	93	413	58	162
North Africa	3	4	6	4	0.2	0.2
India	69	740	87	663	25	77
China	37	480	55	428	10	52
Indonesia	72	156	95	110	45	46
Rest of Asia	65	489	93	455	35	92
Brazil	13	23	53	16	5	8
Rest of Latin America	23	60	62	59	9	25
Total	**52**	**2 528**	**83**	**2 147**	**23**	**461**

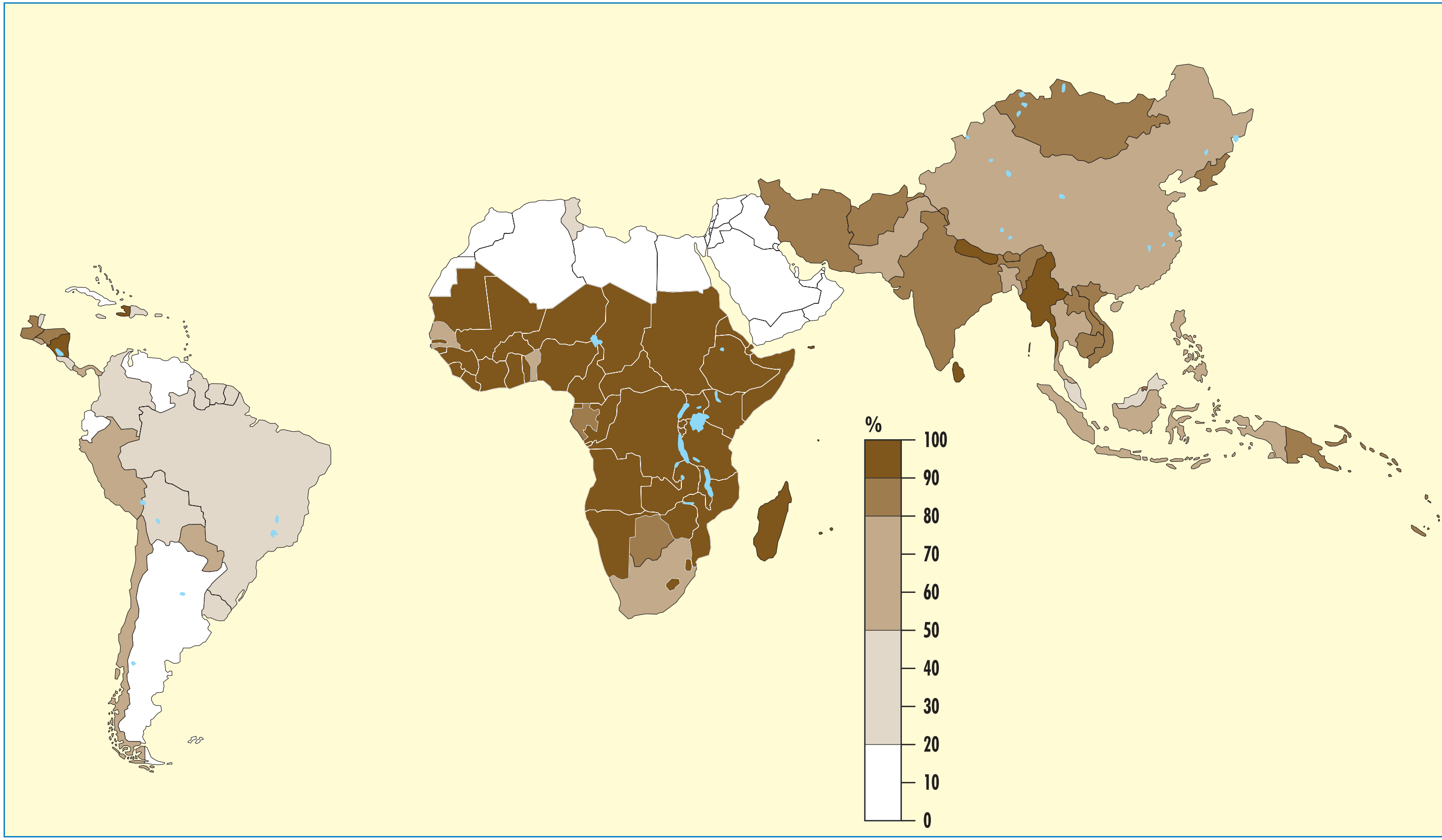
Sources: IEA analysis based on the latest available national census and survey data, including the 2001 Population and Household Census of Botswana; the 2003 Demographic and Health Survey of Nigeria; the National Bureau of Statistics of Tanzania, 2000/01; the 2001 Census of India; Energy Statistics for Indonesia, 2006; the Bangladesh Bureau of Statistics, 2005; the National Statistical Office Thailand, 2000; ORC Macro (2006); WHO (2006).

consumption, while in Tanzania, with per-capita income of only $320, the share is nearly 95%.[7] There are also important differences between rural and urban households. For example, fuelwood for cooking is three times more important in rural areas than in urban areas in both India and Botswana (Figure 15.2).

Households do not simply substitute one fuel for another as income increases, but instead add fuels in a process of "fuel stacking". Modern forms of energy are usually applied sparingly at first and for particular services (such as electricity for radio and television, or LPG for making tea and coffee) rather than completely supplanting an existing form of energy that already supplies a service adequately. The most energy-consuming activities in the household – cooking and heating – are the last to switch. Use of multiple fuels provides a sense of energy security, since complete dependence on a single fuel or technology leaves households vulnerable to price variations and unreliable service. Some reluctance to discontinue cooking with fuelwood may also be due to taste preferences and the familiarity of cooking with traditional technologies. In India and several other countries, for example, many wealthy households retain a wood stove for baking traditional breads. As incomes increase and fuel options widen, the fuel mix may change, but wood is rarely entirely excluded. Over the long term

7. Per-capita incomes are taken from World Bank (2006).

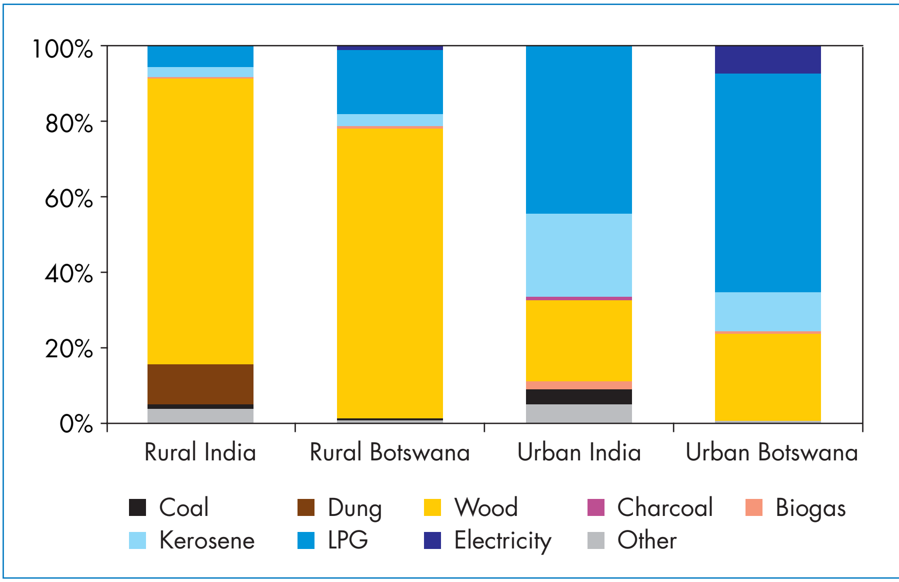
Figure 15.1: **Share of Traditional Biomass in Residential Consumption by Country**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA databases.

Figure 15.2: **Primary Energy Source for Cooking in Households in India and Botswana**



Note: The high electricity share in urban Botswana is due to the provision of cheap surplus electricity from South Africa by Eskom.

Sources: *Census of India*, 2001, available from www.censusindia.net and *2001 Population and Household Census of Botswana,* Census Unit, Botswana.

and on a regional scale, however, households in countries that become richer will shift away from cooking exclusively with biomass using inefficient technologies (Smith *et al.*, 2004).

Harmful Effects of Current Cooking Fuels and Technologies

Health

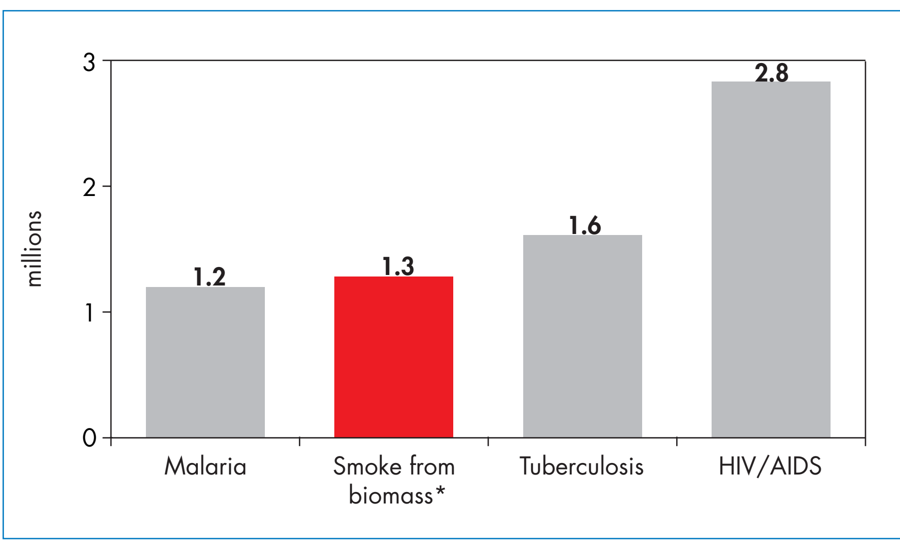
The World Health Organization (WHO) estimates that 1.5 million premature deaths per year are directly attributable to indoor air pollution from the use of solid fuels.[8] That is more than 4 000 deaths per day, more than half of them children under five years of age. More than 85% of these deaths (about

8. There are specific targets associated with each of the eight Millennium Development Goals. For each target, several indicators have been established to assess progress in achieving the goals. The WHO is responsible for Indicator 29 (Goal 7) – the proportion of the population using solid fuels. This category includes coal and biomass resources. In this chapter, the targets and projections consider biomass only.

1.3 million people) are due to biomass use, the rest due to coal. This means that indoor air pollution associated with biomass use is directly responsible for more deaths than malaria, almost as many as tuberculosis and almost half as many as HIV/AIDS (Figure 15.3). In developing countries, only malnutrition, unprotected sex, and lack of clean water and sanitation were greater health threats (WHO, 2006). Just as the extent of dependence on polluting fuels and inefficient stoves varies widely around the world, so does the death toll due to indoor smoke. The number of premature deaths is highest in southeast Asia and sub-Saharan Africa (Figure 15.4).

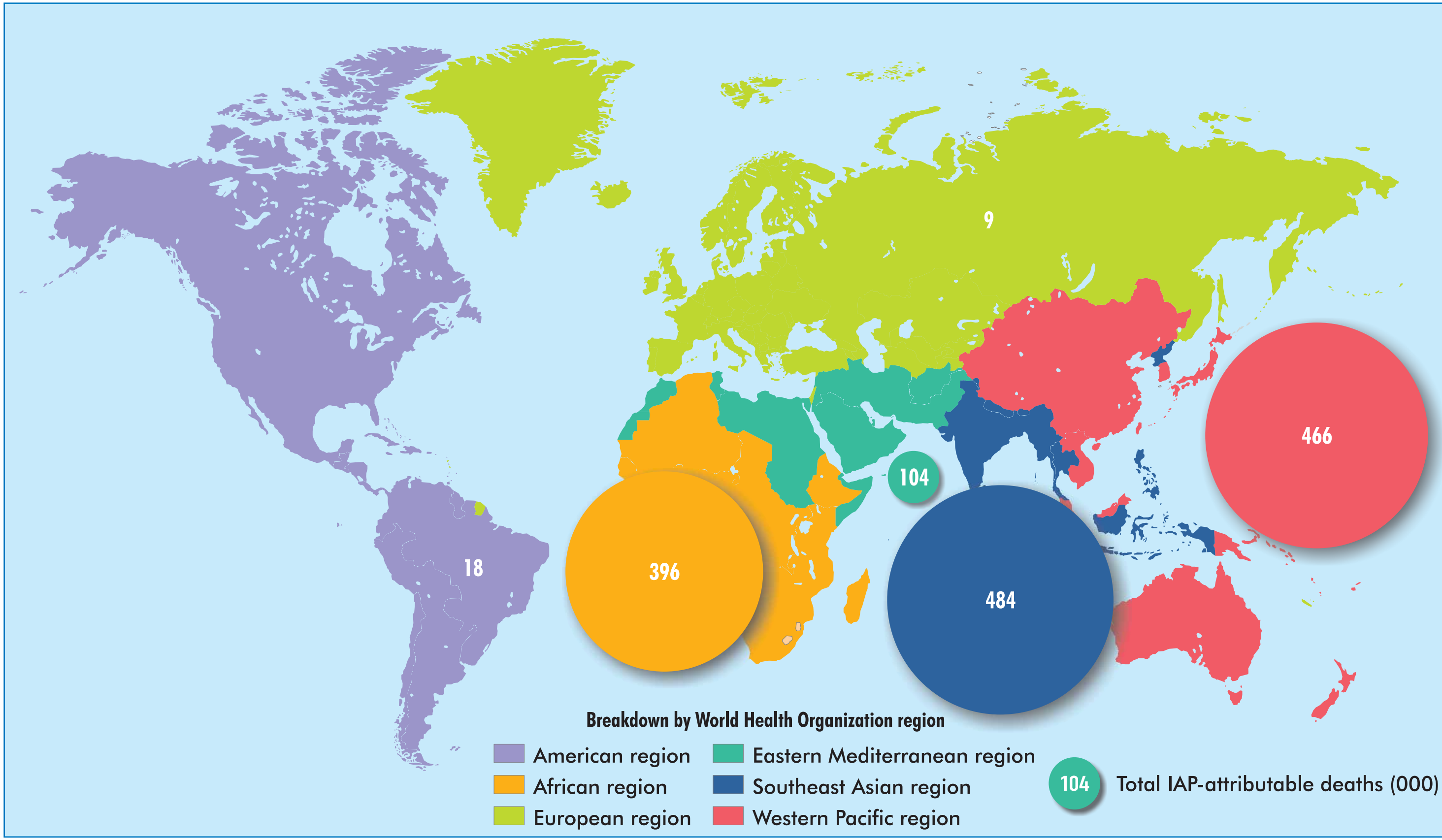
Fuelwood, roots, agricultural residues and animal dung all produce high emissions of carbon monoxide, hydrocarbons and particulate matter (Smith *et al.,* 2000). Hydrocarbon emissions are highest from the burning of dung for fuel, while particulate emissions are highest from agricultural residues. Women and children suffer most from indoor air pollution because they are traditionally responsible for cooking and other household chores, which involve spending hours by the cooking fire exposed to smoke. Young children are particularly susceptible to disease, which accounts for their predominance in the statistics for premature deaths due to the use of biomass for cooking.

Figure 15.3: **Annual Deaths Worldwide by Cause**



* IEA estimate based on WHO figure for all solid fuels.
Source: WHO Statistical Information System, available at www.who.int/whosis.

Figure 15.4: **Deaths per Year Caused by Indoor Air Pollution, by WHO Region**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: Countries are grouped according to WHO regions. Deaths include those, mainly in China, attributable to the use of coal.
Source: WHO (2006).

The effects of exposure to indoor air pollution depend on the source of pollution (fuel and stove type), how pollution is dispersed (housing and ventilation) and how much of their time household members spend indoors. The type of fuel used and individuals' participation in food preparation have consistently been the most important indicators. The prevalence of indoor air pollution is significantly higher where income is below $1 per day per capita (WHO, 2004). As well as being much more dependent on biomass, poor households rely on low-quality cooking equipment and live in poorly ventilated housing, exacerbating the negative health impact, as there is incomplete combustion and non-dissipation of smoke.

It is estimated that indoor air pollution causes about 36% of lower respiratory infections and 22% of chronic respiratory disease (UNEP, 2006). A child exposed to indoor air pollution is two to three times more likely to catch pneumonia, which is one of the world's leading killers of young children. In addition, there is evidence to link indoor smoke to low birth weight, infant mortality, tuberculosis, cataracts and asthma. As well as direct effects on health, indoor air pollution worsens the suffering and shortens the lives of those with both communicable diseases such as malaria, tuberculosis and HIV/AIDS, and chronic diseases, notably cardiovascular diseases and chronic respiratory diseases, which are by far the world's worst killers. Four out of five deaths due to chronic diseases are in low- and middle-income countries (WHO, 2005).

Environment

Inefficient and unsustainable cooking practices can have serious implications for the environment, such as land degradation and local and regional air pollution. There is some localised deforestation, but depletion of forest cover on a large scale has not been found to be attributable to demand for fuelwood (Arnold *et al.,* 2003). Fuelwood is more often gathered from the roadside and trees outside forests, rather than from natural forests. Clearing of land for agricultural development and timber are the main causes of deforestation in developing countries. Studies at the regional level indicate that as much as two-thirds of fuelwood for cooking worldwide comes from non-forest sources such as agricultural land and roadsides. Charcoal, on the other hand, is usually produced from forest resources. Unsustainable production of charcoal in response to urban demand, particularly in sub-Saharan Africa, places a strain on biomass resources. Charcoal production is often inefficient and can lead to localised deforestation and land degradation around urban centres.[9] Scarcity of wood typically leads to greater use of agricultural residues and animal dung for

9. As a result of charcoal production for urban and peri-urban households, biomass resources have been devastated in a 200 to 300 kilometre radius around Luanda, Angola (IEA, 2006).

cooking. When dung and residues are used for fuel rather than left in the fields or ploughed back into fields, soil fertility is reduced and propensity to soil erosion is increased.

Figure 15.5 shows the supply and demand balance of wood resources in East Africa. Red areas represent the risk of environmental impact due to overexploitation. In these areas, the supply of biomass energy resources is insufficient to meet the demand. The red deficit areas in Tanzania, along the border with Kenya, are the result of high consumption of fuelwood and charcoal, stemming from high population density and low levels of production of woody biomass.

The Burden of Fuel Collection

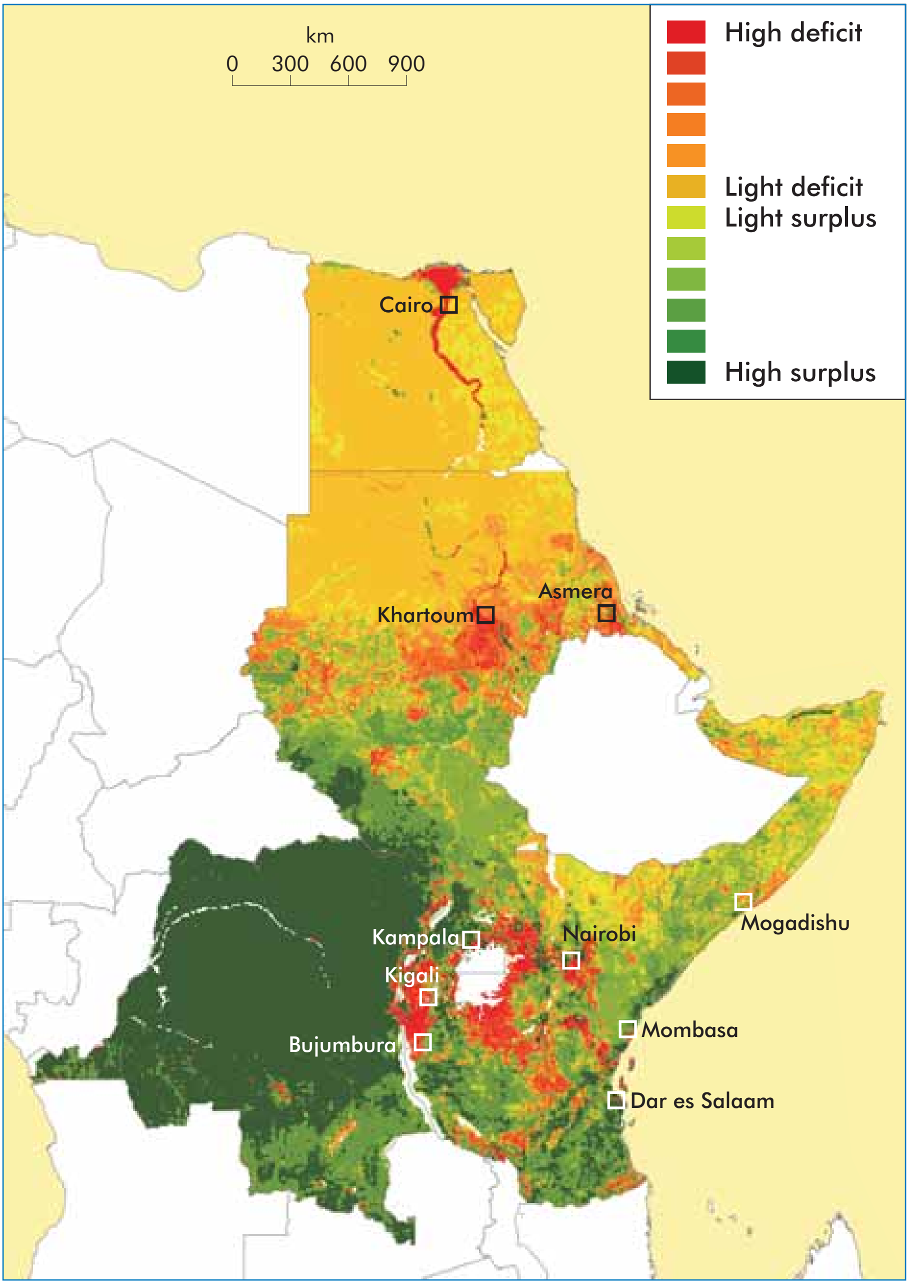
In developing regions reliant on biomass, women and children are responsible for fuel collection, a time-consuming and exhausting task. The average fuelwood load in sub-Saharan Africa is around 20 kg but loads of 38 kg (Rwelamira, 1999) have also been recorded. Women can suffer serious long-term physical damage from strenuous work without sufficient recuperation. This risk, as well as the risk of falls, bites or assault, rises steeply the further from home women have to walk, for example because of conversion of land to agricultural uses.

Figure 15.6 shows the distance travelled for fuelwood collection in rural areas of Tanzania. The average distance is highest in the central region of Singida, at over ten kilometres per day, followed by the western regions near Lake Tanganyika, where it is greater than five kilometres per day. Collection time has a significant opportunity cost, limiting the opportunity for women and children to improve their education and engage in income-generating activities. Many children, especially girls, are withdrawn from school to attend to domestic chores related to biomass use, reducing their literacy and restricting their economic opportunities. Modern energy services promote economic development by enhancing the productivity of labour and capital. More efficient technologies provide higher-quality energy services at lower costs and free up household time, especially that of women and children, for more productive purposes.[10]

There are important development benefits to be gained from expanding access to modern energy services. The UN Millennium Project (2005) has emphasised that close links exist between energy and all eight of the Millennium Development Goals (MDGs). Modern energy services help reduce

10. See also WEO-2004 and Victor (2005) for further discussion of the link between energy and economic development.

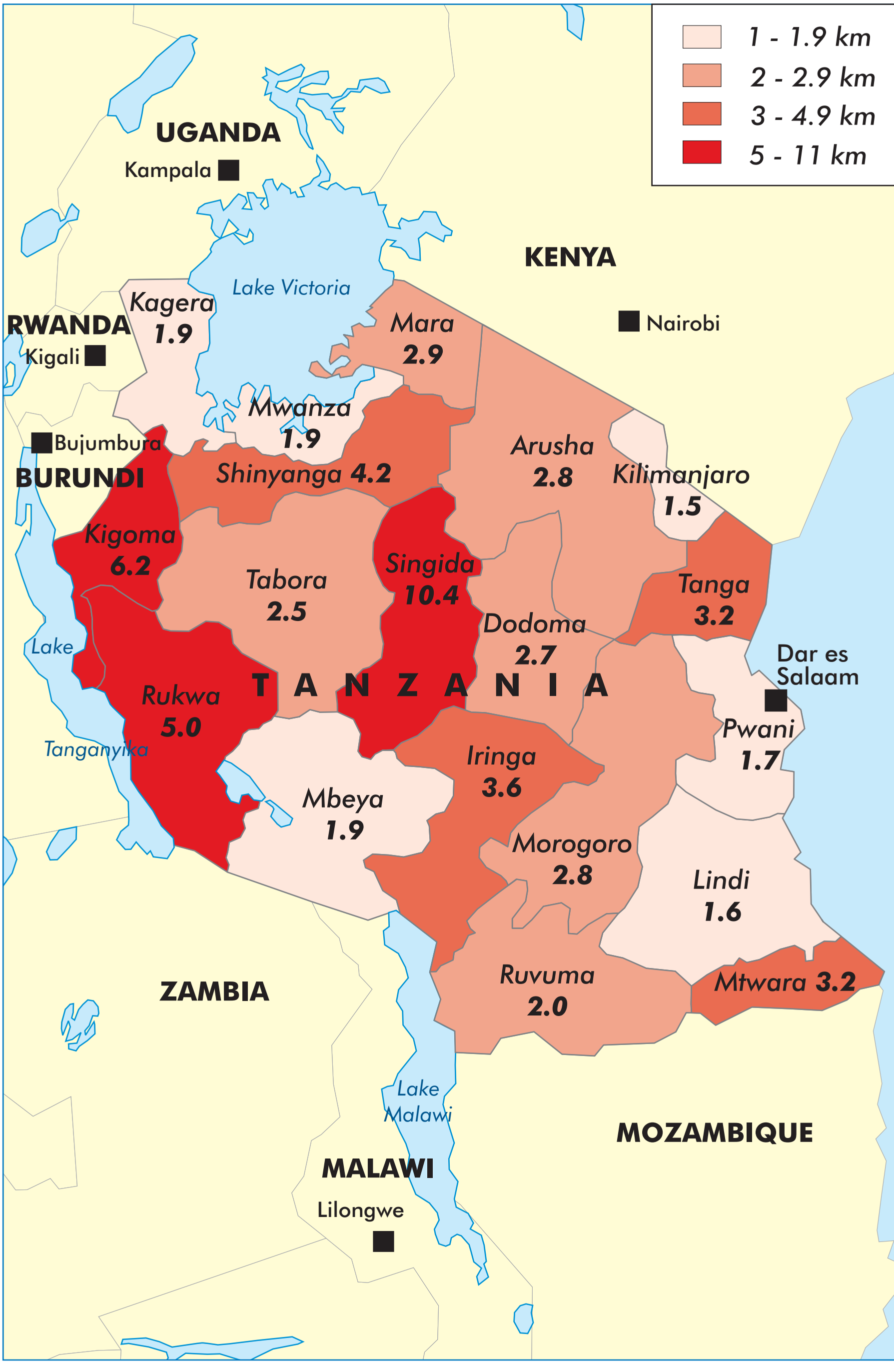
Figure 15.5: **Woodfuel Supply and Demand Balance in East Africa**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: Based on the estimated consumption of fuelwood and charcoal, and production of woody biomass within cells of approximately 10x10 km (5 arc-minutes), applying the Woodfuel Integrated Supply/Demand Overview Mapping (WISDOM) methodology.
Source: Drigo, R. based on FAO (2006).

Figure 15.6: **Distance Travelled to Collect Fuelwood in Rural Tanzania**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: *Household Budget Survey 2000/01*, National Bureau of Statistics, Tanzania.

poverty (MDG 1) and can play a critical role in improving educational opportunities for children, empowering women and promoting gender equality (MDGs 2 and 3). The availability of adequate clean energy is important in reducing child mortality (MDG 4). Reducing the carrying of heavy loads of fuelwood improves maternal health (MDG 5). Inefficient combustion of fuelwood exacerbates respiratory illnesses and other diseases (MDG 6). Fuel substitution and improved stove efficiencies would help alleviate the environmental damage of biomass use (MDG 7). Finally, widespread substitution of modern energy for traditional biomass can be a rallying point for global partnerships (MDG 8).

Outlook for Household Biomass Use in Developing Countries

Without strong new policies to expand access to cleaner fuels and technologies, the number of people in developing countries relying on traditional biomass as their main fuel for cooking will continue to increase as the global population increases. In the Reference Scenario, in which no new policies are introduced, the number rises from 2.5 billion in 2004 to 2.6 billion in 2015 and to 2.7 billion in 2030 (Table 15.2). Residential biomass demand in developing countries is projected to rise from 771 Mtoe in 2004 to 818 Mtoe in 2030. These projections take into account the fuel substitution and the market penetration of more efficient technologies that would occur as a result of rising per-capita incomes, fuel availability and other factors.

Household sizes by region have been incorporated into the projections, but the rural/urban split has not been estimated through to 2030. Almost all of the growth in population will, in fact, be in urban areas, but the categorisation

Table 15.2: **People Relying on Traditional Biomass** (million)

	2004	**2015**	**2030**
Sub-Saharan Africa	575	627	720
North Africa	4	5	5
India	740	777	782
China	480	453	394
Indonesia	156	171	180
Rest of Asia	489	521	561
Brazil	23	26	27
Rest of Latin America	60	60	58
Total	**2 528**	**2 640**	**2 727**

between rural and urban is arbitrary in the statistics of many countries and growth could be in small towns and villages as much as in mega-cities. In line with historical trends, per-capita biomass consumption in each region is assumed to remain constant at 2004 levels over the *Outlook* period (for example, 0.35 toe for sub-Saharan Africa). On the basis of past experience, the share of people relying on traditional biomass technologies will decline faster in towns than in rural areas.

Most of the projected increase in the number of people relying on traditional biomass will occur in Asia and sub-Saharan Africa. In many of these countries, per-capita incomes are not expected to increase enough for people to be able to switch away from traditional biomass to any significant degree. In China, however, the number of people relying on biomass will decline. It will increase only slightly in Brazil, thanks to strong national programmes (Box 15.1). In Indonesia, the rate of growth in the number of people relying on biomass will decline, but there will still be an absolute increase in 2030 over 2004. In the developing world as a whole, the share of the population still relying on biomass is projected to have dropped by 2030 from 52% to 42%.

Box 15.1: The Brazilian Experience with LPG

In Brazil, 98% of households (including 93% of rural households) have access to LPG – a situation that can be attributed to government policy that has promoted the development of an LPG delivery infrastructure in all regions, including rural regions, and subsidies to LPG users (Jannuzzi and Sanga, 2004; Lucon *et al.*, 2004). Until the late 1990s, the rise in LPG use was accompanied by a sharp decline in residential wood consumption.

During the period 1973-2001, retail LPG prices were set at the same level in all regions and the average level of the subsidy amounted to 18% of the retail price. In May 2001, end-user prices were liberalised, as part of a process of deregulating the petroleum sector. At the same time, the government introduced an *Auxilio-Gas* ("gas assistance") programme to enable qualifying low-income households to purchase LPG. Qualifying families were those with incomes less than half the minimum wage (an average daily per-capita income of $0.34 a day in 2003). The total programme cost in 2002 was about half that of price subsidisation. This programme now forms part of the *Bolsa Familia*, by far the largest conditional cash transfer programme in the developing world (Managing for Development Results, 2006). Recent LPG price increases, however, appear to have led to a reversal of the trend towards lower residential biomass consumption (Figure 15.10).

Improving the Way Biomass is Used

For many households, switching away from traditional biomass is not feasible in the short term. Improving the way biomass is supplied and used for cooking is, therefore, an important way of reducing its harmful effects. This can be achieved either through transformation of biomass into less polluting forms or through improved stoves and better ventilation.

Charcoal and agricultural residue briquettes have a higher energy content than fuelwood and so reduce the amount of fuel needed. Although charcoal is often produced using traditional techniques, with low transformation efficiencies, there is some evidence that fuelwood supply in developing countries can be adequate, even in densely populated areas, if resources are well managed. Even less polluting than briquettes are modern biomass fuels such as ethanol gel, plant oils and biogas (discussed in the next section).

A second approach is to improve the efficiency of biomass use through provision of improved stoves and enhanced ventilation. Adding chimneys to stoves is the most effective improvement to be made from the point of view of health. Increasing household ventilation is also a very cost-effective measure. Other technologies include "retained heat" cookers, fan stoves and "rocket" stoves. Improved stoves are not prohibitively expensive, ranging from $2 in Ethiopia to $10-$15 for rocket stoves in Guatemala. Improved biomass stoves save from 10% to 50% of biomass consumption for the same cooking service provided (REN21, 2005) and can reduce indoor air pollution by up to one-half. A study of indoor air pollution levels in Bangladesh confirms that kitchen design and ventilation play a key role in reducing emissions. Particulate levels in houses using wood, but with good ventilation, were found to be lower even than those in houses using LPG (Dasgupta *et al.*, 2004).

Today, about 560 million households rely on traditional biomass for cooking. Since the 1980s, hundreds of millions of improved stoves have been distributed worldwide, with varying degrees of success. China's Ministry of Agriculture estimated that, in 1998, 185 million out of 236 million rural households had improved biomass or coal stoves (Sinton *et al.*, 2004). In India, an estimated 34 million stoves have been distributed, while in Africa 5 million improved biomass stoves are in use (REN21, 2005). The number of improved stoves actually still in operation in all regions may be significantly less than the number distributed.

Modern Cooking Fuels and Stoves

In the long run, and even today in areas where sustainable biomass use is not possible, a modern cooking fuel solution is the most appropriate way to reduce the health risks and time-loss suffered by women and children. There are a range of fuels that can substitute for, or supplement the use of, biomass in the household energy mix. Each modern fuel has distinct characteristics and costs, as shown in Table 15.3. Some are already widely available.

Table 15.3: **Costs and Characteristics of Selected Fuels**

	Capital cost*	Fuel cost	Notes
Biogas	$100-1 000	0	Commercially available; direct fuel cost is zero (requires water and dung or leafy biomass material, usually collected in non-commercial form); more economic at village scale; an important option for some rural areas, in China and other parts of Asia; less favoured in Africa, where villages are more dispersed; formed by anaerobic digestion.
Plant oils	$38-45	$0.45-$0.60 per litre	Deployment phase; functions like a kerosene pressure stove; safer than kerosene or LPG; burns oils such as coconut, palm, rapeseed, castor and jatropha; renewable resource which can be locally produced.
DME	$45-60	$0.25-$0.35 per kg	Demonstration phase; similar to LPG; dimethyl ether (DME) is today manufactured in small-scale facilities by dehydration of methanol derived from natural gas or coal. DME can also be produced from biomass. The construction of large plants for making methanol and DME from coal has recently been announced in China (Box 15.2), where most production is used for blending with LPG.
Ethanol gel	$2-20	$0.30-$0.70 per litre	Deployment phase; viable particularly in areas with large sugar cane plantations that produce ethanol; safe and clean biomass cooking fuel, being promoted in several African and south Asian countries.
Kerosene	$30-40	$0.50-$0.60 per litre	Commercially available; produces more emissions than LPG and carries a higher risk of injury; available as a liquid or gas; in liquid form, easier to transport and distribute and can be purchased in any quantity.
LPG	$45-60	$0.55-$0.70 per kg	Commercially available, more widely in urban areas than rural; issues of affordability and distribution limit use in rural areas; disadvantages of LPG for low-income households are its relatively large start-up cost and refill cost.

* Cost of digester for biogas; cost of stove and cylinder for all other fuels.

In view of their ability to reduce indoor air pollution levels substantially and their short-term potential for expansion, a number of fuels are well-placed to make major contributions to improving the household energy situation in developing countries. LPG is already quite well established in some countries. Ethanol gel is also potentially very important, particularly in sugar-producing countries, because of its low cost. Biogas has considerable potential in many rural communities, though the capital costs are not directly comparable to those of liquid fuels.

Box 15.2: **Household Coal and Alternatives in China**

China differs from most other developing countries because of the predominance of coal use for cooking and heating. China has the world's third-largest proven reserves of coal (BP, 2006). This coal can contain large quantities of arsenic, lead, mercury, other poisonous metals and fluorine. Burned in unventilated stoves, these pollutants pose a serious health threat. In addition to the health impacts associated with smoke from biomass described earlier, with coal there is evidence of a strong correlation with lung cancer in women (WHO, 2006).

The Chinese government is taking steps to increase access to fuels such as biogas and DME. The National Development and Reform Commission has recently recommended that policies supporting DME be strengthened and that standards be established. The cost of DME production from coal can be much lower than the cost of imported LPG. It can be mixed with LPG in any proportion but, with blends of up to 20%, no LPG stove modification is necessary. Plans have been announced for expanding DME production from coal in China to more than 3 million tonnes per year by 2010. This could provide cooking fuel to at least 40 million people.

Quantifying the Potential Impact of Modern Cooking Fuels and Stoves

The UN Millennium Project has adopted a target of reducing by 50% the number of households using biomass as their primary cooking fuel by 2015.[11] The cost of achieving this target is assessed below, as well as the potential effects

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11. The UN Millennium Project recommendation related to energy for cooking is the following: *Enable the use of modern fuels for 50% of those who at present use traditional biomass for cooking. In addition, support (a) efforts to develop and adopt the use of improved cookstoves, (b) measures to reduce the adverse health impacts from cooking with biomass, and (c) measures to increase sustainable biomass production* (UN Millennium Project *et al.*, 2005).

on global oil demand and related emissions. The costs and other implications of expanding access to cleaner, more efficient fuels and technologies for all households by 2030 are also described.

LPG is used as a proxy for modern fuels in this analysis. However, especially in the period 2015 to 2030, other options include ethanol gel, plant oils, biogas and DME. The appropriate choice will vary by country, by region and over time.[12] Some communities will prefer the cleaner, more efficient use of biomass energy. Biogas might be an especially attractive option for India and some regions in both east and southeast Asia, because of their abundant biomass resources. Other modern biomass fuels and LPG might be a more appropriate option for Africa, Latin America and parts of east Asia. DME is likely to become an important complement to LPG in China in the near term and its use might spread to other regions if it offers clear cost advantages over LPG.

There will still be significant biomass use in developing countries in 2030. This could be a positive development, as stressed earlier in the chapter, as long as improved cooking stoves are adopted. Nevertheless, large-scale substitution of traditional biomass by alternative fuels will need to take place as well. The objective in this section is to illustrate the scale of the task. Meeting the 2015 target would mean 1.3 billion people switching to LPG as their primary fuel, while universal access in 2030 would call for 2.7 billion people to switch (Table 15.4).

Table 15.4: **Additional Number of People Needing to Gain Access to Modern Fuels** (millions)

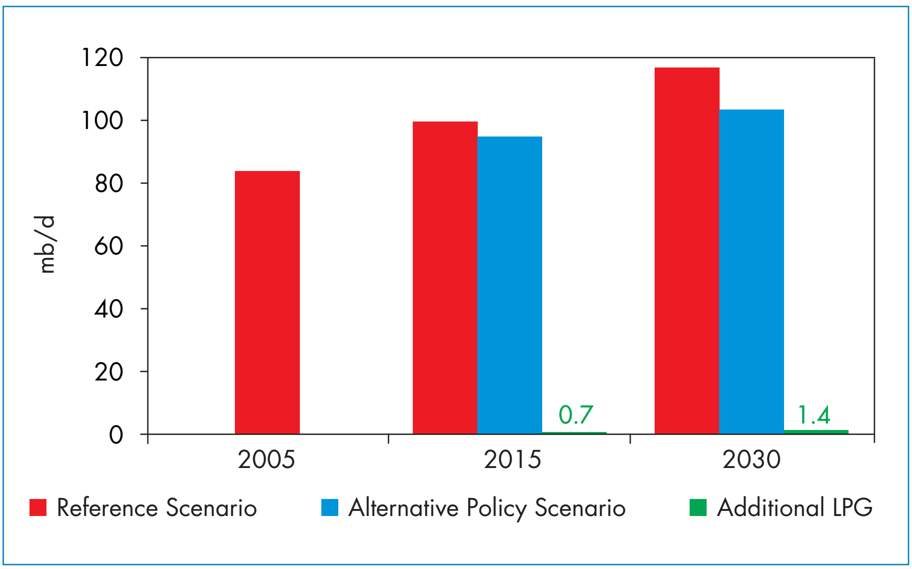
	Between 2004 and 2015	**Between 2015 and 2030**
Sub-Saharan Africa	314	406
North Africa	2	3
India	389	394
China	226	168
Indonesia	85	94
Rest of Asia	261	300
Brazil	13	14
Rest of Latin America	30	28
Total	**1 320**	**1 407**

12. For example, the Indonesian government is commencing a programme to replace kerosene with LPG in urban households and to replace biomass with coal briquettes in some rural areas.

Implications for Oil Demand

LPG is generated as a by-product of both oil refining and natural gas production. The incremental world oil and gas demand which would result from widespread take-up of LPG is negligible. Assuming average consumption of LPG of 22 kg per person per year[13] and assuming all of this LPG was derived from oil rather than natural gas, providing 1.3 billion additional people with LPG by 2015 would increase oil demand by 0.7 mb/d, or 0.69% of the 99 mb/d projected in the Reference Scenario (Figure 15.7). The increase would be 0.72% in the Alternative Policy Scenario. If all households currently using biomass switched to LPG by 2030, the rise in oil demand would be 1.4 mb/d. Such a figure is but a tiny fraction of the fuel lost through the flaring of natural gas.[14] These are upper bounds because, as noted earlier, LPG is just one of several energy carriers that could be pursued as substitutes for traditional biomass, whereas these calculations have taken LPG as a proxy for them all.

Figure 15.7: **Additional LPG Demand Associated with Switching Compared with World Oil Demand**



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13. A weighted average based on WHO data for developing country households currently using LPG.
14. Around 60% of global LPG supply comes from natural gas processing.

Implications for Greenhouse Gas Emissions

The overall effect on greenhouse-gas emissions of switching from biomass to LPG is very difficult to quantify because it depends on many factors, including the particular fuels involved, the types of stoves used and whether the biomass is being replaced by new planting. Both biomass and non-biomass fuels emit CO_2 and other greenhouse gases. If burnt biomass is not replaced by new growth, a net addition of CO_2 to the atmosphere occurs. Also, inefficient biomass combustion produces some gases which have an even more powerful greenhouse effect than CO_2. Although biomass used with traditional stoves can be carbon-neutral (if CO_2 emissions from the combustion process are offset by absorption during regrowth), the process is not emissions-neutral unless the biomass fuel is burnt efficiently and completely (UNEP, 2006). Although the overall impact on emissions of switching to modern fuels can be either positive or negative, improved stoves and greater conversion efficiency would result in unambiguous emissions reductions from all fuels.

Costs and Financial Implications

Switching to LPG involves capital expenditure for the stove and cylinder and recurring expenditure for the fuel itself. Costs per household vary somewhat by region according to differences in household size. The capital expenditure for the equipment (stoves and cylinders) is assumed to be \$50 per household (UN Millennium Project *et al.*, 2005).[15] On that basis, the total stove and cylinder cost would be \$13.6 billion in the period to 2015 (Table 15.5), or \$1.5 billion per year, and \$14.5 billion in the period 2015-2030. Spending needs would be highest in India.

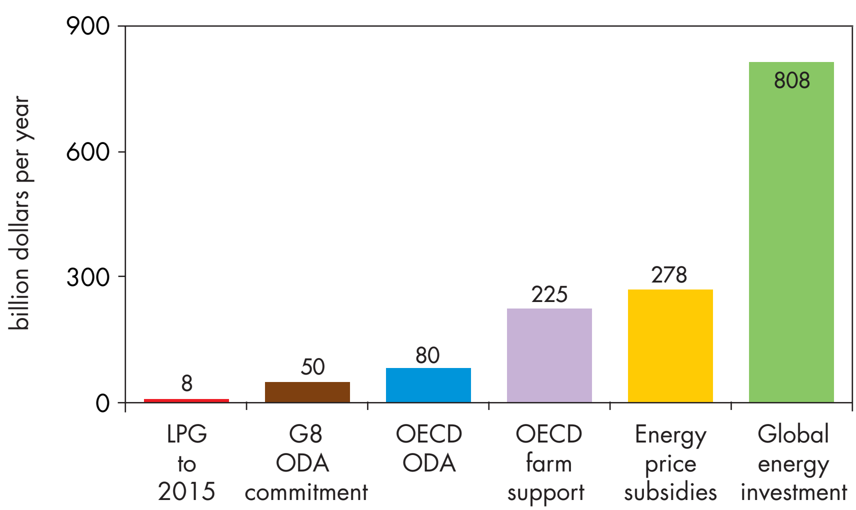
Fuel costs are estimated to be \$0.55 per kilogram of LPG, based on 2005 consumer prices in a sample of developing countries. Combined with start-up capital costs, the total bill (capital *plus* fuel costs) for households switching to LPG would then be \$8 billion per year in the period to 2015 and \$18 billion per year from now to 2030. Although these costs are not negligible, they are small compared with allocations of resources elsewhere in the world economy (Figure 15.8). For example, the annualised capital and operating costs through to 2030 represent 10.6% of what OECD countries spent on Official Development Assistance (ODA) in 2004, 3% of the estimated \$278 billion that developing and transition economies spent on energy price subsidies in 2005 (Chapter 11) and 1% of the \$808 billion that will need to be spent annually on global energy infrastructure in the Reference Scenario (Chapter 2).

15. The UNDP/WLPGA LP Gas Challenge estimates \$45 to \$60 for a stove, a cylinder and 6kg of gas.

Table 15.5: **Purchase Cost of LPG Stoves and Cylinders by Region**
($ billion)

	50% target in 2015	2015-2030	100% provision in 2030
Sub-Saharan Africa	3.0	3.9	6.9
North Africa	0.02	0.02	0.04
India	3.9	3.9	7.8
China	2.5	1.8	4.3
Indonesia	0.9	1.0	2.0
Rest of Asia	2.9	3.3	6.2
Brazil	0.1	0.1	0.3
Rest of Latin America	0.3	0.3	0.6
Total	**13.6**	**14.5**	**28.1**

Figure 15.8: **Comparison of Average Annual Cost of LPG Fuel and Technology, 2007-2015, with Other Annual Allocations of Resources**
($ billion)



Sources: G8 ODA Commitment – additional ODA per year by 2010; OECD ODA – www.oecd.org/dac; OECD Farm Support – OECD (2006a); Energy Price Subsidies – total for developing countries and transition economies (Chapter 11); Global Energy Investment – total requirement in the Reference Scenario (Chapter 2).

Analysis by the World Health Organization suggests that the societal benefits of such expenditure outweigh the costs by a very wide margin. The figure for the societal benefit/cost ratio of a global clean cooking initiative, as estimated by the WHO (2006), is so high that the findings on the value of such an initiative are robust under a wide range of alternative assumptions. The WHO estimates that the total benefits of meeting this UN Millennium Project-based target by 2015 through switching to LPG would average $91 billion per year (Table 15.6).

Table 15.6: **Benefits of Cleaner Cooking** ($ billion per year)

Health-care savings	0.38
Time savings due to childhood and adult illnesses prevented: school attendance days gained for children and productivity gains for children and adults	1.46
Time savings due to less time spent on fuel collection and cooking: productivity gains	43.98
Value of deaths averted among children and adults	38.73
Environmental benefits	6.07
Total benefits	**90.62**

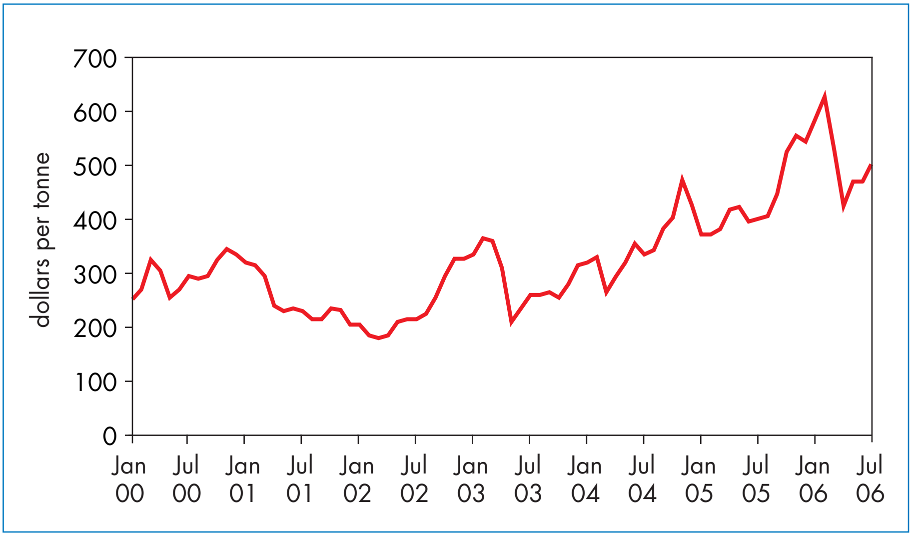
Note: Societal economic benefits of providing LPG to half the population by 2015 who would otherwise be using solid fuels for cooking in 2015.
Source: WHO (2006).

Policy Implications

Meeting the cooking-fuel target will require government action. On the supply side, it can be difficult to establish a commercially viable LPG distribution network in the face of low population density, poor roads, and low LPG uptake and consumption among those who sign up for LPG. The absence of economies of scale in catering to rural domestic consumers is one of the main factors hindering LPG access. Infrequent delivery of refill cylinders serves as a disincentive to switching to LPG. Demand-side barriers include low per-capita incomes, lack of awareness of the benefits of alternative fuels, inappropriate stove designs and simple force of habit. Moreover, even were LPG widely available, many poor households would not be able to afford the required capital investments. The start-up cost of buying a stove and paying a deposit for a fuel canister represents a serious barrier for many households.

The trend worldwide is towards removal of price subsidies, linking final consumer prices of kerosene and LPG to international market prices. These have fluctuated significantly in recent years (Figure 15.9), reflecting swings in international crude oil prices: the Saudi LPG contract price, a benchmark for international prices, has ranged from a low of $200 per tonne in 2002 to over $600 per tonne in early 2006. If fluctuations of that magnitude were reflected in domestic cooking fuel prices, poor households would find it difficult to pay for fuel or budget for future purchases.

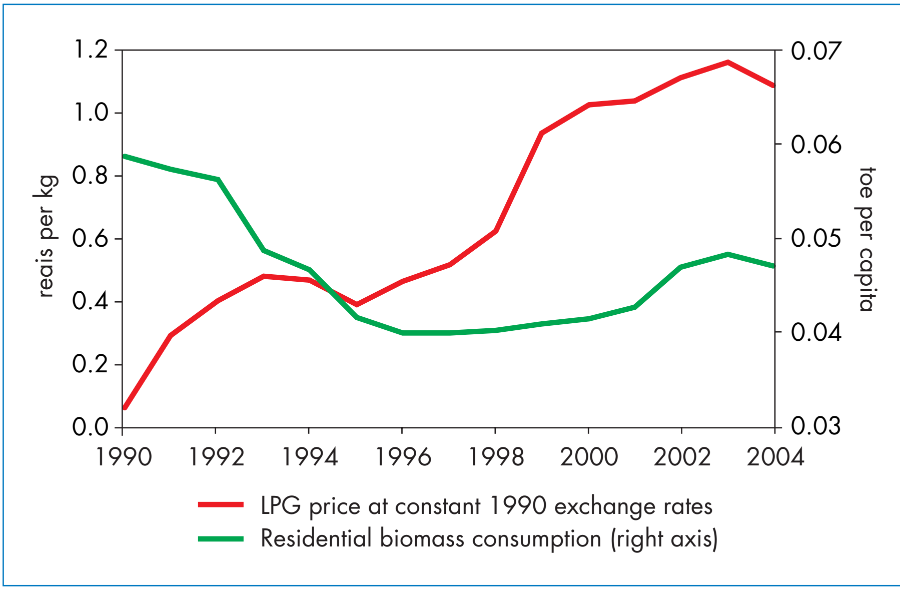
Figure 15.9: **Saudi Aramco Contract LPG Price** (butane, $ per tonne)



Notes: Saudi Aramco Contract is a benchmark LPG price. The price of propane differed only very slightly from that of butane over the period shown in the chart.
Source: LPG Australia, available at www.lpgaustralia.com.au.

Although more analysis is needed, there is evidence that the trend to switch away from traditional biomass is being reversed under the pressure of higher oil prices. In Brazil, for example, biomass consumption per capita has stopped declining and even started to increase, as many poor households switch back to fuelwood, in the face of higher LPG prices (Figure 15.10). In some poor communities in Brazil, inefficient stoves adapted to burning scraps of wood have resurfaced. As countries remove their price controls and let domestic prices rise to world levels, they are likely to face the same predicament.

Figure 15.10: **Residential Biomass Consumption and LPG Retail Price in Brazil**



Source: LPG prices – Economic Commission for Latin America and the Caribbean; Residential biomass consumption – IEA databases.

There are many ways in which policy-makers and other stakeholders can help make clean fuels affordable. The LP Gas Rural Energy Challenge[16], among other initiatives, is working to this end. One approach is to encourage the development of microfinance (Box 15.3). There may also be a case for subsidising the up-front costs of buying gas stoves and cylinders, in view of the potentially large impact and relatively small overall cost of such a programme. Governments could also facilitate commercialisation of LPG by designing financial incentives and training private entrepreneurs, setting technical standards, extending credit facilities to stove-makers and providing marketing support. Another approach is to promote the use of smaller LPG cylinders. These would lower the initial deposit fee and refilling costs, encouraging more regular LPG consumption, especially in rural areas, and more widespread use of the fuel. This approach has had some success in Morocco. On the other hand, small cylinders do involve higher transaction costs and hence higher unit prices. Also, reliance on more frequent refills can become a problem if the supply system is unreliable.

16. More information is available at www.undp.org/energy/lpg.htm and www.worldlpgas.com.

Box 15.3: **The Role of Microfinance in Expanding the Use of Modern Fuels**

Microfinance institutions allow households and villages to mobilise the capital needed to make small energy investments. Notably, women's access to such financial services has increased in the past decade. Worldwide, four out of five micro-borrowers are women. Microfinance is particularly important in rural areas where farmers have no income for long periods of the year.

One of the principal barriers to the penetration of modern cooking fuels is the high initial cost of the cylinder purchase (in the case of LPG) and the stove. An option to overcome up-front costs is for a bank or financial institution to offer financing for the cylinder and appliance over a year or more. There are strong arguments for using the community as a vehicle for this financing and making it jointly and individually responsible for repayment.

Energy service companies can assist with cost barriers by providing energy to customers on a fee-for-service basis, retaining ownership of some or all of the energy equipment, pooling subsidies and investment incentives and amortising over time the balance of equipment costs in the fees charged to customers. An affordable connection fee would be collected, offsetting some equipment costs, with the remainder amortised in the charges for each refill. If the customer returns the bottle for refill, credit risk and collection costs for LPG decline significantly.

Providing improved stoves and canisters is a necessary, but not a sufficient condition for expanding the use of modern fuels. Annual fuel costs are typically several times the annualised cost of stoves and canisters. Many rural households would not be able to afford LPG, even with microfinance or subsidised capital investment. The challenge is especially daunting for those dependent on agriculture, where incomes are not only low but volatile. In such cases, efforts to tackle energy poverty would clearly need to go hand in hand with broader policies aimed at alleviating poverty more generally and promoting economic development. Clean-cooking initiatives would ideally be carried out in parallel with programmes for education, rural electrification and industrialisation, which would also enable time freed up to be productively reallocated. In general, income-support or social welfare programmes are a far more effective way of addressing poverty than subsidies to the fuels themselves.

One of the recommendations of the UN Millennium Project was that objectives regarding energy services should be placed on a par with the original Millennium Development Goals. Efforts by groups such as the LP Gas Rural Energy Challenge have had some success but, at the global level, the resources and attention devoted to improving energy use for cooking are not commensurate with the magnitude of the problem. Compared with the international response to hunger, HIV/AIDS, dirty water, poor sanitation and malaria, energy use for cooking has received extremely limited funding and high-level political backing. Even in countries where the vast majority of the population relies on traditional biomass for cooking, access to electricity has received much more attention and investment. Climate-driven programmes have also tended to bypass household energy use for cooking, since biomass-based energy sources were regarded as emissions-neutral. There are opportunities for the private sector to make up the shortfall in funding. Support to microfinance institutions could also be an effective approach, as would new financing mechanisms, such as the MDG Carbon Facility of the UNDP.[17]

Large electricity generation, transmission and distribution projects primarily benefit industry and urban populations, while most rural and poor people depend on biomass (OECD, 2006b). Effective, comprehensive policies need to include the forms of energy used by the poor – for cooking, lighting, productive appliances and transport – rather than concentrate on provision of electricity alone as an end in itself.

Detailed, accurate statistics on energy supply and consumption are essential for proper policy and market analysis. Efforts are under way to improve regular data collection through international surveys such as the Living Standards Measurement Study and the Multiple Indicators Cluster Surveys. The IEA and FAO are developing a standard joint terminology (FAO, 2004). Greater coverage, both geographical and temporal, is needed and more resources should be devoted to achieving this. Better information on markets and technologies is also needed. Although the findings of this chapter are robust, better data would allow for more detailed analysis at the local and household levels.

Governments could increase provision of training programmes to develop skills and expertise in the area of improved stoves and housing design, and to educate people about the health risks of indoor air pollution. Simple measures can be very effective, such as improving public awareness of changes that can reduce smoke levels, like drying wood thoroughly before use and shortening cooking time (by using a pot lid). Similar gains can be made from improvements in household design, such as increasing the number of window openings in the kitchen, providing gaps between roof and wall and moving the stove out of the living area.

17. The MDG Carbon Facility was founded on the basis that climate change threatens to significantly undermine efforts to achieve the Millennium Development Goals. More information is available at www.mdgcarbonfacility.org.

The benefit/cost ratio of government intervention to help poor households gain access to affordable modern energy has been found to be very high and the cost would be small compared with total aid budgets or global energy investment. Greater energy efficiency and diversity of energy sources in developing countries would provide a gain in energy security at only a very small cost in terms of the increase in world oil and gas demand.

Effective policies will need to be locally designed, since there are substantial differences between and even within countries. Regulatory reforms can improve the affordability, availability and safety of a range of cooking fuels and technologies. Governments can also support cleaner cooking by developing national databases which include information on the population to be served, potential fuels, stoves, the infrastructure and potential providers, together with cost analyses and estimates of the ability and willingness to pay, as a function of income. Long-term commitments are needed from development partners to scale up energy investments, transfer knowledge and deploy financing instruments which will leverage private capital, particularly in countries with the largest concentration of the energy-poor, such as those in sub-Saharan Africa and south Asia.

FOCUS ON BRAZIL

HIGHLIGHTS

- Brazil is Latin America's largest energy consumer, accounting for over 40% of the region's consumption. Its energy mix is dominated by renewable energy sources and oil. In the Reference Scenario, primary energy demand is projected to grow annually at 2.1%, from 200 Mtoe in 2004 to 352 Mtoe in 2030. Energy demand is 38 Mtoe lower in the Alternative Policy Scenario, growing at just 1.7% per year, thanks to energy-efficiency improvements. Electricity and oil make up most of the reduction.
- Crude oil production is expected to reach 3.1 mb/d in 2015 and 3.7 mb/d in 2030 in the Reference Scenario. Brazil became self-sufficient on a net basis for the first time in 2006 and remains so in both scenarios over the *Outlook* period, provided that the necessary investment in the upstream oil sector, especially for exploration, is forthcoming. The share of imports in natural gas use drops, despite rapidly rising demand – on the assumption that the country's gas reserves are developed quickly enough. This will call for more private investment and a more effective regulatory framework.
- Brazil is the world's second-largest producer and largest exporter of ethanol. It is also expanding its production and use of biodiesel. The share of biofuels in road-transport fuel demand rises from 14% in 2004 to 23% in 2030 in the Reference Scenario and to 30% in the Alternative Policy Scenario.
- Brazil is expected to continue to rely on hydropower to meet most of its power-generation needs, building about 66 GW of new capacity in 2004-2030 in the Reference Scenario. Dams are likely to be located far from centres of demand, requiring large investments in transmission lines to connect them to the national grid.
- The investment needed to meet the projected growth in energy supply in the Reference Scenario is considerable, some \$470 billion (in year-2005 dollars) in 2005-2030. The power sector alone needs over \$250 billion, half for generation and half for transmission and distribution. Cumulative upstream oil investment totals over \$100 billion. In the Alternative Policy Scenario, investment needs on the supply side are reduced by \$7 billion in the oil and gas sectors and

$46 billion in the power sector, but demand-side investments are higher. Winning investor confidence in order to secure financing in the power sector will hinge on careful implementation of the new power model.

- The major challenges for Brazil's energy sector will be mobilising investment in oil, gas and electricity infrastructure and resolving environmental issues over the construction of large dams, pipelines and transmission lines. A priority for the government will be to strengthen its policy and regulatory framework in order to secure the necessary investments.

Overview

Brazil has a very dynamic energy sector. Recent government policies have brought considerable improvements in energy efficiency in the residential and industry sectors and have succeeded in increasing the penetration of non-hydro renewable energy in the power-generation mix. Impressive technological advances have been made in production of crude oil in deep and ultra-deep water and of ethanol from sugar cane. These achievements will continue to serve as an inspiration to other developing countries with similar aspirations.

Brazil is the largest country in Latin America and the fifth-largest in the world by surface area. It also had the world's fifth-largest population in 2004, with 184 million inhabitants. Brazil is Latin America's largest energy consumer, accounting for over 40% of the region's primary consumption in 2004. Brazil's primary energy mix is dominated by oil, which accounts for 42% of total demand, hydropower (14%) and other renewable energy sources (27%). Energy intensity, measured by the ratio of energy demand to GDP, has declined over the past three decades. But the share of fossil fuels in the primary mix has increased and growth in CO_2 emissions has been on a par with growth in energy demand (Table 16.1).

Table 16.1: **Key Energy Indicators for Brazil**

	1980	2004	1980-2004*
Total primary energy demand (Mtoe)	111	200	2.5%
Total primary energy demand per capita (toe)	0.9	1.1	0.8%
Total primary energy demand /GDP (toe/dollar of GDP in PPPs)	0.1	0.1	0.4%
Share of oil in total primary energy demand (%)	50	42	–0.7%
Share of hydro in total power generation (%)	81	65	–0.9%
CO_2 emissions (Mt)**	178	323	2.5%

* Average annual growth rate. ** Excludes emissions from land use, land use change and forestry.

Brazil has vast energy and natural resources, including about 11.2 billion barrels of proven oil reserves and 306 billion cubic metres of gas. Among Latin American countries, Brazil ranks second to Venezuela in oil and natural gas reserves. In April 2006, Brazil achieved self-sufficiency in crude oil consumption, largely as a result of investments in exploration and production. Rising domestic ethanol production and consumption, combined with a slowdown in the growth rate in energy demand in the transport sector, has also helped to free up oil for export. Brazil has a large renewable energy supply potential, with 260 GW of technical hydropower potential and 143 GW of technical wind-power potential. Brazil is the world's second-largest ethanol producer, after the United States, and the world's largest ethanol exporter. The ethanol is derived from sugar cane. Development of these vast resources, however, has been hindered by cyclical economic disruptions and shortages of long-term and low-cost capital.

Brazil faces a number of energy and environmental challenges. Natural gas demand has increased considerably over the last few years, as the government kept gas prices low to encourage energy diversification. A rapid expansion of gas imports fuelled this growth. In 2004, imports from Bolivia accounted for 43% of gas consumption in Brazil.[1] Particularly in the light of the recent nationalisation of the energy sector in Bolivia, Brazil is seeking to reduce this concentrated gas import-dependence by accelerating development of the Espirito Santo and Santos basins and by importing LNG. Environmental concerns will, however, need to be addressed. Much more investment will be needed to exploit domestic gas resources and to expand the gas transportation and distribution infrastructure. Hydropower accounted for over three-quarters of Brazil's electricity-generating capacity in 2004 and the government plans to authorise the building of new large hydropower plants; but there are important environmental and financial obstacles. The government is actively promoting the use of sugar-cane residue (bagasse) for cogeneration of heat and power and other non-hydro renewables-based electricity generation.

The Political and Economic Outlook

The Political Scene

In 2002, Luiz Inacio Lula da Silva was elected president of Brazil. The new administration's macroeconomic management has generally exceeded expectations. To consolidate its support, particularly among the poor, the

1. The Brazilian government estimates that, in the first quarter of 2006, imports from Bolivia accounted for 48% of gas consumption.

Administration has increased public spending and raised the minimum wage. A presidential election is scheduled for October 2006, as this book goes to press.

The Brazilian government is very active on the international scene. At the fifth ministerial conference of the World Trade Organization (WTO) at Cancun, Mexico in September 2003, Brazil assumed the leadership of a new group of developing countries, the G20 group. Under its direction, this group has shown resistance to changing the rules of government procurement, investment and competition, unless industrialised countries agree to concessions on subsidies, particularly in agriculture. The government is working to remove tariffs on global ethanol trade. Brazil has ratified the Kyoto Protocol.

The National Economy

Brazil's economy is the largest in Latin America, with GDP of $1 577 billion (in PPP terms and year-2005 dollars) in 2005. Growth in gross domestic product slowed during 2001 and 2002, to some 2% per year from around 2.7% per year in the 1990s, reflecting the slowdown of the world economy. GDP declined by 0.4% in 2003 but rebounded in 2004, to 4.9%. The expansion was driven predominantly by higher investment and external demand for Brazil's manufactured goods. This sector's contribution to GDP fell in 2005, however, and, combined with weak growth in the agricultural sector due to drought, GDP expanded by only 3.3%. GDP growth is expected to recover slightly in 2006 to 3.5%. The services sector accounts for about half of Brazil's GDP. Industry represents about 40% and agriculture 10%.

GDP per capita, at $8 311 in 2004, was higher than the average for Latin America, but still far below the average per-capita income of $28 400 in the OECD countries. There are sharp disparities in per-capita income in Brazil. According to the United Nations Development Programme, Brazil had the highest Gini coefficient – a measure reflecting the degree of income inequality – in Latin America and the seventh-highest in the world in 2001 (UNDP, 2004). Government reforms, however, have been successful in lowering the degree of income inequality in recent years. Only 4% of Brazilian households lack access to electricity, but the share reaches 25% in rural areas and is even higher in the north and northeast regions. The "Electricity for All" programme aims to give access to all households by 2015.

The Brazilian government has been successful in meeting and, in some cases, surpassing stringent fiscal targets set in consultation with the International Monetary Fund. In December 2005, the government paid off $15.5 billion owed to the IMF (IMF, 2006a). The Central Bank raised interest rates sharply during the first half of 2003. The easing of monetary policy in the second half of 2003, however, combined with a strengthening world economy, allowed growth to rebound in 2004, but the recovery was dampened by further monetary tightening in 2005. Economic volatility has stymied the current administration's efforts to reduce poverty and unemployment.

The Brazilian economy has experienced several periods of volatility in the past. By 2004, Brazil had accumulated $200 billion of external debt. Public debt has declined, thanks to large primary surpluses (at about 5% of GDP), steady GDP growth, a marked appreciation of the exchange rate and rising international reserves. Public domestic debt as a percentage of GDP remains high, however, reaching 59% in 2003. Financing this debt and controlling inflation, has pushed up domestic interest rates, which peaked at just under 20% in 2005, among the highest in the world (World Bank, 2006). This has had the effect of reducing domestic public and private investment, including that in long-term energy projects. The net public debt to GDP ratio is expected to continue to fall slightly over the *Outlook* period (EIU, 2006).

Brazil is second only to China among emerging markets as a recipient of net foreign direct investment. Foreign direct investment was $15.1 billion in 2005 and is expected to reach $15.6 billion in 2006 (IMF, 2006b). Since structural reforms were first launched in the energy sector in the 1990s, the share of foreign capital in energy projects has increased rapidly. However, participation in energy infrastructure investment by private-sector capital, both domestic and international, has been lower than expected, because of regulatory risk and high interest rates.

Key Assumptions

The projections in this *Outlook* assume that the Brazilian economy will grow on average by 3.3% per year from 2004 to 2015 (Table 16.2).[2] Growth is assumed to slow thereafter, bringing down the average for the entire *Outlook* period to 3% per year. In the short and medium term, both private consumption and investment are expected to support somewhat faster growth, but growth is expected to be slower towards the end of the projection period.

Table 16.2: **GDP and Population Growth Rates in Brazil in the Reference Scenario** (average annual rate of change)

	1980-2004	1990-2004	2004-2015	2015-2030	2004-2030
GDP	2.1%	2.6%	3.3%	2.8%	3.0%
Population	1.7%	1.5%	1.2%	0.8%	0.9%
GDP per capita	0.4%	1.0%	2.1%	2.0%	2.1%

2. See Chapter 1 for a discussion of GDP and population assumptions.

Brazil's rate of population growth is declining, from some 2% per year in the 1980s to 1.5% from 1990 to 2004. This *Outlook* assumes that the population will increase by 0.9% per year on average to 2030, reaching 235 million. Over 80% of the population is urban. This relatively large share by developing world standards is explained by historically high rates of population growth in towns and cities, rural to urban migration and the urbanisation of areas previously classified as rural.

Recent Trends and Developments in the Energy Sector

In the last decade, Brazil's energy sector has undergone profound regulatory and structural changes. Petrobras, the national oil and gas company, had exclusive rights to explore and produce oil and gas up to 1995, when the Ninth Amendment to the Brazilian Constitution was issued. This change allowed other companies to become involved in oil and gas exploration and production. In 1997, the Oil Law was adopted, establishing the legal and regulatory framework for the oil industry in Brazil. Since then, over fifty companies, including Petrobras, have acquired rights to explore and produce oil and gas in Brazil. The national regulator for oil and gas, Agência Nacional do Petróleo (ANP), began auctioning exploration blocks in 1999. The seventh bidding round for oil concessions in October 2005 was considered one of the most successful rounds so far since most of the blocks with potential for gas discoveries were awarded. There was also increased participation from domestic companies.

Since December 2000, the oil and gas upstream sector has been fully liberalised and opened to private investors. More than 50 companies are currently active in exploration, though Petrobras retains a dominant position in the sector, producing almost all of Brazil's oil and natural gas. This dominance will lessen as other companies reap the benefits of their investments in exploration. In August 2003, Shell became the first private company to operate an offshore producing field.

As part of the deregulation of the oil and gas sector, end-user prices were liberalised in May 2001 and major subsidies were eliminated. A voucher programme for liquefied petroleum gas (LPG) was set up to assist the poorest households. In Brazil, 98% of households have access to LPG (Box 15.1 in Chapter 15).

Reforms in the power sector were launched in the 1990s.[3] After a period of experimentation with mixed success and the power crisis of 2001, the Brazilian government introduced a new regulatory framework aimed at attracting

3. See de Oliveira (2003) for an overview of power sector reform in Brazil.

investment in 2004. Concessions for the construction of over 10 000 kilometres of transmission lines were awarded and the reliability of the integrated grid has improved. Electricity generation and distribution have also been opened up to private capital. Today 66% of the distribution capacity and 28% of the generating capacity in the Brazilian electricity sector is privately owned.

Box 16.1: **Regional Integration in South American Energy Markets**

Brazil plays an important role in the South American energy market. During the 1970s and 1980s, large multinational hydroelectric dams on the borders of Brazil, Paraguay, Argentina and Uruguay were constructed, providing the main drivers for regional energy integration. In 1991, Argentina, Brazil, Paraguay, and Uruguay formed the Mercado Comun do Sul (Mercosur) to promote intra-regional trade and to co-ordinate macroeconomic policies.

In the late 1990s and early 2000s, projects for transmission grids and gas pipelines boosted regional energy integration. Brazil signed agreements with Venezuela, Uruguay and Argentina in early 2000 to import/export electricity. Meanwhile, gas connections were built with Bolivia and Argentina. There are now three transnational gas pipelines and several electricity transmission lines linking Brazil with neighbouring countries. Another cross-border project under discussion is “Blue Corridors” – a pipeline network that would ultimately connect several cities across Latin America, including Rio de Janeiro and São Paulo in Brazil, Buenos Aires in Argentina, Montevideo in Uruguay and Santiago in Chile.

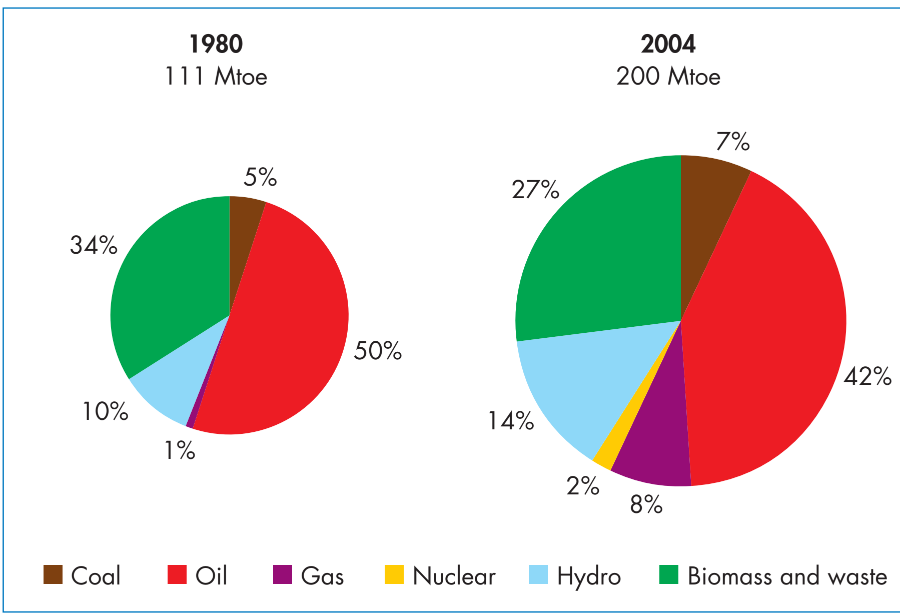
In February 2005, the Venezuelan state oil company, PDVSA, announced the signing of 14 energy accords with Petrobras. The accords anticipate cooperation in the oil, gas, refining, transport and petrochemical sectors, as well as the exchange of biofuels technology and the possible participation by Petrobras in an LNG export project in Venezuela. The two countries are also interested in cooperating on a project to build a refinery in Pernambuco State in the northeast of Brazil.

The nationalisation of Bolivia’s gas sector in May 2006 put a strain on Bolivian-Brazilian relations. Bolivian imports covered 43% of Brazil’s consumption in 2004. Future import levels are uncertain: prices are currently being renegotiated. The assets of Petrobras in Bolivia have been nationalised and the near-term prospects of expanding the Brazil-Bolivia pipeline have dimmed.

Outlook for Energy Demand

Brazil's energy mix has become more diversified over the past several decades. In 1980, biomass use accounted for 34% of total energy demand. Most of this was traditional use for cooking and heating in the residential sector. Total biomass use declined to 27% in 2004 (Figure 16.1). The use of biomass today is predominantly based on modern energy technologies, such as the production of ethanol from sugar cane, the cogeneration of electricity from sugar cane bagasse, the use of sawdust and black liquor (a by-product of the pulp and paper industries) and the production of charcoal from eucalyptus plantations by steelmakers. Fuelwood use for cooking and heating fell from 25 Mtoe in 1971 to 11 Mtoe in 2004, though there are indications that high oil prices have recently reversed this trend. Poor households in the north and northeast, the least developed part of the country, still rely predominately on fuelwood to meet their cooking and heating needs.

Figure 16.1: **Primary Fuel Mix, 1980 and 2004**



The share of oil in total primary energy demand has declined since the 1980s. The share of natural gas has grown considerably, particularly in recent years, reaching 8% in 2004. Between 1999 and 2004, gas demand grew by over 20% per year – the result of a deliberate government policy to diversify energy sources. Gas-fired generation is used as a backup source of electricity, to stabilise seasonal changes in hydropower supply due to rainfall variations. Today, about 44% of marketed gas consumption is in the industry sector, while about a quarter is used for power generation. Gas is also used in the transport sector. Brazil had over one million vehicles running on compressed natural gas (CNG) in 2005.[4] In some large metropolitan areas, like São Paulo and Rio de Janeiro, the government is promoting programmes to displace diesel with natural gas in city buses. The share of coal in the primary energy mix increased from 5% in 1980 to 7% in 2004.

Reference Scenario

In the Reference Scenario, Brazil's primary energy demand is projected to grow at an average annual growth rate of 2.1%, from 200 Mtoe in 2004 to 349 Mtoe in 2030 (Table 16.3). This is somewhat slower than the growth of 2.5% per year from 1980 to 2004. Demand grows more rapidly in the period up to 2015, at 2.6%. Brazil's energy intensity continues to decline, by 0.9% per year, as the structure of its economy progressively approaches that of OECD countries today.

Table 16.3: **Primary Energy Demand in the Reference Scenario in Brazil**
(Mtoe)

	1990	2004	2015	2030	2004-2030*
Coal	9.7	14.2	15.1	18.0	0.9%
Oil	57.7	84.8	108.4	141.7	2.0%
Gas	3.2	15.8	25.9	41.2	3.8%
Nuclear	0.6	3.0	6.3	6.3	2.9%
Hydro	17.8	27.6	38.0	50.0	2.3%
Biomass ans waste	41.6	54.4	70.6	89.8	1.9%
Other renewables	0.0	0.0	0.5	1.9	25.4%
Total	**130.6**	**199.8**	**264.8**	**348.8**	**2.1%**

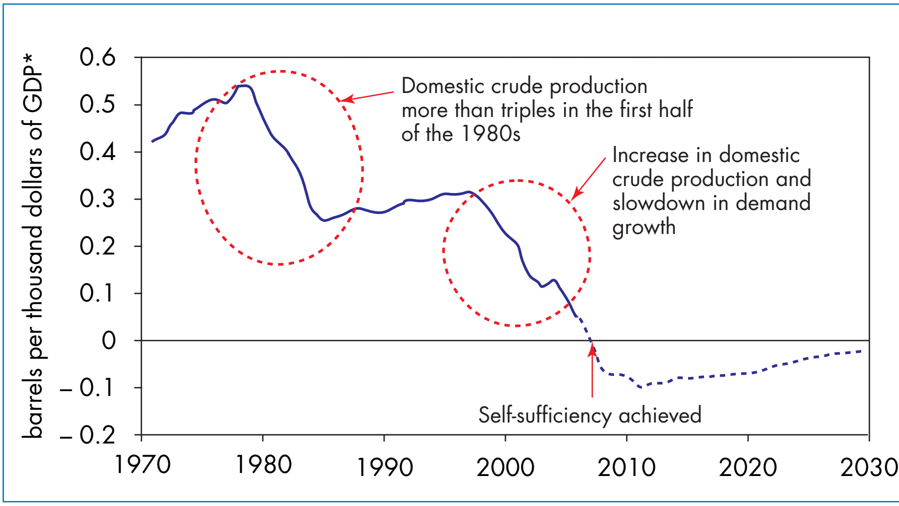
* Average annual rate of growth.

Oil remains the dominant fuel in Brazil's energy mix. Its share of total primary energy supply remains broadly unchanged at around 40% throughout the projection period. Oil consumption is expected to increase from 2.1 mb/d in 2004 to 3.5 mb/d in 2030. Some two-thirds of this increase is for transport. Oil-import intensity – oil imports relative to GDP – fell dramatically in Brazil in the early 1980s and in the second half of the 1990s, as a result of rapid growth in

4. www.greencarcongress.com, 17 November 2005.

domestic oil production and increased use of ethanol for transport. Although Brazil still imports oil products, these volumes are balanced by exports of crude oil. The country became self-sufficient for the first time in April 2006, when the latest deep-water project came on stream. Import intensity is expected to continue to decline over the first half of the projection period. Though it begins to rise by around 2012 (Figure 16.2), Brazil remains a net oil exporter through to 2030.

Figure 16.2: **Oil Import Intensity in Brazil**



* In year-2005 dollars, adjusted for PPP.

Natural gas use increases rapidly over the *Outlook* period in the Reference Scenario, at an annual rate of 3.8%, mainly in the industry and power-generation sectors. The share of gas in total primary energy demand rises from 8% in 2004 to 12% in 2030. Demand increases faster in the period to 2015, at 4.6% per year. Coal demand increases by only 0.9% per year, and its share in primary demand falls from 7% in 2004 to just over 5% by 2030. The contribution of nuclear power will increase when a third nuclear power plant comes on line some time before 2015. The capacity factor of nuclear power plants is assumed to improve from 69% in 2004 to 87% by 2010 and to stay at this level thereafter. The share of non-hydro renewable energy, mostly biomass, remains roughly constant at about 27%. The trend towards greater use of modern forms of biomass is expected to continue.

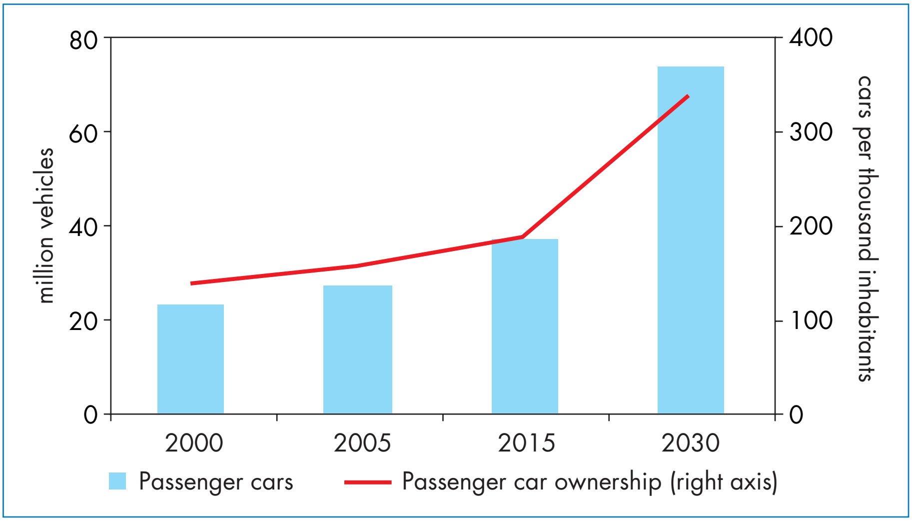
Total final energy consumption increases from 171 Mtoe in 2004 to 298 Mtoe in 2030, an average rate of growth of 2.2% per year. This is less than the rate from 1990 to 2004, reflecting expected efficiency improvements in all end-use sectors. Final oil demand rises by 2% per year and oil accounts for 77% of total energy demand for transport in 2030. Final natural gas consumption more than doubles, reaching 21.2 Mtoe in 2030, with industrial demand accounting for 80% of the increase. Demand for renewable energy, almost entirely biomass and waste, increases from 47 Mtoe in 2004 to nearly 80 Mtoe in 2030.

Among end-use sectors, **transport** demand grows most briskly, by 2.7% per year. Transport demand grew much slower in recent years, by some 1.6% per year from 1999 to 2004, thanks to efficiency gains. These improvements are expected to continue, but stronger GDP growth over the next decade causes demand growth to accelerate. The share of transport energy demand in total final consumption is projected to rise from 30% in 2004 to 35% in 2030.

Rising incomes will lead to increased car ownership and driving, as well as to more freight. Policies are expected to have a significant impact; in particular, the vehicle labelling policy, part of Petrobras' CONPET programme, is likely to encourage the uptake of more efficient vehicles. The share of ethanol-fuelled cars and flex-fuel vehicles (FFVs) in the car stock is also expected to continue to rise. Demand for biofuels for transport increases from 6.4 Mtoe in 2004 to 20.3 Mtoe in 2030, an average rate of increase of 4.6% per year.

Passenger car ownership in Brazil, at about 150 vehicles per 1 000 people, is more than three times higher than the average for the rest of Latin America. Car ownership in Brazil is projected to rise to over 335 per 1 000 people by 2030, roughly three-quarters the ownership in Europe today. The passenger car stock nearly triples over the *Outlook* period (Figure 16.3).

Figure 16.3: **Passenger Car Stock in Brazil in the Reference and Alternative Policy Scenarios**

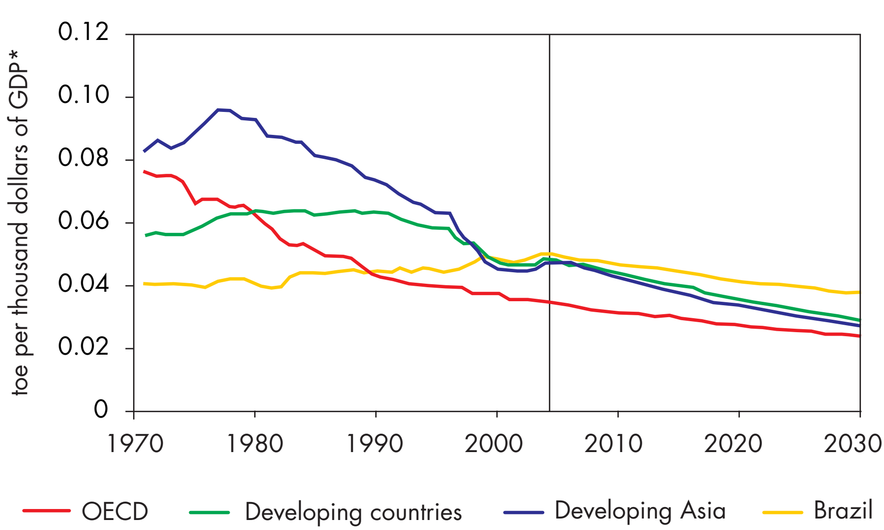


16

Industrial energy demand grows by 1.9% per year on average over the *Outlook* period, compared with past growth of 3.5% per year from 1990 to 2004. Despite investments in energy efficiency over the past decade, there is still plenty of scope for reducing energy intensity, particularly in the cement, pulp and paper and aluminium industries (Machado *et al.*, 2005). Over the past three decades, industrial energy intensity declined on average in developing countries. Intensity rose, however, in Brazil. Efficiency is only expected to improve slowly over the *Outlook* period (Figure 16.4). The shares of gas and electricity in final consumption in industry rise. Electricity use in industry accounts for 21% of total demand by 2030, up from 19% in 2004. Gas demand rises the fastest, however, at 3.4% per year on average, and will account for 13.5% of industrial energy demand in 2030. Gas demand in the petrochemical industry accounts for most of this increase. The iron and steel industry will account for more than 90% of the increase in coal demand. Biomass use in the industrial sector grows from 30 Mtoe in 2004 to 43 Mtoe in 2030, but its share falls from 39% to 34%.

The Brazilian petrochemical sector is currently undergoing a phase of rapid expansion, with Petrobras taking an active role. Rio Polímeros, located near Petrobras' Duque de Caxias refinery in Rio de Janeiro and close to the Campos basin, was inaugurated in June 2005. The complex consists of a polyethylene unit of 540 000 tonnes per year and pioneers the use of ethane and propane as feedstock. Rio Polímeros is close to demand centres in the south and

Figure 16.4: **Industrial Energy Intensity in Selected Regions, 1970-2030**



* In year-2005 dollars, adjusted for PPP.

Table 16.4: **Primary Energy Demand in the Alternative Policy Scenario in Brazil** (Mtoe)

	1990	**2004**	**2015**	**2030**	**2004-2030***
Coal	9.7	14.2	13.3	14.8	0.2%
Oil	57.7	84.8	100.7	118.7	1.3%
Gas	3.2	15.8	25.9	35.0	3.1%
Nuclear	0.6	3.0	6.3	8.9	4.2%
Hydro	17.8	27.6	35.7	41.3	1.6%
Biomass and waste	41.6	54.4	69.2	88.7	1.9%
Other renewables	0.0	0.0	0.5	3.1	27.8%
Total	**130.6**	**199.8**	**251.6**	**310.5**	**1.7%**

* Average annual growth rate.

Figure 16.5: **Primary Energy Demand in the Reference and Alternative Policy Scenarios in Brazil** (Mtoe)

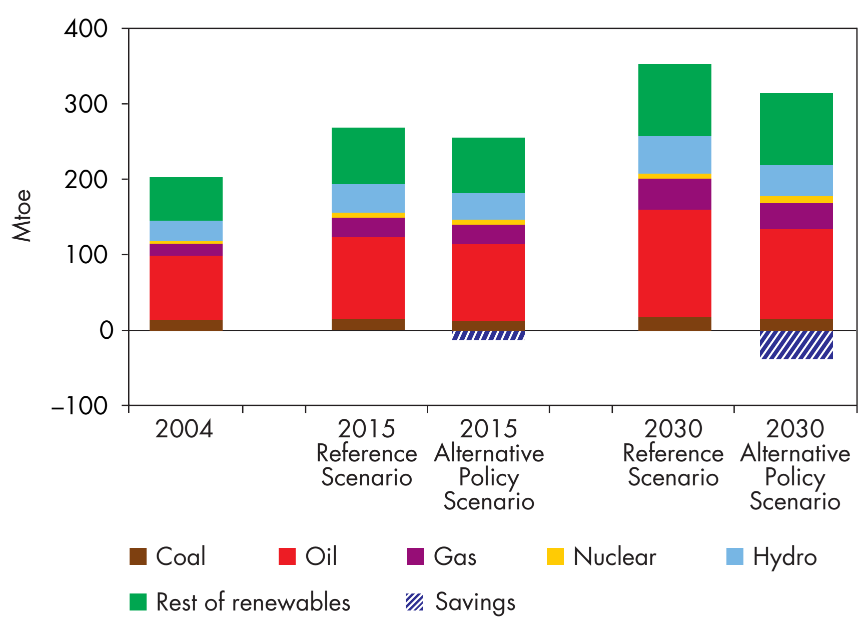


Table 16.5: **Main Policies and Programmes Considered in the Alternative Policy Scenario**

Sector	Policy	Programme/measure	Impact/target
Power	CDE Conta de Desenvolvimento Energético (Energy Development Account)	Financing for renewable energy power projects	Encourages renewable energy use at the state level; in force until 2030 and is managed by Eletrobrás.
	SWERVA Solar and Wind Energy Resource Assessment	Assessment of wind and solar energy resources	Wind atlases have been developed for the entire country, to help increase penetration of wind energy.
	PROINFA, Phase 2	Target for renewable energy	10% target for renewable energy in power generation sector.
Transport	PROBIODIESEL Programme of Technological Development for Biodiesel	Mandated biodiesel ratio	2% will be mandated by 2008 and 5% by 2013.
Industry	Energy-efficiency standards	Tax incentives and low-interest loans for efficient technologies	Replace current installed motors by high-performance electric motors at the end of their useful life and more efficient industrial equipment.
	Local pollutant emissions offset law (São Paulo)	Air quality improvements	Provides for the establishment of Air Emissions Reduction Programmes in areas with restricted air quality.

Table 16.5: **Main Policies and Programmes Considered in the Alternative Policy Scenario** *(Continued)*

Sector	Policy	Programme/measure	Impact/target
Residential and services	Reluz National Programme for Efficient Public Lighting	Energy-efficiency standards	Improves energy efficiency of public lighting, saving 2.4 TWh/year and reducing consumption by 540 MW in peak time (state-run programme).
	CONPET Programa de Etiquetagem de Fogões e Aquecedores	Programme for labelling of household goods, such as refrigerators	Increased efficiency of appliances.
	Solar thermal law (São Paulo)	Renewable energy technology standards	Requires the installation of solar water heating systems in new buildings and in those being rehabilitated in São Paulo after 2010.

southeast regions of Brazil, which account for about 80% of the domestic consumption of polyethylene. In March 2006, Petrobras announced plans to build a 150 000-b/d refinery and petrochemical complex in the State of Rio de Janeiro – the COMPERJ complex. The plant is designed to use heavy oil coming from the Marlim field. Production is expected to start in 2012.

Residential and services[5] energy demand is projected to grow by 2% per year on average over the *Outlook* period, broadly in line with previous growth of 2.1% per year from 1990 to 2004. Because of rationing during the power supply crisis of 2001, electricity demand in the residential sector fell dramatically. The Brazilian Labelling Program, which encouraged the uptake of more efficient technologies, achieved considerable energy savings. Since the labelling of stoves, in particular, new models purchased consume on average 13% less LPG than older ones (Centro Clima *et al.,* 2006). Appliance ownership is much higher in urban areas. Whereas some 90% of urban households had a refrigerator or freezer in 2000, only about half of rural households owned one. Nationwide, ownership of air-conditioners (7%) and computers (11%) is low.

Energy demand in the residential and services sector is projected to grow fastest in the first half of the projection period. Electricity accounts for most of the growth in demand to 2030, as appliance ownership levels increase, and its share of total residential and services energy use rises from 39% in 2004 to 46% in 2030. Use of biomass and waste continues to grow in the short term because of high oil prices, but this effect weakens over the projection period.

Alternative Policy Scenario

Primary energy demand grows much less quickly in the Alternative Policy Scenario (Table 16.4). By 2030, primary demand is 38 Mtoe lower than in the Reference Scenario (Figure 16.5). Most of the energy savings come from lower demand in the transport and industry sectors, thanks to policies and programmes to improve energy efficiency. Policies are assumed to have an even greater impact on energy savings in the Alternative Policy Scenario (Table 16.5). Fuel switching in the power sector towards more nuclear energy and non-hydro renewables, mainly bagasse, accounts for 3.4 Mtoe of fossil-fuel savings. In 2030, oil demand is 23 Mtoe lower than in the Reference Scenario. The increased use of flex-fuel vehicles, higher efficiency of conventional vehicles and an increase in the use of biodiesel result in a 15.2 Mtoe reduction in oil demand for transport.

In the Alternative Policy Scenario, total final consumption in 2030 is 11% lower than in the Reference Scenario (Table 16.6). Most of the gains come

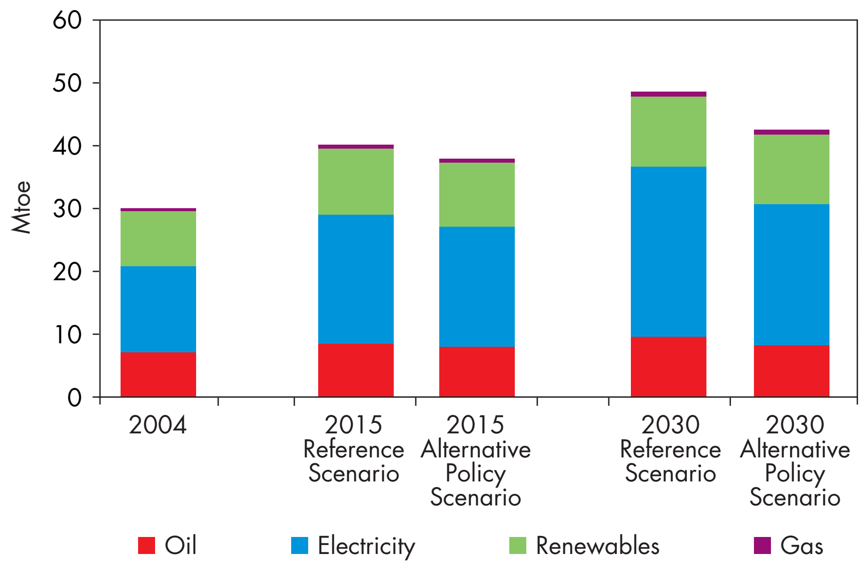
5. Residential and services demand also includes energy demand in the agricultural and public sectors.

Table 16.6: **Change in Total Final Consumption in the Alternative Policy Scenario* in 2030**

	Industry	Transport	Residential	Services	Total
Coal	–12%	0	0	0	–12%
Oil	–11%	–19%	–14%	–12%	–15%
Gas	–8%	–2%	0%	0%	–7%
Electricity	–14%	0%	–19%	–16%	–15%
Biomass and waste	–7%	13%	–7%	–6%	–2%
Other renewables	0	0	77%	0	76%
Total	**–10%**	**–12%**	**–12%**	**–15%**	**–11%**

* Compared with the Reference Scenario.

Figure 16.6: **Residential and Services Energy Demand in the Reference and Alternative Policy Scenarios**



from faster improvements in energy efficiency in the transport and industry sectors. Energy savings amount to around 12.5 Mtoe in each of these sectors. The 6-Mtoe reduction in residential and services energy demand is substantial, given the efficiency improvements which are already incorporated into the Reference Scenario. End-use oil demand sees the greatest decline, from 131 Mtoe in 2030 in the Reference Scenario to 111 Mtoe in the Alternative Policy Scenario. Final demand for biomass and waste declines slightly, by 2 Mtoe, mostly because of energy efficiency improvements in the industry sector. Although demand for biofuels for transport is higher, energy savings in the use of biomass for industry and residential use offset this expansion.

Transport demand is 12.6 Mtoe lower than in the Reference Scenario. Oil demand in the transport sector grows by 1.5% per year, much slower than in the Reference Scenario, while demand for biofuels grows more rapidly, at 5.1% per year. By 2030, biofuels for transport account for 30% of road transport fuel demand. Policies aimed at increasing the efficiency of the vehicle fleet also lower transport demand growth in the Alternative Policy Scenario.

Demand in the industry sector in the Alternative Policy Scenario grows by 1.5% per year on average. By 2030, it is 10% lower than in the Reference Scenario. The biggest drop is in electricity demand, thanks to the increased efficiencies of motors. Gas demand is only slightly lower in the Alternative Policy Scenario. Use of biomass is 7% less, but its share stays at about 35%.

Energy demand in the residential and services sector in the Alternative Policy Scenario grows by 1.5% per year on average and is 10% less in 2030 compared with the Reference Scenario (Figure 16.6). Overall percentage savings in this sector are less than savings in both the residential and services sectors because there is very little change in energy demand in the agricultural sector. Electricity demand is lower, growing by only 1.9% per year, as a result of stronger policies to promote energy-efficient lighting and the enforcement of tougher standards for appliances.

Outlook for Supply

Oil

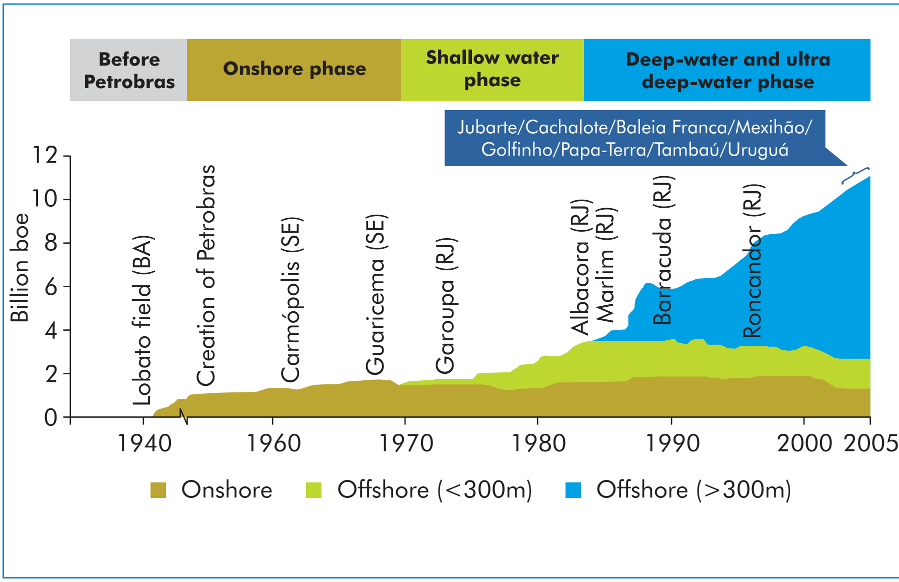
Resources and Reserves

Brazil is the world's 15th-largest oil producer, with proven reserves of 11.2 billion barrels (*Oil and Gas Journal,* 2005).[6] Oil reserves increased nearly eightfold from 1980 to 2005. Brazil has made impressive technological advances in deep-water exploration and production, with several recent discoveries of large fields containing over one billion barrels of oil equivalent. Deep-water and ultra-deep-water exploration have yielded significant discoveries (Figure 16.7).

There are still vast unexplored areas, which have high potential for new discoveries. So far, drilling concessions have been offered for less than 7% of the promising areas. The offshore basins of Espirito Santo, Campos and Santos, where large discoveries have been made, have been the main focus of interest.

6. Petrobras reported reserves of 12.3 billion barrels in December 2005.

Figure 16.7: **Brazil's Proven Reserves by Date of Discovery**



Note: State abbreviations are BA – Bahia; SE – Sergipe; RJ – Rio de Janeiro; AM - Amazonas.
Source: Petrobras.

In 2003, Petrobras discovered new light-oil reserves in Espirito Santo, in what is one of the largest light-oil offshore fields. Most known Brazilian reserves are heavy oil and Petrobras imports light oil for blending to improve oil quality.

Brazilian oil production reached 1.7 mb/d in 2005 and is expected to reach 1.9 mb/d in 2006. Output has nearly doubled since the late 1990s. The main oilfields are offshore Rio de Janeiro State, in the Campos basin (Figure 16.8). About 85% of oil comes from offshore fields, increasingly from deep waters.[7] Roncador is the largest discovery made in Brazil, with estimated proven reserves of around 2.9 billion barrels (Table 16.7). The field is located in the Campos basin at 1 360 metres. In the Reference Scenario, crude oil production is expected to reach 3.1 mb/d in 2015 and 3.7 mb/d in 2030. Production from currently producing fields is expected to increase by 44% to 2015 (Table 16.8), then begin to decline. Fields awaiting development and new fields will represent some 45% of crude oil production in 2030.

Oil demand in Brazil rises to 2.7 mb/d in 2015 and to 3.5 mb/d in 2030 in the Reference Scenario (Figure 16.9). It increases to 2.9 mb/d in 2030 in the

7. Deep and ultra-deep water definitions can vary by basin. Deep water is typically defined as water depths greater than 500 metres, and ultra-deep water beyond 1 000 metres

Figure 16.8: **Oil and Gas Fields and Related Infrastructure in Brazil**

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Table 16.7: **Major Oilfields Currently in Production in Brazil**

Field	**Year of first production**	**Remaining proven and probable oil reserves at end-2005** (million barrels)	**Cumulative production to 2005** (million barrels)	**API gravity** (degrees)
Agua Grande	1951	319	306	37
Albacora	1987	879	558	28
Aracas	1965	172	141	37
Barracuda	1997	807	97	24
Bicudo	1982	169	109	22
Bijupira	1993	156	46	30
Bonito	1979	195	102	25
Buracica	1959	220	173	37
Canto do Amaro	1986	301	192	44
Carapeba	1988	228	198	25
Carmopolis	1963	442	202	20
Cherne	1983	270	220	25
Enchova	1977	174	149	21
Espadarte	2000	246	56	n/a
Fazenda Alegre	1996	211	24	17
Garoupa	1979	207	122	31
Guaricema	1968	86	0	41
Linguado	1981	166	124	30
Marimba	1985	432	278	29
Marlim	1991	2 680	1 446	20
Marlim Sul	1994	2 485	295	20
Miranga - Miranga Profundo	1965	271	212	41
Namorado	1979	397	353	28
Pampo	1980	336	262	21
Roncador	2000	2 900	117	25
Ubarana	1976	297	100	36

Note: NGLs and condensates are not included.
Source: IHS Energy databases.

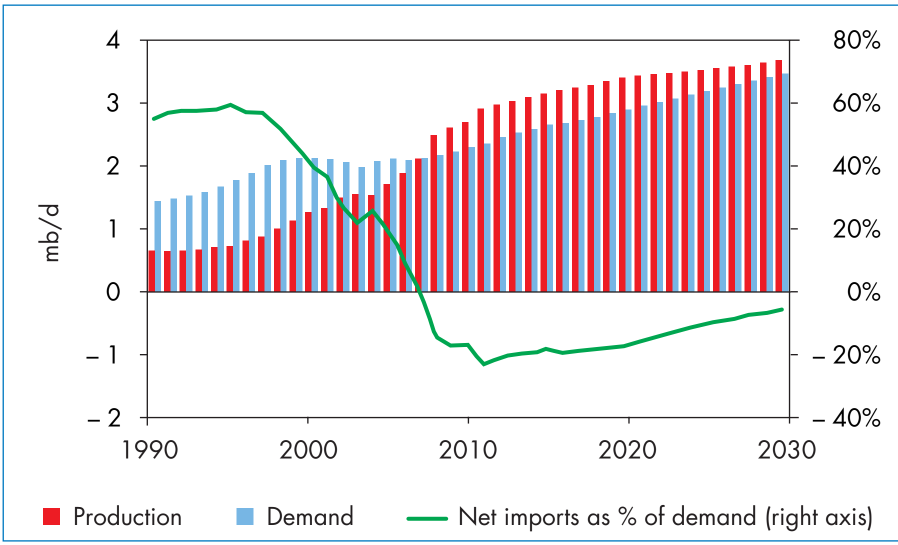
Alternative Policy Scenario. In both scenarios, Brazil remains self-sufficient throughout the *Outlook* period on the assumption that the large investments in exploration and infrastructure that this would entail occur in a timely fashion.

Table 16.8: **Brazil's Oil Production in the Reference Scenario** (mb/d)

	2004	**2015**	**2030**
Currently producing fields	1.5	2.7	2.0
Fields awaiting development	0.0	0.4	0.7
Reserve additions and new discoveries	0.0	0.0	1.0
Total	**1.5**	**3.1**	**3.7**

Source: IEA analysis.

Figure 16.9: **Brazil's Oil Balance in the Reference Scenario**



To maintain self-sufficiency, Brazil needs to continue to invest heavily in exploration, as today it is producing the oil that was discovered in the 1980s and 1990s. Petrobras has set itself a new target of domestic oil and gas production of 2.9 mb/d by 2011, with planned investments in exploration and production of $41 billion. Production is expected to focus increasingly on deep-water fields (Box 16.2). Maintaining self-sufficiency beyond 2012-2014 will require major new discoveries. The IEA has undertaken a field-by-field analysis of oil production in Brazil, which has been used to project production by source over the *Outlook* period (Figure 16.10).

Box 16.2: **Petrobras's Development of Deep-Water Crude Oil Production**

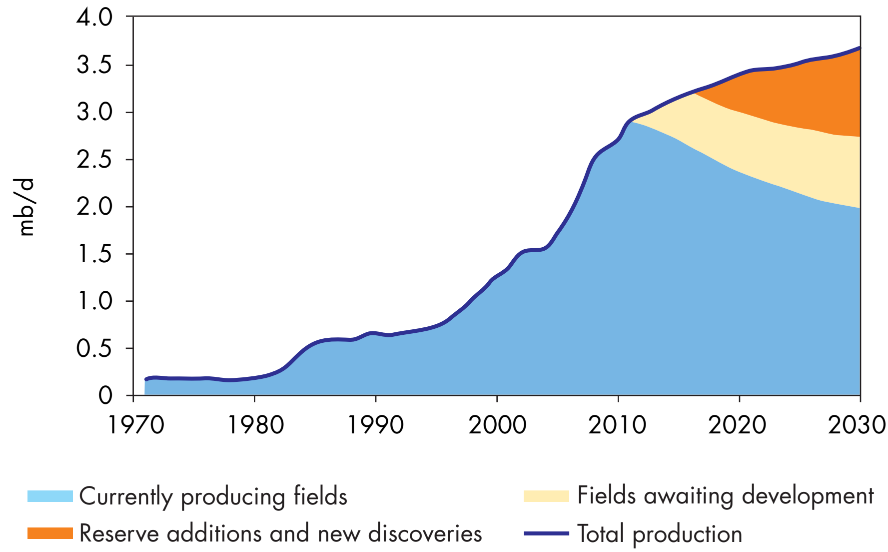
Following the oil price peaks in the 1970s, offshore oil exploration commenced in Brazil. Fields closest to shore were exploited first and technological improvements in drilling, rigs, mooring, robotics and pipes followed. Research into new technologies was spearheaded by CENPES, the research arm of Petrobras. In 1986, a Technological Development Programme on Deepwater Production Systems (PROCAP) was established. The six-year programme led to the development of semi-submersible floating production systems that permitted production in waters 1 000 metres deep in the Albacora and Marlim oilfields. In 1993, Petrobras embarked on PROCAP 2000, which aimed at designing systems capable of producing in 2 000 metres of water. This programme led to the design and execution of an extended-reach well in deep water, the development of a horizontal Christmas tree for use at 2 500 metres depth, installation and operation of an electric submersible pump in a subsea deep-water well, a subsea separation system called the vertical annular separation and pumping system, and a subsea multiphase pumping system for deep water. This programme supported exploration and production in the Campos basin, leading to the discovery of the major Roncador oilfield.

PROCAP 3000, launched in 2000, aims to increase production from existing deep-water fields and to extend exploration and production to depths of around 3 000 metres. PROCAP 3000 is expected to support the next phases of the Marlim Sul, Roncador, Marlim Leste and Albacora Leste oilfields. Unit capital costs and lifting costs in deep-water fields already in production are expected to be reduced.

Refining Capacity and Oil-Product Supply

Current installed refining capacity in Brazil is around 1.9 mb/d, which is insufficient to meet domestic consumption. Petrobras plans to increase refining capacity to 2.4 mb/d by the middle of the next decade. More than four-fifths of Brazil's oil refining capacity is located in the south and southeast regions. Only two refineries are not in these regions: a large refinery in Bahia State, with capacity of 284 000 b/d, and a small refinery for domestic supply in Manaus in Amazonas, with capacity of 43 000 b/d. There are currently 13 refineries operating in Brazil, of which 11 are operated by Petrobras. The remaining two are the Refinaria de Petroleos Manguinhos (in Rio de Janeiro State), which is owned by Repsol-YPF in partnership with Grupo Peixoto de Castro, and the Refinaria de Ipiranga. These two refineries, however, are currently not operating at full capacity because they are not designed to refine Brazilian crude, and high international oil prices make operation unprofitable.

Figure 16.10: **Brazil's Crude Oil Production by Source in the Reference Scenario**



Any expansion of refining capacity must conform to the government's refining plan, which aims to minimise oil-product imports. A key element of this plan is the use of vegetable oil to replace fossil diesel (Box 16.3). The major focus of

Box 16.3: **Refinery Conversion with H-BIO Technology**

Brazil has undertaken a major initiative to supplement fossil diesel with diesel produced from biomass. In the H-BIO process, vegetable oil is blended with mineral diesel fractions in hydrotreating units. Today, these units are mainly used to reduce the sulphur content of diesel and for quality improvement in petroleum refineries. The most important aspect of the H-BIO process is its very high conversion yield. The converted product improves the quality of diesel in the refinery, mainly by increasing the cetane number and by reducing the sulphur content and density.

Petrobras plans to have the H-BIO process operating in at least three refineries by the end of 2007. Vegetable oil consumption will be about 256 000 m^3 per year, which was about 10% of Brazilian soybean oil exports in 2005. Introduction of the H-BIO process in two more Petrobras refineries is planned for 2008, which will increase the total vegetable oil consumption to about 425 000 m^3 per year. These two programmes will require investments of around $60 million.

Petrobras's investments is to improve the quality of oil products. New legislation requires sulphur in diesel/gasoline to be below 50 parts per million (ppm). Most of Petrobras's refineries are not designed to process heavy crude oil, which accounts for most of Brazilian crude oil production. Petrobras plans to invest $14.2 billion from 2007 to 2011 to expand and modernise its refineries and to add value to its products. Some 31% of this investment will be to improve the quality of diesel and gasoline, 26% to improve conversion and the rest to expand and overhaul existing refinery units.[8] Petrobras is planning to build two new refineries, one in Rio de Janeiro State and another in Pernambuco, in the northeast, in association with PVDSA, the Venezuelan state-owned oil company. These are expected to come on line in 2012.

Natural Gas

Resources and Reserves

Proven natural gas reserves at the end of 2005 were 306 bcm (Cedigaz, 2006). The United States Geological Survey estimates that undiscovered gas reserves are 5 500 bcm, more than 15 times proven reserves (USGS, 2000). The Santos and Campos basins have the largest reserves with about 37%, followed by São Paulo with about 24% and Amazonas with about 15%. About two-thirds of the gas reserves are located offshore, usually as associated gas. In 2003, Petrobras announced the discovery of 419 bcm of new reserves in the offshore Santos basin in the southeast, but only 70 bcm has as yet been certified as proven.

Until recently, natural gas was produced solely as a by-product of oil and about 30% was reinjected or flared. Petrobras plans to increase investment to accelerate the development of Brazil's domestic natural gas resources, especially from the Santos basin, in order to supply the large and rapidly growing market of the southeast. In the seventh licensing round in 2005, about 90% of the blocks in new onshore exploratory areas which were thought to be gas-prone were awarded. To reduce the country's dependence on imported Bolivian gas, the government recently requested a 30% increase in the number of gas-prone exploration blocks to be offered at the eighth bidding round, scheduled for November 2006. This round includes the Espírito Santo and Santos basins as well as the unexplored offshore basins of Curumuxatiba, Pará-Maranhão and Ribeirinhas, in the country's northeastern region. The Campos basin was excluded from this round.

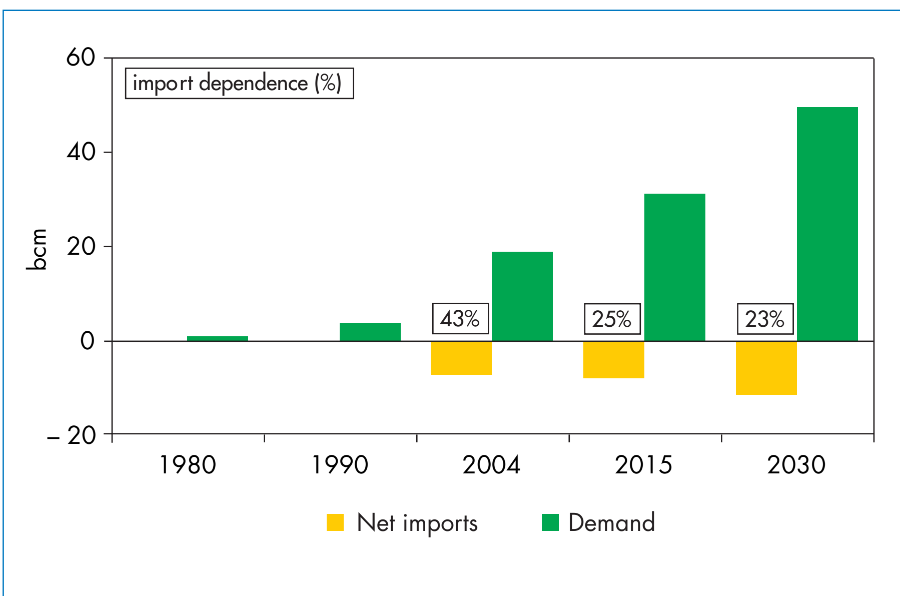
8. Speech by Jose Sergio Gabrielli de Azevedo, President and CEO of Petrobras, "Business Plan 2007-2011", 5 July 2006.

Production and Imports

Gas production reached 18.7 bcm in 2005, up from 7.2 bcm in 2000. Production is projected to increase to 23 bcm in 2015 and to 38 bcm in 2030 in the Reference Scenario, growing at an average rate of 4.6% per year over the *Outlook* period. Gas-import dependence declines over the *Outlook* period, but the rate of decline slows after 2015 (Figure 16.11).

In order to increase domestic gas production, Brazil needs to make major investments in resource development and in its gas distribution network. Compared with other Latin American countries, the Brazilian gas pipeline network is underdeveloped. The total network spans some 8 000 km, including the Brazilian portions of cross-border pipelines. However, it covers only a small part of the country, mainly serving São Paulo and Rio de Janeiro in the south and the coastal states in the northeast. Petrobras also recently announced an "Anticipated Production Plan" to accelerate natural gas production at the Espírito Santo and Campos basins. In the Campos basin, there are two main offshore gathering platforms, at Enchova and Garoupa, from which gas is piped to shore before being transported to the Duque de Caxias refinery. Petrobras is planning a large-scale project to construct an integrated pipeline system (GASENE) connecting the southeast of the country with the north and northeast. This would enable the development of markets in the northern regions, which could be supplied in the future by the new discoveries made in the Santos basin.

Figure 16.11: **Natural Gas Balance in Brazil in the Reference Scenario**



Development of the onshore natural gas reservoir in Urucu in Amazonas State is limited to producing and processing a small fraction of LPG for local consumers, because of inadequate transport infrastructure. The Urucu proven reserves total 48 bcm. Petrobras has been investing in two pipelines connecting the Urucu gas field to Porto Velho and to Manaus, but environmental concerns have slowed construction. The pipeline from Coari to Manaus, one of the main consumer centres of the region, is currently under construction. When this pipeline goes into service, Petrobras will produce and sell natural gas in Amazonas.

Our projections for natural gas supply are based on the assumption that Brazil is able to increase investment in domestic gas production and infrastructure. Gas demand growth, which has been phenomenal in recent years, is expected to slow with the liberalisation of gas prices. Demand is, nevertheless, expected to continue to rise. Given that expanded gas imports from Bolivia are no longer an acceptable option for the Brazilian government, domestic production will have to increase considerably to meet demand. Renegotiations with Bolivia on gas import prices are expected to result in higher gas prices in Brazil. Prices already increased in July 2006, since they are indexed to a basket of international fuel oil prices.

The key uncertainty is whether the investment needed to develop the reserves and build the new transportation infrastructure will be forthcoming. In addition to the investment planned by Petrobras, private and foreign investment will also be required. We project that $16 billion will be needed in the period to 2015 in the Reference Scenario. A further $32 billion is needed from 2015 to 2030. The success of the 8th bidding round will be an indicator of what level of foreign participation can be expected and so of future production trends. Expanding gas output will hinge on a stable investment environment.

Even if Brazil is able substantially to increase domestic gas production, it will still need to expand imports. The first pipeline to connect Brazil to foreign natural gas sources was the Bolivia-Brazil gas pipeline (Gasbol), inaugurated in 1999. The Transportadora de Gas del Mercosur (TGM) pipeline came on line in June 2000, marking the first exports of gas from Argentina to Brazil. In the Reference Scenario, imports account for a quarter of total gas demand in 2015 and 23% in 2030. In the short term, gas imports from Bolivia will not increase since all the planned investment in expanding capacity has been cancelled by Petrobras following the 1st May 2006 nationalisation of the company's assets in Bolivia. In the long term, gas could be imported from Venezuela.

LNG imports are expected to boost supplies over the *Outlook* period. Petrobras is planning to install LNG regasification terminals by 2008. One terminal will be close to Rio de Janeiro, with production capacity of 14 million m^3 per day. A second unit would be located off the coast of the northeastern State of Ceará, where there is large demand from power stations, with production capacity of 6 million m^3 per day.

Coal

Coal resources amount to about 30 billion tonnes (Federal Institute for Geosciences and Natural Resources Reserves, 2004). Proven reserves are just over 10 billion tonnes (BP, 2006). Coal reserves are not well surveyed in the vast northern regions of the country. Coal deposits of various qualities and quantities have been found in many areas in Brazil, but the largest and lowest-cost reserves are found in the south (Rio Grande do Sul and Santa Catarina). The largest reserves are located in the Candiota mine, in Rio Grande do Sul, accounting for almost one-quarter of total reserves.

Brazil produced 5.4 million tonnes of coal in 2004; however, it consumed 21.9 million tonnes. Brazil's coal reserves have high ash and sulphur contents, with low caloric values, which explains the low level of domestic production. Brazil imports coking coal for steel-making, mainly from the United States and Australia, and uses domestic resources for power generation. Brazil has only one mine-mouth generating complex, Candiota I and II, where local coal is able to compete in price with imported coal. A very limited amount of coal is exported to Argentina. Brazil's national development bank, Banco Nacional de Desenvolvimento Economico e Social (BNDES), is developing a plan to expand the country's coal industry. Two new coal-fired generation projects are under construction: Candiota III and Jacuí.

In the Reference Scenario, coal production is projected to increase to 7.6 million tonnes in 2015. Production increases further in the second half of the *Outlook* period, reaching 11.8 million tonnes in 2030. As demand for coal continues to rise, from 21.9 million tonnes in 2004 to 34 million tonnes in 2030, coal imports keep growing. They reach 22 million tonnes in 2030, up from 16 million tonnes now.

Biomass

Resources and Production

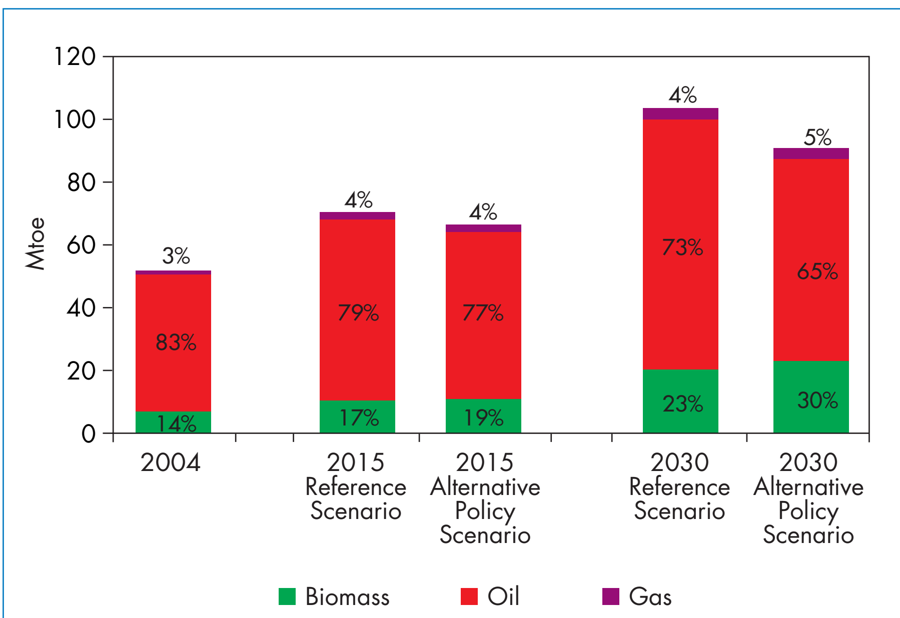
Brazil has extensive and diverse biomass resources, which are exploited for energy in many ways. The country is a highly efficient producer of large-scale industrial charcoal, with biomass-to-charcoal conversion efficiencies ranging from 30% to 35%, particularly from plantations. Charcoal production has increasingly become a professional activity, with most charcoal being produced from dedicated plantations.[9] In 2000, about 72% of charcoal was produced from eucalyptus plantations, compared with 34% in 1990.

9. Dedicated plantations are not being employed in Maranhão State in the northeast for environmental reasons.

Almost all sugar-cane distilleries in Brazil use bagasse-fired steam turbine systems to provide steam and electricity to meet on site factory needs. Most biomass cogeneration is in São Paulo State, where 40 sugar mills sell some 1.3 GW of surplus power to the grid. The Brazilian cane industry has the potential to produce up to 12 GW in the long term – 6 GW in São Paolo State (WADE, 2004). The public authorities are promoting bagasse-based cogeneration to reduce the country's reliance on hydropower. Apart from bagasse, only a small proportion of the large potentially recoverable residues from commercial crops and forestry are used for energy purposes. Landfill gas is also underdeveloped. With the exception of bagasse, there is a lack of consistent and reliable data on biomass resources and their potential as an energy source. This is particularly the case with regard to residues in the pulp and paper industry, which are produced in large quantities.

Brazil is a major producer and consumer of biomass-based ethanol for transport. Biodiesel demand and production are growing steadily. Demand for biofuels for transport increases rapidly in the Reference Scenario, from 6.4 Mtoe in 2004 to 20.3 Mtoe in 2030 – an average rate of growth of 4.6% per year. Their share of Brazil's road transport fuel increases from 14% in 2004 to 23% in 2030 (Figure 16.12).[10]

Figure 16.12: **Biofuels Penetration in the Road-Transport Sector in Brazil in the Reference and Alternative Policy Scenarios, 2004-2030**



10. See Chapter 14 for an analysis of the global biofuels market and Brazil in this context.

This trend is bolstered by strong growth in sales of flex-fuel vehicles, which can run on gasoline or ethanol or a mixture of both. Another factor contributing to the growth in biofuels is a programme started in late 2004 to add 5% of biodiesel to diesel fuel by 2013. The programme was set up to assist poor rural farmers. In the Alternative Policy Scenario, demand for biofuels grows more rapidly, by 5.1% per year over the projection period. By 2030, biofuels for transport account for 30% of road transport fuel demand.

Ethanol

Brazil is the world's largest producer of fuel ethanol from sugar cane. Brazil's national ethanol programme, ProAlcool, was launched in response to the oil crises in the 1970s. From 1983 to 1988, 90% of the 800 000 new cars sold each year on average in Brazil were running on ethanol. The strong increase in consumption caused a severe shortage of ethanol at the end of 1989. This shortage resulted in a loss of consumer confidence in the security of ethanol supply and discredited ProAlcool. By the end of the 1990s, the sales of ethanol-fuelled cars amounted to less than 1% of total car sales because of uncertainties about future ethanol availability and price. But the benefits of the ProAlcool programme were important: lead was phased out completely in 1991 and carbon monoxide, unburned hydrocarbons and sulphur emissions were reduced considerably. Moreover, major investments were made in improving the production of sugar cane (Box 16.4), and the country developed a competitive advantage in the production of ethanol.

In 2003, car manufacturers, beginning with Volkswagen, introduced "flex-fuel" vehicles, which are capable of running on any combination of hydrous ethanol and a gasoline-anhydrous ethanol blend. Such vehicles allow consumers to choose any combination of the cheapest fuel while protecting them from any fuel shortages. FFVs do not cost any more than conventional vehicles. Today, the government estimates that flex-fuel vehicles account for more than three-quarters of new car sales in Brazil. Pure gasoline is no longer sold.

Brazil's ethanol production was 15.9 billion litres in 2005, more than a third of global production, of which 2.6 billion litres were exported. Brazil has a 50% share of global ethanol trade. Importers include the United States (but not for transport), India, Venezuela, Nigeria, China, South Korea and Europe. The Brazilian government is negotiating exports with Japan. South Africa and Brazil are also in the process of signing a memorandum of understanding for technical assistance in ethanol production. Brazil is also offering support to India to produce ethanol and the two countries signed an agreement in September 2006 to increase cooperation. The Brazilian government believes that increasing the number of suppliers in developing countries will expand the global ethanol market. Several Central American Caribbean countries have duty-free access to the US market. By encouraging ethanol production and refining through joint

Box 16.4: **Technological Developments in Sugar-Cane and Ethanol Production**

Most of the reduction in the cost of producing ethanol in recent years has come from the agricultural phase of ethanol production. Around 60% to 70% of the final cost of ethanol is the cost of the sugar cane. Agricultural yield and the amount of sucrose in the plant have a strong impact on cost. Average productivity in Brazil is around 65 tonnes per hectare (t/ha), but it can be as high as 100 to 110 t/ha in São Paulo State. Since the beginning of ProAlcool, yields have improved by about 33% in São Paulo, with the development of new varieties and the improvement of agricultural practices (IAEA, 2006). Many operations have been mechanised over the past 25 years, but advances in harvesting are more recent. In the past five years in the midwest, southeast and southern regions, about 35% of the area planted with sugar cane has been harvested mechanically and, of this, about 20% has been harvested without previously burning the field. Up to 90% of the sugar cane is harvested mechanically in some regions. It is estimated that the widespread application of mechanised harvesting would achieve a significant further reduction in the per-tonne cost of sugar cane.

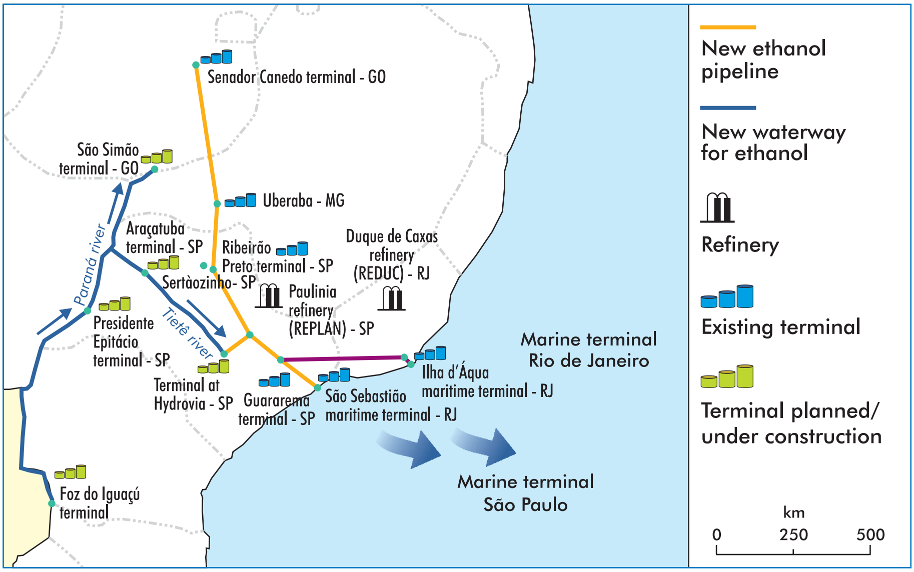
Throughout the evolution of ProAlcool, technological priorities have changed. Initially, the focus was on increasing equipment productivity. The size of Brazilian mills also increased. Some mills now have a crushing capacity of 6 million tonnes of sugar cane per year and capacity is expected to increase to 10 million tonnes by 2010. The focus was then shifted to improvements in conversion efficiencies. Over the past 15 years, the primary focus has been on better management of the processing units. In the future, attention is expected to be given to reducing water needs. On average, five cubic metres (cm) of water are used for each tonne of sugar cane processed, though values range from 0.7 cm/tonne to 20 cm/tonne.

Average ethanol production yields have grown from 3 900 litres per hectare per year (l/ha/year) in the early 1980s to 5 600 l/ha/year in the late 1990s. In the most efficient units, yields are now as high as 8 000 to 10 000 l/ha/year.

programmes in these countries, Brazilian sugar producers can export ethanol to the United States. Brazil is also working more generally to remove trade barriers that prevent the development of a global biofuels market.

To meet rising domestic and export demand for ethanol, the Brazilian government plans to increase productive capacity and to build ports with storage tanks and loading facilities. It also plans to improve railway and pipeline links between the ports and sugar-producing regions. Petrobras is building a new ethanol port in Santos, which will increase Brazil's export capacity to 5.6 billion litres by the end of 2007. New waterways are also planned (Figure 16.13).

Figure 16.13: **Planned Infrastructural Developments for Ethanol in Brazil**



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: State abbreviations are: GO – Goais; SP – São Paulo; MG – Minas Gerais; RJ – Rio de Janeiro.
Source: Petrobras.

Brazil will also need to establish a clear regulatory framework in order to increase production and to address the potential environmental and social impacts of expanding ethanol production. To this end, the Brazilian government is carrying out a strategic environmental assessment to determine where to plant sugar cane in the future. Currently, the amount of land devoted to the growing of sugar cane is far less than land set aside for planting other crops. In 2005, less than 10% of the cultivated area was used for growing sugar cane, compared with 20% for corn and nearly 35% for soybeans. Yet the highly-intensive production systems for ethanol have caused environmental damage through the use of fertilizers and pesticides. Sugar cane is also a major source of air pollution, due to burning practices prior to manual harvesting. The phase-out of burning is being enforced in Brazil, with a deadline for complete phase-out by 2022. In the longer term, the possible emergence of ligno-cellulosic ethanol production could lower costs and increase demand for ethanol (see Chapter 14). Good environmental legislation and enforcement are essential to ensure the sustainability of ethanol production. In this regard, Brazil is in a position to be a role model for other countries with emerging biofuels markets.

Biodiesel

Brazil is actively pursuing a domestic biodiesel market. The government expects that by December 2006 about 3 500 stations will market biodiesel. Biodiesel distribution and marketing are carried out by Petrobras Distribuidora, The company has already invested nearly \$9.3 million to adapt its facilities to biodiesel. The logistics of the biodiesel market differ from those of fossil diesel. Refineries that produce conventional oil are located closer to distribution centres, while biodiesel production centres are in the interior of the country.

Fuel distributors will be required to market biodiesel as of 2008. The government plans to give priority to the programme in less developed regions, such as the northeast and the Jequitinhonha Valley. Targets under Probiodiesel, the Brazilian Programme of Technological Development for Biodiesel, call for 2% of diesel from biodiesel by 2008 and 5% by 2013. The government estimates that the planted area that would be required to supply the 2% biodiesel/diesel fuel mix would be 1 500 million hectares. Biodiesel is supplied to distributors by rural producers through auctions promoted by the National Petroleum Agency (ANP).

Power and Heat

In 2004, electricity generation in Brazil was 387 TWh. Brazil's share of hydropower in the electricity mix, at 83%, is one of the highest in the world. In terms of the volume of electricity output from hydro, Brazil ranked third in the world in 2004 behind China and Canada. Natural gas, however, has made an increasing contribution over the past several years. Its share reached 5% in 2004, up from less than 1% in 1999. Oil, coal, nuclear and non-hydro renewables each contributed about 3% in 2004. Use of biomass, mostly in the form of bagasse, accounts for the majority of non-hydro renewable energy-based generation.

Brazil is expected to develop further its large hydropower resources. The Belo-Monte hydropower plant will be the first large dam built in Amazonas since the Tucuruí dam was completed in the early 1980s. The capacity of the Belo-Monte plant has not been confirmed, because of concerns about the environmental impacts associated with reservoir size. A decision is expected at the end of 2006. Other dams upstream from Belo-Monte are also being considered. Dams are also planned for the Madeira River in Rondonia State in the west. All of these plants are located far from centres of demand and will require significant investment in new transmission lines to connect them to the national integrated grid.

The construction of very large hydro facilities in the Amazon region has been controversial. There is a fear that the environmental and social impacts of the Tucuruí dam, which were more severe than was foreseen during construction and persist in operation, will be replicated if other dams are built (Rovere and Mendes, 2000). The problems include forest loss, leading to loss of natural ecosystems and to greenhouse gas emissions. The current administration has undertaken reforms to address environmental effects, building on the lessons learnt from Tucuruí, Alvina and Barra Grande. In September 2006, the government approved the environmental impact study for the planned Santo Antonio and Jirau hydroelectric projects along the Madeira River. Although the projects still have to be submitted for public consultation and have to obtain environmental licences, the government's approval is a positive development in light of delays that have held up numerous projects in the past. There is a growing consensus at the global level about the potential benefits of hydropower. The private sector's interest in financing hydropower projects is also growing (Box 6.1 in Chapter 6).

Brazil built gas-fired power plants at a rapid rate following the electricity crisis in 2001. But today, many of them are running well below capacity. Most of the plants were built in partnership with Petrobras. Development of more gas-fired power plants is very uncertain at the moment and will depend on the terms, including price and availability, of contracts for natural gas and the development of gas infrastructure. Investors are seeking long-term contracts to protect their investments. But in an electricity market dominated by hydropower, electricity prices will be highly dependent on rainfall levels.

The economic attractiveness of gas-fired power plants for foreign investors will depend critically on the type of contracts established. Few new gas-fired power plants are expected to be built in the next decade or so. Gas supply is expected to increase over time, however, so that output from plants already built will increase and some new gas-fired power stations will be built in the longer term. Gas-fired electricity generation is expected to represent 9% of total electricity generation in 2030, growing, on average, at a rate of about 5% a year over the *Outlook* period.

Brazil has two nuclear power plants, Angra I (626 MW) and Angra II (1 275 MW). Angra II was connected to the grid in July 2000. Construction of a third nuclear power plant, Angra III, was halted for political and economic reasons, but may be resumed in the next few years. Angra III will not go on line before 2010. The Reference Scenario projections assume that Angra III will add another 1.3 GW of capacity in southeastern Brazil after 2010. The construction of more nuclear power plants is once again under discussion, as in many other countries around the world, spurred by high fossil-fuel prices and concerns about security of supply. Brazil has the seventh-largest uranium reserves in the world, of which 57% are "reasonably assured" – a category akin to proven (NEA/IAEA, 2006).

In the Reference Scenario, electricity generation is projected to reach 731 TWh in 2030 (Table 16.9). Generation grows by 3.2% per year between 2004 and 2015, and then slows to 1.9% per year through to 2030. Hydropower is projected to grow at 2.9% per year in the period to 2015. From 2015 to 2030, however, as demand for electricity grows at a lower rate and the best hydro sites have been exploited, hydropower development decelerates. The share of hydropower in total electricity generation dips slightly to 79% in 2030. Electricity generation from biomass, mostly bagasse in the southeast region, is projected to rise to 29 TWh in 2030. Wind power increases to 11 TWh. The growth in non-hydro renewables results largely from government incentives, such as the PROINFA programme (Box 16.5).

Electricity generating capacity was 87 GW in 2004, 80% of which was accounted for by large hydropower plants. About 1%, or 900 MW, of total generating capacity in Brazil is in combined heat and power plants, mostly in industrial facilities. Some 46% of these plants run on sugar-cane bagasse and 31% use natural gas (Machado *et al.*, 2005). To meet demand growth over the *Outlook* period, Brazil needs to add 98 GW of new capacity by 2030 in the Reference Scenario. Hydropower makes up 67% of the additional capacity and new gas-fired capacity 15% (Figure 16.14). Some 9 GW of additional capacity from non-hydro renewable energy sources comes on line by 2030, mostly biomass and wind. Solar power emerges as a new source of generation towards the end of the projection period, on the assumption that it becomes competitive. To increase flexibility of supply, gas-fired plants are likely to be converted to running on a combination of gas and either biomass, diesel or light fuel oil. The investment required to build additional generating capacity over the next three decades in Brazil is enormous (see the Investment section below).

Table 16.9: **Electricity Generation Mix in Brazil in the Reference Scenario** (TWh)

	1990	**2004**	**2015**	**2030**
Coal	4.5	10.4	7.4	6.5
Oil	5.6	12.3	11.0	12.7
Gas	0.0	19.3	41.5	65.3
Nuclear	2.2	11.6	24.2	24.2
Hydro	206.7	320.8	441.5	581.1
Other renewables	3.8	12.5	23.1	41.3
Total	**222.8**	**386.9**	**548.8**	**731.2**

Box 16.5: **Prospects for Renewable Energy-Based Generation**

The Brazilian Alternative Energy Sources Incentive Programme (Programa de Incentivo às Fontes Alternativas de Energia Elétrica – "PROINFA"), launched in 2004, provides incentives to stimulate the use of alternative sources of energy. PROINFA's long-term goal is to increase the share of wind, biomass, and small and medium-sized hydroelectric facilities to 10% of electricity generation by 2020. The Brazilian government has designated Eletrobrás as the primary buyer of electricity generated by PROINFA projects, entering into long-term power purchase agreements at a guaranteed price. The guaranteed price for wind is 90% of the average supply tariff, for small hydro it is 70% and for biomass 50%. Several of the Eletrobrás Group's regional electricity companies are minority shareholders (up to 49%) in special purpose entities which own and operate PROINFA projects. Brazil's national development bank (BNDES) agreed to provide 70% of the financing for the projects and the Brazilian Energy Fund, launched in December 2004, should assist in funding the remaining 30%.

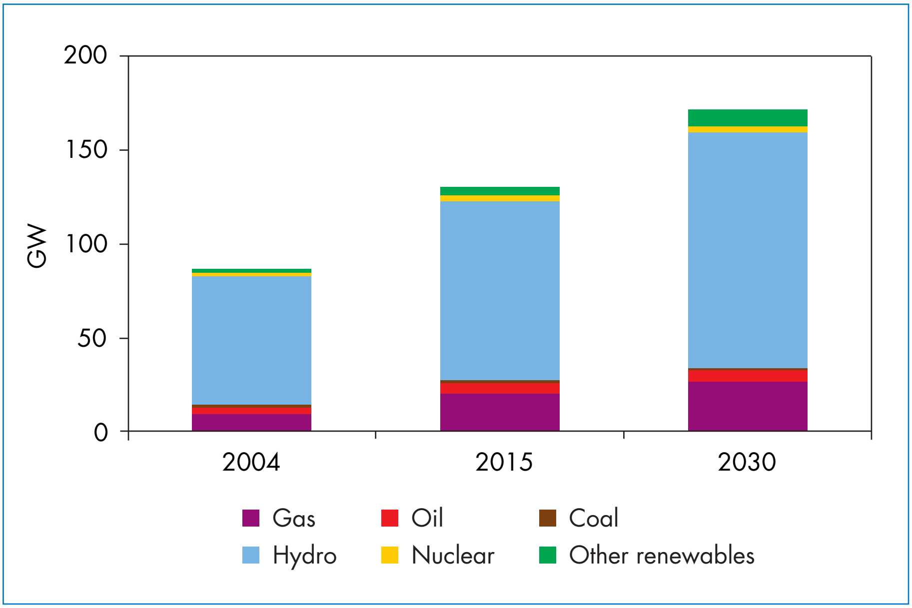
PROINFA is being implemented in two phases. In Phase 1, Eletrobrás had a target for 3 300 MW of renewable capacity by 2006. As of September 2006, 1 191 MW of small hydro, 1 423 MW of wind and 701 MW of biomass capacity had been accepted for PROINFA.[11] In Phase 2, Eletrobrás will be expected to lead the way to the fulfilment of PROINFA's 10% goal of electricity generation from renewables.

At 17% of total domestic supply in 2004, transmission and distribution losses in Brazil are among the highest in the world. They average only about 7% in OECD countries. Losses are high in Brazil because of the long distances over which power is transmitted, the old and poorly maintained systems with high losses and power theft. Insufficient investment in transmission and distribution facilities was one of the causes of the electricity crisis in 2001 and will be one of the major challenges over the *Outlook* period (see below).

In March 2004, the Brazilian government approved a new power-sector model. It is intended to address some of the regulatory concerns that had discouraged greater investment in expanding the country's power-generating and transmission capacity. Under the new regulations, two trading mechanisms will be established. The first is an electricity pool in which all distributors will be

11. See "Acompanhamento das Centrais Geradoras do PROINFA - Versão Agosto de 2006 at http://www.aneel.gov.br/37.htm.

Figure 16.14: **Power Generating Capacity in Brazil in the Reference Scenario**



able to participate. Supply contracts will be regulated. The second is an unregulated market which will be used by independent power producers and large consumers to negotiate bilateral contracts. The model also establishes new rules for the award of contracts for new generation plants to bidders who offer the lowest tariffs. The government is holding auctions for new electricity generation projects, including small and large hydro and biomass plants, with the aim of reducing power-supply risk and avoiding future supply shortages.

Although generating costs are low, electricity is considered very expensive for final consumers, particularly for households. Taxes and special charges to cover the cost of extending electrification make up more than 40% of the average electricity bill. The "Electricity for All" programme aims to give access to electricity to all households by 2015. The cross-subsidies involved in this programme increase tariffs for the non-subsidised population by 10%.

In the Alternative Policy Scenario, electricity generation is nearly 16% lower in 2030 than in the Reference Scenario and the fuel mix is different. There is much less gas and oil, and coal-fired generation almost disappears. Non-hydro renewables provide 49 TWh of generation, compared with 41 TWh in the Reference Scenario. Most of this increase is from bagasse cogeneration, which is boosted by more ethanol production in the Alternative Policy Scenario and stronger policies to connect bagasse producers to the grid. Nuclear power also increases its contribution by 41%, to 34.1 TWh in 2030, on the assumption that one more nuclear power plant is built after 2020. The share of hydropower generation remains broadly unchanged.

Environmental Issues

Environmental issues in Brazil have a very high profile, both domestically and internationally, where Brazil is a major player in discussions regarding the environment. Brazil's Amazon rainforest makes up 30% of the world's remaining tropical forests, provides shelter to at least one-tenth of the world's plant and animal species and is a vast source of freshwater.

Energy-related environmental problems include oil spills, air pollution, flooding, deforestation and induced occupation of areas cleared for transmission lines and pipelines. Oil spills cause severe environmental damage. Air pollution is mainly due to rapid urbanisation, industrial activities, poor fuel quality and biomass burning. The level of indoor air pollution from cooking with fuelwood is high in some areas. There are environmental pollution laws in place, with provision for sanctions. The government is working to enforce the requirements stemming from environmental impact assessments.

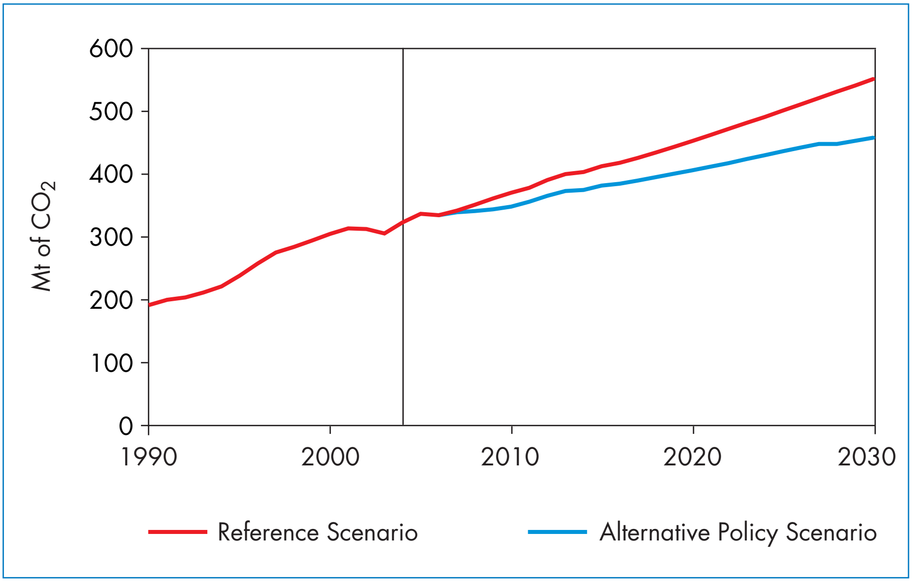
The construction of large dams is a major environmental issue. The Brazilian government favours the development of dams but there is considerable opposition. Because of opposition from environmental groups and weak institutional capacity at the federal level, hydropower generation projects have been delayed, despite the benefits these projects can offer when designed properly, such as multiple use of water and lower CO_2 emissions. If new dams are not constructed, the government may have no option but to invest in fossil-fuel plants and CO_2 emissions will rise.

Brazil's energy-related CO_2 emissions grew by 3.8% per year from 1990 to 2004. The carbon intensity of the economy grew, because of greater use of fossil fuels. CO_2 emissions per unit of GDP in PPP terms, however, were 20% lower than the average for the Latin American region as a whole in 2004 and 45% lower than in OECD countries. Use of hydropower and ethanol go some way to explaining this. Per-capita emissions in Brazil, at 1.8 tonnes in 2004, are among the lowest in the world and compare with 11 tonnes per capita in OECD countries.

Brazil ratified the Kyoto Protocol in 2002. As a developing country, Brazil is not currently required to reduce its CO_2 emissions, but like other developing countries, benefits from foreign investment encouraged by the Clean

Development Mechanism (CDM), to promote the development of energy sources that would lower carbon emissions. There were 66 CDM projects registered in Brazil as of September 2006.[12]

Figure 16.15: **Brazil's Energy-Related CO_2 Emissions in the Reference and Alternative Policy Scenarios**



In the Reference Scenario, energy-related CO_2 emissions are projected to reach 551 million tonnes by 2030, up from 323 million tonnes in 2004 and nearly three times higher than their 1990 level. Transport continues to contribute most to total emissions, its share increasing slightly from 42% today to 45% in 2030. The industrial sector's share of emissions remains flat. Those from power generation will decline slightly.

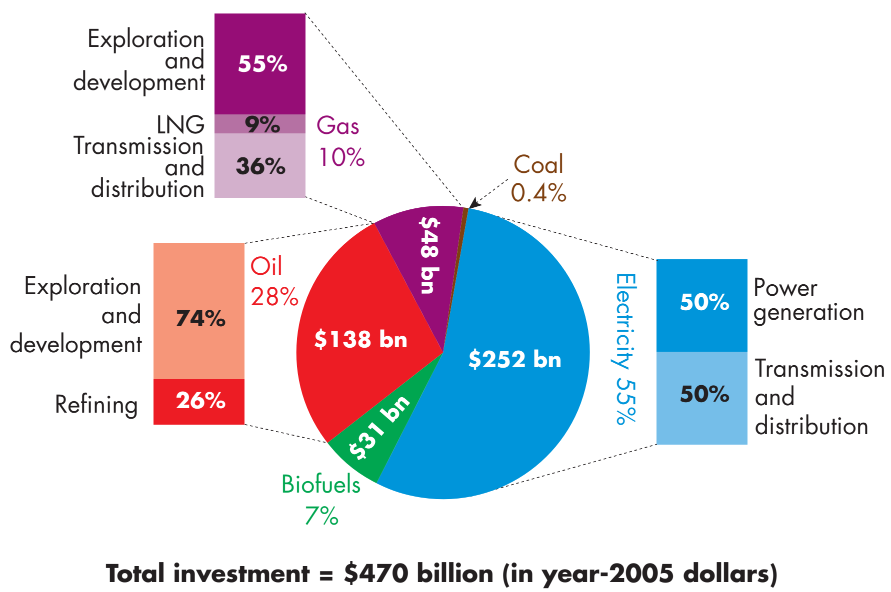
In the Alternative Policy Scenario, total CO_2 emissions reach 458 Mt in 2030, considerably lower than in the Reference Scenario (Figure 16.15). The decline is due to greater energy efficiency, more nuclear and renewables-based generation and more biofuels for transport. Emissions of CO_2 per unit of energy consumed are lower than in 2004. From a share today of 40% of primary energy use, the share of renewables remains flat in the Reference Scenario but rises by two percentage points in the Alternative Policy Scenario.

12. www.unfccc.int, accessed on 10 September 2006.

Investment

The cumulative amount of investment needed to underpin the projected growth in energy supply in Brazil is $470 billion (in year-2005 dollars) over the period 2005-2030 in the Reference Scenario. The electricity sector accounts for 54% of this spending, half for generation and the other half for investment in new transmission and distribution infrastructure (Figure 16.16). The $127 billion needed for generating capacity is two-thirds of that needed to meet all the additional demand in the rest of Latin America.

Figure 16.16: **Brazil's Cumulative Investment in Energy-Supply Infrastructure in the Reference Scenario, 2005-2030**



Note: See Chapter 2 for an explanation of the methodology used to project investment.

The private sector will be increasingly called upon to meet investment requirements. But that will require reform of the pricing structure and Brazil's regulatory regime to become more transparent and consistent. Investment in Brazil's transmission and distribution systems amounts to about $125 billion over the *Outlook* period.

Cumulative oil and gas investments amount to over $185 billion over the projection period. Upstream oil investment, at about $102 billion, or $4.1 billion per year, accounts for the majority of this. Expansion of the oil refining sector adds another $1.4 billion per year. These investments will be necessary to maintain self-sufficiency. Cumulative gas investments are projected at $48 billion, or $1.9 billion per year. Exploration and development of new fields needed to reduce dependence on gas imports will account for over half of total investment. Coal investment needs are negligible, because unit capital costs are low and new capacity needs minimal. To meet projected increases in biofuels demand, Brazil will need to invest some $31 billion over the *Outlook* period. This sum will represent nearly 20% of global investment in biofuels.

Required investments in the oil and gas sectors are lower in the Alternative Policy Scenario. Oil investment is $132 billion; $6 billion lower but still over $5 billion per year. Investments in the upstream oil sector will remain the same, but refinery investments fall. Cumulative gas investments are $47 billion over the *Outlook* period in the Alternative Policy Scenario. Reduced gas demand generates lower investment needs in the upstream and downstream sectors.

Lower electricity demand in the Alternative Policy Scenario reduces cumulative investment requirements to $206 billion, $47 billion less than in the Reference Scenario. Investments in transmission and distribution are considerably lower, at $82 billion. Generation investments are $3 billion lower. In the biofuels sector, some $6 billion more is needed to meet the demand expected in the Alternative Policy Scenario.

Total projected investment in the energy sector in the Reference Scenario is equal to around 1% of Brazil's GDP. Financing will be difficult, given the country's poorly developed domestic capital markets. External financing could account for a significant proportion of total capital flows to the Brazilian energy sector, especially in the oil and electricity industries if the right conditions were created.

On the demand side, the policies considered in the Alternative Policy Scenario lead to considerable increases in the amount of investment needed for energy efficiency improvements in the electricity and transport sectors. Cumulative investment requirements for more efficient electric equipment are $46 billion higher, compared with the Reference Scenario. In the transport sector, investment requirements are $42 billion higher.[13]

13. See Chapter 8 for a discussion of demand-side investments in the Alternative Policy Scenario.

ANNEXES

TABLES FOR REFERENCE AND ALTERNATIVE POLICY SCENARIO PROJECTIONS

General Note to the Tables

For OECD countries and non-OECD countries, the analysis of energy demand is based on data up to 2004, published in mid-2006 in *Energy Balances of OECD Countries* and in *Energy Balances of Non-OECD Countries.*[1]

The tables show projections of energy demand, electricity generation and capacity, and CO_2 emissions[2] for the following regions:

- World
- OECD
- OECD North America
- United States
- OECD Pacific
- Japan
- OECD Europe
- European Union
- Transition economies
- Russia
- Developing countries
- Developing Asia
- China
- India
- Latin America
- Brazil
- Middle East
- Africa

The definitions for regions, fuels and sectors are in Annex C.

Both in the text of this book and in the tables, rounding may cause some differences between the total and the sum of the individual components.

1. In the *World Energy Outlook*, petrochemical feedstocks are included in the industry sector.
2. Total CO_2 emissions include emissions from "other transformation, own use and losses", as well as from power generation and heat plants, and total final consumption (as shown in the tables).

Reference Scenario: World

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**8 732**	**11 204**	**14 071**	**17 095**	**100**	**100**	**100**	**2.1**	**1.6**
Coal	2 183	2 773	3 666	4 441	25	26	26	2.6	1.8
Oil	3 181	3 940	4 750	5 575	35	34	33	1.7	1.3
of which international marine bunkers	*114*	*165*	*180*	*197*	*1*	*1*	*1*	*0.8*	*0.7*
Gas	1 680	2 302	3 017	3 869	21	21	23	2.5	2.0
Nuclear	525	714	810	861	6	6	5	1.2	0.7
Hydro	185	242	317	408	2	2	2	2.5	2.0
Biomass and waste	923	1 176	1 375	1 645	10	10	10	1.4	1.3
Other renewables	56	57	136	296	1	1	2	8.3	6.6
Power generation and heat plants	**2 800**	**4 133**	**5 483**	**6 926**	**100**	**100**	**100**	**2.6**	**2.0**
Coal	1 190	1 888	2 577	3 232	46	47	47	2.9	2.1
Oil	328	292	302	241	7	6	3	0.3	–0.7
Gas	486	875	1 229	1 683	21	22	24	3.1	2.5
Nuclear	525	714	810	861	17	15	12	1.2	0.7
Hydro	185	242	317	408	6	6	6	2.5	2.0
Biomass and waste	54	74	137	265	2	3	4	5.8	5.0
Other renewables	32	49	113	236	1	2	3	7.8	6.2
Other transformation, own use and losses	**878**	**1 064**	**1 313**	**1 583**	**100**	**100**	**100**	**1.9**	**1.5**
of which electricity	*189*	*263*	*368*	*486*	*25*	*28*	*31*	*3.1*	*2.4*
Total final consumption	**6 154**	**7 639**	**9 562**	**11 664**	**100**	**100**	**100**	**2.1**	**1.6**
Coal	765	641	823	923	8	9	8	2.3	1.4
Oil	2 543	3 228	3 965	4 786	42	41	41	1.9	1.5
Gas	1 004	1 219	1 516	1 839	16	16	16	2.0	1.6
Electricity	826	1 236	1 765	2 416	16	18	21	3.3	2.6
Heat	177	255	287	324	3	3	3	1.1	0.9
Biomass and waste	815	1 052	1 182	1 317	14	12	11	1.1	0.9
Other renewables	24	7	23	60	0	0	1	11.2	8.4
Industry	**2 134**	**2 511**	**3 283**	**3 932**	**100**	**100**	**100**	**2.5**	**1.7**
Coal	470	499	686	798	20	21	20	2.9	1.8
Oil	550	665	820	909	26	25	23	1.9	1.2
Gas	551	564	724	890	22	22	23	2.3	1.8
Electricity	382	512	729	940	20	22	24	3.3	2.4
Heat	72	100	109	116	4	3	3	0.8	0.6
Biomass and waste	109	169	212	275	7	6	7	2.1	1.9
Other renewables	0	1	1	4	0	0	0	5.8	7.4
Transport	**1 435**	**1 969**	**2 454**	**3 111**	**100**	**100**	**100**	**2.0**	**1.8**
Oil	1 370	1 861	2 286	2 884	94	93	93	1.9	1.7
Biofuels	6	15	54	92	1	2	3	12.1	7.1
Other fuels	59	93	114	135	5	5	4	1.8	1.4
Residential, services and agriculture	**2 339**	**2 905**	**3 497**	**4 221**	**100**	**100**	**100**	**1.7**	**1.4**
Coal	240	106	98	90	4	3	2	–0.7	–0.6
Oil	450	499	592	664	17	17	16	1.6	1.1
Gas	422	586	709	849	20	20	20	1.7	1.4
Electricity	421	689	987	1 409	24	28	33	3.3	2.8
Heat	105	154	177	207	5	5	5	1.3	1.1
Biomass and waste	696	864	911	946	30	26	22	0.5	0.3
Other renewables	4	7	22	56	0	1	1	11.5	8.5
Non-energy use	**246**	**254**	**329**	**400**	**100**	**100**	**100**	**2.4**	**1.8**

Reference Scenario: World

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**11 731**	**17 408**	**24 816**	**33 750**	**100**	**100**	**100**	**3.3**	**2.6**
Coal	4 478	6 917	10 609	14 703	40	43	44	4.0	2.9
Oil	1 313	1 161	1 195	940	7	5	3	0.3	–0.8
Gas	1 613	3 412	5 236	7 790	20	21	23	4.0	3.2
Nuclear	2 013	2 740	3 108	3 304	16	13	10	1.2	0.7
Hydro	2 148	2 809	3 682	4 749	16	15	14	2.5	2.0
Renewables (excluding hydro)	166	369	986	2 264	2	4	7	9.3	7.2
Biomass and waste	*125*	*227*	*422*	*805*	*1*	*2*	*2*	*5.8*	*5.0*
Wind	*4*	*82*	*433*	*1 132*	*0*	*2*	*3*	*16.3*	*10.6*
Geothermal	*36*	*56*	*100*	*174*	*0*	*0*	*1*	*5.5*	*4.5*
Solar	*1*	*4*	*30*	*142*	*0*	*0*	*0*	*19.7*	*14.5*
Tide and wave	*1*	*1*	*1*	*12*	*0*	*0*	*0*	*9.1*	*12.4*

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**4 054**	**5 652**	**7 875**	**100**	**100**	**100**	**3.1**	**2.6**
Coal	1 235	1 826	2 565	30	32	33	3.6	2.9
Oil	453	480	378	11	8	5	0.5	–0.7
Gas	1 055	1 604	2 468	26	28	31	3.9	3.3
Nuclear	364	391	416	9	7	5	0.7	0.5
Hydro	851	1 079	1 373	21	19	17	2.2	1.9
of which pumped storage	*79*	*79*	*79*	*2*	*1*	*1*	*0.0*	*0.0*
Renewables (excluding hydro)	96	271	674	2	5	9	9.9	7.8
Biomass and waste	*36*	*68*	*129*	*1*	*1*	*2*	*5.9*	*5.0*
Wind	*48*	*168*	*430*	*1*	*3*	*5*	*12.1*	*8.8*
Geothermal	*8*	*15*	*25*	*0*	*0*	*0*	*5.4*	*4.4*
Solar	*4*	*20*	*87*	*0*	*0*	*1*	*16.4*	*13.0*
Tide and wave	*0*	*0*	*3*	*0*	*0*	*0*	*4.0*	*9.9*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**20 463**	**26 079**	**33 333**	**40 420**	**100**	**100**	**100**	**2.3**	**1.7**
Coal	8 081	10 625	14 217	17 293	41	43	43	2.7	1.9
Oil	8 561	10 199	12 239	14 334	39	37	35	1.7	1.3
of which international marine bunkers	*363*	*521*	*569*	*622*	*2*	*2*	*2*	*0.8*	*0.7*
Gas	3 820	5 254	6 877	8 793	20	21	22	2.5	2.0
Power generation and heat plants	**6 955**	**10 587**	**14 209**	**17 680**	**100**	**100**	**100**	**2.7**	**2.0**
Coal	4 764	7 600	10 353	12 946	72	73	73	2.9	2.1
Oil	1 053	934	960	762	9	7	4	0.3	–0.8
Gas	1 138	2 054	2 896	3 972	19	20	22	3.2	2.6
Total final consumption	**12 047**	**13 668**	**17 017**	**20 324**	**100**	**100**	**100**	**2.0**	**1.5**
Coal	3 188	2 817	3 636	4 102	21	21	20	2.3	1.5
Oil	6 595	8 091	9 972	12 124	59	59	60	1.9	1.6
of which transport	*3 758*	*5 112*	*6 328*	*7 993*	*37*	*37*	*39*	*2.0*	*1.7*
Gas	2 264	2 760	3 409	4 098	20	20	20	1.9	1.5

Reference Scenario: OECD

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**4 518**	**5 502**	**6 261**	**6 860**	**100**	**100**	**100**	**1.2**	**0.9**
Coal	1 063	1 129	1 231	1 301	21	20	19	0.8	0.5
Oil	1 894	2 236	2 468	2 591	41	39	38	0.9	0.6
Gas	844	1 199	1 429	1 648	22	23	24	1.6	1.2
Nuclear	449	604	645	621	11	10	9	0.6	0.1
Hydro	101	109	121	131	2	2	2	1.0	0.7
Biomass and waste	140	187	278	386	3	4	6	3.7	2.8
Other renewables	28	37	88	181	1	1	3	8.0	6.3
Power generation and heat plants	**1 701**	**2 197**	**2 549**	**2 820**	**100**	**100**	**100**	**1.4**	**1.0**
Coal	750	906	1 029	1 119	41	40	40	1.2	0.8
Oil	148	115	107	66	5	4	2	–0.7	–2.1
Gas	175	371	483	593	17	19	21	2.4	1.8
Nuclear	449	604	645	621	27	25	22	0.6	0.1
Hydro	101	109	121	131	5	5	5	1.0	0.7
Biomass and waste	52	61	91	147	3	4	5	3.8	3.5
Other renewables	25	31	72	144	1	3	5	8.0	6.1
Other transformation, own use and losses	**381**	**416**	**447**	**486**	**100**	**100**	**100**	**0.7**	**0.6**
of which electricity	*105*	*118*	*136*	*153*	*28*	*30*	*31*	*1.3*	*1.0*
Total final consumption	**3 135**	**3 826**	**4 393**	**4 892**	**100**	**100**	**100**	**1.3**	**1.0**
Coal	229	134	120	108	3	3	2	–1.0	–0.8
Oil	1 638	2 000	2 244	2 409	52	51	49	1.1	0.7
Gas	591	747	843	923	20	19	19	1.1	0.8
Electricity	547	753	914	1 093	20	21	22	1.8	1.4
Heat	40	59	71	83	2	2	2	1.6	1.3
Biomass and waste	87	127	187	239	3	4	5	3.6	2.5
Other renewables	3	6	15	37	0	0	1	8.4	7.1
Industry	**1 015**	**1 152**	**1 297**	**1 393**	**100**	**100**	**100**	**1.1**	**0.7**
Coal	159	115	108	100	10	8	7	–0.6	–0.5
Oil	323	376	431	433	33	33	31	1.2	0.5
Gas	261	310	342	370	27	26	27	0.9	0.7
Electricity	223	269	309	351	23	24	25	1.3	1.0
Heat	14	17	20	23	1	2	2	1.7	1.2
Biomass and waste	35	64	85	112	6	7	8	2.6	2.2
Other renewables	0	1	1	4	0	0	0	4.2	7.0
Transport	**986**	**1 283**	**1 484**	**1 660**	**100**	**100**	**100**	**1.3**	**1.0**
Oil	960	1 244	1 412	1 571	97	95	95	1.2	0.9
Biofuels	0	9	39	52	1	3	3	14.3	7.0
Other fuels	26	30	33	38	2	2	2	1.0	1.0
Residential, services and agriculture	**1 036**	**1 273**	**1 476**	**1 689**	**100**	**100**	**100**	**1.4**	**1.1**
Coal	68	17	11	7	1	1	0	–4.1	–3.5
Oil	259	263	266	257	21	18	15	0.1	–0.1
Gas	311	416	479	528	33	32	31	1.3	0.9
Electricity	316	475	593	728	37	40	43	2.0	1.7
Heat	27	42	50	60	3	3	4	1.6	1.4
Biomass and waste	52	54	63	75	4	4	4	1.4	1.2
Other renewables	3	6	14	34	0	1	2	8.7	7.1
Non-energy use	**98**	**119**	**137**	**150**	**100**	**100**	**100**	**1.3**	**0.9**

Reference Scenario: OECD

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**7 571**	**10 118**	**12 185**	**14 468**	**100**	**100**	**100**	**1.7**	**1.4**
Coal	3 059	3 842	4 548	5 391	38	37	37	1.5	1.3
Oil	695	527	482	297	5	4	2	–0.8	–2.2
Gas	770	1 854	2 515	3 345	18	21	23	2.8	2.3
Nuclear	1 725	2 319	2 475	2 382	23	20	16	0.6	0.1
Hydro	1 170	1 267	1 412	1 519	13	12	11	1.0	0.7
Renewables (excluding hydro)	152	310	753	1 534	3	6	11	8.4	6.3
Biomass and waste	*118*	*196*	*306*	*485*	*2*	*3*	*3*	*4.2*	*3.6*
Wind	*4*	*77*	*358*	*840*	*1*	*3*	*6*	*15.0*	*9.6*
Geothermal	*29*	*35*	*59*	*95*	*0*	*0*	*1*	*4.8*	*3.9*
Solar	*1*	*2*	*28*	*103*	*0*	*0*	*1*	*29.5*	*17.3*
Tide and wave	*1*	*1*	*1*	*11*	*0*	*0*	*0*	*9.1*	*12.3*

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**2 360**	**2 826**	**3 545**	**100**	**100**	**100**	**1.6**	**1.6**
Coal	656	749	928	28	27	26	1.2	1.3
Oil	234	226	140	10	8	4	–0.3	–2.0
Gas	654	866	1 209	28	31	34	2.6	2.4
Nuclear	305	309	296	13	11	8	0.1	–0.1
Hydro	428	458	486	18	16	14	0.6	0.5
of which pumped storage	*79*	*79*	*79*	*3*	*3*	*2*	*0.0*	*0.0*
Renewables (excluding hydro)	82	219	485	3	8	14	9.3	7.1
Biomass and waste	*31*	*49*	*78*	*1*	*2*	*2*	*4.3*	*3.6*
Wind	*43*	*142*	*325*	*2*	*5*	*9*	*11.4*	*8.1*
Geothermal	*5*	*8*	*13*	*0*	*0*	*0*	*4.6*	*3.7*
Solar	*3*	*19*	*66*	*0*	*1*	*2*	*18.5*	*12.8*
Tide and wave	*0*	*0*	*3*	*0*	*0*	*0*	*4.0*	*9.8*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**11 051**	**12 827**	**14 391**	**15 495**	**100**	**100**	**100**	**1.1**	**0.7**
Coal	4 101	4 334	4 762	5 058	34	33	33	0.9	0.6
Oil	5 029	5 713	6 320	6 628	45	44	43	0.9	0.6
Gas	1 920	2 780	3 309	3 808	22	23	25	1.6	1.2
Power generation and heat plants	**3 904**	**4 905**	**5 636**	**6 115**	**100**	**100**	**100**	**1.3**	**0.9**
Coal	3 024	3 665	4 159	4 514	75	74	74	1.2	0.8
Oil	471	372	346	213	8	6	3	–0.7	–2.1
Gas	409	867	1 130	1 388	18	20	23	2.4	1.8
Total final consumption	**6 553**	**7 274**	**8 063**	**8 625**	**100**	**100**	**100**	**0.9**	**0.7**
Coal	1 012	589	528	474	8	7	5	–1.0	–0.8
Oil	4 196	4 967	5 598	6 030	68	69	70	1.1	0.7
of which transport	*2 688*	*3 445*	*3 966*	*4 418*	*47*	*49*	*51*	*1.3*	*1.0*
Gas	1 345	1 717	1 938	2 121	24	24	25	1.1	0.8

Reference Scenario: OECD North America

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**2 256**	**2 756**	**3 184**	**3 575**	**100**	**100**	**100**	**1.3**	**1.0**
Coal	486	581	670	740	21	21	21	1.3	0.9
Oil	927	1 137	1 292	1 415	41	41	40	1.2	0.8
Gas	517	637	740	824	23	23	23	1.4	1.0
Nuclear	179	238	254	275	9	8	8	0.6	0.6
Hydro	51	55	58	61	2	2	2	0.6	0.4
Biomass and waste	78	91	133	182	3	4	5	3.5	2.7
Other renewables	19	17	37	77	1	1	2	7.1	5.9
Power generation and heat plants	**845**	**1 086**	**1 272**	**1 450**	**100**	**100**	**100**	**1.4**	**1.1**
Coal	413	524	618	692	48	49	48	1.5	1.1
Oil	47	54	52	39	5	4	3	–0.4	–1.3
Gas	95	173	218	248	16	17	17	2.1	1.4
Nuclear	179	238	254	275	22	20	19	0.6	0.6
Hydro	51	55	58	61	5	5	4	0.6	0.4
Biomass and waste	41	27	40	72	2	3	5	3.8	3.9
Other renewables	19	15	31	62	1	2	4	6.9	5.6
Other transformation, own use and losses	**190**	**197**	**219**	**253**	**100**	**100**	**100**	**1.0**	**1.0**
of which electricity	*56*	*56*	*66*	*76*	*29*	*30*	*30*	*1.4*	*1.1*
Total final consumption	**1 552**	**1 906**	**2 218**	**2 506**	**100**	**100**	**100**	**1.4**	**1.1**
Coal	59	39	35	31	2	2	1	–1.0	–0.8
Oil	822	1 025	1 186	1 323	54	53	53	1.3	1.0
Gas	360	402	442	471	21	20	19	0.9	0.6
Electricity	271	371	450	548	19	20	22	1.8	1.5
Heat	3	4	6	7	0	0	0	3.9	2.4
Biomass and waste	37	64	92	110	3	4	4	3.4	2.1
Other renewables	0	2	6	15	0	0	1	8.4	7.6
Industry	**448**	**511**	**572**	**620**	**100**	**100**	**100**	**1.0**	**0.7**
Coal	49	36	33	30	7	6	5	–0.8	–0.7
Oil	131	153	181	187	30	32	30	1.5	0.8
Gas	157	171	181	192	34	32	31	0.5	0.4
Electricity	94	107	121	140	21	21	23	1.1	1.0
Heat	1	3	5	6	1	1	1	3.9	2.2
Biomass and waste	16	40	52	63	8	9	10	2.5	1.8
Other renewables	0	0	0	0	0	0	0	4.0	3.1
Transport	**575**	**738**	**871**	**996**	**100**	**100**	**100**	**1.5**	**1.2**
Oil	556	713	831	952	97	95	96	1.4	1.1
Biofuels	0	7	21	24	1	2	2	10.3	4.9
Other fuels	19	19	19	20	3	2	2	0.3	0.3
Residential, services and agriculture	**477**	**588**	**691**	**799**	**100**	**100**	**100**	**1.5**	**1.2**
Coal	10	3	2	1	1	0	0	–4.0	–4.2
Oil	83	90	92	92	15	13	12	0.2	0.1
Gas	185	212	243	259	36	35	32	1.2	0.8
Electricity	176	263	329	407	45	48	51	2.1	1.7
Heat	2	1	1	1	0	0	0	4.1	2.9
Biomass and waste	21	17	20	22	3	3	3	1.2	1.0
Other renewables	0	2	5	15	0	1	2	8.6	7.7
Non-energy use	**52**	**69**	**83**	**92**	**100**	**100**	**100**	**1.7**	**1.1**

Reference Scenario: OECD North America

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**3 809**	**4 970**	**5 999**	**7 255**	**100**	**100**	**100**	**1.7**	**1.5**
Coal	1 790	2 217	2 711	3 327	45	45	46	1.8	1.6
Oil	217	231	216	167	5	4	2	–0.6	–1.2
Gas	406	851	1 158	1 412	17	19	19	2.8	2.0
Nuclear	687	913	973	1 057	18	16	15	0.6	0.6
Hydro	593	637	679	713	13	11	10	0.6	0.4
Renewables (excluding hydro)	115	121	261	579	2	4	8	7.2	6.2
Biomass and waste	*90*	*83*	*125*	*221*	*2*	*2*	*3*	*3.8*	*3.8*
Wind	*3*	*16*	*87*	*264*	*0*	*1*	*4*	*16.9*	*11.5*
Geothermal	*21*	*22*	*39*	*62*	*0*	*1*	*1*	*5.2*	*4.0*
Solar	*1*	*1*	*10*	*31*	*0*	*0*	*0*	*28.7*	*16.0*
Tide and wave	*0*	*0*	*0*	*2*	*0*	*0*	*0*	*8.0*	*16.8*

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**1 180**	**1 401**	**1 741**	**100**	**100**	**100**	**1.6**	**1.5**
Coal	365	434	546	31	31	31	1.6	1.6
Oil	96	99	73	8	7	4	0.3	–1.1
Gas	407	507	652	35	36	37	2.0	1.8
Nuclear	112	118	128	9	8	7	0.5	0.5
Hydro	178	183	190	15	13	11	0.2	0.3
of which pumped storage	*20*	*20*	*20*	*2*	*1*	*1*	*0.0*	*0.0*
Renewables (excluding hydro)	22	60	152	2	4	9	9.3	7.6
Biomass and waste	*12*	*18*	*33*	*1*	*1*	*2*	*4.2*	*4.1*
Wind	*7*	*30*	*92*	*1*	*2*	*5*	*13.9*	*10.3*
Geothermal	*3*	*6*	*9*	*0*	*0*	*0*	*5.0*	*3.9*
Solar	*1*	*6*	*18*	*0*	*0*	*1*	*25.6*	*14.5*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*	*13.0*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**5 554**	**6 694**	**7 721**	**8 528**	**100**	**100**	**100**	**1.3**	**0.9**
Coal	1 882	2 249	2 600	2 878	34	34	34	1.3	1.0
Oil	2 485	2 967	3 401	3 740	44	44	44	1.3	0.9
Gas	1 187	1 478	1 720	1 910	22	22	22	1.4	1.0
Power generation and heat plants	**1 991**	**2 648**	**3 114**	**3 433**	**100**	**100**	**100**	**1.5**	**1.0**
Coal	1 618	2 065	2 433	2 726	78	78	79	1.5	1.1
Oil	151	178	171	127	7	5	4	–0.4	–1.3
Gas	222	404	510	579	15	16	17	2.1	1.4
Total final consumption	**3 211**	**3 678**	**4 198**	**4 622**	**100**	**100**	**100**	**1.2**	**0.9**
Coal	262	168	151	135	5	4	3	–1.0	–0.8
Oil	2 122	2 587	3 029	3 402	70	72	74	1.4	1.1
of which transport	*1 584*	*2 030*	*2 416*	*2 767*	*55*	*58*	*60*	*1.6*	*1.2*
Gas	827	923	1 018	1 084	25	24	23	0.9	0.6

Reference Scenario: United States

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**1 924**	**2 324**	**2 653**	**2 929**	**100**	**100**	**100**	**1.2**	**0.9**
Coal	458	545	624	695	23	24	24	1.2	0.9
Oil	767	946	1 065	1 150	41	40	39	1.1	0.8
Gas	439	515	579	599	22	22	20	1.1	0.6
Nuclear	159	212	221	243	9	8	8	0.4	0.5
Hydro	23	23	25	26	1	1	1	0.6	0.3
Biomass and waste	62	71	110	155	3	4	5	4.2	3.1
Other renewables	14	11	28	60	0	1	2	8.4	6.6
Power generation and heat plants	**745**	**944**	**1 089**	**1 227**	**100**	**100**	**100**	**1.3**	**1.0**
Coal	391	495	578	653	52	53	53	1.4	1.1
Oil	27	33	32	23	4	3	2	–0.3	–1.4
Gas	90	147	173	169	16	16	14	1.5	0.5
Nuclear	159	212	221	243	22	20	20	0.4	0.5
Hydro	23	23	25	26	2	2	2	0.6	0.3
Biomass and waste	40	24	37	67	3	3	5	4.2	4.1
Other renewables	14	9	23	47	1	2	4	8.5	6.4
Other transformation, own use and losses	**154**	**144**	**151**	**160**	**100**	**100**	**100**	**0.4**	**0.4**
of which electricity	*49*	*45*	*50*	*56*	*31*	*33*	*35*	*1.1*	*0.9*
Total final consumption	**1 304**	**1 599**	**1 847**	**2 059**	**100**	**100**	**100**	**1.3**	**1.0**
Coal	54	34	31	28	2	2	1	–0.9	–0.8
Oil	695	865	989	1 088	54	54	53	1.2	0.9
Gas	303	335	367	382	21	20	19	0.8	0.5
Electricity	226	313	376	454	20	20	22	1.7	1.4
Heat	2	3	5	6	0	0	0	4.4	2.5
Biomass and waste	23	47	73	88	3	4	4	4.2	2.5
Other renewables	0	2	5	14	0	0	1	8.3	7.3
Industry	**357**	**404**	**448**	**472**	**100**	**100**	**100**	**0.9**	**0.6**
Coal	45	31	29	27	8	6	6	–0.6	–0.6
Oil	104	123	145	149	31	32	32	1.5	0.7
Gas	124	135	140	143	33	31	30	0.3	0.2
Electricity	75	81	87	97	20	19	20	0.6	0.7
Heat	0	2	4	5	1	1	1	4.5	2.4
Biomass and waste	9	31	42	52	8	9	11	3.0	2.1
Other renewables	0	0	0	0	0	0	0	3.5	3.0
Transport	**499**	**638**	**741**	**833**	**100**	**100**	**100**	**1.4**	**1.0**
Oil	484	617	707	796	97	95	96	1.3	1.0
Biofuels	0	7	20	23	1	3	3	10.2	4.8
Other fuels	16	14	14	14	2	2	2	–0.1	0.0
Residential, services and agriculture	**403**	**497**	**584**	**674**	**100**	**100**	**100**	**1.5**	**1.2**
Coal	10	3	2	1	1	0	0	–4.0	–4.2
Oil	63	65	63	64	13	11	9	–0.2	–0.1
Gas	164	186	213	225	37	36	33	1.2	0.7
Electricity	152	231	289	357	47	49	53	2.0	1.7
Heat	2	1	1	1	0	0	0	4.1	2.9
Biomass and waste	14	9	11	13	2	2	2	1.7	1.4
Other renewables	0	2	5	13	0	1	2	8.5	7.4
Non-energy use	**44**	**60**	**73**	**80**	**100**	**100**	**100**	**1.7**	**1.1**

Reference Scenario: United States

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**3 203**	**4 148**	**4 951**	**5 913**	**100**	**100**	**100**	**1.6**	**1.4**
Coal	1 700	2 090	2 529	3 128	50	51	53	1.7	1.6
Oil	131	139	138	100	3	3	2	0.0	–1.3
Gas	382	732	914	954	18	18	16	2.0	1.0
Nuclear	611	813	849	933	20	17	16	0.4	0.5
Hydro	273	271	291	297	7	6	5	0.6	0.3
Renewables (excluding hydro)	106	102	229	502	2	5	8	7.6	6.3
Biomass and waste	*86*	*72*	*112*	*204*	*2*	*2*	*3*	*4.2*	*4.1*
Wind	*3*	*14*	*77*	*219*	*0*	*2*	*4*	*16.5*	*11.1*
Geothermal	*16*	*15*	*30*	*49*	*0*	*1*	*1*	*6.1*	*4.5*
Solar	*1*	*1*	*10*	*29*	*0*	*0*	*0*	*29.8*	*16.2*
Tide and wave	*0*	*0*	*0*	*1*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**995**	**1 166**	**1 431**	**100**	**100**	**100**	**1.5**	**1.4**
Coal	334	397	504	34	34	35	1.6	1.6
Oil	74	76	54	7	6	4	0.2	–1.2
Gas	373	440	529	38	38	37	1.5	1.4
Nuclear	98	101	111	10	9	8	0.3	0.5
Hydro	97	99	100	10	8	7	0.2	0.1
of which pumped storage	*20*	*20*	*20*	*2*	*2*	*1*	*0.0*	*0.0*
Renewables (excluding hydro)	19	53	132	2	5	9	9.7	7.7
Biomass and waste	*10*	*16*	*30*	*1*	*1*	*2*	*4.6*	*4.5*
Wind	*7*	*27*	*77*	*1*	*2*	*5*	*13.3*	*9.8*
Geothermal	*2*	*4*	*7*	*0*	*0*	*0*	*5.7*	*4.3*
Solar	*0*	*6*	*17*	*0*	*1*	*1*	*26.2*	*14.7*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0.0*	*11.3*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**4 832**	**5 769**	**6 573**	**7 138**	**100**	**100**	**100**	**1.2**	**0.8**
Coal	1 774	2 110	2 421	2 702	37	37	38	1.3	1.0
Oil	2 047	2 448	2 798	3 044	42	43	43	1.2	0.8
Gas	1 011	1 212	1 353	1 392	21	21	19	1.0	0.5
Power generation and heat plants	**1 829**	**2 403**	**2 784**	**3 039**	**100**	**100**	**100**	**1.3**	**0.9**
Coal	1 532	1 949	2 273	2 567	81	82	84	1.4	1.1
Oil	88	110	107	76	5	4	3	–0.3	–1.4
Gas	210	344	404	396	14	14	13	1.5	0.5
Total final consumption	**2 731**	**3 101**	**3 517**	**3 812**	**100**	**100**	**100**	**1.1**	**0.8**
Coal	239	146	132	119	5	4	3	–0.9	–0.8
Oil	1 795	2 184	2 539	2 814	70	72	74	1.4	1.0
of which transport	*1 381*	*1 759*	*2 074*	*2 334*	*57*	*59*	*61*	*1.5*	*1.1*
Gas	697	771	846	880	25	24	23	0.8	0.5

Reference Scenario: OECD Pacific

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**640**	**880**	**1 030**	**1 119**	**100**	**100**	**100**	**1.4**	**0.9**
Coal	138	217	239	230	25	23	21	0.9	0.2
Oil	340	399	429	433	45	42	39	0.7	0.3
Gas	69	124	158	188	14	15	17	2.3	1.6
Nuclear	66	108	155	196	12	15	17	3.4	2.3
Hydro	11	12	13	13	1	1	1	0.3	0.4
Biomass and waste	10	14	23	36	2	2	3	4.8	3.8
Other renewables	5	6	13	24	1	1	2	6.9	5.4
Power generation and heat plants	**238**	**365**	**452**	**502**	**100**	**100**	**100**	**2.0**	**1.2**
Coal	60	139	159	152	38	35	30	1.3	0.3
Oil	54	30	25	13	8	6	3	–1.4	–3.0
Gas	40	67	82	99	18	18	20	1.9	1.5
Nuclear	66	108	155	196	29	34	39	3.4	2.3
Hydro	11	12	13	13	3	3	3	0.3	0.4
Biomass and waste	3	5	8	13	1	2	3	4.4	3.7
Other renewables	3	5	9	16	1	2	3	6.0	4.8
Other transformation, own use and losses	**62**	**82**	**86**	**89**	**100**	**100**	**100**	**0.5**	**0.3**
of which electricity	*11*	*16*	*18*	*19*	*19*	*21*	*21*	*1.3*	*0.7*
Total final consumption	**437**	**586**	**679**	**739**	**100**	**100**	**100**	**1.4**	**0.9**
Coal	49	39	40	40	7	6	5	0.4	0.1
Oil	268	345	379	395	59	56	53	0.9	0.5
Gas	26	55	72	83	9	11	11	2.5	1.6
Electricity	86	132	163	184	23	24	25	1.9	1.3
Heat	0	5	6	7	1	1	1	2.3	1.6
Biomass and waste	6	9	15	23	1	2	3	5.0	3.8
Other renewables	2	1	4	8	0	1	1	10.1	7.4
Industry	**179**	**233**	**265**	**283**	**100**	**100**	**100**	**1.2**	**0.8**
Coal	39	38	39	39	16	15	14	0.4	0.1
Oil	81	103	112	115	44	42	41	0.8	0.4
Gas	12	24	31	35	11	12	12	2.2	1.3
Electricity	43	58	68	75	25	26	27	1.5	1.0
Heat	0	3	4	4	1	1	2	2.3	1.6
Biomass and waste	4	7	10	15	3	4	5	3.5	3.2
Other renewables	0	0	0	0	0	0	0	–0.5	–0.2
Transport	**117**	**164**	**187**	**202**	**100**	**100**	**100**	**1.2**	**0.8**
Oil	115	161	183	197	98	98	97	1.2	0.8
Biofuels	0	0	0	1	0	0	0	53.6	23.6
Other fuels	2	3	4	4	2	2	2	2.4	1.7
Residential, services and agriculture	**127**	**174**	**210**	**236**	**100**	**100**	**100**	**1.7**	**1.2**
Coal	9	1	1	1	1	0	0	–1.1	–0.8
Oil	58	66	67	66	38	32	28	0.2	0.0
Gas	14	30	40	47	17	19	20	2.6	1.7
Electricity	42	72	92	105	42	44	44	2.2	1.4
Heat	0	2	3	3	1	1	1	2.2	1.5
Biomass and waste	2	2	5	7	1	2	3	8.0	4.9
Other renewables	1	1	3	8	1	2	3	12.0	8.4
Non-energy use	**15**	**16**	**17**	**18**	**100**	**100**	**100**	**0.6**	**0.5**

Reference Scenario: OECD Pacific

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**1 130**	**1 719**	**2 104**	**2 353**	**100**	**100**	**100**	**1.9**	**1.2**
Coal	253	630	746	738	37	35	31	1.6	0.6
Oil	274	164	140	72	10	7	3	–1.4	–3.1
Gas	198	340	414	510	20	20	22	1.8	1.6
Nuclear	255	413	594	751	24	28	32	3.4	2.3
Hydro	133	142	146	155	8	7	7	0.3	0.4
Renewables (excluding hydro)	17	30	63	127	2	3	5	7.1	5.8
Biomass and waste	*13*	*21*	*31*	*48*	*1*	*1*	*2*	*3.7*	*3.2*
Wind	*0*	*2*	*14*	*42*	*0*	*1*	*2*	*17.6*	*11.6*
Geothermal	*4*	*6*	*10*	*15*	*0*	*0*	*1*	*4.5*	*3.5*
Solar	*0*	*0*	*7*	*22*	*0*	*0*	*1*	*45.1*	*22.0*
Tide and wave	*0*	*0*	*0*	*1*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**386**	**443**	**518**	**100**	**100**	**100**	**1.3**	**1.1**
Coal	94	113	123	24	25	24	1.6	1.0
Oil	69	61	40	18	14	8	–1.2	–2.0
Gas	89	111	153	23	25	30	2.0	2.1
Nuclear	61	74	94	16	17	18	1.7	1.7
Hydro	65	68	71	17	15	14	0.4	0.3
of which pumped storage	*28*	*28*	*28*	*7*	*6*	*6*	*0.0*	*0.0*
Renewables (excluding hydro)	7	16	37	2	4	7	8.5	6.8
Biomass and waste	*3*	*5*	*8*	*1*	*1*	*1*	*4.9*	*3.7*
Wind	*2*	*5*	*13*	*0*	*1*	*3*	*11.1*	*8.6*
Geothermal	*1*	*1*	*2*	*0*	*0*	*0*	*4.0*	*3.2*
Solar	*1*	*5*	*14*	*0*	*1*	*3*	*13.8*	*9.8*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**1 564**	**2 055**	**2 295**	**2 316**	**100**	**100**	**100**	**1.0**	**0.5**
Coal	519	803	897	858	39	39	37	1.0	0.3
Oil	885	960	1 028	1 025	47	45	44	0.6	0.3
Gas	160	292	369	433	14	16	19	2.2	1.5
Power generation and heat plants	**538**	**847**	**960**	**923**	**100**	**100**	**100**	**1.1**	**0.3**
Coal	276	596	683	647	70	71	70	1.2	0.3
Oil	167	94	81	42	11	8	5	–1.3	–3.0
Gas	94	157	195	234	19	20	25	2.0	1.5
Total final consumption	**957**	**1 118**	**1 242**	**1 298**	**100**	**100**	**100**	**1.0**	**0.6**
Coal	219	174	181	179	16	15	14	0.4	0.1
Oil	679	817	895	930	73	72	72	0.8	0.5
of which transport	*320*	*440*	*502*	*540*	*39*	*40*	*42*	*1.2*	*0.8*
Gas	60	126	165	189	11	13	15	2.5	1.6

Reference Scenario: Japan

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**446**	**533**	**586**	**606**	**100**	**100**	**100**	**0.9**	**0.5**
Coal	77	116	116	98	22	20	16	0.0	–0.7
Oil	253	253	253	236	47	43	39	0.0	–0.3
Gas	48	72	89	100	14	15	17	1.9	1.3
Nuclear	53	74	101	133	14	17	22	2.9	2.3
Hydro	8	8	8	8	2	1	1	–0.2	0.0
Biomass and waste	5	6	13	19	1	2	3	6.8	4.4
Other renewables	3	4	7	11	1	1	2	5.6	4.3
Power generation and heat plants	**171**	**219**	**256**	**275**	**100**	**100**	**100**	**1.4**	**0.9**
Coal	25	60	61	45	27	24	16	0.2	–1.1
Oil	48	24	19	9	11	7	3	–2.1	–3.7
Gas	33	47	56	64	21	22	23	1.7	1.2
Nuclear	53	74	101	133	34	40	48	2.9	2.3
Hydro	8	8	8	8	4	3	3	–0.2	0.0
Biomass and waste	2	4	5	8	2	2	3	3.1	2.6
Other renewables	1	3	5	8	1	2	3	4.7	3.9
Other transformation, own use and losses	**41**	**52**	**52**	**51**	**100**	**100**	**100**	**–0.1**	**–0.1**
of which electricity	*7*	*9*	*10*	*9*	*17*	*19*	*19*	*0.6*	*0.1*
Total final consumption	**306**	**354**	**383**	**391**	**100**	**100**	**100**	**0.7**	**0.4**
Coal	32	27	28	27	8	7	7	0.2	0.0
Oil	189	214	219	213	60	57	55	0.2	0.0
Gas	15	27	32	34	8	8	9	1.8	1.0
Electricity	65	83	94	101	23	25	26	1.1	0.7
Heat	0	1	1	1	0	0	0	1.9	1.3
Biomass and waste	3	2	7	12	1	2	3	11.0	6.3
Other renewables	1	1	2	3	0	1	1	8.5	5.6
Industry	**130**	**136**	**145**	**145**	**100**	**100**	**100**	**0.6**	**0.2**
Coal	32	27	28	27	20	19	19	0.2	0.0
Oil	59	61	62	59	45	43	41	0.2	–0.2
Gas	5	11	14	14	8	10	10	2.0	1.0
Electricity	32	34	36	37	25	25	25	0.5	0.3
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	3	2	5	8	2	4	6	7.6	4.9
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**76**	**94**	**98**	**98**	**100**	**100**	**100**	**0.4**	**0.2**
Oil	74	92	96	95	98	98	97	0.3	0.1
Biofuels	0	0	0	1	0	0	1	–	–
Other fuels	1	2	2	2	2	2	2	1.8	1.2
Residential, services and agriculture	**89**	**115**	**131**	**139**	**100**	**100**	**100**	**1.2**	**0.7**
Coal	0	0	0	0	0	0	0	–	–
Oil	45	50	51	51	44	39	36	0.2	0.0
Gas	11	16	18	20	14	14	14	1.5	0.9
Electricity	31	48	57	62	41	43	45	1.6	1.0
Heat	0	1	1	1	1	1	1	1.9	1.3
Biomass and waste	0	0	2	3	0	1	2	46.7	19.6
Other renewables	1	1	2	3	1	1	2	8.4	5.6
Non-energy use	**11**	**10**	**9**	**9**	**100**	**100**	**100**	**–0.6**	**–0.4**

Reference Scenario: Japan

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**838**	**1 071**	**1 208**	**1 280**	**100**	**100**	**100**	**1.1**	**0.7**
Coal	116	294	303	226	27	25	18	0.3	–1.0
Oil	251	133	103	49	12	9	4	–2.3	–3.8
Gas	166	244	281	330	23	23	26	1.3	1.2
Nuclear	202	282	389	510	26	32	40	2.9	2.3
Hydro	89	94	92	94	9	8	7	–0.2	0.0
Renewables (excluding hydro)	13	23	40	71	2	3	6	5.1	4.4
Biomass and waste	*12*	*19*	*26*	*37*	*2*	*2*	*3*	*3.1*	*2.7*
Wind	*0*	*1*	*5*	*16*	*0*	*0*	*1*	*12.8*	*10.0*
Geothermal	*2*	*3*	*5*	*7*	*0*	*0*	*1*	*3.4*	*2.7*
Solar	*0*	*0*	*4*	*10*	*0*	*0*	*1*	*101.5*	*38.9*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**261**	**271**	**305**	**100**	**100**	**100**	**0.4**	**0.6**
Coal	44	44	43	17	16	14	0.0	–0.1
Oil	58	49	32	22	18	11	–1.6	–2.3
Gas	61	70	96	24	26	31	1.2	1.7
Nuclear	45	50	66	17	19	22	0.9	1.5
Hydro	47	47	48	18	17	16	0.1	0.1
of which pumped storage	*25*	*25*	*25*	*9*	*9*	*8*	*0.0*	*0.0*
Renewables (excluding hydro)	5	10	20	2	4	7	6.7	5.5
Biomass and waste	*2*	*4*	*6*	*1*	*1*	*2*	*4.9*	*3.6*
Wind	*1*	*2*	*5*	*0*	*1*	*2*	*6.5*	*6.7*
Geothermal	*1*	*1*	*1*	*0*	*0*	*0*	*3.0*	*2.5*
Solar	*1*	*3*	*8*	*0*	*1*	*3*	*10.6*	*7.7*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**1 057**	**1 211**	**1 250**	**1 154**	**100**	**100**	**100**	**0.3**	**–0.2**
Coal	292	414	420	345	34	34	30	0.1	–0.7
Oil	650	623	620	577	51	50	50	0.0	–0.3
Gas	115	174	210	233	14	17	20	1.7	1.1
Power generation and heat plants	**354**	**454**	**466**	**384**	**100**	**100**	**100**	**0.2**	**–0.6**
Coal	125	269	274	203	59	59	53	0.2	–1.1
Oil	151	74	59	28	16	13	7	–2.1	–3.7
Gas	78	111	134	153	24	29	40	1.7	1.2
Total final consumption	**660**	**715**	**744**	**734**	**100**	**100**	**100**	**0.4**	**0.1**
Coal	151	129	132	129	18	18	18	0.2	0.0
Oil	474	523	537	525	73	72	72	0.2	0.0
of which transport	*206*	*252*	*261*	*259*	*35*	*35*	*35*	*0.3*	*0.1*
Gas	36	62	75	79	9	10	11	1.7	0.9

Reference Scenario: OECD Europe

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**1 622**	**1 866**	**2 047**	**2 165**	**100**	**100**	**100**	**0.8**	**0.6**
Coal	438	330	322	331	18	16	15	–0.2	0.0
Oil	627	700	747	743	38	36	34	0.6	0.2
Gas	258	439	531	637	24	26	29	1.7	1.4
Nuclear	204	259	236	150	14	12	7	–0.8	–2.1
Hydro	38	42	50	56	2	2	3	1.7	1.1
Biomass and waste	52	83	122	168	4	6	8	3.6	2.8
Other renewables	4	14	38	80	1	2	4	9.5	6.9
Power generation and heat plants	**618**	**746**	**825**	**869**	**100**	**100**	**100**	**0.9**	**0.6**
Coal	277	243	252	275	33	31	32	0.3	0.5
Oil	48	31	30	13	4	4	2	–0.5	–3.2
Gas	40	131	182	247	18	22	28	3.0	2.5
Nuclear	204	259	236	150	35	29	17	–0.8	–2.1
Hydro	38	42	50	56	6	6	6	1.7	1.1
Biomass and waste	8	29	43	62	4	5	7	3.7	3.0
Other renewables	3	11	32	66	2	4	8	9.9	7.0
Other transformation, own use and losses	**129**	**138**	**142**	**144**	**100**	**100**	**100**	**0.3**	**0.2**
of which electricity	*38*	*46*	*52*	*58*	*33*	*36*	*40*	*1.1*	*0.9*
Total final consumption	**1 146**	**1 333**	**1 496**	**1 646**	**100**	**100**	**100**	**1.1**	**0.8**
Coal	121	56	45	37	4	3	2	–2.0	–1.6
Oil	548	630	679	691	47	45	42	0.7	0.4
Gas	204	290	329	369	22	22	22	1.1	0.9
Electricity	190	250	300	362	19	20	22	1.7	1.4
Heat	37	50	58	68	4	4	4	1.4	1.2
Biomass and waste	44	54	79	106	4	5	6	3.6	2.6
Other renewables	1	3	6	14	0	0	1	7.4	6.4
Industry	**388**	**408**	**460**	**490**	**100**	**100**	**100**	**1.1**	**0.7**
Coal	70	41	36	31	10	8	6	–1.3	–1.1
Oil	112	120	138	131	29	30	27	1.3	0.3
Gas	92	114	130	143	28	28	29	1.2	0.9
Electricity	86	104	121	136	25	26	28	1.4	1.0
Heat	13	11	11	12	3	2	3	0.6	0.6
Biomass and waste	14	17	23	34	4	5	7	2.6	2.6
Other renewables	0	0	0	3	0	0	1	9.1	11.2
Transport	**295**	**381**	**426**	**462**	**100**	**100**	**100**	**1.0**	**0.7**
Oil	289	371	398	422	97	93	91	0.6	0.5
Biofuels	0	2	18	27	1	4	6	22.2	10.5
Other fuels	6	8	10	14	2	2	3	2.0	2.0
Residential, services and agriculture	**432**	**511**	**574**	**654**	**100**	**100**	**100**	**1.1**	**1.0**
Coal	50	13	8	5	3	1	1	–4.4	–3.7
Oil	117	107	107	99	21	19	15	0.0	–0.3
Gas	112	174	196	222	34	34	34	1.1	0.9
Electricity	99	140	172	216	27	30	33	1.9	1.7
Heat	24	39	47	56	8	8	9	1.5	1.3
Biomass and waste	29	35	38	45	7	7	7	0.9	1.0
Other renewables	1	3	5	11	0	1	2	7.3	5.7
Non-energy use	**31**	**33**	**37**	**40**	**100**	**100**	**100**	**0.8**	**0.7**

Reference Scenario: OECD Europe

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**2 632**	**3 429**	**4 082**	**4 860**	**100**	**100**	**100**	**1.6**	**1.3**
Coal	1 016	994	1 090	1 326	29	27	27	0.8	1.1
Oil	203	132	126	59	4	3	1	–0.4	–3.1
Gas	167	663	943	1 423	19	23	29	3.3	3.0
Nuclear	782	992	907	574	29	22	12	–0.8	–2.1
Hydro	443	488	587	651	14	14	13	1.7	1.1
Renewables (excluding hydro)	20	159	429	828	5	10	17	9.4	6.5
Biomass and waste	*15*	*92*	*150*	*216*	*3*	*4*	*4*	*4.6*	*3.4*
Wind	*1*	*59*	*257*	*535*	*2*	*6*	*11*	*14.3*	*8.8*
Geothermal	*4*	*7*	*10*	*18*	*0*	*0*	*0*	*3.6*	*3.6*
Solar	*0*	*1*	*10*	*50*	*0*	*0*	*1*	*25.0*	*17.0*
Tide and wave	*1*	*1*	*1*	*9*	*0*	*0*	*0*	*9.2*	*11.5*

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**794**	**982**	**1 287**	**100**	**100**	**100**	**2.0**	**1.9**
Coal	197	202	260	25	21	20	0.2	1.1
Oil	69	66	27	9	7	2	–0.4	–3.6
Gas	158	249	404	20	25	31	4.2	3.7
Nuclear	132	116	74	17	12	6	–1.2	–2.2
Hydro	185	207	225	23	21	18	1.0	0.8
of which pumped storage	*31*	*31*	*31*	*4*	*3*	*2*	*0.0*	*0.0*
Renewables (excluding hydro)	53	142	296	7	14	23	9.3	6.8
Biomass and waste	*16*	*26*	*37*	*2*	*3*	*3*	*4.3*	*3.2*
Wind	*35*	*107*	*220*	*4*	*11*	*17*	*10.8*	*7.4*
Geothermal	*1*	*1*	*2*	*0*	*0*	*0*	*3.8*	*3.7*
Solar	*1*	*7*	*35*	*0*	*1*	*3*	*18.1*	*13.9*
Tide and wave	*0*	*0*	*2*	*0*	*0*	*0*	*4.3*	*9.1*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**3 934**	**4 078**	**4 375**	**4 651**	**100**	**100**	**100**	**0.6**	**0.5**
Coal	1 700	1 282	1 264	1 321	31	29	28	–0.1	0.1
Oil	1 660	1 787	1 891	1 864	44	43	40	0.5	0.2
Gas	574	1 009	1 219	1 466	25	28	32	1.7	1.4
Power generation and heat plants	**1 376**	**1 409**	**1 562**	**1 759**	**100**	**100**	**100**	**0.9**	**0.9**
Coal	1 130	1 003	1 043	1 141	71	67	65	0.4	0.5
Oil	152	100	94	43	7	6	2	–0.5	–3.2
Gas	93	306	425	575	22	27	33	3.0	2.5
Total final consumption	**2 384**	**2 478**	**2 624**	**2 705**	**100**	**100**	**100**	**0.5**	**0.3**
Coal	532	247	196	161	10	7	6	–2.1	–1.6
Oil	1 395	1 563	1 674	1 697	63	64	63	0.6	0.3
of which transport	*784*	*976*	*1 048*	*1 111*	*39*	*40*	*41*	*0.6*	*0.5*
Gas	458	668	755	847	27	29	31	1.1	0.9

Reference Scenario: European Union

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**1 546**	**1 756**	**1 894**	**1 973**	**100**	**100**	**100**	**0.7**	**0.4**
Coal	427	311	290	283	18	15	14	–0.6	–0.4
Oil	591	656	695	685	37	37	35	0.5	0.2
Gas	255	417	500	597	24	26	30	1.7	1.4
Nuclear	203	257	231	147	15	12	7	–1.0	–2.1
Hydro	23	26	31	33	1	2	2	1.6	1.0
Biomass and waste	44	77	115	158	4	6	8	3.7	2.8
Other renewables	3	11	32	70	1	2	4	10.2	7.3
Power generation and heat plants	**601**	**712**	**768**	**788**	**100**	**100**	**100**	**0.7**	**0.4**
Coal	276	238	236	244	33	31	31	–0.1	0.1
Oil	48	31	30	13	4	4	2	–0.4	–3.3
Gas	39	122	170	232	17	22	29	3.1	2.5
Nuclear	203	257	231	147	36	30	19	–1.0	–2.1
Hydro	23	26	31	33	4	4	4	1.6	1.0
Biomass and waste	8	28	41	57	4	5	7	3.5	2.8
Other renewables	3	10	30	62	1	4	8	10.3	7.2
Other transformation, own use and losses	**122**	**127**	**129**	**128**	**100**	**100**	**100**	**0.1**	**0.0**
of which electricity	*37*	*43*	*47*	*51*	*34*	*36*	*40*	*0.8*	*0.7*
Total final consumption	**1 086**	**1 244**	**1 380**	**1 504**	**100**	**100**	**100**	**0.9**	**0.7**
Coal	114	44	31	22	4	2	1	–3.3	–2.7
Oil	513	589	630	636	47	46	42	0.6	0.3
Gas	204	282	315	349	23	23	23	1.0	0.8
Electricity	177	228	269	319	18	19	21	1.5	1.3
Heat	41	51	59	70	4	4	5	1.4	1.2
Biomass and waste	36	49	74	101	4	5	7	3.9	2.8
Other renewables	0	1	2	7	0	0	0	9.0	8.2
Industry	**371**	**378**	**418**	**441**	**100**	**100**	**100**	**0.9**	**0.6**
Coal	65	32	24	18	9	6	4	–2.8	–2.2
Oil	105	112	127	118	30	30	27	1.1	0.2
Gas	92	112	127	138	30	30	31	1.1	0.8
Electricity	80	94	106	119	25	25	27	1.2	0.9
Heat	15	11	12	13	3	3	3	0.6	0.6
Biomass and waste	14	17	23	34	5	5	8	2.6	2.7
Other renewables	0	0	0	2	0	0	0	37.4	28.4
Transport	**279**	**361**	**401**	**434**	**100**	**100**	**100**	**1.0**	**0.7**
Oil	273	351	374	394	97	93	91	0.6	0.4
Biofuels	0	2	18	27	1	4	6	22.2	10.5
Other fuels	6	8	10	13	2	2	3	2.0	2.0
Residential, services and agriculture	**407**	**475**	**527**	**593**	**100**	**100**	**100**	**0.9**	**0.9**
Coal	48	11	6	3	2	1	1	–5.3	–4.9
Oil	107	97	97	89	20	18	15	0.0	–0.3
Gas	112	168	186	207	35	35	35	0.9	0.8
Electricity	92	128	155	191	27	29	32	1.7	1.5
Heat	26	40	48	57	8	9	10	1.6	1.4
Biomass and waste	22	30	33	40	6	6	7	1.1	1.2
Other renewables	0	1	2	6	0	0	1	8.6	7.0
Non-energy use	**29**	**30**	**33**	**36**	**100**	**100**	**100**	**0.9**	**0.7**

Reference Scenario: European Union

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**2 444**	**3 154**	**3 673**	**4 303**	**100**	**100**	**100**	**1.4**	**1.2**
Coal	1 012	975	1 015	1 165	31	28	27	0.4	0.7
Oil	205	131	126	56	4	3	1	–0.4	–3.2
Gas	159	605	868	1 332	19	24	31	3.3	3.1
Nuclear	778	988	885	564	31	24	13	–1.0	–2.1
Hydro	271	300	359	385	10	10	9	1.6	1.0
Renewables (excluding hydro)	19	156	419	802	5	11	19	9.4	6.5
Biomass and waste	*14*	*90*	*145*	*201*	*3*	*4*	*5*	*4.4*	*3.2*
Wind	*1*	*59*	*255*	*529*	*2*	*7*	*12*	*14.3*	*8.8*
Geothermal	*3*	*6*	*8*	*13*	*0*	*0*	*0*	*3.2*	*3.5*
Solar	*0*	*1*	*10*	*50*	*0*	*0*	*1*	*20.0*	*14.9*
Tide and wave	*1*	*1*	*1*	*9*	*0*	*0*	*0*	*9.2*	*11.5*

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**723**	**886**	**1 158**	**100**	**100**	**100**	**1.9**	**1.8**
Coal	191	186	226	26	21	20	–0.2	0.6
Oil	71	68	29	10	8	2	–0.5	–3.4
Gas	146	234	388	20	26	33	4.4	3.8
Nuclear	131	114	74	18	13	6	–1.3	–2.2
Hydro	131	143	151	18	16	13	0.8	0.5
of which pumped storage	*28*	*28*	*28*	*4*	*3*	*2*	*0.0*	*0.0*
Renewables (excluding hydro)	52	140	291	7	16	25	9.4	6.8
Biomass and waste	*16*	*25*	*35*	*2*	*3*	*3*	*4.2*	*3.1*
Wind	*34*	*106*	*217*	*5*	*12*	*19*	*10.8*	*7.3*
Geothermal	*1*	*1*	*2*	*0*	*0*	*0*	*3.3*	*3.5*
Solar	*1*	*7*	*34*	*0*	*1*	*3*	*18.5*	*14.0*
Tide and wave	*0*	*0*	*2*	*0*	*0*	*0*	*4.3*	*9.1*

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**3 808**	**3 847**	**4 048**	**4 216**	**100**	**100**	**100**	**0.5**	**0.4**
Coal	1 666	1 211	1 136	1 124	31	28	27	–0.6	–0.3
Oil	1 571	1 675	1 759	1 715	44	43	41	0.4	0.1
Gas	571	962	1 152	1 377	25	28	33	1.7	1.4
Power generation and heat plants	**1 382**	**1 366**	**1 470**	**1 593**	**100**	**100**	**100**	**0.7**	**0.6**
Coal	1 128	980	974	1 007	72	66	63	–0.1	0.1
Oil	158	100	96	42	7	7	3	–0.4	–3.3
Gas	94	285	400	544	21	27	34	3.1	2.5
Total final consumption	**2 264**	**2 306**	**2 409**	**2 460**	**100**	**100**	**100**	**0.4**	**0.2**
Coal	500	201	138	100	9	6	4	–3.3	–2.7
Oil	1 304	1 457	1 548	1 559	63	64	63	0.6	0.3
of which transport	*741*	*924*	*985*	*1 038*	*40*	*41*	*42*	*0.6*	*0.4*
Gas	458	649	723	802	28	30	33	1.0	0.8

Reference Scenario: Transition Economies

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**1 488**	**1 077**	**1 259**	**1 420**	**100**	**100**	**100**	**1.4**	**1.1**
Coal	330	203	228	203	19	18	14	1.1	0.0
Oil	454	223	263	298	21	21	21	1.5	1.1
Gas	599	536	633	745	50	50	52	1.5	1.3
Nuclear	60	73	81	104	7	6	7	1.0	1.4
Hydro	23	26	29	35	2	2	2	1.1	1.1
Biomass and waste	0	17	18	23	2	1	2	0.9	1.2
Other renewables	21	1	5	13	0	0	1	21.3	12.2
Power generation and heat plants	**574**	**535**	**604**	**654**	**100**	**100**	**100**	**1.1**	**0.8**
Coal	171	133	149	116	25	25	18	1.0	–0.5
Oil	80	26	23	16	5	4	2	–1.3	–1.8
Gas	240	272	312	366	51	52	56	1.3	1.2
Nuclear	60	73	81	104	14	13	16	1.0	1.4
Hydro	23	26	29	35	5	5	5	1.1	1.1
Biomass and waste	0	4	4	5	1	1	1	–1.2	0.5
Other renewables	0	0	5	12	0	1	2	24.9	13.5
Other transformation, own use and losses	**200**	**157**	**176**	**202**	**100**	**100**	**100**	**1.1**	**1.0**
of which electricity	*43*	*39*	*44*	*50*	*25*	*25*	*25*	*1.1*	*1.0*
Total final consumption	**1 014**	**704**	**825**	**947**	**100**	**100**	**100**	**1.5**	**1.1**
Coal	104	44	51	56	6	6	6	1.5	1.0
Oil	340	168	204	234	24	25	25	1.8	1.3
Gas	306	227	278	329	32	34	35	1.8	1.4
Electricity	121	95	116	144	13	14	15	1.9	1.6
Heat	123	159	162	167	23	20	18	0.2	0.2
Biomass and waste	0	12	14	17	2	2	2	1.6	1.4
Other renewables	21	0	0	1	0	0	0	1.8	5.6
Industry	**446**	**245**	**289**	**337**	**100**	**100**	**100**	**1.5**	**1.2**
Coal	44	31	38	42	13	13	13	1.9	1.2
Oil	79	28	35	40	11	12	12	2.0	1.4
Gas	199	81	103	129	33	36	38	2.2	1.8
Electricity	76	45	57	72	18	20	21	2.1	1.8
Heat	47	58	54	50	24	19	15	–0.6	–0.6
Biomass and waste	0	2	2	3	1	1	1	1.6	1.5
Other renewables	0	0	0	0	0	0	0	37.1	25.4
Transport	**154**	**140**	**176**	**204**	**100**	**100**	**100**	**2.1**	**1.4**
Oil	135	90	115	133	64	66	66	2.2	1.5
Biofuels	0	0	0	0	0	0	0	13.1	8.3
Other fuels	18	50	60	70	35	34	34	1.8	1.3
Residential, services and agriculture	**340**	**302**	**341**	**385**	**100**	**100**	**100**	**1.1**	**0.9**
Coal	54	11	12	12	4	3	3	0.5	0.3
Oil	78	35	37	39	11	11	10	0.5	0.5
Gas	95	105	124	140	35	36	36	1.5	1.1
Electricity	36	41	50	62	14	15	16	1.8	1.6
Heat	76	101	107	117	33	31	30	0.6	0.6
Biomass and waste	0	10	12	14	3	3	4	1.5	1.3
Other renewables	1	0	0	1	0	0	0	1.1	4.4
Non-energy use	**75**	**17**	**19**	**22**	**100**	**100**	**100**	**1.1**	**1.1**

Reference Scenario: Transition Economies

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**1 840**	**1 536**	**1 882**	**2 281**	**100**	**100**	**100**	**1.9**	**1.5**
Coal	501	322	401	332	21	21	15	2.0	0.1
Oil	252	54	43	28	4	2	1	–2.0	–2.5
Gas	586	575	766	1 056	37	41	46	2.6	2.4
Nuclear	231	279	312	399	18	17	18	1.0	1.4
Hydro	269	303	342	403	20	18	18	1.1	1.1
Renewables (excluding hydro)	0	3	19	62	0	1	3	17.9	12.3
Biomass and waste	*0*	*2*	*3*	*23*	*0*	*0*	*1*	*2.9*	*9.7*
Wind	*0*	*0*	*11*	*28*	*0*	*1*	*1*	*53.9*	*24.5*
Geothermal	*0*	*0*	*5*	*11*	*0*	*0*	*0*	*25.3*	*13.5*
Solar	*0*	*1*	*0*	*1*	*0*	*0*	*0*	*–13.3*	*1.1*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**405**	**456**	**555**	**100**	**100**	**100**	**1.1**	**1.2**
Coal	109	99	87	27	22	16	–0.9	–0.9
Oil	30	28	15	7	6	3	–0.6	–2.5
Gas	137	183	268	34	40	48	2.7	2.6
Nuclear	40	42	54	10	9	10	0.3	1.1
Hydro	88	100	116	22	22	21	1.1	1.0
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	1	5	15	0	1	3	20.4	12.9
Biomass and waste	*0*	*1*	*4*	*0*	*0*	*1*	*3.1*	*8.5*
Wind	*0*	*4*	*9*	*0*	*1*	*2*	*34.8*	*17.7*
Geothermal	*0*	*1*	*2*	*0*	*0*	*0*	*24.2*	*13.2*
Solar	*0*	*0*	*1*	*0*	*0*	*0*	*49.5*	*27.3*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**3 731**	**2 560**	**2 977**	**3 193**	**100**	**100**	**100**	**1.4**	**0.9**
Coal	1 109	783	890	782	31	30	25	1.2	0.0
Oil	1 230	573	663	735	22	22	23	1.3	1.0
Gas	1 392	1 204	1 425	1 675	47	48	52	1.5	1.3
Power generation and heat plants	**1 515**	**1 287**	**1 440**	**1 412**	**100**	**100**	**100**	**1.0**	**0.4**
Coal	690	557	622	488	43	43	35	1.0	–0.5
Oil	263	90	75	54	7	5	4	–1.6	–2.0
Gas	562	641	743	871	50	52	62	1.3	1.2
Total final consumption	**2 015**	**1 169**	**1 412**	**1 625**	**100**	**100**	**100**	**1.7**	**1.3**
Coal	416	224	264	291	19	19	18	1.5	1.0
Oil	908	427	517	591	37	37	36	1.8	1.3
of which transport	*330*	*232*	*296*	*343*	*20*	*21*	*21*	*2.2*	*1.5*
Gas	691	518	630	743	44	45	46	1.8	1.4

Reference Scenario: Russia

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**n.a.**	**640**	**751**	**854**	**100**	**100**	**100**	**1.5**	**1.1**
Coal	n.a.	104	114	106	16	15	12	0.8	0.1
Oil	n.a.	130	152	170	20	20	20	1.4	1.0
Gas	n.a.	345	413	478	54	55	56	1.6	1.3
Nuclear	n.a.	38	46	68	6	6	8	1.8	2.3
Hydro	n.a.	15	16	17	2	2	2	0.6	0.5
Biomass and waste	n.a.	7	7	6	1	1	1	–0.5	–0.3
Other renewables	n.a.	0	4	8	0	0	1	24.1	13.1
Power generation and heat plants	**n.a.**	**350**	**395**	**436**	**100**	**100**	**100**	**1.1**	**0.9**
Coal	n.a.	76	82	71	22	21	16	0.7	–0.3
Oil	n.a.	17	16	12	5	4	3	–0.5	–1.4
Gas	n.a.	199	228	257	57	58	59	1.2	1.0
Nuclear	n.a.	38	46	68	11	12	16	1.8	2.3
Hydro	n.a.	15	16	17	4	4	4	0.6	0.5
Biomass and waste	n.a.	4	3	3	1	1	1	–1.7	–1.7
Other renewables	n.a.	0	4	8	0	1	2	23.9	13.0
Other transformation, own use and losses	**n.a.**	**93**	**105**	**121**	**100**	**100**	**100**	**1.1**	**1.0**
of which electricity	*n.a.*	*24*	*27*	*31*	*26*	*26*	*26*	*1.3*	*1.1*
Total final consumption	**n.a.**	**425**	**494**	**561**	**100**	**100**	**100**	**1.4**	**1.1**
Coal	n.a.	17	20	20	4	4	4	1.2	0.7
Oil	n.a.	95	114	129	22	23	23	1.6	1.2
Gas	n.a.	125	160	192	29	32	34	2.3	1.7
Electricity	n.a.	55	67	82	13	14	15	1.7	1.5
Heat	n.a.	130	131	135	31	27	24	0.1	0.1
Biomass and waste	n.a.	3	3	3	1	1	1	1.0	1.1
Other renewables	n.a.	0	0	0	0	0	0	–	–
Industry	**n.a.**	**146**	**169**	**189**	**100**	**100**	**100**	**1.3**	**1.0**
Coal	n.a.	10	12	13	7	7	7	1.8	1.0
Oil	n.a.	15	18	20	10	11	11	1.6	1.1
Gas	n.a.	44	58	71	30	35	38	2.7	1.9
Electricity	n.a.	29	35	43	20	21	23	1.8	1.6
Heat	n.a.	48	44	40	33	26	21	–0.7	–0.6
Biomass and waste	n.a.	1	1	1	0	1	1	1.4	1.6
Other renewables	n.a.	0	0	0	0	0	0	–	–
Transport	**n.a.**	**95**	**119**	**139**	**100**	**100**	**100**	**2.1**	**1.5**
Oil	n.a.	54	68	78	57	57	56	2.1	1.4
Biofuels	n.a.	0	0	0	0	0	0	20.0	11.4
Other fuels	n.a.	41	51	61	43	43	44	2.1	1.5
Residential, services and agriculture	**n.a.**	**176**	**198**	**223**	**100**	**100**	**100**	**1.1**	**0.9**
Coal	n.a.	6	7	7	4	3	3	0.5	0.3
Oil	n.a.	19	20	22	11	10	10	0.6	0.5
Gas	n.a.	47	57	67	27	29	30	1.9	1.4
Electricity	n.a.	20	24	30	11	12	14	1.9	1.6
Heat	n.a.	82	87	94	47	44	42	0.5	0.5
Biomass and waste	n.a.	2	2	2	1	1	1	0.4	0.4
Other renewables	n.a.	0	0	0	0	0	0	–	–
Non-energy use	**n.a.**	**8**	**9**	**10**	**100**	**100**	**100**	**0.6**	**0.9**

Reference Scenario: Russia

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**n.a.**	**926**	**1 104**	**1 324**	**100**	**100**	**100**	**1.6**	**1.4**
Coal	n.a.	161	183	173	17	17	13	1.2	0.3
Oil	n.a.	24	21	14	3	2	1	–1.0	–2.1
Gas	n.a.	419	526	642	45	48	48	2.1	1.7
Nuclear	n.a.	145	176	261	16	16	20	1.8	2.3
Hydro	n.a.	176	188	200	19	17	15	0.6	0.5
Renewables (excluding hydro)	n.a.	2	10	34	0	1	3	15.1	11.1
Biomass and waste	*n.a.*	*2*	*2*	*13*	*0*	*0*	*1*	*0.0*	*8.0*
Wind	*n.a.*	*0*	*5*	*12*	*0*	*0*	*1*	*81.0*	*33.3*
Geothermal	*n.a.*	*0*	*4*	*9*	*0*	*0*	*1*	*22.6*	*12.4*
Solar	*n.a.*	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Tide and wave	*n.a.*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**220**	**242**	**286**	**100**	**100**	**100**	**0.9**	**1.0**
Coal	48	46	46	22	19	16	–0.5	–0.2
Oil	9	9	6	4	4	2	0.3	–1.5
Gas	94	112	140	43	46	49	1.5	1.5
Nuclear	22	24	35	10	10	12	0.8	1.9
Hydro	46	49	52	21	20	18	0.5	0.5
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	1	3	8	0	1	3	15.6	10.8
Biomass and waste	*0*	*0*	*2*	*0*	*0*	*1*	*0.0*	*6.3*
Wind	*0*	*2*	*4*	*0*	*1*	*1*	*57.6*	*25.6*
Geothermal	*0*	*1*	*1*	*0*	*0*	*0*	*21.6*	*12.1*
Solar	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**n.a.**	**1 512**	**1 746**	**1 883**	**100**	**100**	**100**	**1.3**	**0.8**
Coal	n.a.	418	457	415	28	26	22	0.8	0.0
Oil	n.a.	323	370	406	21	21	22	1.2	0.9
Gas	n.a.	772	920	1 062	51	53	56	1.6	1.2
Power generation and heat plants	**n.a.**	**853**	**936**	**943**	**100**	**100**	**100**	**0.9**	**0.4**
Coal	n.a.	325	350	303	38	37	32	0.7	–0.3
Oil	n.a.	59	52	38	7	6	4	–1.0	–1.6
Gas	n.a.	469	534	601	55	57	64	1.2	1.0
Total final consumption	**n.a.**	**597**	**734**	**845**	**100**	**100**	**100**	**1.9**	**1.3**
Coal	n.a.	90	105	110	15	14	13	1.4	0.8
Oil	n.a.	227	272	307	38	37	36	1.6	1.2
of which transport	*n.a.*	*128*	*161*	*186*	*22*	*22*	*22*	*2.1*	*1.4*
Gas	n.a.	279	357	428	47	49	51	2.3	1.7

Reference Scenario: Developing Countries

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**2 612**	**4 460**	**6 372**	**8 619**	**100**	**100**	**100**	**3.3**	**2.6**
Coal	790	1 442	2 207	2 936	32	35	34	3.9	2.8
Oil	719	1 317	1 839	2 490	30	29	29	3.1	2.5
Gas	236	567	955	1 475	13	15	17	4.9	3.7
Nuclear	15	37	84	136	1	1	2	7.7	5.1
Hydro	61	107	166	243	2	3	3	4.1	3.2
Biomass and waste	783	972	1 078	1 236	22	17	14	0.9	0.9
Other renewables	7	18	43	102	0	1	1	8.0	6.8
Power generation and heat plants	**524**	**1 401**	**2 331**	**3 452**	**100**	**100**	**100**	**4.7**	**3.5**
Coal	268	848	1 399	1 997	61	60	58	4.7	3.3
Oil	100	150	172	159	11	7	5	1.2	0.2
Gas	71	233	434	724	17	19	21	5.8	4.5
Nuclear	15	37	84	136	3	4	4	7.7	5.1
Hydro	61	107	166	243	8	7	7	4.1	3.2
Biomass and waste	2	9	42	113	1	2	3	15.0	10.2
Other renewables	7	18	35	80	1	2	2	6.5	6.0
Other transformation, own use and losses	**297**	**491**	**689**	**895**	**100**	**100**	**100**	**3.1**	**2.3**
of which electricity	*42*	*106*	*189*	*284*	*22*	*27*	*32*	*5.4*	*3.9*
Total final consumption	**2 005**	**3 109**	**4 344**	**5 825**	**100**	**100**	**100**	**3.1**	**2.4**
Coal	432	464	651	759	15	15	13	3.1	1.9
Oil	566	1 060	1 518	2 143	34	35	37	3.3	2.7
Gas	108	245	395	587	8	9	10	4.5	3.4
Electricity	157	388	735	1 178	12	17	20	6.0	4.4
Heat	14	37	55	74	1	1	1	3.6	2.7
Biomass and waste	728	914	981	1 061	29	23	18	0.6	0.6
Other renewables	0	1	8	22	0	0	0	22.6	13.3
Industry	**673**	**1 114**	**1 697**	**2 202**	**100**	**100**	**100**	**3.9**	**2.7**
Coal	268	354	540	656	32	32	30	3.9	2.4
Oil	147	261	355	435	23	21	20	2.8	2.0
Gas	91	173	278	391	16	16	18	4.4	3.2
Electricity	83	198	363	516	18	21	23	5.7	3.8
Heat	11	25	35	43	2	2	2	3.0	2.1
Biomass and waste	74	104	125	160	9	7	7	1.7	1.7
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**296**	**547**	**794**	**1 248**	**100**	**100**	**100**	**3.4**	**3.2**
Oil	275	526	758	1 180	96	96	95	3.4	3.2
Biofuels	6	6	15	40	1	2	3	8.1	7.3
Other fuels	14	14	20	27	3	3	2	3.4	2.6
Residential, services and agriculture	**963**	**1 330**	**1 680**	**2 147**	**100**	**100**	**100**	**2.1**	**1.9**
Coal	117	78	76	71	6	5	3	–0.2	–0.3
Oil	114	201	289	368	15	17	17	3.4	2.3
Gas	16	65	106	180	5	6	8	4.6	4.0
Electricity	69	174	345	619	13	21	29	6.4	5.0
Heat	3	11	19	30	1	1	1	5.1	3.9
Biomass and waste	644	800	837	857	60	50	40	0.4	0.3
Other renewables	0	1	8	22	0	0	1	22.4	13.3
Non-energy use	**73**	**119**	**174**	**228**	**100**	**100**	**100**	**3.5**	**2.5**

Reference Scenario: Developing Countries

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**2 321**	**5 754**	**10 749**	**17 001**	**100**	**100**	**100**	**5.8**	**4.3**
Coal	917	2 753	5 659	8 979	48	53	53	6.8	4.7
Oil	366	580	670	616	10	6	4	1.3	0.2
Gas	257	983	1 955	3 389	17	18	20	6.4	4.9
Nuclear	57	142	322	523	2	3	3	7.7	5.1
Hydro	709	1 239	1 928	2 827	22	18	17	4.1	3.2
Renewables (excluding hydro)	14	56	215	668	1	2	4	13.0	10.0
Biomass and waste	*7*	*29*	*113*	*298*	*1*	*1*	*2*	*13.1*	*9.4*
Wind	*0*	*5*	*64*	*263*	*0*	*1*	*2*	*26.2*	*16.5*
Geothermal	*8*	*20*	*36*	*69*	*0*	*0*	*0*	*5.5*	*4.9*
Solar	*0*	*2*	*2*	*38*	*0*	*0*	*0*	*0.6*	*11.9*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**1 289**	**2 369**	**3 775**	**100**	**100**	**100**	**5.7**	**4.2**
Coal	470	978	1 550	36	41	41	6.9	4.7
Oil	189	227	223	15	10	6	1.7	0.6
Gas	265	555	992	21	23	26	7.0	5.2
Nuclear	18	41	66	1	2	2	7.5	5.0
Hydro	334	521	771	26	22	20	4.1	3.3
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	13	47	173	1	2	5	12.5	10.5
Biomass and waste	*5*	*18*	*47*	*0*	*1*	*1*	*12.8*	*9.1*
Wind	*4*	*22*	*95*	*0*	*1*	*3*	*16.4*	*12.7*
Geothermal	*3*	*5*	*10*	*0*	*0*	*0*	*5.6*	*4.8*
Solar	*1*	*1*	*21*	*0*	*0*	*1*	*0.0*	*13.5*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**5 317**	**10 171**	**15 396**	**21 111**	**100**	**100**	**100**	**3.8**	**2.8**
Coal	2 871	5 508	8 565	11 453	54	56	54	4.1	2.9
Oil	1 938	3 392	4 688	6 349	33	30	30	3.0	2.4
Gas	507	1 271	2 143	3 310	12	14	16	4.9	3.7
Power generation and heat plants	**1 535**	**4 395**	**7 133**	**10 153**	**100**	**100**	**100**	**4.5**	**3.3**
Coal	1 050	3 378	5 571	7 944	77	78	78	4.7	3.3
Oil	319	472	539	496	11	8	5	1.2	0.2
Gas	167	545	1 024	1 713	12	14	17	5.9	4.5
Total final consumption	**3 479**	**5 226**	**7 541**	**10 073**	**100**	**100**	**100**	**3.4**	**2.6**
Coal	1 760	2 004	2 844	3 337	38	38	33	3.2	2.0
Oil	1 491	2 697	3 857	5 503	52	51	55	3.3	2.8
of which transport	*740*	*1 435*	*2 066*	*3 233*	*27*	*27*	*32*	*3.4*	*3.2*
Gas	228	525	841	1 234	10	11	12	4.4	3.3

Reference Scenario: Developing Asia

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**1 638**	**2 916**	**4 262**	**5 796**	**100**	**100**	**100**	**3.5**	**2.7**
Coal	696	1 309	2 054	2 750	45	48	47	4.2	2.9
Oil	321	713	1 032	1 482	24	24	26	3.4	2.9
Gas	74	203	344	522	7	8	9	4.9	3.7
Nuclear	10	29	69	122	1	2	2	8.3	5.7
Hydro	24	47	84	126	2	2	2	5.4	3.9
Biomass and waste	506	600	645	717	21	15	12	0.7	0.7
Other renewables	6	15	35	78	1	1	1	8.1	6.6
Power generation and heat plants	**323**	**1 011**	**1 728**	**2 532**	**100**	**100**	**100**	**5.0**	**3.6**
Coal	222	775	1 311	1 882	77	76	74	4.9	3.5
Oil	46	56	64	52	6	4	2	1.2	–0.3
Gas	16	85	144	215	8	8	8	4.9	3.6
Nuclear	10	29	69	122	3	4	5	8.3	5.7
Hydro	24	47	84	126	5	5	5	5.4	3.9
Biomass and waste	0	4	27	73	0	2	3	18.3	11.5
Other renewables	6	15	30	62	1	2	2	6.4	5.7
Other transformation, own use and losses	**162**	**300**	**438**	**568**	**100**	**100**	**100**	**3.5**	**2.5**
of which electricity	*24*	*71*	*137*	*207*	*24*	*31*	*36*	*6.2*	*4.2*
Total final consumption	**1 278**	**1 975**	**2 823**	**3 833**	**100**	**100**	**100**	**3.3**	**2.6**
Coal	406	434	618	722	22	22	19	3.3	2.0
Oil	249	581	868	1 313	29	31	34	3.7	3.2
Gas	35	86	150	241	4	5	6	5.2	4.0
Electricity	85	252	522	840	13	18	22	6.8	4.7
Heat	14	37	55	74	2	2	2	3.6	2.7
Biomass and waste	489	585	604	627	30	21	16	0.3	0.3
Other renewables	0	0	6	15	0	0	0	–	–
Industry	**438**	**756**	**1 199**	**1 551**	**100**	**100**	**100**	**4.3**	**2.8**
Coal	245	328	512	625	43	43	40	4.1	2.5
Oil	77	158	223	270	21	19	17	3.1	2.1
Gas	29	61	101	148	8	8	10	4.6	3.4
Electricity	51	144	283	393	19	24	25	6.3	3.9
Heat	11	25	35	43	3	3	3	3.0	2.1
Biomass and waste	26	39	46	72	5	4	5	1.6	2.4
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**122**	**265**	**411**	**741**	**100**	**100**	**100**	**4.1**	**4.0**
Oil	108	257	397	713	97	97	96	4.0	4.0
Biofuels	0	0	4	16	0	1	2	49.9	25.6
Other fuels	14	8	10	13	3	2	2	2.0	1.8
Residential, services and agriculture	**659**	**857**	**1 074**	**1 363**	**100**	**100**	**100**	**2.1**	**1.8**
Coal	114	73	71	66	9	7	5	–0.3	–0.4
Oil	50	116	168	221	14	16	16	3.4	2.5
Gas	5	24	49	92	3	5	7	6.7	5.3
Electricity	29	91	212	404	11	20	30	8.0	5.9
Heat	3	11	19	30	1	2	2	5.1	3.9
Biomass and waste	458	542	550	535	63	51	39	0.1	–0.1
Other renewables	0	0	6	15	0	1	1	–	–
Non-energy use	**59**	**96**	**139**	**178**	**100**	**100**	**100**	**3.4**	**2.4**

Reference Scenario: Developing Asia

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**1 274**	**3 758**	**7 663**	**12 165**	**100**	**100**	**100**	**6.7**	**4.6**
Coal	727	2 442	5 273	8 423	65	69	69	7.2	4.9
Oil	166	222	258	211	6	3	2	1.4	–0.2
Gas	59	406	747	1 113	11	10	9	5.7	4.0
Nuclear	39	110	263	467	3	3	4	8.3	5.7
Hydro	277	545	972	1 467	15	13	12	5.4	3.9
Renewables (excluding hydro)	7	33	150	484	1	2	4	14.7	10.9
Biomass and waste	*0*	*10*	*69*	*192*	*0*	*1*	*2*	*18.7*	*11.8*
Wind	*0*	*4*	*50*	*220*	*0*	*1*	*2*	*26.5*	*17.0*
Geothermal	*7*	*17*	*29*	*48*	*0*	*0*	*0*	*5.1*	*4.1*
Solar	*0*	*2*	*2*	*24*	*0*	*0*	*0*	*0.6*	*10.0*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**789**	**1 567**	**2 513**	**100**	**100**	**100**	**6.4**	**4.6**
Coal	421	913	1 457	53	58	58	7.3	4.9
Oil	62	72	61	8	5	2	1.4	–0.1
Gas	107	209	342	14	13	14	6.3	4.6
Nuclear	14	33	59	2	2	2	8.3	5.7
Hydro	177	304	462	22	19	18	5.0	3.8
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	9	34	131	1	2	5	13.1	10.9
Biomass and waste	*2*	*11*	*30*	*0*	*1*	*1*	*18.5*	*11.6*
Wind	*4*	*18*	*81*	*0*	*1*	*3*	*15.1*	*12.5*
Geothermal	*3*	*4*	*7*	*0*	*0*	*0*	*5.2*	*4.1*
Solar	*1*	*1*	*13*	*0*	*0*	*1*	*0.0*	*11.5*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**3 563**	**7 265**	**11 341**	**15 653**	**100**	**100**	**100**	**4.1**	**3.0**
Coal	2 567	5 071	8 058	10 819	70	71	69	4.3	3.0
Oil	850	1 746	2 530	3 694	24	22	24	3.4	2.9
Gas	146	448	753	1 140	6	7	7	4.8	3.7
Power generation and heat plants	**1 052**	**3 462**	**5 764**	**8 156**	**100**	**100**	**100**	**4.7**	**3.4**
Coal	868	3 083	5 221	7 484	89	91	92	4.9	3.5
Oil	146	178	204	166	5	4	2	1.2	–0.3
Gas	38	200	339	506	6	6	6	4.9	3.6
Total final consumption	**2 355**	**3 472**	**5 136**	**6 963**	**100**	**100**	**100**	**3.6**	**2.7**
Coal	1 642	1 866	2 691	3 168	54	52	45	3.4	2.1
Oil	644	1 432	2 141	3 309	41	42	48	3.7	3.3
of which transport	*290*	*695*	*1 076*	*1 946*	*20*	*21*	*28*	*4.1*	*4.0*
Gas	69	174	304	486	5	6	7	5.2	4.0

Reference Scenario: China

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**877**	**1 626**	**2 509**	**3 395**	**100**	**100**	**100**	**4.0**	**2.9**
Coal	534	999	1 604	2 065	61	64	61	4.4	2.8
Oil	116	319	497	758	20	20	22	4.1	3.4
Gas	16	44	89	157	3	4	5	6.7	5.1
Nuclear	0	13	32	67	1	1	2	8.5	6.4
Hydro	11	30	56	81	2	2	2	5.7	3.8
Biomass and waste	200	221	222	239	14	9	7	0.1	0.3
Other renewables	0	0	8	29	0	0	1	–	–
Power generation and heat plants	**173**	**639**	**1 138**	**1 613**	**100**	**100**	**100**	**5.4**	**3.6**
Coal	145	566	994	1 360	89	87	84	5.2	3.4
Oil	16	22	21	17	3	2	1	–0.4	–0.9
Gas	1	6	21	40	1	2	2	12.1	7.7
Nuclear	0	13	32	67	2	3	4	8.5	6.4
Hydro	11	30	56	81	5	5	5	5.7	3.8
Biomass and waste	0	1	12	32	0	1	2	21.6	13.0
Other renewables	0	0	3	16	0	0	1	–	–
Other transformation, own use and losses	**85**	**176**	**267**	**347**	**100**	**100**	**100**	**3.9**	**2.6**
of which electricity	*12*	*41*	*88*	*130*	*23*	*33*	*38*	*7.2*	*4.5*
Total final consumption	**689**	**1 050**	**1 596**	**2 181**	**100**	**100**	**100**	**3.9**	**2.9**
Coal	332	349	505	579	33	32	27	3.4	2.0
Oil	88	261	425	680	25	27	31	4.5	3.7
Gas	12	33	59	103	3	4	5	5.4	4.5
Electricity	43	151	337	525	14	21	24	7.6	4.9
Heat	13	36	54	73	3	3	3	3.7	2.8
Biomass and waste	200	219	211	207	21	13	9	–0.4	–0.2
Other renewables	0	0	5	13	0	0	1	–	–
Industry	**274**	**470**	**792**	**1 002**	**100**	**100**	**100**	**4.9**	**2.9**
Coal	189	256	415	502	54	52	50	4.5	2.6
Oil	35	70	101	113	15	13	11	3.4	1.9
Gas	10	20	29	42	4	4	4	3.5	2.9
Electricity	30	100	209	282	21	26	28	7.0	4.1
Heat	11	25	34	43	5	4	4	3.0	2.2
Biomass and waste	0	0	4	20	0	0	2	–	–
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**41**	**110**	**195**	**413**	**100**	**100**	**100**	**5.4**	**5.2**
Oil	30	104	186	396	94	95	96	5.5	5.3
Biofuels	0	0	2	8	0	1	2	–	–
Other fuels	11	6	7	9	6	4	2	1.7	1.6
Residential, services and agriculture	**337**	**406**	**519**	**664**	**100**	**100**	**100**	**2.2**	**1.9**
Coal	102	63	58	48	16	11	7	–0.8	–1.0
Oil	18	59	92	119	15	18	18	4.2	2.7
Gas	3	13	29	60	3	6	9	7.9	6.2
Electricity	11	41	110	215	10	21	32	9.3	6.6
Heat	2	11	19	29	3	4	4	5.2	3.9
Biomass and waste	200	219	206	179	54	40	27	–0.6	–0.8
Other renewables	0	0	5	13	0	1	2	–	–
Non-energy use	**38**	**63**	**89**	**101**	**100**	**100**	**100**	**3.2**	**1.8**

Reference Scenario: China

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**650**	**2 237**	**4 942**	**7 624**	**100**	**100**	**100**	**7.5**	**4.8**
Coal	471	1 739	3 966	5 980	78	80	78	7.8	4.9
Oil	49	72	64	54	3	1	1	–1.1	–1.1
Gas	3	19	83	169	1	2	2	14.0	8.7
Nuclear	0	50	124	256	2	3	3	8.5	6.4
Hydro	127	354	650	937	16	13	12	5.7	3.8
Renewables (excluding hydro)	0	2	56	228	0	1	3	32.7	19.0
Biomass and waste	*0*	*2*	*33*	*93*	*0*	*1*	*1*	*26.4*	*14.9*
Wind	*0*	*0*	*21*	*121*	*0*	*0*	*2*	–	–
Geothermal	*0*	*0*	*2*	*5*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*0*	*9*	*0*	*0*	*0*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**442**	**960**	**1 496**	**100**	**100**	**100**	**7.3**	**4.8**
Coal	307	688	1 041	69	72	70	7.6	4.8
Oil	16	19	16	4	2	1	2.1	0.2
Gas	8	29	62	2	3	4	13.2	8.5
Nuclear	6	15	31	1	2	2	8.6	6.5
Hydro	105	195	281	24	20	19	5.8	3.9
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	1	13	65	0	1	4	23.9	16.4
Biomass and waste	*0*	*5*	*15*	*0*	*1*	*1*	*26.5*	*14.7*
Wind	*1*	*7*	*45*	*0*	*1*	*3*	*22.9*	*16.9*
Geothermal	*0*	*0*	*1*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*5*	*0*	*0*	*0*	*0.0*	*17.8*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**2 289**	**4 769**	**7 744**	**10 425**	**100**	**100**	**100**	**4.5**	**3.1**
Coal	1 952	3 897	6 336	8 167	82	82	78	4.5	2.9
Oil	304	779	1 219	1 924	16	16	18	4.2	3.5
Gas	32	93	190	334	2	2	3	6.7	5.1
Power generation and heat plants	**623**	**2 355**	**4 100**	**5 603**	**100**	**100**	**100**	**5.2**	**3.4**
Coal	568	2 269	3 981	5 450	96	97	97	5.2	3.4
Oil	52	72	68	56	3	2	1	–0.4	–0.9
Gas	3	14	50	97	1	1	2	12.1	7.7
Total final consumption	**1 579**	**2 211**	**3 375**	**4 494**	**100**	**100**	**100**	**3.9**	**2.8**
Coal	1 332	1 509	2 212	2 554	68	66	57	3.5	2.0
Oil	225	640	1 055	1 750	29	31	39	4.6	3.9
of which transport	*83*	*290*	*522*	*1 108*	*13*	*15*	*25*	*5.5*	*5.3*
Gas	22	61	109	190	3	3	4	5.4	4.5

Reference Scenario: India

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**361**	**573**	**776**	**1 104**	**100**	**100**	**100**	**2.8**	**2.6**
Coal	105	196	283	450	34	36	41	3.4	3.3
Oil	63	127	184	268	22	24	24	3.4	2.9
Gas	10	23	40	68	4	5	6	5.0	4.2
Nuclear	2	4	18	36	1	2	3	13.8	8.4
Hydro	6	7	12	21	1	2	2	4.5	4.2
Biomass and waste	176	214	236	253	37	30	23	0.9	0.6
Other renewables	0	0	2	7	0	0	1	19.4	12.2
Power generation and heat plants	**73**	**182**	**284**	**481**	**100**	**100**	**100**	**4.2**	**3.8**
Coal	58	147	213	356	81	75	74	3.4	3.5
Oil	4	9	11	11	5	4	2	2.5	0.8
Gas	3	13	20	32	7	7	7	4.0	3.6
Nuclear	2	4	18	36	2	6	8	13.8	8.4
Hydro	6	7	12	21	4	4	4	4.5	4.2
Biomass and waste	0	1	9	19	1	3	4	20.6	11.7
Other renewables	0	0	2	5	0	1	1	17.1	11.4
Other transformation, own use and losses	**19**	**45**	**62**	**84**	**100**	**100**	**100**	**2.9**	**2.4**
of which electricity	*7*	*19*	*31*	*50*	*42*	*50*	*59*	*4.4*	*3.7*
Total final consumption	**294**	**403**	**535**	**738**	**100**	**100**	**100**	**2.6**	**2.3**
Coal	41	36	55	78	9	10	11	4.0	3.0
Oil	54	107	159	242	26	30	33	3.7	3.2
Gas	6	9	18	33	2	3	4	6.8	5.3
Electricity	18	38	75	149	10	14	20	6.2	5.4
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	176	213	227	234	53	42	32	0.6	0.4
Other renewables	0	0	0	1	0	0	0	–	–
Industry	**75**	**109**	**162**	**231**	**100**	**100**	**100**	**3.7**	**2.9**
Coal	28	29	45	64	26	28	28	4.3	3.2
Oil	13	33	48	67	30	30	29	3.7	2.8
Gas	6	8	15	25	7	9	11	6.2	4.5
Electricity	9	17	26	45	15	16	20	4.2	3.9
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	20	23	27	30	21	16	13	1.2	1.0
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**28**	**36**	**50**	**81**	**100**	**100**	**100**	**3.0**	**3.1**
Oil	26	36	49	77	98	97	95	2.9	3.0
Biofuels	0	0	0	2	0	0	3	–	–
Other fuels	3	1	1	2	2	3	3	5.1	3.6
Residential, services and agriculture	**187**	**243**	**294**	**374**	**100**	**100**	**100**	**1.7**	**1.7**
Coal	11	8	10	14	3	3	4	2.4	2.4
Oil	12	26	38	54	11	13	14	3.3	2.8
Gas	0	1	2	8	0	1	2	12.1	10.0
Electricity	8	19	43	94	8	15	25	8.0	6.5
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	156	190	200	202	78	68	54	0.5	0.2
Other renewables	0	0	0	1	0	0	0	–	–
Non-energy use	**4**	**15**	**28**	**52**	**100**	**100**	**100**	**6.1**	**5.0**

Reference Scenario: India

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**289**	**668**	**1 226**	**2 314**	**100**	**100**	**100**	**5.7**	**4.9**
Coal	189	461	836	1 631	69	68	70	5.6	5.0
Oil	13	36	49	46	5	4	2	2.8	1.0
Gas	10	63	99	163	9	8	7	4.1	3.7
Nuclear	6	17	71	140	3	6	6	13.8	8.4
Hydro	72	85	138	246	13	11	11	4.5	4.2
Renewables (excluding hydro)	0	6	33	89	1	3	4	17.5	11.2
Biomass and waste	*0*	*2*	*15*	*34*	*0*	*1*	*1*	*20.6*	*11.7*
Wind	*0*	*4*	*18*	*49*	*1*	*1*	*2*	*15.3*	*10.4*
Geothermal	*0*	*0*	*0*	*1*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*0*	*5*	*0*	*0*	*0*	*23.4*	*31.5*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**131**	**228**	**436**	**100**	**100**	**100**	**5.2**	**4.7**
Coal	72	128	251	55	56	58	5.3	4.9
Oil	8	11	10	6	5	2	2.5	0.9
Gas	14	23	42	10	10	10	4.7	4.4
Nuclear	3	10	19	2	4	4	12.7	8.0
Hydro	31	48	87	24	21	20	4.0	4.0
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	3	9	27	3	4	6	9.7	8.3
Biomass and waste	*0*	*2*	*5*	*0*	*1*	*1*	*19.9*	*11.4*
Wind	*3*	*7*	*18*	*2*	*3*	*4*	*7.8*	*7.2*
Geothermal	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*3*	*0*	*0*	*1*	*0.0*	*19.8*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**588**	**1 103**	**1 620**	**2 544**	**100**	**100**	**100**	**3.6**	**3.3**
Coal	401	734	1 078	1 741	67	67	68	3.5	3.4
Oil	164	314	450	645	29	28	25	3.3	2.8
Gas	23	54	92	157	5	6	6	5.0	4.2
Power generation and heat plants	**245**	**629**	**907**	**1 490**	**100**	**100**	**100**	**3.4**	**3.4**
Coal	225	572	826	1 382	91	91	93	3.4	3.5
Oil	11	26	35	33	4	4	2	2.5	0.8
Gas	8	30	46	75	5	5	5	4.0	3.6
Total final consumption	**328**	**441**	**671**	**1 005**	**100**	**100**	**100**	**3.9**	**3.2**
Coal	171	160	249	356	36	37	35	4.1	3.1
Oil	144	261	382	575	59	57	57	3.5	3.1
of which transport	*72*	*98*	*135*	*211*	*22*	*20*	*21*	*2.9*	*3.0*
Gas	13	19	40	74	4	6	7	6.8	5.3

Reference Scenario: Latin America

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**339**	**484**	**626**	**845**	**100**	**100**	**100**	**2.4**	**2.2**
Coal	17	22	27	37	5	4	4	1.8	1.9
Oil	157	218	256	317	45	41	38	1.5	1.5
Gas	54	98	153	245	20	24	29	4.1	3.6
Nuclear	2	5	10	9	1	2	1	6.0	2.2
Hydro	31	51	69	93	10	11	11	2.8	2.4
Biomass and waste	77	88	106	129	18	17	15	1.8	1.5
Other renewables	1	2	5	14	0	1	2	7.6	7.8
Power generation and heat plants	**69**	**122**	**180**	**272**	**100**	**100**	**100**	**3.6**	**3.1**
Coal	5	8	10	16	6	6	6	2.8	3.0
Oil	14	25	20	11	20	11	4	–2.0	–3.2
Gas	14	27	61	117	23	34	43	7.5	5.7
Nuclear	2	5	10	9	4	5	3	6.0	2.2
Hydro	31	51	69	93	42	38	34	2.8	2.4
Biomass and waste	2	5	7	13	4	4	5	3.6	4.2
Other renewables	1	2	4	12	2	2	5	7.0	7.3
Other transformation, own use and losses	**51**	**57**	**72**	**94**	**100**	**100**	**100**	**2.1**	**1.9**
of which electricity	*8*	*15*	*21*	*30*	*26*	*29*	*31*	*3.0*	*2.7*
Total final consumption	**262**	**380**	**486**	**650**	**100**	**100**	**100**	**2.3**	**2.1**
Coal	7	10	12	15	3	3	2	1.4	1.4
Oil	127	178	217	280	47	45	43	1.8	1.8
Gas	25	54	73	103	14	15	16	2.7	2.5
Electricity	35	60	91	141	16	19	22	3.8	3.3
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	68	77	93	108	20	19	17	1.7	1.3
Other renewables	0	0	0	2	0	0	0	19.7	14.6
Industry	**99**	**151**	**195**	**253**	**100**	**100**	**100**	**2.3**	**2.0**
Coal	7	10	12	15	7	6	6	1.5	1.4
Oil	27	35	44	54	23	22	21	2.0	1.7
Gas	19	38	49	64	25	25	25	2.2	2.0
Electricity	17	29	43	67	19	22	26	3.7	3.3
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	30	39	48	53	26	25	21	1.9	1.2
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**76**	**116**	**143**	**197**	**100**	**100**	**100**	**1.9**	**2.1**
Oil	70	105	125	166	90	87	84	1.6	1.8
Biofuels	6	6	10	20	6	7	10	4.5	4.5
Other fuels	0	5	8	11	4	5	6	4.2	3.2
Residential, services and agriculture	**80**	**103**	**137**	**186**	**100**	**100**	**100**	**2.6**	**2.3**
Coal	0	0	0	0	0	0	0	–2.3	–2.1
Oil	25	29	37	47	28	27	25	2.4	1.9
Gas	6	11	16	28	11	12	15	3.5	3.6
Electricity	17	32	48	74	31	35	40	4.0	3.3
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	32	31	34	34	30	25	19	0.8	0.4
Other renewables	0	0	0	2	0	0	1	19.3	14.5
Non-energy use	**6**	**9**	**11**	**14**	**100**	**100**	**100**	**1.7**	**1.6**

Reference Scenario: Latin America

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**491**	**874**	**1 304**	**1 983**	**100**	**100**	**100**	**3.7**	**3.2**
Coal	15	30	43	77	3	3	4	3.1	3.6
Oil	41	83	76	44	9	6	2	–0.8	–2.4
Gas	55	131	308	655	15	24	33	8.1	6.4
Nuclear	10	19	37	34	2	3	2	6.0	2.2
Hydro	364	589	799	1 084	67	61	55	2.8	2.4
Renewables (excluding hydro)	7	21	40	89	2	3	4	6.0	5.7
Biomass and waste	*7*	*18*	*28*	*51*	*2*	*2*	*3*	*3.8*	*4.0*
Wind	*0*	*0*	*8*	*22*	*0*	*1*	*1*	*31.0*	*16.4*
Geothermal	*1*	*2*	*4*	*12*	*0*	*0*	*1*	*5.3*	*6.5*
Solar	*0*	*0*	*0*	*5*	*0*	*0*	*0*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**206**	**331**	**504**	**100**	**100**	**100**	**4.4**	**3.5**
Coal	5	8	13	3	2	3	3.7	3.4
Oil	28	29	19	14	9	4	0.2	–1.5
Gas	38	107	212	18	32	42	10.0	6.9
Nuclear	3	5	4	1	1	1	4.9	1.8
Hydro	128	174	236	62	53	47	2.8	2.4
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	4	8	20	2	2	4	7.3	6.7
Biomass and waste	*3*	*4*	*8*	*2*	*1*	*2*	*3.4*	*3.7*
Wind	*0*	*3*	*7*	*0*	*1*	*1*	*26.8*	*14.7*
Geothermal	*0*	*1*	*2*	*0*	*0*	*0*	*5.4*	*6.5*
Solar	*0*	*0*	*3*	*0*	*0*	*1*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**602**	**907**	**1 151**	**1 551**	**100**	**100**	**100**	**2.2**	**2.1**
Coal	57	85	103	139	9	9	9	1.7	1.9
Oil	426	601	707	873	66	61	56	1.5	1.4
Gas	119	221	341	539	24	30	35	4.0	3.5
Power generation and heat plants	**98**	**176**	**247**	**374**	**100**	**100**	**100**	**3.2**	**2.9**
Coal	21	35	44	67	20	18	18	2.2	2.6
Oil	45	77	62	33	44	25	9	–2.0	–3.2
Gas	32	64	142	273	36	57	73	7.5	5.7
Total final consumption	**439**	**656**	**815**	**1 067**	**100**	**100**	**100**	**2.0**	**1.9**
Coal	32	47	55	67	7	7	6	1.4	1.4
Oil	350	489	605	790	75	74	74	2.0	1.9
of which transport	*200*	*301*	*361*	*479*	*46*	*44*	*45*	*1.7*	*1.8*
Gas	56	119	155	209	18	19	20	2.4	2.2

Reference Scenario: Brazil

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**131**	**200**	**265**	**349**	**100**	**100**	**100**	**2.6**	**2.2**
Coal	10	14	15	18	7	6	5	0.6	0.9
Oil	58	85	108	142	42	41	41	2.3	2.0
Gas	3	16	26	41	8	10	12	4.6	3.8
Nuclear	1	3	6	6	2	2	2	6.9	2.9
Hydro	18	28	38	50	14	14	14	2.9	2.3
Biomass and waste	42	54	71	90	27	27	26	2.4	1.9
Other renewables	0	0	0	2	0	0	1	50.1	25.4
Power generation and heat plants	**22**	**43**	**61**	**80**	**100**	**100**	**100**	**3.3**	**2.5**
Coal	1	3	2	2	6	3	2	–3.2	–1.9
Oil	1	3	2	3	7	4	4	–1.1	0.0
Gas	0	4	8	13	9	13	16	6.4	4.6
Nuclear	1	3	6	6	7	10	8	6.9	2.9
Hydro	18	28	38	50	65	63	62	2.9	2.3
Biomass and waste	1	2	4	6	6	6	7	4.2	3.3
Other renewables	0	0	0	1	0	1	1	44.6	22.7
Other transformation, own use and losses	**18**	**23**	**29**	**37**	**100**	**100**	**100**	**2.1**	**1.9**
of which electricity	*3*	*7*	*9*	*10*	*29*	*30*	*28*	*2.3*	*1.7*
Total final consumption	**112**	**171**	**226**	**298**	**100**	**100**	**100**	**2.6**	**2.2**
Coal	4	7	8	11	4	4	4	1.7	1.7
Oil	53	78	101	131	46	45	44	2.3	2.0
Gas	2	9	13	21	5	6	7	4.0	3.5
Electricity	18	30	42	56	17	19	19	3.1	2.4
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	35	47	61	78	28	27	26	2.4	2.0
Other renewables	0	0	0	1	0	0	0	–	–
Industry	**48**	**77**	**98**	**125**	**100**	**100**	**100**	**2.3**	**1.9**
Coal	4	7	8	11	9	8	9	1.7	1.7
Oil	14	18	23	28	24	23	23	2.2	1.7
Gas	2	7	11	17	9	11	14	3.8	3.4
Electricity	10	15	19	26	19	20	21	2.5	2.2
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	19	30	37	43	39	38	34	2.0	1.4
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**32**	**52**	**70**	**103**	**100**	**100**	**100**	**2.8**	**2.7**
Oil	27	44	58	79	85	82	77	2.5	2.3
Biofuels	6	6	10	20	12	15	20	4.6	4.6
Other fuels	0	1	2	4	3	3	4	5.0	3.8
Residential, services and agriculture	**29**	**38**	**52**	**63**	**100**	**100**	**100**	**2.8**	**2.0**
Coal	0	0	0	0	0	0	0	–	–
Oil	9	12	15	18	31	29	28	2.1	1.5
Gas	0	0	1	1	1	1	1	3.0	2.4
Electricity	8	15	22	29	39	43	46	3.7	2.6
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	11	11	14	15	29	27	23	2.1	1.2
Other renewables	0	0	0	1	0	0	1	–	–
Non-energy use	**3**	**4**	**5**	**6**	**100**	**100**	**100**	**1.6**	**1.5**

Reference Scenario: Brazil

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**223**	**387**	**549**	**731**	**100**	**100**	**100**	**3.2**	**2.5**
Coal	5	10	7	6	3	1	1	–3.0	–1.8
Oil	6	12	11	13	3	2	2	–1.0	0.1
Gas	0	19	41	65	5	8	9	7.2	4.8
Nuclear	2	12	24	24	3	4	3	6.9	2.9
Hydro	207	321	442	581	83	80	79	2.9	2.3
Renewables (excluding hydro)	4	13	23	41	3	4	6	5.7	4.7
Biomass and waste	*4*	*12*	*20*	*29*	*3*	*4*	*4*	*4.2*	*3.3*
Wind	*0*	*0*	*4*	*11*	*0*	*1*	*2*	*44.6*	*22.1*
Geothermal	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*0*	*1*	*0*	*0*	*0*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**87**	**131**	**172**	**100**	**100**	**100**	**3.8**	**2.7**
Coal	1	2	1	2	1	1	0.8	–1.0
Oil	4	6	6	4	4	4	4.0	1.9
Gas	9	20	26	10	15	15	7.8	4.4
Nuclear	2	3	3	2	2	2	4.8	2.0
Hydro	69	96	127	80	74	74	3.1	2.4
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	2	4	9	2	3	5	6.8	5.8
Biomass and waste	*2*	*3*	*5*	*2*	*2*	*3*	*3.9*	*3.1*
Wind	*0*	*1*	*4*	*0*	*1*	*2*	*39.7*	*20.4*
Geothermal	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*1*	*0*	*0*	*0*	–	–
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**193**	**323**	**412**	**551**	**100**	**100**	**100**	**2.2**	**2.1**
Coal	29	50	52	62	16	13	11	0.3	0.8
Oil	158	238	302	395	74	73	72	2.2	2.0
Gas	6	35	59	93	11	14	17	4.7	3.8
Power generation and heat plants	**12**	**33**	**37**	**47**	**100**	**100**	**100**	**0.9**	**1.4**
Coal	8	15	11	9	46	30	20	–3.2	–1.9
Oil	4	9	8	9	26	21	18	–1.1	0.0
Gas	0	9	18	29	27	49	62	6.4	4.6
Total final consumption	**165**	**267**	**347**	**462**	**100**	**100**	**100**	**2.4**	**2.1**
Coal	18	31	38	48	12	11	10	1.7	1.7
Oil	143	216	278	366	81	80	79	2.3	2.1
of which transport	*81*	*133*	*174*	*240*	*50*	*50*	*52*	*2.5*	*2.3*
Gas	4	20	31	48	7	9	10	4.0	3.5

Reference Scenario: Middle East

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**235**	**479**	**752**	**1 023**	**100**	**100**	**100**	**4.2**	**3.0**
Coal	3	9	14	19	2	2	2	3.6	2.8
Oil	151	265	390	464	55	52	45	3.6	2.2
Gas	78	202	340	525	42	45	51	4.8	3.7
Nuclear	0	0	2	2	0	0	0	–	–
Hydro	1	1	3	4	0	0	0	7.1	3.9
Biomass and waste	1	1	2	6	0	0	1	7.8	6.7
Other renewables	0	1	1	3	0	0	0	5.2	5.6
Power generation and heat plants	**63**	**152**	**254**	**387**	**100**	**100**	**100**	**4.8**	**3.7**
Coal	2	8	12	17	5	5	4	3.5	2.8
Oil	29	54	75	85	35	30	22	3.1	1.8
Gas	30	89	161	274	58	63	71	5.6	4.4
Nuclear	0	0	2	2	0	1	0	–	–
Hydro	1	1	3	4	1	1	1	7.1	3.9
Biomass and waste	0	0	1	4	0	0	1	–	–
Other renewables	0	0	0	1	0	0	0	42.8	28.5
Other transformation, own use and losses	**20**	**58**	**80**	**110**	**100**	**100**	**100**	**3.0**	**2.5**
of which electricity	*4*	*10*	*16*	*24*	*17*	*20*	*22*	*4.5*	*3.5*
Total final consumption	**172**	**320**	**502**	**656**	**100**	**100**	**100**	**4.2**	**2.8**
Coal	0	1	1	2	0	0	0	6.4	3.6
Oil	116	193	288	342	60	57	52	3.7	2.2
Gas	38	84	143	203	26	28	31	4.9	3.4
Electricity	17	41	68	105	13	13	16	4.8	3.7
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	1	1	1	2	0	0	0	1.9	2.4
Other renewables	0	1	1	2	0	0	0	4.8	4.4
Industry	**66**	**120**	**194**	**268**	**100**	**100**	**100**	**4.5**	**3.1**
Coal	0	1	1	2	1	1	1	6.4	3.6
Oil	28	53	70	89	44	36	33	2.6	2.1
Gas	35	59	108	153	49	56	57	5.7	3.8
Electricity	3	8	15	23	7	8	9	5.6	4.1
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	0	0	0	0	0	0	0	1.5	1.5
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**59**	**100**	**151**	**167**	**100**	**100**	**100**	**3.8**	**2.0**
Oil	59	100	150	166	100	100	100	3.8	2.0
Biofuels	0	0	0	0	0	0	0	19.0	14.0
Other fuels	0	0	0	0	0	0	0	1.5	1.5
Residential, services and agriculture	**41**	**91**	**140**	**195**	**100**	**100**	**100**	**4.0**	**3.0**
Coal	0	0	0	0	0	0	0	–	–
Oil	23	32	51	61	35	36	31	4.4	2.5
Gas	3	26	35	50	28	25	25	2.8	2.6
Electricity	14	32	53	82	35	38	42	4.5	3.6
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	1	1	1	1	1	1	0	1.0	1.0
Other renewables	0	1	1	2	1	1	1	4.6	4.4
Non-energy use	**5**	**9**	**17**	**26**	**100**	**100**	**100**	**6.5**	**4.4**

Reference Scenario: Middle East

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**240**	**588**	**976**	**1 502**	**100**	**100**	**100**	**4.7**	**3.7**
Coal	10	37	56	83	6	6	6	3.8	3.1
Oil	117	218	289	321	37	30	21	2.6	1.5
Gas	101	317	586	1 028	54	60	68	5.7	4.6
Nuclear	0	0	7	7	0	1	0	–	–
Hydro	12	17	35	45	3	4	3	7.1	3.9
Renewables (excluding hydro)	0	0	3	19	0	0	1	46.9	25.7
Biomass and waste	*0*	*0*	*3*	*9*	*0*	*0*	*1*	–	–
Wind	*0*	*0*	*1*	*5*	*0*	*0*	*0*	*42.1*	*25.5*
Geothermal	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*0*	*4*	*0*	*0*	*0*	*0.0*	*20.5*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**182**	**300**	**464**	**100**	**100**	**100**	**4.6**	**3.7**
Coal	5	7	11	3	2	2	3.6	3.2
Oil	79	104	123	44	35	26	2.5	1.7
Gas	89	171	304	49	57	66	6.2	4.9
Nuclear	0	1	1	0	0	0	–	–
Hydro	9	16	20	5	5	4	5.0	3.0
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	0	1	5	0	0	1	31.3	22.4
Biomass and waste	*0*	*0*	*1*	*0*	*0*	*0*	*42.4*	*22.0*
Wind	*0*	*0*	*2*	*0*	*0*	*0*	*30.6*	*22.0*
Geothermal	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Solar	*0*	*0*	*2*	*0*	*0*	*1*	*0.0*	*23.0*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**602**	**1 183**	**1 841**	**2 460**	**100**	**100**	**100**	**4.1**	**2.9**
Coal	12	36	54	75	3	3	3	3.9	2.9
Oil	413	690	1 014	1 186	58	55	48	3.6	2.1
Gas	177	458	772	1 198	39	42	49	4.9	3.8
Power generation and heat plants	**172**	**407**	**658**	**973**	**100**	**100**	**100**	**4.5**	**3.4**
Coal	9	31	46	65	8	7	7	3.5	2.8
Oil	92	169	236	268	42	36	28	3.1	1.8
Gas	71	207	376	641	51	57	66	5.6	4.4
Total final consumption	**381**	**676**	**1 048**	**1 310**	**100**	**100**	**100**	**4.1**	**2.6**
Coal	2	4	8	10	1	1	1	6.3	3.5
Oil	294	483	720	847	71	69	65	3.7	2.2
of which transport	*145*	*264*	*397*	*439*	*39*	*38*	*34*	*3.8*	*2.0*
Gas	85	189	319	453	28	30	35	4.9	3.4

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Reference Scenario: Africa

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total primary energy supply	**401**	**582**	**732**	**954**	**100**	**100**	**100**	**2.1**	**1.9**
Coal	74	101	112	131	17	15	14	0.9	1.0
Oil	90	121	161	226	21	22	24	2.6	2.4
Gas	31	64	119	183	11	16	19	5.7	4.1
Nuclear	2	3	4	4	1	1	0	0.9	0.4
Hydro	5	8	11	20	1	1	2	3.1	3.8
Biomass and waste	199	283	324	385	49	44	40	1.2	1.2
Other renewables	0	1	2	7	0	0	1	9.7	8.5
Power generation and heat plants	**69**	**116**	**169**	**261**	**100**	**100**	**100**	**3.4**	**3.2**
Coal	39	57	65	82	49	39	31	1.2	1.4
Oil	11	16	13	11	14	8	4	–2.1	–1.5
Gas	11	31	68	118	27	40	45	7.4	5.2
Nuclear	2	3	4	4	3	2	1	0.9	0.4
Hydro	5	8	11	20	6	6	8	3.1	3.8
Biomass and waste	0	0	7	23	0	4	9	41.2	21.3
Other renewables	0	1	1	4	1	1	2	5.8	6.7
Other transformation, own use and losses	**64**	**76**	**100**	**122**	**100**	**100**	**100**	**2.5**	**1.8**
of which electricity	*6*	*10*	*14*	*23*	*13*	*14*	*19*	*3.4*	*3.3*
Total final consumption	**294**	**434**	**532**	**687**	**100**	**100**	**100**	**1.9**	**1.8**
Coal	19	19	20	20	4	4	3	0.4	0.2
Oil	74	109	145	207	25	27	30	2.7	2.5
Gas	9	20	30	40	5	6	6	3.5	2.7
Electricity	21	35	54	92	8	10	13	4.0	3.8
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	171	251	283	324	58	53	47	1.1	1.0
Other renewables	0	0	1	2	0	0	0	–	–
Industry	**69**	**86**	**108**	**130**	**100**	**100**	**100**	**2.1**	**1.6**
Coal	16	15	15	15	17	14	11	0.2	0.0
Oil	16	15	19	22	17	18	17	2.3	1.6
Gas	8	15	21	26	18	19	20	3.0	2.2
Electricity	12	16	23	33	19	21	25	3.2	2.8
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	18	25	31	34	30	28	26	1.7	1.1
Other renewables	0	0	0	0	0	0	0	–	–
Transport	**39**	**65**	**89**	**142**	**100**	**100**	**100**	**2.9**	**3.1**
Oil	39	64	85	136	98	96	95	2.7	2.9
Biofuels	0	0	1	3	0	1	2	58.9	27.3
Other fuels	0	1	3	3	2	3	2	7.8	4.3
Residential, services and agriculture	**183**	**278**	**328**	**404**	**100**	**100**	**100**	**1.5**	**1.4**
Coal	3	5	5	6	2	2	1	1.1	1.0
Oil	16	25	33	39	9	10	10	2.8	1.8
Gas	1	4	6	10	1	2	3	3.8	3.6
Electricity	9	19	31	59	7	10	15	4.7	4.5
Heat	0	0	0	0	0	0	0	–	–
Biomass and waste	153	226	251	287	81	77	71	1.0	0.9
Other renewables	0	0	1	2	0	0	1	–	–
Non-energy use	**4**	**5**	**7**	**10**	**100**	**100**	**100**	**2.9**	**2.6**

Reference Scenario: Africa

	Electricity generation (TWh)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total generation	**316**	**534**	**807**	**1 351**	**100**	**100**	**100**	**3.8**	**3.6**
Coal	165	244	287	397	46	36	29	1.5	1.9
Oil	42	58	47	39	11	6	3	–1.9	–1.4
Gas	43	130	314	592	24	39	44	8.4	6.0
Nuclear	8	13	15	15	2	2	1	0.9	0.4
Hydro	56	88	122	232	16	15	17	3.1	3.8
Renewables (excluding hydro)	0	2	22	76	0	3	6	24.7	15.3
Biomass and waste	*0*	*0*	*14*	*46*	*0*	*2*	*3*	*41.3*	*21.3*
Wind	*0*	*1*	*5*	*16*	*0*	*1*	*1*	*18.8*	*12.3*
Geothermal	*0*	*1*	*3*	*9*	*0*	*0*	*1*	*11.7*	*9.7*
Solar	*0*	*0*	*0*	*6*	*0*	*0*	*0*	*14.6*	*30.7*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	Capacity (GW)			Shares (%)			Growth (% p.a.)	
	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total capacity	**112**	**172**	**294**	**100**	**100**	**100**	**4.0**	**3.8**
Coal	39	50	69	35	29	23	2.2	2.2
Oil	19	22	20	17	13	7	1.0	0.2
Gas	32	67	134	28	39	45	7.1	5.7
Nuclear	2	2	2	2	1	1	0.0	0.0
Hydro	20	28	53	18	16	18	3.1	3.8
of which pumped storage	*0*	*0*	*0*	*0*	*0*	*0*	–	–
Renewables (excluding hydro)	0	4	17	0	3	6	23.6	15.2
Biomass and waste	*0*	*2*	*7*	*0*	*1*	*2*	*41.2*	*21.1*
Wind	*0*	*2*	*5*	*0*	*1*	*2*	*19.6*	*12.7*
Geothermal	*0*	*0*	*1*	*0*	*0*	*0*	*11.7*	*9.6*
Solar	*0*	*0*	*3*	*0*	*0*	*1*	*0.0*	*23.2*
Tide and wave	*0*	*0*	*0*	*0*	*0*	*0*	–	–

	CO_2 emissions (Mt)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004-2015	2004-2030
Total CO_2 emissions	**550**	**815**	**1 063**	**1 447**	**100**	**100**	**100**	**2.4**	**2.2**
Coal	235	316	350	419	39	33	29	0.9	1.1
Oil	249	354	436	595	43	41	41	1.9	2.0
Gas	65	144	277	433	18	26	30	6.1	4.3
Power generation and heat plants	**214**	**350**	**465**	**649**	**100**	**100**	**100**	**2.6**	**2.4**
Coal	152	229	260	328	65	56	50	1.2	1.4
Oil	35	47	37	29	13	8	5	–2.2	–1.8
Gas	26	74	167	292	21	36	45	7.7	5.4
Total final consumption	**304**	**422**	**542**	**733**	**100**	**100**	**100**	**2.3**	**2.1**
Coal	83	87	90	91	21	17	12	0.3	0.2
Oil	202	292	390	557	69	72	76	2.7	2.5
of which transport	*104*	*174*	*232*	*369*	*41*	*43*	*50*	*2.7*	*2.9*
Gas	19	42	62	85	10	12	12	3.6	2.7

Alternative Policy Scenario: World

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**8 732**	**11 204**	**13 537**	**15 405**	**1.7**	**1.2**	**–3.8**	**–9.9**
Coal	2 183	2 773	3 431	3 512	2.0	0.9	–6.4	–20.9
Oil	3 181	3 940	4 534	4 955	1.3	0.9	–4.6	–11.1
of which international marine bunkers	*114*	*165*	*173*	*177*	*0.4*	*0.3*	*–3.8*	*–9.8*
Gas	1 680	2 302	2 877	3 370	2.0	1.5	–4.6	–12.9
Nuclear	525	714	852	1 070	1.6	1.6	5.1	24.3
Hydro	185	242	321	422	2.6	2.2	1.5	3.2
Biomass and waste	923	1 176	1 374	1 703	1.4	1.4	–0.0	3.6
Other renewables	56	57	148	373	9.1	7.5	8.4	26.1
Power generation and heat plants	**2 800**	**4 133**	**5 246**	**6 134**	**2.2**	**1.5**	**–4.3**	**–11.4**
Coal	1 190	1 888	2 403	2 496	2.2	1.1	–6.8	–22.8
Oil	328	292	284	210	–0.3	–1.3	–5.8	–12.6
Gas	486	875	1 121	1 311	2.3	1.6	–8.7	–22.1
Nuclear	525	714	852	1 070	1.6	1.6	5.1	24.3
Hydro	185	242	321	422	2.6	2.2	1.5	3.2
Biomass and waste	54	74	150	345	6.7	6.1	9.7	30.1
Other renewables	32	49	115	280	8.0	6.9	1.8	18.9
Other transformation, own use and losses	**878**	**1 064**	**1 261**	**1 439**	**1.6**	**1.2**	**–3.9**	**–9.1**
of which electricity	*189*	*263*	*348*	*420*	*2.6*	*1.8*	*–5.6*	*–13.6*
Total final consumption	**6 154**	**7 639**	**9 207**	**10 542**	**1.7**	**1.2**	**–3.7**	**–9.6**
Coal	765	641	774	763	1.7	0.7	–5.9	–17.3
Oil	2 543	3 228	3 783	4 242	1.5	1.1	–4.6	–11.4
Gas	1 004	1 219	1 487	1 721	1.8	1.3	–1.9	–6.4
Electricity	826	1 236	1 682	2 121	2.8	2.1	–4.7	–12.2
Heat	177	255	280	306	0.9	0.7	–2.3	–5.4
Biomass and waste	815	1 052	1 168	1 295	1.0	0.8	–1.2	–1.6
Other renewables	24	7	33	93	14.7	10.3	40.3	54.3
Industry	**2 134**	**2 511**	**3 174**	**3 595**	**2.2**	**1.4**	**–3.3**	**–8.6**
Coal	470	499	645	662	2.4	1.1	–6.0	–17.0
Oil	550	665	789	826	1.6	0.8	–3.9	–9.1
Gas	551	564	711	847	2.1	1.6	–1.8	–4.8
Electricity	382	512	698	845	2.9	1.9	–4.3	–10.1
Heat	72	100	108	116	0.7	0.6	–0.9	–0.5
Biomass and waste	109	169	222	295	2.5	2.2	4.4	7.2
Other renewables	0	1	1	5	6.3	8.3	5.2	24.3
Transport	**1 435**	**1 969**	**2 354**	**2 804**	**1.6**	**1.4**	**–4.1**	**–9.9**
Oil	1 370	1 861	2 166	2 520	1.4	1.2	–5.2	–12.6
Biofuels	6	15	73	147	15.1	9.0	34.1	58.7
Other fuels	59	93	115	138	1.9	1.5	1.3	2.2
Residential, services and agriculture	**2 339**	**2 905**	**3 362**	**3 772**	**1.3**	**1.0**	**–3.9**	**–10.6**
Coal	240	106	92	69	–1.3	–1.6	–6.5	–23.6
Oil	450	499	571	594	1.2	0.7	–3.5	–10.4
Gas	422	586	691	773	1.5	1.1	–2.4	–8.9
Electricity	421	689	935	1 208	2.8	2.2	–5.3	–14.3
Heat	105	154	171	190	1.0	0.8	–3.2	–8.3
Biomass and waste	696	864	870	850	0.1	–0.1	–4.6	–10.1
Other renewables	4	7	32	88	15.2	10.4	42.1	56.4
Non-energy use	**246**	**254**	**317**	**370**	**2.0**	**1.4**	**–3.7**	**–7.6**

Alternative Policy Scenario: World

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**11 731**	**17 408**	**23 682**	**29 835**	**2.8**	**2.1**	**–4.6**	**–11.6**
Coal	4 478	6 917	9 751	10 914	3.2	1.8	–8.1	–25.8
Oil	1 313	1 161	1 154	869	–0.1	–1.1	–3.4	–7.6
Gas	1 613	3 412	4 730	6 170	3.0	2.3	–9.6	–20.8
Nuclear	2 013	2 740	3 268	4 106	1.6	1.6	5.1	24.3
Hydro	2 148	2 809	3 738	4 903	2.6	2.2	1.5	3.2
Renewables (excluding hydro)	166	369	1 041	2 872	9.9	8.2	5.5	26.8
Biomass and waste	*125*	*227*	*455*	*983*	*6.5*	*5.8*	*8.0*	*22.2*
Wind	*4*	*82*	*449*	*1 440*	*16.7*	*11.6*	*3.8*	*27.3*
Geothermal	*36*	*56*	*100*	*185*	*5.5*	*4.7*	*0.3*	*6.3*
Solar	*1*	*4*	*34*	*238*	*21.0*	*16.8*	*12.8*	*67.8*
Tide and wave	*1*	*1*	*2*	*25*	*11.3*	*15.8*	*24.3*	*117.2*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**4 054**	**5 418**	**7 104**	**2.7**	**2.2**	**–4.1**	**–9.8**
Coal	1 235	1 664	1 885	2.7	1.6	–8.9	–26.5
Oil	453	466	336	0.3	–1.1	–3.0	–11.2
Gas	1 055	1 491	2 059	3.2	2.6	–7.0	–16.6
Nuclear	364	412	519	1.1	1.4	5.3	24.7
Hydro	851	1 100	1 431	2.4	2.0	1.9	4.2
of which pumped storage	*79*	*79*	*79*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	96	285	874	10.4	8.9	5.3	29.6
Biomass and waste	*36*	*74*	*158*	*6.7*	*5.8*	*7.9*	*22.0*
Wind	*48*	*174*	*538*	*12.5*	*9.8*	*3.7*	*25.3*
Geothermal	*8*	*15*	*26*	*5.4*	*4.6*	*0.3*	*6.0*
Solar	*4*	*22*	*145*	*17.7*	*15.2*	*12.9*	*65.6*
Tide and wave	*0*	*0*	*7*	*6.0*	*13.3*	*23.7*	*116.9*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**20 463**	**26 079**	**31 586**	**34 080**	**1.8**	**1.0**	**–5.2**	**–15.7**
Coal	8 081	10 625	13 293	13 594	2.1	1.0	–6.5	–21.4
Oil	8 561	10 199	11 737	12 835	1.3	0.9	–4.1	–10.5
of which international marine bunkers	*363*	*521*	*547*	*561*	*0.4*	*0.3*	–3.8	–9.8
Gas	3 820	5 254	6 556	7 651	2.0	1.5	–4.7	–13.0
Power generation and heat plants	**6 955**	**10 587**	**13 203**	**13 749**	**2.0**	**1.0**	**–7.1**	**–22.2**
Coal	4 764	7 600	9 653	9 987	2.2	1.1	–6.8	–22.9
Oil	1 053	934	905	667	–0.3	–1.3	–5.8	–12.5
Gas	1 138	2 054	2 645	3 095	2.3	1.6	–8.7	–22.1
Total final consumption	**12 047**	**13 668**	**16 335**	**18 065**	**1.6**	**1.1**	**–4.0**	**–11.1**
Coal	3 188	2 817	3 424	3 391	1.8	0.7	–5.8	–17.3
Oil	6 595	8 091	9 565	10 833	1.5	1.1	–4.1	–10.6
of which transport	*3 758*	*5 112*	*6 048*	*7 076*	*1.5*	*1.3*	*–4.4*	*–11.5*
Gas	2 264	2 760	3 345	3 841	1.8	1.3	–1.9	–6.3

Alternative Policy Scenario: OECD

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**4 518**	**5 502**	**6 128**	**6 359**	**1.0**	**0.6**	**–2.1**	**–7.3**
Coal	1 063	1 129	1 173	985	0.4	–0.5	–4.7	–24.4
Oil	1 894	2 236	2 383	2 345	0.6	0.2	–3.4	–9.5
Gas	844	1 199	1 372	1 471	1.2	0.8	–4.0	–10.8
Nuclear	449	604	676	754	1.0	0.9	4.8	21.4
Hydro	101	109	123	135	1.1	0.8	1.2	3.4
Biomass and waste	140	187	308	451	4.6	3.4	10.5	16.9
Other renewables	28	37	94	219	8.8	7.0	7.6	20.6
Power generation and heat plants	**1 701**	**2 197**	**2 498**	**2 579**	**1.2**	**0.6**	**–2.0**	**–8.6**
Coal	750	906	978	818	0.7	–0.4	–5.0	–26.9
Oil	148	115	102	58	–1.1	–2.6	–4.7	–11.9
Gas	175	371	450	494	1.8	1.1	–6.7	–16.7
Nuclear	449	604	676	754	1.0	0.9	4.8	21.4
Hydro	101	109	123	135	1.1	0.8	1.2	3.4
Biomass and waste	52	61	96	153	4.3	3.6	5.5	4.0
Other renewables	25	31	73	167	8.2	6.7	1.6	16.3
Other transformation, own use and losses	**381**	**416**	**435**	**451**	**0.4**	**0.3**	**–2.6**	**–7.1**
of which electricity	*105*	*118*	*131*	*135*	*0.9*	*0.5*	*–3.9*	*–11.4*
Total final consumption	**3 135**	**3 826**	**4 283**	**4 528**	**1.0**	**0.7**	**–2.5**	**–7.4**
Coal	229	134	116	100	–1.2	–1.1	–3.2	–7.9
Oil	1 638	2 000	2 165	2 172	0.7	0.3	–3.5	–9.8
Gas	591	747	821	852	0.9	0.5	–2.6	–7.7
Electricity	547	753	879	974	1.4	1.0	–3.8	–11.0
Heat	40	59	70	82	1.5	1.3	–0.9	–1.7
Biomass and waste	87	127	211	298	4.8	3.3	13.0	25.0
Other renewables	3	6	21	51	11.5	8.4	36.6	37.7
Industry	**1 015**	**1 152**	**1 264**	**1 302**	**0.8**	**0.5**	**–2.6**	**–6.5**
Coal	159	115	104	92	–0.9	–0.8	–3.4	–8.2
Oil	323	376	422	413	1.1	0.4	–2.0	–4.7
Gas	261	310	331	341	0.6	0.4	–3.2	–7.6
Electricity	223	269	298	318	0.9	0.6	–3.7	–9.4
Heat	14	17	20	22	1.4	1.0	–2.6	–4.9
Biomass and waste	35	64	87	112	2.9	2.2	2.7	–0.3
Other renewables	0	1	1	4	4.8	8.0	6.2	26.7
Transport	**986**	**1 283**	**1 439**	**1 514**	**1.0**	**0.6**	**–3.1**	**–8.8**
Oil	960	1 244	1 352	1 388	0.8	0.4	–4.2	–11.6
Biofuels	0	9	52	84	17.3	9.0	32.5	62.8
Other fuels	26	30	35	42	1.4	1.4	5.0	11.3
Residential, services and agriculture	**1 036**	**1 273**	**1 448**	**1 572**	**1.2**	**0.8**	**–1.9**	**–6.9**
Coal	68	17	11	6	–4.2	–3.7	–1.2	–5.4
Oil	259	263	259	234	–0.1	–0.4	–2.5	–8.7
Gas	311	416	467	483	1.0	0.6	–2.5	–8.6
Electricity	316	475	569	640	1.7	1.2	–4.0	–12.1
Heat	27	42	50	60	1.6	1.4	–0.2	–0.4
Biomass and waste	52	54	72	102	2.7	2.5	14.9	36.9
Other renewables	3	6	20	47	12.0	8.4	38.6	38.8
Non-energy use	**98**	**119**	**133**	**139**	**1.0**	**0.6**	**–3.0**	**–7.3**

Alternative Policy Scenario: OECD

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**7 571**	**10 118**	**11 728**	**12 895**	**1.4**	**0.9**	**–3.7**	**–10.9**
Coal	3 059	3 842	4 265	3 803	1.0	0.0	–6.2	–29.5
Oil	695	527	456	257	–1.3	–2.7	–5.3	–13.4
Gas	770	1 854	2 213	2 614	1.6	1.3	–12.0	–21.9
Nuclear	1 725	2 319	2 593	2 892	1.0	0.9	4.8	21.4
Hydro	1 170	1 267	1 429	1 570	1.1	0.8	1.2	3.4
Renewables (excluding hydro)	152	310	773	1 759	8.6	6.9	2.7	14.7
Biomass and waste	*118*	*196*	*316*	*483*	*4.4*	*3.5*	*3.1*	*–0.3*
Wind	*4*	*77*	*364*	*993*	*15.1*	*10.3*	*1.7*	*18.2*
Geothermal	*29*	*35*	*59*	*100*	*4.9*	*4.1*	*0.5*	*5.4*
Solar	*1*	*2*	*32*	*159*	*31.0*	*19.3*	*13.9*	*54.3*
Tide and wave	*1*	*1*	*2*	*24*	*11.3*	*15.6*	*24.3*	*109.5*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**2 360**	**2 719**	**3 199**	**1.3**	**1.2**	**–3.8**	**–9.8**
Coal	656	683	630	0.4	–0.2	–8.8	–32.1
Oil	234	215	112	–0.8	–2.8	–4.5	–19.9
Gas	654	808	1 026	1.9	1.7	–6.7	–15.1
Nuclear	305	324	362	0.5	0.7	5.1	22.3
Hydro	428	462	500	0.7	0.6	0.9	2.7
of which pumped storage	*79*	*79*	*79*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	82	226	568	9.6	7.7	3.4	17.1
Biomass and waste	*31*	*51*	*78*	*4.7*	*3.6*	*4.4*	*0.0*
Wind	*43*	*145*	*369*	*11.6*	*8.6*	*1.9*	*13.5*
Geothermal	*5*	*8*	*14*	*4.7*	*3.9*	*0.4*	*5.3*
Solar	*3*	*21*	*101*	*19.9*	*14.6*	*13.5*	*53.4*
Tide and wave	*0*	*0*	*6*	*6.0*	*13.0*	*23.7*	*109.3*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**11 051**	**12 827**	**13 828**	**13 184**	**0.7**	**0.1**	**–3.9**	**–14.9**
Coal	4 101	4 334	4 534	3 792	0.4	–0.5	–4.8	–25.0
Oil	5 029	5 713	6 114	5 990	0.6	0.2	–3.3	–9.6
Gas	1 920	2 780	3 180	3 402	1.2	0.8	–3.9	–10.7
Power generation and heat plants	**3 904**	**4 905**	**5 333**	**4 631**	**0.8**	**–0.2**	**–5.4**	**–24.3**
Coal	3 024	3 665	3 949	3 288	0.7	–0.4	–5.1	–27.2
Oil	471	372	330	187	–1.1	–2.6	–4.7	–11.9
Gas	409	867	1 054	1 156	1.8	1.1	–6.7	–16.8
Total final consumption	**6 553**	**7 274**	**7 814**	**7 827**	**0.7**	**0.3**	**–3.1**	**–9.3**
Coal	1 012	589	514	442	–1.2	–1.1	–2.7	–6.9
Oil	4 196	4 967	5 410	5 421	0.8	0.3	–3.4	–10.1
of which transport	*2 688*	*3 445*	*3 814*	*3 915*	*0.9*	*0.5*	*–3.8*	*–11.4*
Gas	1 345	1 717	1 891	1 965	0.9	0.5	–2.4	–7.4

Alternative Policy Scenario: OECD North America

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**2 256**	**2 756**	**3 102**	**3 285**	**1.1**	**0.7**	**–2.6**	**–8.1**
Coal	486	581	641	598	0.9	0.1	–4.3	–19.3
Oil	927	1 137	1 249	1 271	0.9	0.4	–3.4	–10.2
Gas	517	637	721	757	1.1	0.7	–2.6	–8.1
Nuclear	179	238	254	310	0.6	1.0	–	12.7
Hydro	51	55	59	63	0.6	0.5	0.3	2.9
Biomass and waste	78	91	140	196	4.0	3.0	5.3	7.9
Other renewables	19	17	39	89	7.7	6.5	6.2	15.7
Power generation and heat plants	**845**	**1 086**	**1 238**	**1 322**	**1.2**	**0.8**	**–2.7**	**–8.8**
Coal	413	524	590	553	1.1	0.2	–4.4	–20.0
Oil	47	54	51	36	–0.5	–1.6	–1.5	–7.8
Gas	95	173	212	222	1.9	1.0	–2.9	–10.5
Nuclear	179	238	254	310	0.6	1.0	–	12.7
Hydro	51	55	59	63	0.6	0.5	0.3	2.9
Biomass and waste	41	27	40	68	3.8	3.7	–0.1	–5.6
Other renewables	19	15	31	69	6.9	6.1	–0.7	12.3
Other transformation, own use and losses	**190**	**197**	**214**	**236**	**0.7**	**0.7**	**–2.3**	**–6.4**
of which electricity	*56*	*56*	*64*	*69*	*1.2*	*0.8*	*–2.9*	*–9.2*
Total final consumption	**1 552**	**1 906**	**2 160**	**2 301**	**1.1**	**0.7**	**–2.6**	**–8.2**
Coal	59	39	34	29	–1.3	–1.1	–3.0	–6.5
Oil	822	1 025	1 144	1 183	1.0	0.6	–3.6	–10.6
Gas	360	402	431	437	0.6	0.3	–2.5	–7.3
Electricity	271	371	437	497	1.5	1.1	–2.9	–9.3
Heat	3	4	6	7	3.6	2.1	–3.0	–5.9
Biomass and waste	37	64	100	128	4.1	2.7	7.7	16.9
Other renewables	0	2	8	20	12.2	8.7	45.2	29.6
Industry	**448**	**511**	**556**	**576**	**0.8**	**0.5**	**–2.9**	**–7.0**
Coal	49	36	32	28	–1.1	–0.9	–3.2	–6.9
Oil	131	153	177	178	1.3	0.6	–2.2	–5.0
Gas	157	171	175	175	0.2	0.1	–3.5	–8.9
Electricity	94	107	117	129	0.8	0.7	–3.0	–8.2
Heat	1	3	5	6	3.6	2.0	–3.5	–7.2
Biomass and waste	16	40	51	60	2.3	1.6	–2.3	–4.9
Other renewables	0	0	0	0	4.0	3.1	–	–
Transport	**575**	**738**	**844**	**896**	**1.2**	**0.7**	**–3.1**	**–10.1**
Oil	556	713	796	830	1.0	0.6	–4.2	–12.8
Biofuels	0	7	29	46	13.8	7.5	40.4	89.2
Other fuels	19	19	19	20	0.4	0.3	1.2	1.3
Residential, services and agriculture	**477**	**588**	**679**	**743**	**1.3**	**0.9**	**–1.8**	**–7.0**
Coal	10	3	2	1	–3.9	–4.1	0.8	4.1
Oil	83	90	91	89	0.1	0.0	–0.9	–3.4
Gas	185	212	238	242	1.0	0.5	–2.0	–6.7
Electricity	176	263	319	368	1.8	1.3	–2.9	–9.7
Heat	2	1	1	1	4.1	2.9	–0.0	–0.0
Biomass and waste	21	17	20	22	1.2	1.0	–0.0	–0.0
Other renewables	0	2	8	20	12.5	8.8	46.8	30.1
Non-energy use	**52**	**69**	**81**	**86**	**1.4**	**0.8**	**–2.6**	**–6.0**

Alternative Policy Scenario: OECD North America

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**3 809**	**4 970**	**5 829**	**6 595**	**1.5**	**1.1**	**–2.8**	**–9.1**
Coal	1 790	2 217	2 578	2 588	1.4	0.6	–4.9	–22.2
Oil	217	231	213	153	–0.7	–1.6	–1.5	–8.0
Gas	406	851	1 125	1 286	2.6	1.6	–2.8	–8.9
Nuclear	687	913	973	1 191	0.6	1.0	–	12.7
Hydro	593	637	681	734	0.6	0.5	0.3	2.9
Renewables (excluding hydro)	115	121	259	644	7.1	6.6	–0.9	11.2
Biomass and waste	*90*	*83*	*125*	*207*	*3.8*	*3.6*	*0.1*	*–6.2*
Wind	*3*	*16*	*84*	*324*	*16.4*	*12.4*	*–3.9*	*23.0*
Geothermal	*21*	*22*	*39*	*63*	*5.2*	*4.1*	*–*	*1.8*
Solar	*1*	*1*	*11*	*46*	*29.7*	*17.8*	*8.5*	*48.7*
Tide and wave	*0*	*0*	*0*	*4*	*8.0*	*19.8*	*–*	*95.9*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**1 180**	**1 364**	**1 602**	**1.3**	**1.2**	**–2.6**	**–8.0**
Coal	365	412	418	1.1	0.5	–5.0	–23.5
Oil	96	97	65	0.1	–1.5	–1.9	–10.0
Gas	407	492	592	1.7	1.4	–3.0	–9.2
Nuclear	112	118	144	0.5	1.0	–	12.5
Hydro	178	183	195	0.3	0.4	0.2	2.5
of which pumped storage	*20*	*20*	*20*	*0.0*	*0.0*	*–*	*–*
Renewables (excluding hydro)	22	61	188	9.6	8.5	2.3	23.4
Biomass and waste	*12*	*18*	*31*	*4.3*	*3.9*	*1.0*	*–5.5*
Wind	*7*	*31*	*120*	*14.1*	*11.4*	*2.0*	*30.4*
Geothermal	*3*	*6*	*9*	*5.0*	*3.9*	*–*	*1.8*
Solar	*1*	*7*	*27*	*26.6*	*16.3*	*9.1*	*49.5*
Tide and wave	*0*	*0*	*1*	*0.0*	*16.0*	*–*	*97.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**5 554**	**6 694**	**7 469**	**7 447**	**1.0**	**0.4**	**–3.3**	**–12.7**
Coal	1 882	2 249	2 490	2 326	0.9	0.1	–4.2	–19.2
Oil	2 485	2 967	3 301	3 360	1.0	0.5	–2.9	–10.2
Gas	1 187	1 478	1 678	1 762	1.2	0.7	–2.5	–7.7
Power generation and heat plants	**1 991**	**2 648**	**2 989**	**2 816**	**1.1**	**0.2**	**–4.0**	**–18.0**
Coal	1 618	2 065	2 326	2 180	1.1	0.2	–4.4	–20.0
Oil	151	178	168	117	–0.5	–1.6	–1.5	–7.9
Gas	222	404	495	519	1.9	1.0	–2.9	–10.5
Total final consumption	**3 211**	**3 678**	**4 076**	**4 177**	**0.9**	**0.5**	**–2.9**	**–9.6**
Coal	262	168	149	131	–1.1	–1.0	–1.4	–3.2
Oil	2 122	2 587	2 932	3 033	1.1	0.6	–3.2	–10.8
of which transport	*1 584*	*2 030*	*2 330*	*2 426*	*1.3*	*0.7*	*–3.6*	*–12.3*
Gas	827	923	996	1 013	0.7	0.4	–2.2	–6.6

Alternative Policy Scenario: United States

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**1 924**	**2 324**	**2 588**	**2 701**	**1.0**	**0.6**	**–2.4**	**–7.8**
Coal	458	545	598	569	0.8	0.2	–4.1	–18.1
Oil	767	946	1 030	1 035	0.8	0.3	–3.3	–10.1
Gas	439	515	567	561	0.9	0.3	–2.0	–6.3
Nuclear	159	212	221	278	0.4	1.0	–	14.4
Hydro	23	23	25	26	0.7	0.3	0.1	–
Biomass and waste	62	71	117	164	4.7	3.3	5.8	5.6
Other renewables	14	11	30	68	9.1	7.1	6.7	13.4
Power generation and heat plants	**745**	**944**	**1 062**	**1 127**	**1.1**	**0.7**	**–2.5**	**–8.2**
Coal	391	495	553	530	1.0	0.3	–4.2	–18.8
Oil	27	33	32	21	–0.4	–1.8	–1.9	–9.0
Gas	90	147	171	163	1.4	0.4	–0.8	–3.8
Nuclear	159	212	221	278	0.4	1.0	–	14.4
Hydro	23	23	25	26	0.7	0.3	0.1	–
Biomass and waste	40	24	37	58	4.1	3.5	–0.6	–12.9
Other renewables	14	9	22	51	8.2	6.8	–2.4	9.0
Other transformation, own use and losses	**154**	**144**	**148**	**150**	**0.2**	**0.2**	**–2.1**	**–6.1**
of which electricity	*49*	*45*	*49*	*51*	*0.9*	*0.5*	*–2.7*	*–9.1*
Total final consumption	**1 304**	**1 599**	**1 800**	**1 894**	**1.1**	**0.7**	**–2.5**	**–8.0**
Coal	54	34	30	26	–1.2	–1.0	–2.9	–5.8
Oil	695	865	954	975	0.9	0.5	–3.5	–10.4
Gas	303	335	357	353	0.6	0.2	–2.6	–7.5
Electricity	226	313	366	412	1.4	1.1	–2.8	–9.2
Heat	2	3	5	6	4.1	2.3	–3.1	–6.3
Biomass and waste	23	47	80	106	5.0	3.2	9.1	19.7
Other renewables	0	2	8	18	12.0	8.3	45.4	28.3
Industry	**357**	**404**	**435**	**439**	**0.7**	**0.3**	**–2.8**	**–7.0**
Coal	45	31	28	25	–0.9	–0.8	–3.1	–6.2
Oil	104	123	142	142	1.3	0.5	–2.1	–5.0
Gas	124	135	135	130	0.0	–0.1	–3.5	–8.8
Electricity	75	81	84	88	0.4	0.3	–3.0	–8.6
Heat	0	2	4	4	4.2	2.1	–3.9	–8.2
Biomass and waste	9	31	41	49	2.7	1.8	–2.4	–5.2
Other renewables	0	0	0	0	3.5	3.0	–	–
Transport	**499**	**638**	**720**	**753**	**1.1**	**0.6**	**–2.9**	**–9.6**
Oil	484	617	678	697	0.9	0.5	–4.1	–12.4
Biofuels	0	7	28	43	13.5	7.3	38.8	88.1
Other fuels	16	14	14	13	–0.3	–0.3	–2.4	–6.3
Residential, services and agriculture	**403**	**497**	**574**	**627**	**1.3**	**0.9**	**–1.8**	**–7.0**
Coal	10	3	2	1	–3.9	–4.1	0.8	4.1
Oil	63	65	63	61	–0.3	–0.2	–0.9	–3.5
Gas	164	186	208	210	1.1	0.5	–2.0	–6.7
Electricity	152	231	281	323	1.8	1.3	–2.8	–9.4
Heat	2	1	1	1	4.1	2.9	–	–
Biomass and waste	14	9	11	13	1.7	1.4	–0.0	–0.0
Other renewables	0	2	8	17	12.4	8.5	47.0	28.9
Non-energy use	**44**	**60**	**71**	**75**	**1.5**	**0.8**	**–2.6**	**–6.0**

Alternative Policy Scenario: United States

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**3 203**	**4 148**	**4 816**	**5 380**	**1.4**	**1.0**	**–2.7**	**–9.0**
Coal	1 700	2 090	2 410	2 473	1.3	0.6	–4.7	–20.9
Oil	131	139	136	91	–0.2	–1.6	–1.8	–8.7
Gas	382	732	908	928	2.0	0.9	–0.7	–2.7
Nuclear	611	813	849	1 067	0.4	1.0	–	14.4
Hydro	273	271	291	297	0.7	0.3	0.1	–
Renewables (excluding hydro)	106	102	222	524	7.3	6.5	–3.1	4.5
Biomass and waste	*86*	*72*	*112*	*177*	*4.1*	*3.5*	*–0.6*	*–12.9*
Wind	*3*	*14*	*69*	*253*	*15.5*	*11.7*	*–9.6*	*15.5*
Geothermal	*16*	*15*	*30*	*49*	*6.1*	*4.5*	–	–
Solar	*1*	*1*	*11*	*43*	*30.8*	*17.9*	*8.6*	*46.5*
Tide and wave	*0*	*0*	*0*	*2*	–	–	–	*156.4*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**995**	**1 137**	**1 317**	**1.2**	**1.1**	**–2.5**	**–7.9**
Coal	334	378	393	1.1	0.6	–4.7	–22.0
Oil	74	74	48	0.0	–1.6	–2.2	–11.2
Gas	373	432	494	1.3	1.1	–1.9	–6.7
Nuclear	98	101	127	0.3	1.0	–	14.4
Hydro	97	99	100	0.2	0.1	0.1	–
of which pumped storage	*20*	*20*	*20*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	19	53	155	9.7	8.3	0.2	17.4
Biomass and waste	*10*	*16*	*27*	*4.6*	*3.9*	*0.4*	*–12.4*
Wind	*7*	*26*	*96*	*13.1*	*10.8*	*–1.9*	*23.8*
Geothermal	*2*	*4*	*7*	*5.7*	*4.3*	–	–
Solar	*0*	*7*	*25*	*27.2*	*16.4*	*9.2*	*46.9*
Tide and wave	*0*	*0*	*0*	*0.0*	*15.4*	–	*156.4*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**4 832**	**5 769**	**6 371**	**6 266**	**0.9**	**0.3**	**–3.1**	**–12.2**
Coal	1 774	2 110	2 323	2 217	0.9	0.2	–4.0	–18.0
Oil	2 047	2 448	2 719	2 739	1.0	0.4	–2.8	–10.0
Gas	1 011	1 212	1 329	1 310	0.8	0.3	–1.8	–5.9
Power generation and heat plants	**1 829**	**2 403**	**2 683**	**2 536**	**1.0**	**0.2**	**–3.6**	**–16.6**
Coal	1 532	1 949	2 177	2 086	1.0	0.3	–4.2	–18.8
Oil	88	110	105	69	–0.4	–1.8	–1.9	–9.0
Gas	210	344	400	381	1.4	0.4	–0.8	–3.8
Total final consumption	**2 731**	**3 101**	**3 419**	**3 452**	**0.9**	**0.4**	**–2.8**	**–9.4**
Coal	239	146	131	116	–1.0	–0.9	–1.0	–1.8
Oil	1 795	2 184	2 461	2 515	1.1	0.5	–3.0	–10.6
of which transport	*1 381*	*1 759*	*2 005*	*2 058*	*1.2*	*0.6*	*–3.3*	*–11.8*
Gas	697	771	827	821	0.6	0.2	–2.2	–6.7

Alternative Policy Scenario: OECD Pacific

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**640**	**880**	**1 005**	**1 054**	**1.2**	**0.7**	**–2.4**	**–5.9**
Coal	138	217	224	172	0.3	–0.9	–6.2	–25.4
Oil	340	399	414	400	0.4	0.0	–3.4	–7.6
Gas	69	124	154	155	2.0	0.9	–2.9	–17.2
Nuclear	66	108	157	227	3.5	2.9	1.4	15.8
Hydro	11	12	13	14	0.4	0.5	1.2	3.5
Biomass and waste	10	14	30	56	7.2	5.5	29.1	53.9
Other renewables	5	6	13	31	7.4	6.5	5.6	29.3
Power generation and heat plants	**238**	**365**	**442**	**468**	**1.7**	**1.0**	**–2.2**	**–6.7**
Coal	60	139	147	100	0.5	–1.3	–7.7	–34.1
Oil	54	30	22	9	–2.6	–4.6	–12.5	–34.7
Gas	40	67	80	73	1.7	0.4	–2.7	–25.8
Nuclear	66	108	157	227	3.5	2.9	1.4	15.8
Hydro	11	12	13	14	0.4	0.5	1.2	3.5
Biomass and waste	3	5	13	26	8.8	6.3	58.4	91.9
Other renewables	3	5	9	20	6.4	5.8	4.5	28.1
Other transformation, own use and losses	**62**	**82**	**84**	**82**	**0.2**	**0.0**	**–2.7**	**–7.0**
of which electricity	*11*	*16*	*17*	*17*	*0.9*	*0.3*	*–3.4*	*–9.5*
Total final consumption	**437**	**586**	**661**	**694**	**1.1**	**0.7**	**–2.7**	**–6.1**
Coal	49	39	39	37	0.1	–0.2	–2.9	–7.8
Oil	268	345	368	367	0.6	0.2	–3.0	–7.0
Gas	26	55	70	76	2.2	1.3	–3.2	–8.0
Electricity	86	132	157	166	1.6	0.9	–3.5	–9.5
Heat	0	5	6	7	2.0	1.4	–3.0	–5.3
Biomass and waste	6	9	17	30	6.2	4.9	12.7	31.9
Other renewables	2	1	4	11	10.9	8.6	8.6	32.3
Industry	**179**	**233**	**259**	**272**	**1.0**	**0.6**	**–2.1**	**–4.0**
Coal	39	38	38	36	0.1	–0.2	–3.0	–8.0
Oil	81	103	110	111	0.7	0.3	–1.6	–3.9
Gas	12	24	30	32	2.0	1.1	–3.0	–6.9
Electricity	43	58	66	71	1.2	0.8	–2.4	–5.7
Heat	0	3	4	4	2.0	1.4	–3.8	–5.4
Biomass and waste	4	7	10	17	3.7	3.7	1.2	14.3
Other renewables	0	0	0	1	1.2	5.6	21.3	336.9
Transport	**117**	**164**	**181**	**187**	**0.9**	**0.5**	**–3.1**	**–7.1**
Oil	115	161	176	180	0.8	0.4	–3.8	–8.5
Biofuels	0	0	1	3	70.4	28.9	213.8	199.8
Other fuels	2	3	4	5	3.0	2.1	6.0	10.6
Residential, services and agriculture	**127**	**174**	**203**	**217**	**1.4**	**0.9**	**–3.3**	**–7.9**
Coal	9	1	1	1	–1.1	–0.8	–0.0	–0.0
Oil	58	66	65	60	–0.1	–0.3	–3.2	–8.1
Gas	14	30	38	42	2.3	1.3	–3.8	–9.6
Electricity	42	72	88	91	1.8	0.9	–4.6	–12.8
Heat	0	2	3	3	2.0	1.3	–2.0	–5.2
Biomass and waste	2	2	5	10	9.6	6.5	17.8	46.8
Other renewables	1	1	4	9	12.7	9.2	7.5	21.3
Non-energy use	**15**	**16**	**17**	**17**	**0.4**	**0.3**	**–2.1**	**–6.1**

Alternative Policy Scenario: OECD Pacific

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**1 130**	**1 719**	**2 034**	**2 136**	**1.5**	**0.8**	**–3.3**	**–9.2**
Coal	253	630	682	469	0.7	–1.1	–8.7	–36.4
Oil	274	164	122	46	–2.6	–4.8	–12.6	–36.2
Gas	198	340	403	397	1.6	0.6	–2.7	–22.2
Nuclear	255	413	603	870	3.5	2.9	1.4	15.8
Hydro	133	142	148	161	0.4	0.5	1.2	3.5
Renewables (excluding hydro)	17	30	76	194	9.0	7.5	21.2	52.8
Biomass and waste	*13*	*21*	*40*	*69*	*6.0*	*4.7*	*28.1*	*44.1*
Wind	*0*	*2*	*18*	*73*	*20.1*	*14.0*	*26.9*	*75.0*
Geothermal	*4*	*6*	*10*	*15*	*4.5*	*3.7*	*–*	*4.2*
Solar	*0*	*0*	*8*	*34*	*46.3*	*24.1*	*9.6*	*58.7*
Tide and wave	*0*	*0*	*0*	*2*	*–*	*–*	*–*	*151.8*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**386**	**428**	**483**	**1.0**	**0.9**	**–3.2**	**–6.8**
Coal	94	108	86	1.2	–0.3	–4.0	–29.6
Oil	69	53	20	–2.5	–4.7	–13.5	–50.7
Gas	89	106	140	1.6	1.8	–4.0	–8.2
Nuclear	61	75	108	1.9	2.2	1.3	15.2
Hydro	65	68	72	0.4	0.4	0.1	2.4
of which pumped storage	*28*	*28*	*28*	*0.0*	*0.0*	*–*	*–*
Renewables (excluding hydro)	7	18	55	9.6	8.5	11.8	49.8
Biomass and waste	*3*	*7*	*11*	*7.4*	*5.1*	*29.0*	*39.7*
Wind	*2*	*5*	*21*	*11.7*	*10.6*	*6.4*	*59.3*
Geothermal	*1*	*1*	*2*	*4.0*	*3.4*	*–0.0*	*4.1*
Solar	*1*	*5*	*21*	*14.1*	*11.6*	*3.0*	*52.5*
Tide and wave	*0*	*0*	*0*	*–*	*–*	*–*	*122.1*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**1 564**	**2 055**	**2 187**	**1 918**	**0.6**	**–0.3**	**–4.7**	**–17.2**
Coal	519	803	838	620	0.4	–1.0	–6.6	–27.8
Oil	885	960	990	941	0.3	–0.1	–3.7	–8.1
Gas	160	292	359	357	1.9	0.8	–2.9	–17.5
Power generation and heat plants	**538**	**847**	**892**	**625**	**0.5**	**–1.2**	**–7.1**	**–32.3**
Coal	276	596	630	424	0.5	–1.3	–7.8	–34.4
Oil	167	94	71	27	–2.5	–4.6	–12.4	–35.2
Gas	94	157	190	173	1.7	0.4	–2.7	–25.8
Total final consumption	**957**	**1 118**	**1 204**	**1 203**	**0.7**	**0.3**	**–3.0**	**–7.3**
Coal	219	174	176	166	0.1	–0.2	–2.7	–7.3
Oil	679	817	868	863	0.5	0.2	–3.1	–7.2
of which transport	*320*	*440*	*483*	*494*	*0.9*	*0.4*	*–3.8*	*–8.5*
Gas	60	126	160	174	2.2	1.2	–3.2	–7.9

Alternative Policy Scenario: Japan

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**446**	**533**	**571**	**563**	**0.6**	**0.2**	**–2.5**	**–7.0**
Coal	77	116	108	74	–0.6	–1.7	–6.6	–24.5
Oil	253	253	243	218	–0.4	–0.6	–3.7	–7.7
Gas	48	72	86	78	1.6	0.3	–2.5	–21.8
Nuclear	53	74	101	143	2.9	2.6	–	7.9
Hydro	8	8	8	8	–0.2	0.0	–	–
Biomass and waste	5	6	17	27	9.4	5.7	29.9	37.9
Other renewables	3	4	7	15	6.2	5.4	6.3	31.6
Power generation and heat plants	**171**	**219**	**249**	**250**	**1.2**	**0.5**	**–2.7**	**–9.1**
Coal	25	60	55	26	–0.7	–3.1	–9.6	–42.2
Oil	48	24	16	5	–3.7	–5.9	–16.6	–45.5
Gas	33	47	55	45	1.5	–0.2	–2.2	–30.1
Nuclear	53	74	101	143	2.9	2.6	–	7.9
Hydro	8	8	8	8	–0.2	0.0	–	–
Biomass and waste	2	4	8	12	7.3	4.5	54.9	60.9
Other renewables	1	3	5	10	5.1	4.8	4.6	27.2
Other transformation, own use and losses	**41**	**52**	**50**	**47**	**–0.3**	**–0.4**	**–2.7**	**–7.6**
of which electricity	*7*	*9*	*9*	*8*	*0.2*	*–0.3*	*–3.9*	*–11.0*
Total final consumption	**306**	**354**	**373**	**365**	**0.5**	**0.1**	**–2.8**	**–6.5**
Coal	32	27	27	25	–0.1	–0.3	–2.9	–7.9
Oil	189	214	213	199	0.0	–0.3	–2.8	–6.6
Gas	15	27	31	32	1.5	0.7	–3.2	–7.3
Electricity	65	83	91	90	0.8	0.3	–3.9	–10.7
Heat	0	1	1	1	1.9	1.3	–	–
Biomass and waste	3	2	8	14	12.1	7.2	11.7	22.9
Other renewables	1	1	2	5	9.5	7.1	10.6	42.4
Industry	**130**	**136**	**142**	**138**	**0.4**	**0.1**	**–2.0**	**–4.5**
Coal	32	27	27	25	–0.1	–0.3	–2.9	–7.9
Oil	59	61	62	57	0.1	–0.3	–1.0	–2.8
Gas	5	11	13	13	1.6	0.6	–4.0	–8.8
Electricity	32	34	35	34	0.2	0.0	–2.8	–7.5
Heat	0	0	0	0	–	–	–	–
Biomass and waste	3	2	5	9	7.7	5.5	0.7	16.3
Other renewables	0	0	0	0	–	–	–	–
Transport	**76**	**94**	**96**	**92**	**0.1**	**–0.1**	**–2.8**	**–6.0**
Oil	74	92	93	88	0.0	–0.2	–3.7	–7.8
Biofuels	0	0	1	2	–	–	231.1	216.2
Other fuels	1	2	2	2	2.5	1.7	8.0	14.1
Residential, services and agriculture	**89**	**115**	**126**	**127**	**0.9**	**0.4**	**–3.5**	**–8.8**
Coal	0	0	0	0	–	–	–	–
Oil	45	50	50	46	–0.1	–0.3	–3.3	–8.3
Gas	11	16	18	18	1.2	0.6	–3.1	–7.0
Electricity	31	48	54	54	1.2	0.5	–4.8	–13.2
Heat	0	1	1	1	1.9	1.3	–	–
Biomass and waste	0	0	2	3	48.0	19.7	10.0	2.9
Other renewables	1	1	2	5	9.4	7.1	10.6	42.4
Non-energy use	**11**	**10**	**9**	**8**	**–0.9**	**–0.8**	**–3.0**	**–9.4**

Alternative Policy Scenario: Japan

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**838**	**1 071**	**1 161**	**1 142**	**0.7**	**0.2**	**–3.9**	**–10.7**
Coal	116	294	271	129	–0.7	–3.1	–10.5	–43.1
Oil	251	133	86	27	–3.9	–6.0	–16.6	–45.7
Gas	166	244	275	246	1.1	0.0	–2.0	–25.6
Nuclear	202	282	389	550	2.9	2.6	–	7.9
Hydro	89	94	92	94	–0.2	0.0	–	–
Renewables (excluding hydro)	13	23	48	97	6.8	5.6	19.2	37.4
Biomass and waste	*12*	*19*	*31*	*44*	*4.7*	*3.4*	*19.4*	*17.1*
Wind	*0*	*1*	*7*	*27*	*16.5*	*12.4*	*42.5*	*75.0*
Geothermal	*2*	*3*	*5*	*7*	*3.4*	*3.1*	–	*9.2*
Solar	*0*	*0*	*5*	*17*	*103.7*	*41.7*	*13.0*	*69.6*
Tide and wave	*0*	*0*	*0*	*1*	–	–	–	*129.5*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**261**	**263**	**276**	**0.1**	**0.2**	**–3.2**	**–9.7**
Coal	44	44	26	0.0	–2.0	–	–39.1
Oil	58	41	12	–3.2	–5.9	–16.5	–62.9
Gas	61	68	87	0.9	1.4	–3.7	–8.5
Nuclear	45	50	71	0.9	1.8	–	7.9
Hydro	47	47	48	0.1	0.1	–	–
of which pumped storage	*25*	*25*	*25*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	5	12	30	8.4	7.2	20.0	53.7
Biomass and waste	*2*	*5*	*7*	*7.1*	*4.3*	*24.4*	*21.2*
Wind	*1*	*2*	*9*	*9.2*	*8.9*	*31.5*	*71.5*
Geothermal	*1*	*1*	*1*	*3.0*	*2.9*	–	*9.1*
Solar	*1*	*4*	*13*	*11.8*	*10.0*	*12.8*	*71.1*
Tide and wave	*0*	*0*	*0*	–	–	–	*130.4*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**1 057**	**1 211**	**1 188**	**955**	**–0.2**	**–0.9**	**–5.0**	**–17.2**
Coal	292	414	390	248	–0.5	–2.0	–7.3	–28.2
Oil	650	623	594	527	–0.4	–0.6	–4.2	–8.6
Gas	115	174	204	181	1.5	0.1	–2.6	–22.4
Power generation and heat plants	**354**	**454**	**428**	**240**	**–0.5**	**–2.4**	**–8.3**	**–37.6**
Coal	125	269	248	117	–0.7	–3.1	–9.6	–42.2
Oil	151	74	49	15	–3.7	–5.9	–16.6	–45.5
Gas	78	111	131	107	1.5	–0.1	–2.2	–30.1
Total final consumption	**660**	**715**	**721**	**680**	**0.1**	**–0.2**	**–3.1**	**–7.3**
Coal	151	129	128	119	–0.1	–0.3	–2.9	–8.0
Oil	474	523	521	489	0.0	–0.3	–3.0	–7.0
of which transport	*206*	*252*	*252*	*239*	*0.0*	*–0.2*	*–3.7*	*–7.8*
Gas	36	62	72	73	1.4	0.6	–3.5	–7.8

Alternative Policy Scenario: OECD Europe

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**1 622**	**1 866**	**2 021**	**2 020**	**0.7**	**0.3**	**–1.2**	**–6.7**
Coal	438	330	307	215	–0.6	–1.6	–4.5	–35.0
Oil	627	700	720	674	0.3	–0.1	–3.6	–9.3
Gas	258	439	498	558	1.2	0.9	–6.2	–12.4
Nuclear	204	259	265	217	0.2	–0.7	12.0	45.0
Hydro	38	42	52	58	1.9	1.3	2.2	3.8
Biomass and waste	52	83	138	199	4.7	3.4	12.7	18.7
Other renewables	4	14	42	98	10.4	7.8	9.6	22.7
Power generation and heat plants	**618**	**746**	**819**	**789**	**0.9**	**0.2**	**–0.8**	**–9.2**
Coal	277	243	240	165	–0.1	–1.5	–4.8	–40.1
Oil	48	31	28	13	–0.9	–3.3	–3.6	–1.0
Gas	40	131	158	199	1.7	1.6	–13.1	–19.4
Nuclear	204	259	265	217	0.2	–0.7	12.0	45.0
Hydro	38	42	52	58	1.9	1.3	2.2	3.8
Biomass and waste	8	29	43	59	3.7	2.8	0.5	–3.8
Other renewables	3	11	33	78	10.2	7.7	3.0	17.1
Other transformation, own use and losses	**129**	**138**	**138**	**132**	**0.0**	**–0.2**	**–3.0**	**–8.5**
of which electricity	*38*	*46*	*49*	*49*	*0.6*	*0.3*	*–5.4*	*–14.8*
Total final consumption	**1 146**	**1 333**	**1 462**	**1 533**	**0.8**	**0.5**	**–2.3**	**–6.9**
Coal	121	56	43	34	–2.3	–1.9	–3.6	–9.2
Oil	548	630	653	622	0.3	–0.1	–3.8	–10.0
Gas	204	290	320	339	0.9	0.6	–2.6	–8.1
Electricity	190	250	285	310	1.2	0.8	–5.3	–14.2
Heat	37	50	58	68	1.3	1.2	–0.4	–0.8
Biomass and waste	44	54	95	140	5.3	3.7	19.4	31.9
Other renewables	1	3	9	21	11.1	8.1	45.4	49.9
Industry	**388**	**408**	**448**	**454**	**0.9**	**0.4**	**–2.4**	**–7.3**
Coal	70	41	34	28	–1.7	–1.5	–4.1	–9.6
Oil	112	120	135	124	1.1	0.1	–2.1	–5.0
Gas	92	114	127	134	0.9	0.6	–2.8	–6.2
Electricity	86	104	114	118	0.9	0.5	–5.2	–12.8
Heat	13	11	11	12	0.5	0.5	–1.9	–3.5
Biomass and waste	14	17	26	35	3.8	2.7	14.6	1.6
Other renewables	0	0	0	3	9.1	11.2	–	–
Transport	**295**	**381**	**413**	**431**	**0.7**	**0.5**	**–3.0**	**–6.8**
Oil	289	371	380	378	0.2	0.1	–4.4	–10.4
Biofuels	0	2	21	36	24.1	11.7	19.2	33.8
Other fuels	6	8	11	17	3.0	2.9	11.8	26.4
Residential, services and agriculture	**432**	**511**	**566**	**612**	**0.9**	**0.7**	**–1.4**	**–6.4**
Coal	50	13	8	5	–4.5	–4.0	–1.7	–8.1
Oil	117	107	104	85	–0.3	–0.9	–3.4	–14.1
Gas	112	174	191	199	0.8	0.5	–2.8	–10.5
Electricity	99	140	162	181	1.3	1.0	–5.9	–16.3
Heat	24	39	47	56	1.5	1.3	–0.1	–0.2
Biomass and waste	29	35	47	70	2.8	2.7	22.3	53.5
Other renewables	1	3	8	18	11.3	7.7	49.4	63.6
Non-energy use	**31**	**33**	**35**	**36**	**0.4**	**0.3**	**–4.3**	**–10.9**

Alternative Policy Scenario: OECD Europe

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**2 632**	**3 429**	**3 866**	**4 163**	**1.1**	**0.7**	**–5.3**	**–14.3**
Coal	1 016	994	1 005	746	0.1	–1.1	–7.8	–43.8
Oil	203	132	121	58	–0.8	–3.1	–3.5	–0.7
Gas	167	663	685	931	0.3	1.3	–27.4	–34.6
Nuclear	782	992	1 017	832	0.2	–0.7	12.0	45.0
Hydro	443	488	600	676	1.9	1.3	2.2	3.8
Renewables (excluding hydro)	20	159	438	921	9.6	7.0	2.1	11.3
Biomass and waste	*15*	*92*	*151*	*207*	*4.6*	*3.2*	*0.4*	*–4.0*
Wind	*1*	*59*	*262*	*596*	*14.5*	*9.3*	*2.2*	*11.4*
Geothermal	*4*	*7*	*11*	*21*	*3.9*	*4.3*	*2.7*	*19.0*
Solar	*0*	*1*	*12*	*78*	*27.4*	*19.0*	*22.8*	*55.8*
Tide and wave	*1*	*1*	*2*	*18*	*11.5*	*14.7*	*25.6*	*108.7*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**794**	**926**	**1 115**	**1.4**	**1.3**	**–5.7**	**–13.4**
Coal	197	162	126	–1.7	–1.7	–19.7	–51.3
Oil	69	66	27	–0.4	–3.6	–	–
Gas	158	210	294	2.7	2.4	–15.5	–27.3
Nuclear	132	131	110	–0.1	–0.7	12.8	48.3
Hydro	185	211	232	1.2	0.9	1.7	3.1
of which pumped storage	*31*	*31*	*31*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	53	146	325	9.6	7.2	2.9	9.8
Biomass and waste	*16*	*27*	*36*	*4.5*	*3.1*	*1.8*	*–3.3*
Wind	*35*	*109*	*227*	*11.0*	*7.5*	*1.6*	*3.6*
Geothermal	*1*	*1*	*3*	*4.0*	*4.3*	*2.6*	*18.5*
Solar	*1*	*9*	*54*	*20.5*	*15.8*	*24.4*	*55.9*
Tide and wave	*0*	*0*	*5*	*6.4*	*12.3*	*24.9*	*110.8*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**3 934**	**4 078**	**4 172**	**3 818**	**0.2**	**–0.3**	**–4.6**	**–17.9**
Coal	1 700	1 282	1 206	846	–0.6	–1.6	–4.6	–35.9
Oil	1 660	1 787	1 823	1 689	0.2	–0.2	–3.6	–9.4
Gas	574	1 009	1 143	1 283	1.1	0.9	–6.2	–12.5
Power generation and heat plants	**1 376**	**1 409**	**1 452**	**1 189**	**0.3**	**–0.7**	**–7.0**	**–32.4**
Coal	1 130	1 003	993	683	–0.1	–1.5	–4.8	–40.1
Oil	152	100	91	42	–0.9	–3.3	–3.6	–1.0
Gas	93	306	369	464	1.7	1.6	–13.1	–19.4
Total final consumption	**2 384**	**2 478**	**2 533**	**2 448**	**0.2**	**0.0**	**–3.5**	**–9.5**
Coal	532	247	189	146	–2.4	–2.0	–3.7	–9.5
Oil	1 395	1 563	1 609	1 524	0.3	–0.1	–3.8	–10.2
of which transport	*784*	*976*	*1 001*	*995*	*0.2*	*0.1*	*–4.4*	*–10.4*
Gas	458	668	735	778	0.9	0.6	–2.6	–8.2

Alternative Policy Scenario: European Union

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**1 546**	**1 756**	**1 877**	**1 847**	**0.6**	**0.2**	**–0.9**	**–6.4**
Coal	427	311	281	182	–0.9	–2.0	–3.1	–35.9
Oil	591	656	671	620	0.2	–0.2	–3.5	–9.5
Gas	255	417	469	523	1.1	0.9	–6.2	–12.4
Nuclear	203	257	259	214	0.1	–0.7	12.3	45.7
Hydro	23	26	32	35	1.9	1.2	2.8	5.2
Biomass and waste	44	77	131	189	4.9	3.5	13.6	20.0
Other renewables	3	11	34	85	10.9	8.2	6.7	21.5
Power generation and heat plants	**601**	**712**	**767**	**720**	**0.7**	**0.0**	**–0.1**	**–8.6**
Coal	276	238	229	147	–0.3	–1.8	–3.0	–39.9
Oil	48	31	29	12	–0.8	–3.5	–4.1	–6.1
Gas	39	122	147	186	1.7	1.6	–13.6	–19.9
Nuclear	203	257	259	214	0.1	–0.7	12.3	45.7
Hydro	23	26	32	35	1.9	1.2	2.8	5.2
Biomass and waste	8	28	41	54	3.5	2.6	–0.0	–5.3
Other renewables	3	10	31	73	10.6	7.9	3.1	17.4
Other transformation, own use and losses	**122**	**127**	**125**	**117**	**–0.2**	**–0.3**	**–2.9**	**–8.6**
of which electricity	*37*	*43*	*44*	*43*	*0.3*	*0.1*	*–5.2*	*–15.1*
Total final consumption	**1 086**	**1 244**	**1 351**	**1 403**	**0.8**	**0.5**	**–2.1**	**–6.7**
Coal	114	44	30	20	–3.6	–3.0	–2.6	–8.7
Oil	513	589	607	572	0.3	–0.1	–3.7	–10.0
Gas	204	282	307	322	0.8	0.5	–2.4	–7.9
Electricity	177	228	255	273	1.0	0.7	–5.1	–14.4
Heat	41	51	59	69	1.3	1.2	–0.6	–1.3
Biomass and waste	36	49	90	135	5.7	4.0	21.1	34.3
Other renewables	0	1	4	12	13.1	10.1	50.0	55.9
Industry	**371**	**378**	**410**	**410**	**0.7**	**0.3**	**–2.0**	**–7.1**
Coal	65	32	23	16	–3.1	–2.6	–3.3	–10.4
Oil	105	112	125	113	1.0	0.0	–1.4	–4.1
Gas	92	112	123	130	0.9	0.6	–2.6	–5.9
Electricity	80	94	101	102	0.7	0.3	–5.2	–13.9
Heat	15	11	11	12	0.5	0.5	–1.8	–3.5
Biomass and waste	14	17	26	34	3.9	2.7	14.8	1.6
Other renewables	0	0	0	2	37.4	28.4	–	–
Transport	**279**	**361**	**389**	**404**	**0.7**	**0.4**	**–3.1**	**–6.8**
Oil	273	351	357	352	0.2	0.0	–4.5	–10.7
Biofuels	0	2	21	36	24.1	11.7	19.2	33.8
Other fuels	6	8	11	16	3.1	3.0	12.6	27.8
Residential, services and agriculture	**407**	**475**	**520**	**557**	**0.8**	**0.6**	**–1.3**	**–6.1**
Coal	48	11	6	3	–5.3	–4.9	–0.1	–0.4
Oil	107	97	94	76	–0.3	–0.9	–3.2	–14.5
Gas	112	168	181	185	0.7	0.4	–2.7	–10.4
Electricity	92	128	146	160	1.2	0.9	–5.7	–16.1
Heat	26	40	48	57	1.5	1.3	–0.3	–0.8
Biomass and waste	22	30	42	65	3.2	3.1	26.4	62.1
Other renewables	0	1	4	10	12.9	9.4	52.0	75.3
Non-energy use	**29**	**30**	**32**	**32**	**0.5**	**0.3**	**–3.7**	**–10.6**

Alternative Policy Scenario: European Union

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**2 444**	**3 154**	**3 484**	**3 681**	**0.9**	**0.6**	**–5.2**	**–14.5**
Coal	1 012	975	955	657	–0.2	–1.5	–5.9	–43.6
Oil	205	131	121	53	–0.7	–3.4	–4.0	–5.3
Gas	159	605	617	856	0.2	1.3	–29.0	–35.7
Nuclear	778	988	995	822	0.1	–0.7	12.3	45.7
Hydro	271	300	369	405	1.9	1.2	2.8	5.2
Renewables (excluding hydro)	19	156	427	888	9.6	6.9	1.9	10.7
Biomass and waste	*14*	*90*	*144*	*191*	*4.4*	*2.9*	*–0.0*	*–5.2*
Wind	*1*	*59*	*261*	*586*	*14.5*	*9.2*	*2.1*	*10.8*
Geothermal	*3*	*6*	*8*	*17*	*3.5*	*4.3*	*3.6*	*23.9*
Solar	*0*	*1*	*12*	*77*	*22.0*	*16.8*	*19.8*	*54.2*
Tide and wave	*1*	*1*	*2*	*18*	*11.5*	*14.6*	*25.6*	*107.1*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**723**	**833**	**1 000**	**1.3**	**1.3**	**–5.9**	**–13.7**
Coal	191	151	109	–2.1	–2.1	–18.8	–51.7
Oil	71	68	29	–0.5	–3.4	–	–
Gas	146	198	281	2.8	2.6	–15.7	–27.4
Nuclear	131	127	107	–0.3	–0.8	11.3	45.5
Hydro	131	146	157	1.0	0.7	2.0	3.7
of which pumped storage	*28*	*28*	*28*	*0.0*	*0.0*	–	–
Renewables (excluding hydro)	52	144	317	9.6	7.2	2.6	8.9
Biomass and waste	*16*	*25*	*33*	*4.3*	*2.9*	*0.6*	*–5.3*
Wind	*34*	*108*	*223*	*11.0*	*7.5*	*1.6*	*2.8*
Geothermal	*1*	*1*	*2*	*3.6*	*4.4*	*3.6*	*23.7*
Solar	*1*	*9*	*53*	*20.6*	*15.9*	*21.8*	*54.4*
Tide and wave	*0*	*0*	*5*	*6.4*	*12.2*	*24.9*	*109.2*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**3 808**	**3 847**	**3 879**	**3 465**	**0.1**	**–0.4**	**–4.2**	**–17.8**
Coal	1 666	1 211	1 102	711	–0.9	–2.0	–3.0	–36.8
Oil	1 571	1 675	1 697	1 551	0.1	–0.3	–3.5	–9.6
Gas	571	962	1 080	1 204	1.1	0.9	–6.2	–12.6
Power generation and heat plants	**1 382**	**1 366**	**1 383**	**1 080**	**0.1**	**–0.9**	**–5.9**	**–32.2**
Coal	1 128	980	945	605	–0.3	–1.8	–3.0	–39.9
Oil	158	100	92	39	–0.8	–3.5	–4.1	–6.5
Gas	94	285	346	436	1.8	1.6	–13.5	–20.0
Total final consumption	**2 264**	**2 306**	**2 330**	**2 227**	**0.1**	**–0.1**	**–3.3**	**–9.5**
Coal	500	201	134	90	–3.6	–3.0	–2.8	–9.2
Oil	1 304	1 457	1 491	1 398	0.2	–0.2	–3.7	–10.3
of which transport	*741*	*924*	*940*	*927*	*0.2*	*0.0*	*–4.5*	*–10.7*
Gas	458	649	705	738	0.8	0.5	–2.4	–7.9

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Alternative Policy Scenario: Transition Economies

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**1 488**	**1 077**	**1 210**	**1 285**	**1.1**	**0.7**	**–3.9**	**–9.5**
Coal	330	203	218	183	0.6	–0.4	–4.7	–9.7
Oil	454	223	248	263	1.0	0.6	–5.8	–11.8
Gas	599	536	608	639	1.2	0.7	–3.9	–14.3
Nuclear	60	73	83	124	1.2	2.1	1.8	19.3
Hydro	23	26	29	36	1.1	1.2	0.1	3.0
Biomass and waste	0	17	19	26	1.2	1.7	2.6	14.3
Other renewables	21	1	6	15	21.9	12.8	4.8	15.4
Power generation and heat plants	**574**	**535**	**580**	**597**	**0.7**	**0.4**	**–3.8**	**–8.6**
Coal	171	133	142	106	0.6	–0.9	–5.0	–8.7
Oil	80	26	23	15	–1.3	–2.0	–0.7	–5.5
Gas	240	272	295	295	0.7	0.3	–5.6	–19.4
Nuclear	60	73	83	124	1.2	2.1	1.8	19.3
Hydro	23	26	29	36	1.1	1.2	0.1	3.0
Biomass and waste	0	4	4	8	–0.2	2.5	11.9	67.0
Other renewables	0	0	5	13	25.0	13.9	0.8	8.9
Other transformation, own use and losses	**200**	**157**	**165**	**177**	**0.5**	**0.5**	**–6.3**	**–12.4**
of which electricity	*43*	*39*	*41*	*44*	*0.5*	*0.5*	*–6.1*	*–12.8*
Total final consumption	**1 014**	**704**	**795**	**851**	**1.1**	**0.7**	**–3.7**	**–10.2**
Coal	104	44	49	49	1.1	0.4	–4.1	–12.3
Oil	340	168	190	204	1.1	0.8	–6.7	–12.8
Gas	306	227	272	297	1.6	1.0	–2.3	–9.7
Electricity	121	95	112	130	1.6	1.2	–3.5	–10.0
Heat	123	159	157	152	–0.1	–0.2	–2.8	–8.5
Biomass and waste	0	12	14	17	1.6	1.4	0.2	0.0
Other renewables	21	0	0	2	8.0	8.7	91.8	114.6
Industry	**446**	**245**	**279**	**301**	**1.2**	**0.8**	**–3.6**	**–10.5**
Coal	44	31	36	37	1.4	0.7	–4.5	–12.2
Oil	79	28	33	36	1.5	0.9	–4.4	–11.5
Gas	199	81	100	114	1.9	1.3	–3.6	–11.7
Electricity	76	45	54	66	1.7	1.5	–3.9	–8.3
Heat	47	58	53	46	–0.8	–0.9	–2.3	–8.7
Biomass and waste	0	2	2	3	1.6	1.5	–	–
Other renewables	0	0	0	0	37.1	25.4	–	–
Transport	**154**	**140**	**166**	**184**	**1.5**	**1.0**	**–5.8**	**–9.6**
Oil	135	90	105	115	1.4	0.9	–8.9	–14.0
Biofuels	0	0	0	0	18.4	10.3	64.8	58.7
Other fuels	18	50	60	69	1.8	1.3	–0.0	–1.4
Residential, services and agriculture	**340**	**302**	**332**	**346**	**0.9**	**0.5**	**–2.6**	**–10.1**
Coal	54	11	11	10	0.2	–0.3	–3.2	–14.0
Oil	78	35	36	35	0.3	0.1	–2.5	–10.2
Gas	95	105	121	125	1.3	0.7	–2.3	–11.2
Electricity	36	41	48	53	1.5	1.0	–3.7	–13.8
Heat	76	101	104	107	0.3	0.2	–3.0	–8.5
Biomass and waste	0	10	12	14	1.4	1.3	–0.6	–1.3
Other renewables	1	0	0	1	7.7	8.2	99.3	153.0
Non-energy use	**75**	**17**	**18**	**20**	**0.5**	**0.7**	**–5.7**	**–11.1**

Alternative Policy Scenario: Transition Economies

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**1 840**	**1 536**	**1 821**	**2 093**	**1.6**	**1.2**	**–3.2**	**–8.3**
Coal	501	322	373	269	1.3	–0.7	–7.1	–19.1
Oil	252	54	43	24	–2.1	–3.1	–0.8	–13.7
Gas	586	575	723	821	2.1	1.4	–5.6	–22.2
Nuclear	231	279	317	477	1.2	2.1	1.8	19.3
Hydro	269	303	342	415	1.1	1.2	0.1	3.0
Renewables (excluding hydro)	0	3	24	87	20.7	13.8	28.7	39.8
Biomass and waste	*0*	*2*	*8*	*35*	*12.8*	*11.6*	*175.3*	*55.6*
Wind	*0*	*0*	*11*	*40*	*54.5*	*26.2*	*4.3*	*42.5*
Geothermal	*0*	*0*	*5*	*11*	*25.3*	*13.5*	–	–
Solar	*0*	*1*	*0*	*1*	*–13.3*	*2.3*	–	*35.6*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*500.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**405**	**443**	**505**	**0.8**	**0.9**	**–2.9**	**–8.9**
Coal	109	98	71	–1.0	–1.6	–1.4	–17.8
Oil	30	27	15	–0.6	–2.6	–0.2	–2.2
Gas	137	170	214	2.0	1.7	–7.2	–20.0
Nuclear	40	43	64	0.5	1.8	1.6	19.0
Hydro	88	100	119	1.1	1.1	0.1	2.7
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	1	6	22	22.1	14.4	17.2	41.6
Biomass and waste	*0*	*1*	*6*	*10.6*	*10.3*	*117.1*	*53.1*
Wind	*0*	*4*	*14*	*35.2*	*19.3*	*3.4*	*44.8*
Geothermal	*0*	*1*	*2*	*24.2*	*13.1*	–	*–2.6*
Solar	*0*	*0*	*1*	*49.5*	*28.8*	–	*35.6*
Tide and wave	*0*	*0*	*0*	–	–	–	*531.6*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**3 731**	**2 560**	**2 842**	**2 786**	**1.0**	**0.3**	**–4.5**	**–12.7**
Coal	1 109	783	848	705	0.7	–0.4	–4.7	–9.9
Oil	1 230	573	626	649	0.8	0.5	–5.5	–11.7
Gas	1 392	1 204	1 368	1 431	1.2	0.7	–4.0	–14.5
Power generation and heat plants	**1 515**	**1 287**	**1 368**	**1 197**	**0.6**	**–0.3**	**–5.0**	**–15.2**
Coal	690	557	592	446	0.6	–0.8	–4.9	–8.6
Oil	263	90	75	50	–1.6	–2.2	–0.7	–5.7
Gas	562	641	701	701	0.8	0.3	–5.6	–19.5
Total final consumption	**2 015**	**1 169**	**1 354**	**1 446**	**1.3**	**0.8**	**–4.1**	**–11.0**
Coal	416	224	253	256	1.1	0.5	–4.2	–12.1
Oil	908	427	484	516	1.1	0.7	–6.4	–12.6
of which transport	*330*	*232*	*270*	*295*	*1.4*	*0.9*	*–8.7*	*–13.9*
Gas	691	518	616	674	1.6	1.0	–2.2	–9.3

Alternative Policy Scenario: Russia

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**n.a.**	**640**	**715**	**780**	**1.0**	**0.8**	**–4.8**	**–8.7**
Coal	n.a.	104	111	102	0.6	–0.1	–2.1	–3.8
Oil	n.a.	130	140	149	0.7	0.5	–7.7	–12.2
Gas	n.a.	345	391	417	1.1	0.7	–5.4	–12.7
Nuclear	n.a.	38	46	77	1.8	2.8	–	13.5
Hydro	n.a.	15	16	18	0.6	0.7	–	5.1
Biomass and waste	n.a.	7	7	6	–0.5	–0.3	0.5	0.1
Other renewables	n.a.	0	4	9	24.4	13.5	3.0	11.3
Power generation and heat plants	**n.a.**	**350**	**378**	**402**	**0.7**	**0.5**	**–4.3**	**–7.9**
Coal	n.a.	76	81	70	0.6	–0.3	–0.7	–0.7
Oil	n.a.	17	16	12	–0.6	–1.4	–1.9	–0.6
Gas	n.a.	199	212	213	0.6	0.3	–7.1	–17.2
Nuclear	n.a.	38	46	77	1.8	2.8	–	13.5
Hydro	n.a.	15	16	18	0.6	0.7	–	5.1
Biomass and waste	n.a.	4	3	3	–1.7	–1.7	–	–
Other renewables	n.a.	0	4	9	24.0	13.2	0.8	4.9
Other transformation, own use and losses	**n.a.**	**93**	**96**	**104**	**0.2**	**0.4**	**–9.2**	**–14.4**
of which electricity	*n.a.*	*24*	*26*	*28*	*0.6*	*0.6*	*–6.6*	*–11.2*
Total final consumption	**n.a.**	**425**	**471**	**510**	**0.9**	**0.7**	**–4.6**	**–9.1**
Coal	n.a.	17	19	18	0.8	0.3	–4.9	–10.1
Oil	n.a.	95	104	112	0.8	0.6	–8.8	–13.5
Gas	n.a.	125	154	177	1.9	1.4	–3.5	–7.6
Electricity	n.a.	55	64	75	1.3	1.1	–4.4	–8.6
Heat	n.a.	130	128	124	–0.2	–0.2	–2.7	–7.8
Biomass and waste	n.a.	3	3	3	1.1	1.1	1.1	0.1
Other renewables	n.a.	0	0	1	–	–	170.9	787.4
Industry	**n.a.**	**146**	**161**	**174**	**0.9**	**0.7**	**–4.6**	**–8.3**
Coal	n.a.	10	12	12	1.3	0.7	–5.0	–7.6
Oil	n.a.	15	17	18	0.9	0.7	–7.6	–10.1
Gas	n.a.	44	55	64	2.1	1.5	–5.8	–9.9
Electricity	n.a.	29	34	41	1.4	1.4	–4.1	–5.4
Heat	n.a.	48	43	37	–0.9	–1.0	–2.2	–8.0
Biomass and waste	n.a.	1	1	1	1.4	1.6	–	–
Other renewables	n.a.	0	0	0	–	–	–	–
Transport	**n.a.**	**95**	**113**	**128**	**1.6**	**1.1**	**–5.6**	**–8.2**
Oil	n.a.	54	61	66	1.1	0.8	–10.1	–14.9
Biofuels	n.a.	0	0	0	26.4	13.6	75.6	63.1
Other fuels	n.a.	41	51	61	2.1	1.5	0.0	0.0
Residential, services and agriculture	**n.a.**	**176**	**190**	**200**	**0.7**	**0.5**	**–3.8**	**–10.2**
Coal	n.a.	6	6	6	0.0	–0.4	–5.2	–15.7
Oil	n.a.	19	19	19	0.2	0.0	–4.4	–12.1
Gas	n.a.	47	55	60	1.5	1.0	–3.9	–11.1
Electricity	n.a.	20	23	25	1.3	1.0	–6.2	–15.5
Heat	n.a.	82	85	87	0.2	0.2	–2.9	–7.7
Biomass and waste	n.a.	2	2	2	0.1	0.0	–3.3	–8.6
Other renewables	n.a.	0	0	1	–	–	182.3	823.5
Non-energy use	**n.a.**	**8**	**8**	**9**	**–0.6**	**0.4**	**–11.8**	**–11.6**

Alternative Policy Scenario: Russia

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**n.a.**	**926**	**1 067**	**1 256**	**1.3**	**1.2**	**–3.4**	**–5.1**
Coal	n.a.	161	178	150	1.0	–0.3	–2.3	–13.1
Oil	n.a.	24	20	13	–1.4	–2.2	–4.1	–3.3
Gas	n.a.	419	490	544	1.4	1.0	–6.8	–15.2
Nuclear	n.a.	145	176	297	1.8	2.8	–	13.5
Hydro	n.a.	176	188	210	0.6	0.7	–	5.1
Renewables (excluding hydro)	n.a.	2	14	42	18.1	12.0	32.9	22.0
Biomass and waste	*n.a.*	*2*	*5*	*16*	*9.4*	*8.8*	*169.2*	*20.4*
Wind	*n.a.*	*0*	*5*	*17*	*82.2*	*35.0*	*7.4*	*38.9*
Geothermal	*n.a.*	*0*	*4*	*9*	*22.6*	*12.4*	–	–
Solar	*n.a.*	*0*	*0*	*0*	–	–	–	–
Tide and wave	*n.a.*	*0*	*0*	*0*	–	–	–	–

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**220**	**234**	**270**	**0.6**	**0.8**	**–3.4**	**–5.7**
Coal	48	45	40	–0.7	–0.7	–2.5	–13.1
Oil	9	9	6	0.3	–1.5	–	–
Gas	94	104	120	0.9	0.9	–6.9	–14.2
Nuclear	22	24	40	0.8	2.4	–	13.5
Hydro	46	49	55	0.5	0.7	–	5.2
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	1	3	10	17.7	11.8	21.4	26.9
Biomass and waste	*0*	*1*	*3*	*6.7*	*7.0*	*103.5*	*18.8*
Wind	*0*	*2*	*6*	*58.4*	*27.3*	*5.6*	*40.7*
Geothermal	*0*	*1*	*1*	*21.6*	*12.0*	–	*–3.0*
Solar	*0*	*0*	*0*	–	–	–	–
Tide and wave	*0*	*0*	*0*	–	–	–	–

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**n.a.**	**1 512**	**1 661**	**1 685**	**0.9**	**0.4**	**–4.9**	**–10.5**
Coal	n.a.	418	449	403	0.7	–0.1	–1.7	–3.0
Oil	n.a.	323	343	358	0.6	0.4	–7.2	–11.8
Gas	n.a.	772	869	925	1.1	0.7	–5.5	–13.0
Power generation and heat plants	**n.a.**	**853**	**895**	**837**	**0.4**	**–0.1**	**–4.4**	**–11.2**
Coal	n.a.	325	347	301	0.6	–0.3	–0.7	–0.7
Oil	n.a.	59	51	38	–1.2	–1.7	–1.9	–0.6
Gas	n.a.	469	496	498	0.5	0.2	–7.1	–17.2
Total final consumption	**n.a.**	**597**	**693**	**761**	**1.4**	**0.9**	**–5.5**	**–9.9**
Coal	n.a.	90	100	100	0.9	0.4	–5.0	–9.4
Oil	n.a.	227	249	266	0.8	0.6	–8.4	–13.4
of which transport	*n.a.*	*128*	*145*	*159*	*1.1*	*0.8*	*–10.0*	*–14.8*
Gas	n.a.	279	345	396	1.9	1.4	–3.4	–7.5

Alternative Policy Scenario: Developing Countries

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**2 612**	**4 460**	**6 025**	**7 583**	**2.8**	**2.1**	**–5.4**	**–12.0**
Coal	790	1 442	2 040	2 344	3.2	1.9	–7.5	–20.2
Oil	719	1 317	1 730	2 170	2.5	1.9	–5.9	–12.8
Gas	236	567	897	1 260	4.3	3.1	–6.1	–14.6
Nuclear	15	37	93	192	8.7	6.5	11.4	40.9
Hydro	61	107	169	251	4.3	3.4	2.0	3.2
Biomass and waste	783	972	1 047	1 226	0.7	0.9	–2.8	–0.8
Other renewables	7	18	48	140	9.0	8.1	10.5	37.2
Power generation and heat plants	**524**	**1 401**	**2 168**	**2 958**	**4.0**	**2.9**	**–7.0**	**–14.3**
Coal	268	848	1 284	1 571	3.8	2.4	–8.2	–21.3
Oil	100	150	159	137	0.5	–0.4	–7.2	–13.6
Gas	71	233	377	522	4.5	3.2	–13.1	–27.8
Nuclear	15	37	93	192	8.7	6.5	11.4	40.9
Hydro	61	107	169	251	4.3	3.4	2.0	3.2
Biomass and waste	2	9	50	184	16.8	12.3	18.6	62.3
Other renewables	7	18	36	100	6.7	6.9	2.5	25.3
Other transformation, own use and losses	**297**	**491**	**661**	**810**	**2.7**	**1.9**	**–4.2**	**–9.4**
of which electricity	*42*	*106*	*176*	*242*	*4.7*	*3.2*	*–6.7*	*–14.9*
Total final consumption	**2 005**	**3 109**	**4 130**	**5 163**	**2.6**	**2.0**	**–4.9**	**–11.4**
Coal	432	464	609	615	2.5	1.1	–6.6	–19.0
Oil	566	1 060	1 428	1 866	2.7	2.2	–5.9	–13.0
Gas	108	245	395	573	4.4	3.3	–0.2	–2.5
Electricity	157	388	691	1 018	5.4	3.8	–6.0	–13.6
Heat	14	37	53	72	3.4	2.6	–2.6	–2.7
Biomass and waste	728	914	943	980	0.3	0.3	–3.9	–7.6
Other renewables	0	1	12	40	26.9	15.9	45.9	80.1
Industry	**673**	**1 114**	**1 632**	**1 992**	**3.5**	**2.3**	**–3.8**	**–9.6**
Coal	268	354	505	533	3.3	1.6	–6.6	–18.7
Oil	147	261	333	377	2.2	1.4	–6.1	–13.3
Gas	91	173	280	392	4.5	3.2	0.7	0.1
Electricity	83	198	346	461	5.2	3.3	–4.8	–10.8
Heat	11	25	35	48	3.2	2.6	2.4	11.4
Biomass and waste	74	104	132	180	2.2	2.1	5.6	12.6
Other renewables	0	0	0	0	–	–	–	–
Transport	**296**	**547**	**750**	**1 106**	**2.9**	**2.7**	**–5.5**	**–11.3**
Oil	275	526	708	1 018	2.7	2.6	–6.5	–13.8
Biofuels	6	6	21	62	11.3	9.1	38.0	53.4
Other fuels	14	14	20	27	3.3	2.5	–0.9	–1.4
Residential, services and agriculture	**963**	**1 330**	**1 581**	**1 854**	**1.6**	**1.3**	**–5.8**	**–13.6**
Coal	117	78	70	52	–0.9	–1.5	–7.7	–26.9
Oil	114	201	276	325	2.9	1.9	–4.5	–11.7
Gas	16	65	104	166	4.3	3.7	–2.4	–8.2
Electricity	69	174	318	515	5.6	4.3	–7.8	–16.9
Heat	3	11	17	23	3.9	2.8	–11.9	–23.3
Biomass and waste	644	800	786	734	–0.2	–0.3	–6.1	–14.3
Other renewables	0	1	12	40	26.7	15.9	46.8	80.6
Non-energy use	**73**	**119**	**167**	**211**	**3.1**	**2.2**	**–3.9**	**–7.5**

Alternative Policy Scenario: Developing Countries

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**2 321**	**5 754**	**10 133**	**14 847**	**5.3**	**3.7**	**–5.7**	**–12.7**
Coal	917	2 753	5 113	6 843	5.8	3.6	–9.7	–23.8
Oil	366	580	655	587	1.1	0.0	–2.3	–4.6
Gas	257	983	1 795	2 735	5.6	4.0	–8.2	–19.3
Nuclear	57	142	358	737	8.7	6.5	11.4	40.9
Hydro	709	1 239	1 967	2 919	4.3	3.4	2.0	3.2
Renewables (excluding hydro)	14	56	244	1 026	14.3	11.8	13.6	53.6
Biomass and waste	*7*	*29*	*132*	*465*	*14.7*	*11.2*	*17.2*	*56.2*
Wind	*0*	*5*	*74*	*407*	*27.8*	*18.5*	*15.5*	*54.7*
Geothermal	*8*	*20*	*36*	*75*	*5.5*	*5.2*	*0.0*	*8.6*
Solar	*0*	*2*	*2*	*78*	*0.6*	*15.0*	–	*104.7*
Tide and wave	*0*	*0*	*0*	*1*	–	–	–	*439.4*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**1 289**	**2 256**	**3 400**	**5.2**	**3.8**	**–4.8**	**–9.9**
Coal	470	884	1 184	5.9	3.6	–9.7	–23.6
Oil	189	223	209	1.5	0.4	–1.9	–6.3
Gas	265	513	819	6.2	4.4	–7.5	–17.4
Nuclear	18	45	93	8.5	6.4	10.9	40.0
Hydro	334	538	813	4.4	3.5	3.2	5.4
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	13	53	284	13.7	12.6	12.7	63.6
Biomass and waste	*5*	*21*	*73*	*14.1*	*11.0*	*13.6*	*56.2*
Wind	*4*	*26*	*156*	*17.9*	*14.9*	*15.5*	*63.8*
Geothermal	*3*	*5*	*11*	*5.6*	*5.2*	*0.0*	*8.4*
Solar	*1*	*1*	*43*	*0.0*	*16.6*	–	*104.4*
Tide and wave	*0*	*0*	*0*	–	–	–	*441.3*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**5 317**	**10 171**	**14 369**	**17 550**	**3.2**	**2.1**	**–6.7**	**–16.9**
Coal	2 871	5 508	7 911	9 097	3.3	1.9	–7.6	–20.6
Oil	1 938	3 392	4 450	5 636	2.5	2.0	–5.1	–11.2
Gas	507	1 271	2 008	2 817	4.2	3.1	–6.3	–14.9
Power generation and heat plants	**1 535**	**4 395**	**6 502**	**7 921**	**3.6**	**2.3**	**–8.9**	**–22.0**
Coal	1 050	3 378	5 113	6 254	3.8	2.4	–8.2	–21.3
Oil	319	472	500	429	0.5	–0.4	–7.2	–13.5
Gas	167	545	890	1 238	4.6	3.2	–13.1	–27.7
Total final consumption	**3 479**	**5 226**	**7 167**	**8 792**	**2.9**	**2.0**	**–5.0**	**–12.7**
Coal	1 760	2 004	2 658	2 693	2.6	1.1	–6.5	–19.3
Oil	1 491	2 697	3 671	4 896	2.8	2.3	–4.8	–11.0
of which transport	*740*	*1 435*	*1 964*	*2 866*	*2.9*	*2.7*	*–5.0*	*–11.4*
Gas	228	525	838	1 202	4.3	3.2	–0.3	–2.5

Alternative Policy Scenario: Developing Asia

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**1 638**	**2 916**	**4 027**	**5 111**	**3.0**	**2.2**	**–5.5**	**–11.8**
Coal	696	1 309	1 902	2 197	3.5	2.0	–7.4	–20.1
Oil	321	713	968	1 286	2.8	2.3	–6.2	–13.2
Gas	74	203	335	495	4.6	3.5	–2.7	–5.1
Nuclear	10	29	78	175	9.6	7.2	13.9	43.7
Hydro	24	47	87	138	5.8	4.2	3.9	9.3
Biomass and waste	506	600	619	718	0.3	0.7	–4.0	0.1
Other renewables	6	15	38	102	8.8	7.7	7.1	30.9
Power generation and heat plants	**323**	**1 011**	**1 624**	**2 220**	**4.4**	**3.1**	**–6.1**	**–12.3**
Coal	222	775	1 210	1 489	4.1	2.5	–7.8	–20.9
Oil	46	56	63	50	1.1	–0.4	–1.4	–2.7
Gas	16	85	126	163	3.6	2.5	–12.8	–24.4
Nuclear	10	29	78	175	9.6	7.2	13.9	43.7
Hydro	24	47	87	138	5.8	4.2	3.9	9.3
Biomass and waste	0	4	30	127	19.4	13.9	11.2	73.6
Other renewables	6	15	30	77	6.7	6.5	2.3	24.2
Other transformation, own use and losses	**162**	**300**	**415**	**504**	**3.0**	**2.0**	**–5.4**	**–11.2**
of which electricity	*24*	*71*	*127*	*174*	*5.4*	*3.5*	*–7.6*	*–16.1*
Total final consumption	**1 278**	**1 975**	**2 669**	**3 368**	**2.8**	**2.1**	**–5.5**	**–12.1**
Coal	406	434	576	582	2.6	1.1	–6.8	–19.5
Oil	249	581	812	1 136	3.1	2.6	–6.5	–13.5
Gas	35	86	158	260	5.7	4.3	5.3	7.9
Electricity	85	252	487	719	6.2	4.1	–6.7	–14.4
Heat	14	37	53	72	3.4	2.6	–2.6	–2.7
Biomass and waste	489	585	575	574	–0.2	–0.1	–4.8	–8.4
Other renewables	0	0	7	24	–	–	32.5	58.0
Industry	**438**	**756**	**1 149**	**1 391**	**3.9**	**2.4**	**–4.2**	**–10.3**
Coal	245	328	477	506	3.5	1.7	–6.8	–19.0
Oil	77	158	205	224	2.4	1.3	–8.1	–16.9
Gas	29	61	109	172	5.4	4.0	8.9	16.2
Electricity	51	144	268	349	5.8	3.4	–5.3	–11.3
Heat	11	25	35	48	3.2	2.6	2.4	11.4
Biomass and waste	26	39	54	92	3.1	3.4	17.2	27.4
Other renewables	0	0	0	0	–	–	–	–
Transport	**122**	**265**	**392**	**668**	**3.6**	**3.6**	**–4.7**	**–9.8**
Oil	108	257	373	623	3.4	3.5	–6.0	–12.6
Biofuels	0	0	9	33	61.8	29.1	132.7	103.6
Other fuels	14	8	10	13	2.0	1.8	–0.0	–0.1
Residential, services and agriculture	**659**	**857**	**995**	**1 145**	**1.4**	**1.1**	**–7.4**	**–16.0**
Coal	114	73	65	46	–1.1	–1.7	–8.3	–29.2
Oil	50	116	158	190	2.8	1.9	–6.0	–14.0
Gas	5	24	48	87	6.5	5.1	–1.9	–5.2
Electricity	29	91	192	328	7.0	5.1	–9.5	–18.8
Heat	3	11	17	23	3.9	2.8	–11.9	–23.3
Biomass and waste	458	542	509	445	–0.6	–0.8	–7.6	–16.7
Other renewables	0	0	7	24	–	–	33.0	58.3
Non-energy use	**59**	**96**	**133**	**164**	**3.0**	**2.1**	**–4.3**	**–7.7**

Alternative Policy Scenario: Developing Asia

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**1 274**	**3 758**	**7 180**	**10 571**	**6.1**	**4.1**	**–6.3**	**–13.1**
Coal	727	2 442	4 789	6 448	6.3	3.8	–9.2	–23.4
Oil	166	222	254	205	1.2	–0.3	–1.6	–3.0
Gas	59	406	662	882	4.5	3.0	–11.4	–20.8
Nuclear	39	110	300	672	9.6	7.2	13.9	43.7
Hydro	277	545	1 009	1 603	5.8	4.2	3.9	9.3
Renewables (excluding hydro)	7	33	165	762	15.7	12.8	10.1	57.5
Biomass and waste	*0*	*10*	*76*	*323*	*19.8*	*14.1*	*10.8*	*68.2*
Wind	*0*	*4*	*58*	*340*	*28.2*	*18.9*	*15.7*	*54.4*
Geothermal	*7*	*17*	*29*	*51*	*5.1*	*4.3*	–	*6.5*
Solar	*0*	*2*	*2*	*47*	*0.6*	*12.9*	–	*98.7*
Tide and wave	*0*	*0*	*0*	*1*	–	–	–	*444.4*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**789**	**1 477**	**2 251**	**5.9**	**4.1**	**–5.7**	**–10.4**
Coal	421	825	1 112	6.3	3.8	–9.7	–23.7
Oil	62	72	60	1.4	–0.1	–0.5	–1.0
Gas	107	188	270	5.3	3.6	–10.3	–21.1
Nuclear	14	38	84	9.6	7.2	13.3	42.6
Hydro	177	317	506	5.4	4.1	4.2	9.6
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	9	38	218	14.1	13.1	10.0	66.0
Biomass and waste	*2*	*12*	*51*	*19.1*	*13.8*	*6.1*	*68.7*
Wind	*4*	*20*	*133*	*16.6*	*14.7*	*15.5*	*64.9*
Geothermal	*3*	*4*	*8*	*5.2*	*4.3*	–	*6.3*
Solar	*1*	*1*	*26*	*0.0*	*14.5*	–	*97.5*
Tide and wave	*0*	*0*	*0*	–	–	–	*441.7*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**3 563**	**7 265**	**10 580**	**12 937**	**3.5**	**2.2**	**–6.7**	**–17.3**
Coal	2 567	5 071	7 462	8 615	3.6	2.1	–7.4	–20.4
Oil	850	1 746	2 388	3 242	2.9	2.4	–5.6	–12.2
Gas	146	448	730	1 080	4.5	3.4	–3.0	–5.3
Power generation and heat plants	**1 052**	**3 462**	**5 313**	**6 470**	**4.0**	**2.4**	**–7.8**	**–20.7**
Coal	868	3 083	4 816	5 925	4.1	2.5	–7.8	–20.8
Oil	146	178	201	161	1.1	–0.4	–1.4	–2.7
Gas	38	200	295	383	3.6	2.5	–12.7	–24.2
Total final consumption	**2 355**	**3 472**	**4 842**	**5 966**	**3.1**	**2.1**	**–5.7**	**–14.3**
Coal	1 642	1 866	2 509	2 543	2.7	1.2	–6.8	–19.7
Oil	644	1 432	2 013	2 895	3.1	2.7	–6.0	–12.5
of which transport	*290*	*695*	*1 013*	*1 703*	*3.5*	*3.5*	*–5.9*	*–12.5*
Gas	69	174	320	528	5.7	4.3	5.4	8.5

Alternative Policy Scenario: China

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**877**	**1 626**	**2 385**	**3 006**	**3.5**	**2.4**	**–5.0**	**–11.4**
Coal	534	999	1 502	1 702	3.8	2.1	–6.4	–17.5
Oil	116	319	464	648	3.4	2.8	–6.6	–14.5
Gas	16	44	101	184	7.9	5.7	12.7	17.1
Nuclear	0	13	41	108	10.9	8.4	26.5	61.7
Hydro	11	30	57	85	5.8	4.0	1.5	5.9
Biomass and waste	200	221	211	235	–0.4	0.2	–5.2	–1.6
Other renewables	0	0	10	44	–	–	21.7	50.4
Power generation and heat plants	**173**	**639**	**1 085**	**1 451**	**4.9**	**3.2**	**–4.7**	**–10.0**
Coal	145	566	929	1 119	4.6	2.7	–6.5	–17.7
Oil	16	22	21	17	–0.5	–0.9	–0.4	–0.4
Gas	1	6	21	37	12.3	7.3	1.7	–7.6
Nuclear	0	13	41	108	10.9	8.4	26.5	61.7
Hydro	11	30	57	85	5.8	4.0	1.5	5.9
Biomass and waste	0	1	13	61	22.7	15.7	10.2	88.1
Other renewables	0	0	4	24	–	–	10.6	54.4
Other transformation, own use and losses	**85**	**176**	**252**	**308**	**3.3**	**2.2**	**–5.5**	**–11.2**
of which electricity	*12*	*41*	*82*	*112*	*6.5*	*3.9*	*–6.3*	*–13.9*
Total final consumption	**689**	**1 050**	**1 513**	**1 901**	**3.4**	**2.3**	**–5.2**	**–12.8**
Coal	332	349	473	474	2.8	1.2	–6.3	–18.2
Oil	88	261	397	582	3.9	3.1	–6.7	–14.4
Gas	12	33	68	126	6.9	5.3	16.1	22.4
Electricity	43	151	318	455	7.0	4.3	–5.8	–13.5
Heat	13	36	53	71	3.4	2.6	–2.7	–2.7
Biomass and waste	200	219	198	174	–0.9	–0.9	–6.0	–15.6
Other renewables	0	0	6	20	–	–	29.4	45.7
Industry	**274**	**470**	**764**	**888**	**4.5**	**2.5**	**–3.6**	**–11.4**
Coal	189	256	388	408	3.9	1.8	–6.4	–18.7
Oil	35	70	93	90	2.6	1.0	–8.5	–20.2
Gas	10	20	39	67	6.2	4.8	33.7	61.1
Electricity	30	100	198	248	6.4	3.6	–5.2	–12.0
Heat	11	25	35	48	3.3	2.6	2.4	11.4
Biomass and waste	0	0	11	25	–	–	197.7	29.4
Other renewables	0	0	0	0	–	–	–	–
Transport	**41**	**110**	**185**	**367**	**4.8**	**4.7**	**–5.4**	**–11.3**
Oil	30	104	175	344	4.9	4.7	–6.3	–13.1
Biofuels	0	0	3	13	–	–	76.1	65.2
Other fuels	11	6	7	9	1.7	1.6	–0.0	0.0
Residential, services and agriculture	**337**	**406**	**478**	**555**	**1.5**	**1.2**	**–7.8**	**–16.5**
Coal	102	63	54	39	–1.4	–1.8	–6.3	–18.9
Oil	18	59	87	102	3.6	2.1	–6.0	–14.3
Gas	3	13	29	58	7.8	6.0	–1.1	–4.0
Electricity	11	41	101	178	8.5	5.8	–7.9	–17.3
Heat	2	11	17	22	4.0	2.9	–12.1	–23.5
Biomass and waste	200	219	184	136	–1.6	–1.8	–10.3	–24.2
Other renewables	0	0	6	20	–	–	29.6	45.8
Non-energy use	**38**	**63**	**85**	**92**	**2.7**	**1.5**	**–4.7**	**–8.8**

Alternative Policy Scenario: China

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**650**	**2 237**	**4 696**	**6 786**	**7.0**	**4.4**	**–5.0**	**–11.0**
Coal	471	1 739	3 666	4 766	7.0	4.0	–7.6	–20.3
Oil	49	72	63	53	–1.1	–1.1	–0.3	–0.2
Gas	3	19	86	159	14.5	8.4	4.4	–6.1
Nuclear	0	50	157	414	10.9	8.4	26.5	61.7
Hydro	127	354	660	992	5.8	4.0	1.5	5.9
Renewables (excluding hydro)	0	2	64	401	34.3	21.6	13.6	75.6
Biomass and waste	*0*	*2*	*36*	*175*	*27.6*	*17.8*	*10.6*	*89.0*
Wind	*0*	*0*	*26*	*197*	–	–	*19.4*	*62.4*
Geothermal	*0*	*0*	*2*	*6*	–	–	–	*19.4*
Solar	*0*	*0*	*0*	*22*	–	–	–	*143.7*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*600.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**442**	**916**	**1 371**	**6.8**	**4.4**	**–4.5**	**–8.4**
Coal	307	638	833	6.9	3.9	–7.2	–20.0
Oil	16	19	17	2.0	0.2	–1.0	1.6
Gas	8	27	54	12.4	7.9	–6.9	–12.7
Nuclear	6	19	50	11.0	8.5	26.5	61.7
Hydro	105	198	298	5.9	4.1	1.5	5.9
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	1	15	120	25.2	19.2	12.0	82.9
Biomass and waste	*0*	*6*	*28*	*26.8*	*17.6*	*2.8*	*90.1*
Wind	*1*	*9*	*79*	*24.9*	*19.5*	*19.3*	*75.9*
Geothermal	*0*	*0*	*1*	–	–	–	*19.4*
Solar	*0*	*0*	*12*	*0.0*	*21.6*	–	*131.1*
Tide and wave	*0*	*0*	*0*	–	–	–	*595.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**2 289**	**4 769**	**7 298**	**8 801**	**3.9**	**2.4**	**–5.8**	**–15.6**
Coal	1 952	3 897	5 935	6 726	3.9	2.1	–6.3	–17.6
Oil	304	779	1 149	1 679	3.6	3.0	–5.7	–12.8
Gas	32	93	214	397	7.9	5.8	12.7	18.9
Power generation and heat plants	**623**	**2 355**	**3 842**	**4 629**	**4.6**	**2.6**	**–6.3**	**–17.4**
Coal	568	2 269	3 723	4 483	4.6	2.7	–6.5	–17.7
Oil	52	72	68	56	–0.5	–0.9	–0.4	–0.4
Gas	3	14	51	90	12.3	7.3	1.7	–7.6
Total final consumption	**1 579**	**2 211**	**3 198**	**3 865**	**3.4**	**2.2**	**–5.3**	**–14.0**
Coal	1 332	1 509	2 078	2 099	3.0	1.3	–6.0	–17.8
Oil	225	640	992	1 528	4.1	3.4	–5.9	–12.7
of which transport	*83*	*290*	*490*	*965*	*4.9*	*4.7*	*–6.1*	*–12.9*
Gas	22	61	127	238	6.9	5.4	17.0	25.4

Alternative Policy Scenario: India

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**361**	**573**	**733**	**964**	**2.3**	**2.0**	**–5.4**	**–12.7**
Coal	105	196	259	338	2.6	2.1	–8.4	–25.0
Oil	63	127	176	238	3.0	2.4	–4.3	–11.3
Gas	10	23	39	63	4.8	3.9	–2.2	–7.7
Nuclear	2	4	19	48	14.4	9.6	5.3	33.1
Hydro	6	7	13	25	5.0	4.9	5.5	20.3
Biomass and waste	176	214	224	241	0.4	0.5	–4.9	–4.7
Other renewables	0	0	3	10	20.9	14.0	14.1	53.2
Power generation and heat plants	**73**	**182**	**268**	**419**	**3.6**	**3.3**	**–5.8**	**–12.9**
Coal	58	147	197	275	2.7	2.4	–7.1	–22.8
Oil	4	9	11	11	2.5	0.8	–0.1	–0.1
Gas	3	13	19	29	3.8	3.2	–2.3	–9.7
Nuclear	2	4	19	48	14.4	9.6	5.3	33.1
Hydro	6	7	13	25	5.0	4.9	5.5	20.3
Biomass and waste	0	1	6	23	16.5	12.4	–31.7	18.9
Other renewables	0	0	2	8	18.5	12.8	13.9	39.7
Other transformation, own use and losses	**19**	**45**	**57**	**69**	**2.2**	**1.6**	**–7.5**	**–18.3**
of which electricity	*7*	*19*	*28*	*40*	*3.5*	*2.9*	*–8.8*	*–18.8*
Total final consumption	**294**	**403**	**508**	**652**	**2.1**	**1.9**	**–5.0**	**–11.7**
Coal	41	36	48	51	2.6	1.3	–13.4	–34.8
Oil	54	107	152	214	3.3	2.7	–4.5	–11.6
Gas	6	9	17	31	6.6	5.0	–2.2	–6.6
Electricity	18	38	72	135	5.9	5.0	–3.6	–9.5
Heat	0	0	0	0	–	–	–	–
Biomass and waste	176	213	218	218	0.2	0.1	–3.9	–6.7
Other renewables	0	0	1	3	–	–	15.0	115.9
Industry	**75**	**109**	**155**	**207**	**3.2**	**2.5**	**–4.4**	**–10.5**
Coal	28	29	40	46	3.2	1.9	–11.7	–27.5
Oil	13	33	47	61	3.4	2.4	–3.3	–8.9
Gas	6	8	15	24	6.1	4.3	–1.5	–2.9
Electricity	9	17	26	42	3.9	3.6	–3.1	–6.8
Heat	0	0	0	0	–	–	–	–
Biomass and waste	20	23	27	33	1.4	1.3	2.8	10.3
Other renewables	0	0	0	0	–	–	–	–
Transport	**28**	**36**	**49**	**74**	**2.7**	**2.8**	**–3.5**	**–9.0**
Oil	26	36	47	67	2.6	2.5	–3.7	–12.2
Biofuels	0	0	0	4	–	–	32.9	84.6
Other fuels	3	1	1	2	5.1	3.6	0.0	0.0
Residential, services and agriculture	**187**	**243**	**277**	**322**	**1.2**	**1.1**	**–5.7**	**–13.9**
Coal	11	8	8	5	0.3	–2.0	–21.0	–68.0
Oil	12	26	35	44	2.5	2.0	–7.9	–19.1
Gas	0	1	2	7	11.4	9.1	–6.4	–18.0
Electricity	8	19	41	83	7.6	5.9	–4.4	–11.7
Heat	0	0	0	0	–	–	–	–
Biomass and waste	156	190	191	181	0.0	–0.2	–4.8	–10.3
Other renewables	0	0	0	2	–	–	16.0	118.9
Non-energy use	**4**	**15**	**27**	**50**	**5.8**	**4.8**	**–3.0**	**–4.8**

Alternative Policy Scenario: India

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**289**	**668**	**1 163**	**2 041**	**5.2**	**4.4**	**–5.1**	**–11.8**
Coal	189	461	765	1 242	4.7	3.9	–8.4	–23.8
Oil	13	36	49	46	2.9	1.0	0.1	0.0
Gas	10	63	96	151	3.9	3.4	–2.2	–7.5
Nuclear	6	17	75	186	14.4	9.6	5.3	33.1
Hydro	72	85	145	296	5.0	4.9	5.5	20.3
Renewables (excluding hydro)	0	6	32	120	16.9	12.5	–5.2	35.3
Biomass and waste	*0*	*2*	*10*	*40*	*16.5*	*12.4*	*–31.7*	*18.9*
Wind	*0*	*4*	*21*	*70*	*17.0*	*11.9*	*16.7*	*41.9*
Geothermal	*0*	*0*	*0*	*1*	–	–	–	–
Solar	*0*	*0*	*0*	*9*	*23.4*	*34.6*	–	*83.7*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*250.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**131**	**221**	**409**	**4.8**	**4.5**	**–3.4**	**–6.2**
Coal	72	117	191	4.5	3.8	–8.4	–23.8
Oil	8	11	10	2.5	0.9	–	–
Gas	14	22	39	4.4	4.1	–2.9	–8.1
Nuclear	3	10	25	13.2	9.2	5.3	33.1
Hydro	31	51	105	4.6	4.7	5.8	20.2
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	3	10	39	10.1	9.9	3.9	46.1
Biomass and waste	*0*	*2*	*6*	*15.8*	*12.1*	*–31.4*	*18.9*
Wind	*3*	*8*	*27*	*9.2*	*8.9*	*15.9*	*48.1*
Geothermal	*0*	*0*	*0*	–	–	–	–
Solar	*0*	*0*	*5*	*0.0*	*22.7*	–	*85.1*
Tide and wave	*0*	*0*	*0*	–	–	–	*250.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**588**	**1 103**	**1 502**	**1 999**	**2.8**	**2.3**	**–7.3**	**–21.4**
Coal	401	734	981	1 286	2.7	2.2	–8.9	–26.1
Oil	164	314	431	568	2.9	2.3	–4.4	–12.0
Gas	23	54	90	145	4.7	3.9	–2.2	–7.8
Power generation and heat plants	**245**	**629**	**847**	**1 167**	**2.7**	**2.4**	**–6.6**	**–21.7**
Coal	225	572	767	1 067	2.7	2.4	–7.1	–22.8
Oil	11	26	35	33	2.5	0.8	–0.1	–0.1
Gas	8	30	45	68	3.8	3.2	–2.3	–9.7
Total final consumption	**328**	**441**	**615**	**789**	**3.1**	**2.3**	**–8.4**	**–21.5**
Coal	171	160	212	217	2.6	1.2	–14.8	–39.0
Oil	144	261	364	503	3.1	2.6	–4.8	–12.5
of which transport	*72*	*98*	*130*	*186*	*2.6*	*2.5*	*–3.7*	*–12.2*
Gas	13	19	39	69	6.6	5.0	–2.2	–6.8

Alternative Policy Scenario: Latin America

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**339**	**484**	**599**	**745**	**2.0**	**1.7**	**–4.3**	**–11.9**
Coal	17	22	24	28	0.6	0.9	–12.7	–24.4
Oil	157	218	241	267	0.9	0.8	–6.0	–15.9
Gas	54	98	145	201	3.6	2.8	–5.3	–18.0
Nuclear	2	5	10	12	6.0	3.2	–	28.8
Hydro	31	51	68	87	2.6	2.1	–1.7	–6.9
Biomass and waste	77	88	107	131	1.8	1.6	0.8	2.0
Other renewables	1	2	5	19	8.2	9.0	6.5	32.5
Power generation and heat plants	**69**	**122**	**171**	**232**	**3.1**	**2.5**	**–4.7**	**–14.7**
Coal	5	8	8	10	0.0	0.9	–26.1	–40.9
Oil	14	25	18	9	–2.8	–3.9	–8.4	–18.1
Gas	14	27	55	85	6.6	4.5	–8.5	–27.1
Nuclear	2	5	10	12	6.0	3.2	–	28.8
Hydro	31	51	68	87	2.6	2.1	–1.7	–6.9
Biomass and waste	2	5	9	15	6.3	4.7	33.2	13.0
Other renewables	1	2	4	15	7.0	8.1	–	20.3
Other transformation, own use and losses	**51**	**57**	**69**	**85**	**1.8**	**1.6**	**–3.1**	**–9.3**
of which electricity	*8*	*15*	*20*	*26*	*2.6*	*2.1*	*–4.2*	*–13.6*
Total final consumption	**262**	**380**	**465**	**575**	**1.9**	**1.6**	**–4.4**	**–11.5**
Coal	7	10	12	13	1.0	0.9	–4.4	–11.2
Oil	127	178	204	234	1.3	1.1	–6.1	–16.5
Gas	25	54	70	93	2.4	2.1	–3.2	–10.3
Electricity	35	60	87	122	3.4	2.7	–4.7	–13.4
Heat	0	0	0	0	–	–	–	–
Biomass and waste	68	77	91	109	1.6	1.3	–1.5	0.8
Other renewables	0	0	1	4	25.8	17.9	73.0	110.8
Industry	**99**	**151**	**188**	**228**	**2.0**	**1.6**	**–3.7**	**–10.0**
Coal	7	10	11	13	1.1	1.0	–4.4	–11.3
Oil	27	35	42	48	1.7	1.2	–3.4	–10.7
Gas	19	38	47	57	1.9	1.6	–3.5	–10.5
Electricity	17	29	41	59	3.4	2.8	–4.1	–11.8
Heat	0	0	0	0	–	–	–	–
Biomass and waste	30	39	46	50	1.5	1.0	–3.7	–5.9
Other renewables	0	0	0	0	–	–	–	–
Transport	**76**	**116**	**134**	**166**	**1.3**	**1.4**	**–6.7**	**–15.7**
Oil	70	105	115	130	0.8	0.8	–8.2	–21.4
Biofuels	6	6	11	25	5.2	5.4	7.4	23.5
Other fuels	0	5	8	11	4.0	3.0	–2.2	–3.4
Residential, services and agriculture	**80**	**103**	**133**	**169**	**2.3**	**1.9**	**–3.1**	**–9.2**
Coal	0	0	0	0	–2.4	–2.8	–1.1	–15.8
Oil	25	29	36	43	2.1	1.5	–3.0	–8.3
Gas	6	11	16	25	3.2	3.0	–2.7	–12.3
Electricity	17	32	46	63	3.4	2.7	–5.2	–15.0
Heat	0	0	0	0	–	–	–	–
Biomass and waste	32	31	34	34	0.7	0.3	–1.1	–2.3
Other renewables	0	0	1	4	25.6	17.9	75.9	111.7
Non-energy use	**6**	**9**	**11**	**13**	**1.4**	**1.3**	**–2.6**	**–8.6**

Alternative Policy Scenario: Latin America

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**491**	**874**	**1 244**	**1 716**	**3.3**	**2.6**	**–4.6**	**–13.5**
Coal	15	30	31	45	0.1	1.5	–28.2	–42.0
Oil	41	83	69	35	–1.6	–3.2	–8.8	–19.0
Gas	55	131	274	473	6.9	5.1	–11.1	–27.9
Nuclear	10	19	37	44	6.0	3.2	–	28.8
Hydro	364	589	786	1 009	2.6	2.1	–1.7	–6.9
Renewables (excluding hydro)	7	21	47	110	7.6	6.6	17.1	23.9
Biomass and waste	*7*	*18*	*34*	*56*	*5.9*	*4.4*	*24.8*	*10.7*
Wind	*0*	*0*	*8*	*32*	*31.0*	*18.1*	–	*46.0*
Geothermal	*1*	*2*	*4*	*13*	*5.3*	*7.0*	–	*12.7*
Solar	*0*	*0*	*0*	*8*	–	–	–	*87.6*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*366.7*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**206**	**319**	**447**	**4.1**	**3.0**	**–3.5**	**–11.4**
Coal	5	7	8	1.9	1.7	–17.4	–35.5
Oil	28	29	18	0.1	–1.8	–1.9	–7.9
Gas	38	100	170	9.3	6.0	–6.4	–19.7
Nuclear	3	5	6	4.9	2.8	–	29.1
Hydro	128	170	218	2.6	2.1	–2.3	–7.5
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	4	9	27	8.5	8.0	13.4	35.0
Biomass and waste	*3*	*6*	*9*	*5.4*	*4.1*	*23.6*	*10.7*
Wind	*0*	*3*	*11*	*26.8*	*16.5*	–	*47.5*
Geothermal	*0*	*1*	*2*	*5.4*	*7.0*	–	*12.7*
Solar	*0*	*0*	*5*	–	–	–	*87.6*
Tide and wave	*0*	*0*	*0*	–	–	–	*381.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**602**	**907**	**1 091**	**1 330**	**1.7**	**1.5**	**–5.2**	**–14.3**
Coal	57	85	88	103	0.2	0.7	–14.6	–26.2
Oil	426	601	679	785	1.1	1.0	–3.9	–10.1
Gas	119	221	324	442	3.6	2.7	–5.0	–17.9
Power generation and heat plants	**98**	**176**	**218**	**266**	**2.0**	**1.6**	**–12.0**	**–29.0**
Coal	21	35	32	39	–0.8	0.5	–28.3	–42.0
Oil	45	77	57	27	–2.8	–3.9	–8.3	–17.9
Gas	32	64	130	199	6.6	4.5	–8.5	–27.1
Total final consumption	**439**	**656**	**787**	**960**	**1.7**	**1.5**	**–3.5**	**–10.1**
Coal	32	47	53	60	1.0	0.9	–4.4	–11.2
Oil	350	489	584	711	1.6	1.4	–3.6	–10.0
of which transport	*200*	*301*	*347*	*426*	*1.3*	*1.3*	*–4.1*	*–11.0*
Gas	56	119	151	189	2.1	1.8	–2.8	–9.9

Alternative Policy Scenario: Brazil

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**131**	**200**	**252**	**311**	**2.1**	**1.7**	**–5.0**	**–11.0**
Coal	10	14	13	15	–0.6	0.2	–12.1	–17.8
Oil	58	85	101	119	1.6	1.3	–7.1	–16.2
Gas	3	16	26	35	4.6	3.1	–0.2	–15.0
Nuclear	1	3	6	9	6.9	4.2	–	40.9
Hydro	18	28	36	41	2.4	1.6	–6.1	–17.5
Biomass and waste	42	54	69	89	2.2	1.9	–1.9	–1.2
Other renewables	0	0	1	3	52.1	27.8	15.3	63.7
Power generation and heat plants	**22**	**43**	**57**	**68**	**2.7**	**1.8**	**–6.0**	**–15.2**
Coal	1	3	1	1	–10.4	–6.1	–57.3	–67.8
Oil	1	3	1	1	–6.7	–3.5	–47.2	–60.8
Gas	0	4	8	9	7.3	3.1	8.9	–31.5
Nuclear	1	3	6	9	6.9	4.2	–	40.9
Hydro	18	28	36	41	2.4	1.6	–6.1	–17.5
Biomass and waste	1	2	4	6	4.8	3.4	6.2	3.8
Other renewables	0	0	0	2	44.6	24.8	–	54.1
Other transformation, own use and losses	**18**	**23**	**28**	**33**	**1.7**	**1.4**	**–4.5**	**–11.3**
of which electricity	*3*	*7*	*8*	*9*	*1.8*	*1.1*	*–5.0*	*–14.3*
Total final consumption	**112**	**171**	**214**	**266**	**2.1**	**1.7**	**–5.0**	**–10.7**
Coal	4	7	8	9	1.2	1.2	–5.2	–12.1
Oil	53	78	94	111	1.7	1.4	–6.2	–15.3
Gas	2	9	13	20	3.7	3.2	–3.3	–6.5
Electricity	18	30	39	47	2.5	1.8	–6.1	–15.1
Heat	0	0	0	0	–	–	–	–
Biomass and waste	35	47	60	76	2.2	1.9	–2.6	–1.6
Other renewables	0	0	0	1	–	–	45.4	76.3
Industry	**48**	**77**	**94**	**112**	**1.9**	**1.5**	**–4.7**	**–10.0**
Coal	4	7	8	9	1.2	1.2	–5.2	–12.2
Oil	14	18	22	25	1.8	1.3	–4.1	–10.8
Gas	2	7	10	16	3.4	3.1	–3.7	–7.7
Electricity	10	15	18	23	2.0	1.6	–5.6	–13.9
Heat	0	0	0	0	–	–	–	–
Biomass and waste	19	30	35	39	1.6	1.1	–4.8	–7.3
Other renewables	0	0	0	0	–	–	–	–
Transport	**32**	**52**	**66**	**91**	**2.3**	**2.2**	**–5.8**	**–12.2**
Oil	27	44	53	64	1.7	1.5	–8.0	–19.1
Biofuels	6	6	11	23	5.1	5.1	5.4	13.2
Other fuels	0	1	2	4	4.8	3.7	–2.2	–2.4
Residential, services and agriculture	**29**	**38**	**50**	**57**	**2.4**	**1.5**	**–4.5**	**–10.1**
Coal	0	0	0	0	–	–	–	–
Oil	9	12	15	16	1.8	1.2	–3.8	–8.5
Gas	0	0	1	1	3.0	2.4	–	–
Electricity	8	15	21	25	3.1	1.9	–6.6	–16.2
Heat	0	0	0	0	–	–	–	–
Biomass and waste	11	11	13	14	1.9	1.0	–2.7	–5.4
Other renewables	0	0	0	1	–	–	47.5	76.9
Non-energy use	**3**	**4**	**5**	**6**	**1.3**	**1.2**	**–2.7**	**–6.3**

Alternative Policy Scenario: Brazil

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**223**	**387**	**514**	**616**	**2.6**	**1.8**	**–6.3**	**–15.7**
Coal	5	10	3	2	–10.4	–6.1	–58.2	–68.5
Oil	6	12	6	5	–6.3	–3.3	–45.2	–59.2
Gas	0	19	42	46	7.3	3.4	0.5	–29.7
Nuclear	2	12	24	34	6.9	4.2	–	40.9
Hydro	207	321	415	480	2.4	1.6	–6.1	–17.5
Renewables (excluding hydro)	4	13	24	49	6.2	5.4	5.2	19.0
Biomass and waste	*4*	*12*	*21*	*30*	*4.8*	*3.4*	*6.2*	*3.8*
Wind	*0*	*0*	*4*	*16*	*44.6*	*23.9*	–	*45.4*
Geothermal	*0*	*0*	*0*	*0*	–	–	–	–
Solar	*0*	*0*	*0*	*3*	–	–	–	*116.0*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*250.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**87**	**124**	**149**	**3.3**	**2.1**	**–4.9**	**–13.6**
Coal	1	1	1	0.0	–1.5	–8.5	–12.2
Oil	4	5	5	3.1	0.8	–9.6	–24.5
Gas	9	21	24	8.2	4.0	4.3	–9.8
Nuclear	2	3	4	4.8	3.3	–	40.9
Hydro	69	89	103	2.4	1.6	–7.0	–18.5
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	2	4	12	7.2	6.9	4.3	31.7
Biomass and waste	*2*	*3*	*5*	*4.5*	*3.3*	*5.8*	*3.6*
Wind	*0*	*1*	*5*	*39.7*	*22.3*	–	*47.8*
Geothermal	*0*	*0*	*0*	–	–	–	–
Solar	*0*	*0*	*2*	–	–	–	*116.0*
Tide and wave	*0*	*0*	*0*	–	–	–	*259.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**193**	**323**	**382**	**458**	**1.5**	**1.3**	**–7.4**	**–16.9**
Coal	29	50	44	49	–1.2	–0.1	–16.0	–20.6
Oil	158	238	279	329	1.5	1.3	–7.4	–16.7
Gas	6	35	59	79	4.7	3.1	–0.0	–15.2
Power generation and heat plants	**12**	**33**	**28**	**27**	**–1.4**	**–0.8**	**–22.4**	**–44.0**
Coal	8	15	5	3	–10.4	–6.1	–57.3	–67.8
Oil	4	9	4	3	–6.7	–3.5	–47.2	–60.8
Gas	0	9	20	20	7.3	3.1	8.9	–31.5
Total final consumption	**165**	**267**	**326**	**396**	**1.8**	**1.5**	**–6.0**	**–14.4**
Coal	18	31	36	43	1.2	1.2	–5.2	–12.1
Oil	143	216	261	308	1.7	1.4	–6.4	–15.8
of which transport	*81*	*133*	*160*	*194*	*1.7*	*1.5*	*–7.9*	*–19.1*
Gas	4	20	30	45	3.7	3.2	–3.3	–6.5

Alternative Policy Scenario: Middle East

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**235**	**479**	**693**	**861**	**3.4**	**2.3**	**–7.8**	**–15.8**
Coal	3	9	9	11	–0.6	0.6	–36.6	–42.9
Oil	151	265	370	423	3.1	1.8	–5.0	–8.9
Gas	78	202	304	405	3.8	2.7	–10.4	–23.0
Nuclear	0	0	2	2	–	–	–	–
Hydro	1	1	3	4	7.1	3.9	–	–
Biomass and waste	1	1	2	7	8.0	7.7	2.1	26.5
Other renewables	0	1	3	10	11.3	10.1	86.6	196.6
Power generation and heat plants	**63**	**152**	**210**	**266**	**3.0**	**2.2**	**–17.1**	**–31.3**
Coal	2	8	7	9	–1.4	0.5	–41.5	–45.0
Oil	29	54	66	68	1.8	0.9	–12.9	–20.5
Gas	30	89	132	176	3.7	2.7	–18.1	–35.9
Nuclear	0	0	2	2	–	–	–	–
Hydro	1	1	3	4	7.1	3.9	–	–
Biomass and waste	0	0	1	5	–	–	5.2	38.4
Other renewables	0	0	0	2	62.0	32.7	301.2	127.7
Other transformation, own use and losses	**20**	**58**	**78**	**104**	**2.8**	**2.3**	**–2.2**	**–5.6**
of which electricity	*4*	*10*	*16*	*22*	*4.1*	*3.0*	*–4.4*	*–11.3*
Total final consumption	**172**	**320**	**485**	**606**	**3.8**	**2.5**	**–3.4**	**–7.5**
Coal	0	1	1	1	5.7	2.1	–7.0	–32.1
Oil	116	193	278	320	3.4	2.0	–3.3	–6.6
Gas	38	84	137	183	4.5	3.0	–3.8	–9.8
Electricity	17	41	65	93	4.3	3.2	–4.4	–11.2
Heat	0	0	0	0	–	–	–	–
Biomass and waste	1	1	1	2	1.9	2.5	–0.6	2.0
Other renewables	0	1	2	8	10.3	9.2	76.9	219.6
Industry	**66**	**120**	**188**	**246**	**4.1**	**2.8**	**–3.4**	**–8.0**
Coal	0	1	1	1	5.7	2.1	–7.0	–32.1
Oil	28	53	68	84	2.4	1.8	–2.4	–5.9
Gas	35	59	104	139	5.3	3.4	–4.1	–9.4
Electricity	3	8	15	22	5.3	3.9	–2.8	–5.1
Heat	0	0	0	0	–	–	–	–
Biomass and waste	0	0	0	0	1.0	1.1	–5.6	–10.1
Other renewables	0	0	0	0	–	–	–	–
Transport	**59**	**100**	**144**	**156**	**3.4**	**1.7**	**–4.2**	**–6.4**
Oil	59	100	144	155	3.4	1.7	–4.2	–6.5
Biofuels	0	0	0	1	19.5	14.5	5.0	12.5
Other fuels	0	0	0	0	1.5	1.5	–	–
Residential, services and agriculture	**41**	**91**	**137**	**179**	**3.7**	**2.6**	**–2.6**	**–8.1**
Coal	0	0	0	0	–	–	–	–
Oil	23	32	50	56	4.2	2.2	–2.2	–8.1
Gas	3	26	34	44	2.5	2.1	–3.1	–11.3
Electricity	14	32	50	71	4.1	3.1	–4.8	–13.0
Heat	0	0	0	0	–	–	–	–
Biomass and waste	1	1	1	1	1.0	1.0	–	–
Other renewables	0	1	2	8	10.2	9.2	78.5	222.2
Non-energy use	**5**	**9**	**17**	**24**	**6.2**	**4.1**	**–2.4**	**–5.9**

Alternative Policy Scenario: Middle East

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**240**	**588**	**933**	**1 333**	**4.3**	**3.2**	**–4.4**	**–11.3**
Coal	10	37	33	46	–1.1	0.8	–41.5	–44.8
Oil	117	218	285	310	2.5	1.4	–1.3	–3.4
Gas	101	317	568	891	5.4	4.1	–3.1	–13.3
Nuclear	0	0	7	7	–	–	–	–
Hydro	12	17	35	45	7.1	3.9	–	–
Renewables (excluding hydro)	0	0	6	34	53.9	28.7	67.6	84.0
Biomass and waste	*0*	*0*	*3*	*13*	–	–	*5.2*	*38.4*
Wind	*0*	*0*	*3*	*12*	*61.8*	*29.6*	*317.0*	*130.0*
Geothermal	*0*	*0*	*0*	*0*	–	–	–	*15.3*
Solar	*0*	*0*	*0*	*10*	*0.0*	*24.3*	–	*124.6*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*500.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**182**	**288**	**418**	**4.3**	**3.3**	**–4.0**	**–9.8**
Coal	5	7	10	3.0	2.6	–6.2	–12.9
Oil	79	101	112	2.2	1.3	–2.9	–8.8
Gas	89	162	265	5.6	4.3	–5.4	–12.8
Nuclear	0	1	1	–	–	–	–
Hydro	9	16	20	5.0	3.0	–	–
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	0	1	11	42.2	25.9	139.2	108.2
Biomass and waste	*0*	*0*	*2*	*44.1*	*23.7*	*14.2*	*41.6*
Wind	*0*	*1*	*4*	*51.7*	*26.1*	*416.7*	*137.2*
Geothermal	*0*	*0*	*0*	–	–	–	*15.3*
Solar	*0*	*0*	*5*	*0.0*	*26.9*	–	*126.4*
Tide and wave	*0*	*0*	*0*	–	–	–	*531.6*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**602**	**1 183**	**1 699**	**2 060**	**3.3**	**2.2**	**–7.7**	**–16.2**
Coal	12	36	35	43	–0.3	0.7	–36.2	–43.2
Oil	413	690	975	1 099	3.2	1.8	–3.9	–7.4
Gas	177	458	690	918	3.8	2.7	–10.6	–23.3
Power generation and heat plants	**172**	**407**	**540**	**659**	**2.6**	**1.9**	**–17.9**	**–32.3**
Coal	9	31	27	36	–1.4	0.5	–41.5	–45.0
Oil	92	169	206	213	1.8	0.9	–12.9	–20.5
Gas	71	207	308	411	3.7	2.7	–18.1	–35.9
Total final consumption	**381**	**676**	**1 026**	**1 232**	**3.9**	**2.3**	**–2.1**	**–6.0**
Coal	2	4	8	7	5.6	2.0	–7.0	–31.9
Oil	294	483	712	816	3.6	2.0	–1.2	–3.6
of which transport	*145*	*264*	*395*	*437*	*3.7*	*2.0*	*–0.3*	*–0.6*
Gas	85	189	307	408	4.5	3.0	–3.8	–9.9

Alternative Policy Scenario: Africa

	Energy demand (Mtoe)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total primary energy supply	**401**	**582**	**706**	**866**	**1.8**	**1.5**	**–3.6**	**–9.2**
Coal	74	101	105	109	0.4	0.3	–5.5	–16.8
Oil	90	121	151	194	2.0	1.8	–6.7	–14.4
Gas	31	64	113	159	5.3	3.5	–4.7	–12.8
Nuclear	2	3	4	4	0.9	0.4	–	–
Hydro	5	8	12	23	4.2	4.3	12.3	13.1
Biomass and waste	199	283	319	369	1.1	1.0	–1.8	–4.0
Other renewables	0	1	3	9	12.1	10.0	26.5	42.7
Power generation and heat plants	**69**	**116**	**162**	**240**	**3.1**	**2.8**	**–3.6**	**–7.8**
Coal	39	57	60	64	0.4	0.4	–8.5	–22.6
Oil	11	16	12	10	–2.2	–1.8	–1.5	–6.6
Gas	11	31	64	99	6.8	4.5	–6.1	–16.1
Nuclear	2	3	4	4	0.9	0.4	–	–
Hydro	5	8	12	23	4.2	4.3	12.3	13.1
Biomass and waste	0	0	9	36	45.2	23.5	36.3	59.3
Other renewables	0	1	1	6	5.9	8.0	1.0	36.1
Other transformation, own use and losses	**64**	**76**	**99**	**117**	**2.4**	**1.6**	**–1.3**	**–4.3**
of which electricity	*6*	*10*	*14*	*21*	*3.1*	*2.9*	*–3.9*	*–9.3*
Total final consumption	**294**	**434**	**511**	**614**	**1.5**	**1.3**	**–4.0**	**–10.6**
Coal	19	19	20	19	0.2	–0.1	–1.5	–8.4
Oil	74	109	134	176	2.0	1.9	–7.3	–15.3
Gas	9	20	29	37	3.2	2.3	–3.3	–8.3
Electricity	21	35	52	84	3.6	3.4	–3.9	–9.2
Heat	0	0	0	0	–	–	–	–
Biomass and waste	171	251	275	295	0.8	0.6	–2.9	–8.9
Other renewables	0	0	1	4	–	–	77.5	54.3
Industry	**69**	**86**	**107**	**126**	**2.0**	**1.5**	**–1.1**	**–2.9**
Coal	16	15	15	13	0.0	–0.5	–2.0	–11.6
Oil	16	15	19	21	2.1	1.3	–2.4	–6.0
Gas	8	15	20	24	2.6	1.8	–4.0	–9.3
Electricity	12	16	22	31	3.0	2.6	–2.2	–5.5
Heat	0	0	0	0	–	–	–	–
Biomass and waste	18	25	31	38	2.0	1.5	2.8	10.3
Other renewables	0	0	0	0	–	–	–	–
Transport	**39**	**65**	**80**	**116**	**1.9**	**2.3**	**–10.0**	**–18.6**
Oil	39	64	76	109	1.6	2.1	–10.7	–19.5
Biofuels	0	0	1	3	60.8	27.3	14.4	1.3
Other fuels	0	1	3	3	7.8	4.3	–	–
Residential, services and agriculture	**183**	**278**	**317**	**362**	**1.2**	**1.0**	**–3.4**	**–10.4**
Coal	3	5	5	6	1.1	0.9	–0.0	–0.3
Oil	16	25	33	36	2.6	1.5	–2.6	–8.3
Gas	1	4	6	9	3.6	3.3	–2.3	–8.5
Electricity	9	19	30	53	4.2	4.0	–5.0	–11.3
Heat	0	0	0	0	–	–	–	–
Biomass and waste	153	226	242	254	0.6	0.5	–3.6	–11.3
Other renewables	0	0	1	4	–	–	80.3	54.9
Non-energy use	**4**	**5**	**7**	**10**	**2.6**	**2.4**	**–2.3**	**–6.0**

Alternative Policy Scenario: Africa

	Electricity generation (TWh)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total generation	**316**	**534**	**776**	**1 227**	**3.5**	**3.3**	**–3.8**	**–9.2**
Coal	165	244	260	304	0.6	0.9	–9.5	–23.3
Oil	42	58	46	37	–2.0	–1.7	–1.5	–6.7
Gas	43	130	291	490	7.6	5.2	–7.3	–17.3
Nuclear	8	13	15	15	0.9	0.4	–	–
Hydro	56	88	137	262	4.2	4.3	12.3	13.1
Renewables (excluding hydro)	0	2	26	119	27.1	17.3	23.1	56.2
Biomass and waste	*0*	*0*	*19*	*73*	*45.4*	*23.5*	*36.4*	*59.3*
Wind	*0*	*1*	*5*	*23*	*18.8*	*13.9*	–	*45.4*
Geothermal	*0*	*1*	*3*	*10*	*11.8*	*10.2*	*0.6*	*14.1*
Solar	*0*	*0*	*0*	*13*	*14.6*	*35.0*	–	*129.0*
Tide and wave	*0*	*0*	*0*	*0*	–	–	–	*600.0*

	Capacity (GW)			Growth (% p.a.)		Change vs. RS (%)	
	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total capacity	**112**	**172**	**284**	**4.0**	**3.6**	**–0.1**	**–3.5**
Coal	39	45	54	1.3	1.2	–9.0	–22.2
Oil	19	21	19	0.8	–0.1	–1.4	–5.8
Gas	32	63	114	6.4	5.0	–6.2	–14.9
Nuclear	2	2	2	0.0	0.0	–	–
Hydro	20	36	68	5.5	4.9	29.1	28.6
of which pumped storage	*0*	*0*	*0*	–	–	–	–
Renewables (excluding hydro)	0	5	28	25.3	17.5	16.1	64.7
Biomass and waste	*0*	*3*	*11*	*44.8*	*23.2*	*31.6*	*57.3*
Wind	*0*	*2*	*8*	*19.6*	*14.4*	–	*49.1*
Geothermal	*0*	*0*	*1*	*11.7*	*10.2*	*0.6*	*14.1*
Solar	*0*	*0*	*7*	*0.0*	*27.2*	–	*130.9*
Tide and wave	*0*	*0*	*0*	–	–	–	*595.0*

	CO_2 emissions (Mt)				Growth (% p.a.)		Change vs. RS (%)	
	1990	2004	2015	2030	2004-2015	2004-2030	2015	2030
Total CO_2 emissions	**550**	**815**	**998**	**1 222**	**1.9**	**1.6**	**–6.1**	**–15.5**
Coal	235	316	327	337	0.3	0.2	–6.7	–19.6
Oil	249	354	409	509	1.3	1.4	–6.3	–14.4
Gas	65	144	263	376	5.6	3.8	–4.9	–13.2
Power generation and heat plants	**214**	**350**	**431**	**526**	**1.9**	**1.6**	**–7.1**	**–19.0**
Coal	152	229	238	254	0.4	0.4	–8.5	–22.6
Oil	35	47	36	28	–2.3	–2.0	–1.2	–6.0
Gas	26	74	157	245	7.1	4.7	–6.3	–16.2
Total final consumption	**304**	**422**	**511**	**634**	**1.8**	**1.6**	**–5.6**	**–13.5**
Coal	83	87	88	83	0.1	–0.2	–1.6	–8.9
Oil	202	292	363	473	2.0	1.9	–6.9	–15.0
of which transport	*104*	*174*	*209*	*300*	*1.7*	*2.1*	*–9.9*	*–18.8*
Gas	19	42	60	78	3.3	2.4	–3.2	–8.2

ELECTRICITY ACCESS

In a continuing effort to improve our understanding of the electrification process, we have updated, for the third time, the database on electrification rates that we first built for the *WEO-2002*. The database has grown in content and quality – with more detailed data on urban and rural electrification but also with more precise data from industry, national surveys and international sources.

The latest available information has been incorporated to give the most accurate picture to date of electricity access in the world, by region and by country. Several major revisions have been made, notably for Brazil, India, Iraq, Ethiopia and Yemen. For India, better and more recent census data and rural surveys have revised the electrification rates upwards. In the case of Iraq, previous data reflected grid network coverage (around 90%), while a recent detailed study by the UNDP has revealed that only 15% of the population has reliable access to electricity. Conflicts have also been taken into account, for instance for Côte d'Ivoire where the negative impact of the civil war on electricity access has been incorporated into the database.

There is no single internationally accepted definition for electricity access. The definition used here covers electricity access at the household level; that is, the number of people who have electricity in their home. It is comprised of electricity sold commercially, both on-grid and off-grid. It also includes self-generated electricity for those countries where access to electricity has been assessed through surveys by national administrations. The data do not capture unauthorised connections. The main data sources are listed in the tables. The electrification rates shown in this annex indicate the number of people with electricity access as a percentage of total population. Rural and urban electrification rates have been collected for most countries, but only the regional averages are shown here.

Where country data appeared contradictory, out of date or unreliable, the IEA Secretariat made estimates based on cross-country comparisons, earlier surveys, data from other international organisations, annual statistical bulletins, publications and journals.[1] Population and urban/rural breakdown projections are taken from *World Population Prospects – The 2004 Revision*, published by the United Nations Population Division.

1. See *WEO* (2002) for approach and methodology.

Contents

The tables which follow show electricity access in 2005 for regional aggregates as well as for the following regions:

- Africa
- Developing Asia
- Latin America
- Middle East

Abbreviations

ADB – Asian Development Bank
ADIAC – Agence d'information d'Afrique centrale
AFREPREN – African Energy Policy Research Network
APERC – Asia Pacific Energy Research Centre
AREED – African Rural Energy Enterprise Development
BPE – Bureau of Public Enterprises, Nigeria
CNHDE – Center for National Health Development in Ethiopia
DHS – Demographic and Health Surveys
DOE – US Department of Energy
ECLAC – Economic Commission for Latin America and the Caribbean
EEPCo – Ethiopian Electric Power Corporation
ESMAP – Energy Sector Management Assistance Programme
GNESD – Global Network on Energy for Sustainable Development
GPOBA – Global Partnership on Output-Based Aid
ILO – International Labour Organization
JICA – Japan International Cooperation Agency
JIRAMA – Jiro sy Rano Malagasy (national water and electricity company), Madagascar
MEMR – Ministry of Energy and Mineral Resources, Indonesia
NRECA – National Rural Electric Cooperative Association
OECD – Organisation for Economic Co-operation and Development
OLADE – Latin American Energy Association
OME – Observatoire Méditerranéen de l'Energie
PLN – National Electric Company, Indonesia
SADC – South African Development Community
TERI – Tata Energy Research Institute, India
UNDP – United Nations Development Programme
USAID – The United States Agency for International Development

Table B1: **Electricity Access in 2005: Regional Aggregates**

	Population million	**Urban population** million	**Population without electricity** million	**Population with electricity** million	**Electrification rate** %	**Urban electrification rate** %	**Rural electrification rate** %
Africa	891	343	554	337	37.8	67.9	19.0
North Africa	*153*	*82*	*7*	*146*	*95.5*	*98.7*	*91.8*
Sub-Saharan Africa	*738*	*261*	*547*	*191*	*25.9*	*58.3*	*8.0*
Developing Asia	3 418	1 063	930	2 488	72.8	86.4	65.1
China and East Asia	*1 951*	*772*	*224*	*1 728*	*88.5*	*94.9*	*84.0*
South Asia	*1 467*	*291*	*706*	*760*	*51.8*	*69.7*	*44.7*
Latin America	449	338	45	404	90.0	98.0	65.6
Middle East	186	121	41	145	78.1	86.7	61.8
Developing countries	**4 943**	**1 866**	**1 569**	**3 374**	**68.3**	**85.2**	**56.4**
Transition economies and OECD	**1 510**	**1 090**	**8**	**1 501**	**99.5**	**100.0**	**98.1**
World	**6 452**	**2 956**	**1 577**	**4 875**	**75.6**	**90.4**	**61.7**

Table B2: **Electricity Access in 2005: Africa**

	Electrification rate %	**Population without electricity** million	**Population with electricity** million	**Sources**
Angola	15.0	13.5	2.4	Empresa Nacional de Electricidade de Angola (2005), SADC (2005)
Benin	22.0	6.5	1.8	ESMAP, Société Béninoise d'Electricité et d'Eau (2004)
Botswana	38.5	1.1	0.7	Botswana Power Corporation Annual Report (2005), SADC (2005)
Burkina Faso	7.0	12.4	0.9	OECD (2003), ESMAP, Mbendi.co.za
Cameroon	47.0	8.7	7.7	ILO/International Institute for Labour Studies (2004), *Cameroon Tribune* (2003)
Congo	19.5	3.2	0.8	ADIAC
Dem. Rep. of Congo	5.8	53.8	3.3	GNESD (2004), SADC (2005)
Côte d'Ivoire	50.0	9.1	9.1	UNDP (2003)
Eritrea	20.2	3.5	0.9	Risoe - Energy for Development (2003)
Ethiopia	15.0	60.8	10.7	EEPCo (2003), US Department of Commerce (2002), CNHDE (2004), Addis Ababa University
Gabon	47.9	0.7	0.7	ESMAP (2000)
Ghana	49.2	11.3	10.9	Energy Foundation of Ghana, Volta River Authority (2004)
Kenya	14.0	29.4	4.8	Kenya Power and Lighting Company (2004)
Lesotho	11.0	1.9	0.2	GNESD (2004)
Madagascar	15.0	15.2	2.7	GNESD (2004), JIRAMA (2004)
Malawi	7.0	11.8	0.9	AFREPREN (2001), SADC (2004)
Mauritius	93.6	0.1	1.2	AFREPREN (2002), SADC (2004)
Mozambique	6.3	18.6	1.3	SADC (2004)
Namibia	34.0	1.4	0.7	SADC (2005)
Nigeria	46.0	71.1	60.5	ESMAP (2005), Ministry of Power (2006), BPE (2006)

Table B2: **Electricity Access in 2005: Africa** *(continued)*

Senegal	33.0	7.8	3.8	GNESD (2004), Commission de Régulation du Secteur de l'Electricité du Sénégal (2004)
South Africa	70.0	14.0	32.6	SADC (2005)
Sudan	30.0	25.4	10.9	SADC (2005), Engineers Without Borders (2004)
Tanzania	11.0	34.2	4.2	SADC (2005), Helio International
Togo	17.0	5.1	1.0	ESMAP (1998)
Uganda	8.9	24.6	2.4	AFREPREN (2001), Ugandan National Administration (2005)
Zambia	19.0	9.5	2.2	AFREPREN (2001), DHS (2001/2002)
Zimbabwe	34.0	8.7	4.5	SADC (2005), AFREPREN
Other Africa	7.6	83.6	6.9	IEA estimate
Sub-Saharan Africa	**25.9**	**546.9**	**190.7**	
Algeria	98.1	0.6	32.3	Ministry of Energy and Mining, Sonelgaz (2004), OME (2006)
Egypt	98.0	1.5	72.4	US Department of Commerce (2004), OME (2006)
Libya	97.0	0.2	5.7	OME (2006)
Morocco	85.1	4.5	25.8	Ministry of Energy and Mines, Office National de l'Electricité *(Annual Report 2004)*
Tunisia	98.9	0.1	10.0	ESI Africa, Institut National de la Statistique, OME (2006)
North Africa	**95.5**	**6.9**	**146.1**	
Africa	**37.8**	**553.7**	**336.8**	

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Table B3: **Electricity Access in 2005: Developing Asia**

	Electrification rate %	**Population without electricity** million	**Population with electricity** million	**Sources**
China	99.4	8.5	1 302.1	Ministry of Science and Technology, DOE, National Renewable Energy Laboratory
Brunei	99.2	0.0	0.4	APERC
Cambodia	20.1	10.9	2.7	World Bank (2004), Ministry of Planning
Chinese Taipei	99.2	0.2	22.9	IEA estimate
DPR Korea	22.0	17.7	5.0	IEA estimate
Indonesia	54.0	101.2	118.8	PLN *Annual Report* (2005), MEMR (2002)
Malaysia	97.8	0.6	24.7	GNESD (2000)
Mongolia	64.6	1.0	1.8	Helio International (2000)
Myanmar	11.3	45.1	5.7	Myanmar Electric Power Enterprise (2003)
Philippines	80.5	16.2	66.8	National Electrification Administration (2005), GPOBA (2003), JICA (2006)
Singapore	100.0	0.0	4.3	GNESD (2000)
Thailand	99.0	0.6	64.1	AFREPREN/GNESD (2004), Electricity Generating Authority *Annual Report* (2004)
Vietnam	84.2	13.2	70.3	World Bank (2005), Electricity of Vietnam (2005)
Other Asia	82.0	8.3	37.9	IEA estimate
China and East Asia	**88.5**	**223.5**	**1 727.5**	
Afghanistan	7.0	27.0	2.0	World Bank, USAID (2005)
Bangladesh	32.0	96.2	45.3	GNESD (2000), Bangladesh Power Development Board, USAID (2005)
India	55.5	487.2	607.6	USAID (2005), TERI (2006), Ministry of Power (2004/2005), Census (2001)
Nepal	33.0	18.1	8.9	ADB (2004), USAID (2005)
Pakistan	54.0	71.1	83.5	Water and Power Development Authority (2005), USAID (2005)
Sri Lanka	66.0	6.7	13.0	GNESD (2001), USAID (2005)
South Asia	**51.8**	**706.2**	**760.3**	
Developing Asia	**72.8**	**929.8**	**2 487.8**	

Table B4: **Electricity Access in 2005: Latin America**

	Electrification rate %	Population without electricity million	Population with electricity million	Sources
Argentina	95.4	1.8	37.1	GNESD (2004), ECLAC (2002)
Bolivia	64.4	3.3	5.9	ECLAC (2003), OLADE (2002)
Brazil	96.5	6.5	179.7	ECLAC (2003)
Chile	98.6	0.2	16.1	APERC, ECLAC (2003)
Colombia	86.1	6.3	39.2	ECLAC (2003)
Costa Rica	98.5	0.1	4.2	ECLAC (2002)
Cuba	95.8	0.5	10.9	OLADE (2002)
Dominican Republic	92.5	0.7	8.2	DHS (2002), OLADE (2002)
Ecuador	90.3	1.3	11.9	ECLAC (2002)
El Salvador	79.5	1.4	5.5	GNESD (2004), ECLAC (2004)
Guatemala	78.6	2.7	9.8	ESMAP (1998/1999), DHS, OLADE (2002)
Haiti	36.0	5.5	3.1	DHS (2000), Engineers Without Borders (2004)
Honduras	61.9	2.7	4.4	ECLAC (2003)
Jamaica	87.3	0.3	2.3	OLADE (2002)
Netherlands Antilles	99.6	0.0	0.2	IEA estimate
Nicaragua	69.3	1.7	3.8	ECLAC (2002), DHS (2001), Global Environment Facility (2001)
Panama	85.2	0.5	2.7	OLADE (2000)
Paraguay	85.8	0.9	5.2	OLADE (2002)
Peru	72.3	7.7	20.2	ECLAC (2004)
Trinidad and Tobago	99.1	0.0	1.3	OLADE (1997)
Uruguay	95.4	0.2	3.3	US Commercial Service (2005)
Venezuela	98.6	0.4	26.1	ECLAC (2003)
Other Latin America	87.3	0.4	2.9	IEA estimate
Latin America	**90.0**	**44.9**	**404.3**	

Table B5: **Electricity Access in 2005: Middle East**

	Electrification rate %	**Population without electricity** million	**Population with electricity** million	**Sources**
Bahrain	99.0	0.0	0.7	World Bank (2004)
Iran	97.3	1.8	66.6	Tavanir, World Energy Council, Sustainable Energy Watch (2005/2006)
Iraq	15.0	22.0	3.9	UNDP - Iraq Living Conditions Survey (2004)
Israel	96.6	0.2	6.7	Israel Electric Corporation *Annual Report* (2004), OME (2006)
Jordan	99.9	0.0	5.5	OME (2006), World Bank
Kuwait	100.0	0.0	2.5	IEA estimate
Lebanon	99.9	0.0	3.6	OME (2006)
Oman	95.5	0.1	2.5	IEA estimate
Qatar	70.5	0.2	0.6	IEA estimate
Saudi Arabia	96.7	0.8	23.6	Ministry of Water and Electricity (2005)
Syria	90.0	1.9	17.1	UNDP, OME (2006)
United Arab Emirates	91.9	0.4	4.1	IEA estimate based on World Bank
Yemen	36.2	13.2	7.5	Ministry of Electricity (2004), World Bank (2005), NRECA (2004)
Middle East	**78.1**	**40.7**	**144.8**	

ABBREVIATIONS AND DEFINITIONS

This annex provides general information on abbreviations, fuel, process and regional definitions, and country groupings used throughout *WEO-2006*. Conversion factors for oil, gas and coal have also been included. Readers interested in obtaining more detailed information should consult the annual IEA publications *Energy Balances of OECD Countries; Energy Balances of Non-OECD Countries; Energy Statistics of OECD Countries; Energy Statistics of Non-OECD Countries; Coal Information; Oil Information; Gas Information;* and *Renewables Information.*

Abbreviations

Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mpg	miles per gallon
Gas	tcf	thousand cubic feet
	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
Oil and Gas	boe	barrels of oil equivalent
Energy	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	GJ	gigajoule (1 joule x 10^9)
	EJ	exajoule (1 joule x 10^{18})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Power	W	Watt (1 joule per second)
	kW	kilowatt (1 Watt x 10^3)
	MW	megawatt (1 Watt x 10^6)
	GW	gigawatt (1 Watt x 10^9)
	TW	terawatt (1 Watt x 10^{12})
Mass	kt	kilotonnes (1 tonne x 10^3)

	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
Coal	tce	tonne of coal equivalent
Area	ha/yr	hectare per year
	Gha	giga-hectare (1 hectare x 10^9)

Fuel Definitions

Biodiesel

Biodiesel is a diesel-equivalent, processed fuel made from the transesterification (a chemical process which removes the glycerine from the oil) of both vegetable oils and animal fats.

Biogas

A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter in a limited amount of oxygen known as anaerobic digestion.

Biomass and Waste

Solid biomass and animal products, gas and liquids derived from biomass and the renewable part of municipal waste.

Brown Coal

Includes sub-bituminous coal and lignite where sub-bituminous coal is defined as non-agglomerating coal with a gross calorific value between 4 165 kcal/kg and 5 700 kcal/kg, and lignite is defined as non-agglomerating coal with a gross calorific value less than 4 165 kcal/kg.

Clean Coal Technologies (CCTs)

Clean coal technologies are designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.

Coal

Coal includes both primary coal (including hard coal and lignite) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, coke-oven gas and blast-furnace gas). Peat is also included in this category.

Condensates

Condensates are liquid hydrocarbon mixtures recovered from non-associated gas reservoirs. They are composed of C_4 and higher carbon number hydrocarbons and normally have an API between 50° and 85°.

Dimethyl Ether (DME)

Clear, odourless gas currently produced by dehydration of methanol from natural gas, but which can also be produced from biomass or coal.

Ethanol

Ethanol is an alcohol made by fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but advanced technology will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

Ethanol Gel

Flammable blended product which can be combusted cleanly in small cookstoves and heaters.

Gas

Includes natural gas (both associated and non-associated with petroleum deposits but excluding natural gas liquids) and gas-works gas.

Gas-to-Liquids (GTLs)

Fischer-Tropsch technology is used to convert natural gas into synthesis gas (syngas) and then, through catalytic reforming or synthesis, into very clean conventional oil products. The main fuel produced in most GTL plants is diesel.

Hard Coal

Coal of gross calorific value greater than 5 700 kcal/kg on an ash-free but moist basis and with a mean random reflectance of vitrinite of at least 0.6. Hard coal is further disaggregated into coking coal and steam coal.

Heavy Petroleum Products

Heavy petroleum products include heavy fuel oil.

Hydro

Hydro refers to the energy content of the electricity produced in hydropower plants, assuming 100% efficiency.

Light Petroleum Products

Light petroleum products include liquefied petroleum gas (LPG), naphtha and gasoline.

Middle Distillates

Middle distillates include jet fuel, diesel and heating oil.

Natural Gas Liquids (NGLs)

Natural gas liquids are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas-processing plants. NGLs include but are not limited to ethane, propane, butane, pentane, natural gasoline and condensates. They may also include small quantities of non-hydrocarbons.

Non-hydro Renewables

Includes biomass, geothermal, solar, wind, tide and wave energy for electricity generation.

Nuclear

Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33%.

Oil

Oil includes crude oil, condensates, 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).

Other Petroleum Products

Other petroleum products include refinery gas, ethane, lubricants, bitumen, petroleum coke and waxes.

Process Definitions

Electricity Generation

Electricity generation is the total amount of electricity generated by power plants. It includes own use and transmission and distribution losses.

Greenfield

The construction of plants or facilities in new areas or where no previous infrastructure exists.

International Marine Bunkers

International marine bunkers cover those quantities delivered to sea-going ships of all flags, including warships. Consumption by ships plying in inland and coastal waters is not included.

Ligno-Cellulosic Technology

Process to produce ethanol from wood or straw by using chemical acid or enzymatic hydrolysis to rupture the plant cells and then separate out the cellulose and hemi-cellulose components to convert to sugars. The residual lignin can be used for heat and power generation.

Lower Heating Value (LHV)

Lower heating value is the heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

Natural Decline Rate

The base production decline rate of an oil or gas field without intervention to enhance production.

Observed Decline Rate

The production decline rate of an oil or gas field after all measures have been taken to maximise production. It is the aggregation of all the production increases and declines of new and mature oil or gas fields in a particular region.

Other Transformation, Own Use and Losses

Other transformation, own use and losses covers the 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 energy use and loss by gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Other Sectors

Other sectors include the residential, services, public and agriculture sectors.

Power and Heat Generation

Power generation refers to fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both public plants and small plants that produce fuel for their own use (autoproducers) are included.

Total Final Consumption (TFC)

Total final consumption 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, services and public) 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.

Total Primary Energy Demand

Total primary energy demand represents domestic demand only, including power generation, other transformation, own use and losses, and total final consumption. Except in the case of world primary energy demand, it excludes international marine bunkers.

Regional Definitions and Country Groupings

Africa

Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo, Democratic Republic of Congo, Côte 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, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Annex I Parties to the United Nations Framework Convention on Climate Change

Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom and United States.

Central Asia

Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan.

China
China refers to the People's Republic of China, including Hong Kong.

Developing Asia
Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia, China, Chinese Taipei, Fiji, French Polynesia, India, Indonesia, Kiribati, Democratic People's Republic of Korea, Laos, Macau, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Tonga, Vietnam and Vanuatu.

Developing Countries
Includes countries in the Africa, Developing Asia, Latin America and Middle East regional groupings.

European Union
Austria, Belgium, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden and United Kingdom.

G8 Countries
Canada, France, Germany, Italy, Japan, Russia, United Kingdom and United States.

Latin America
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, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts and Nevis, Saint Lucia, St. Vincent and Grenadines, Suriname, Trinidad and Tobago, Uruguay and Venezuela.

MENA
Middle East and North Africa.

Middle East
Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates and Yemen. It includes the neutral zone between Saudi Arabia and Iraq.

North Africa
Algeria, Egypt, Libya, Morocco and Tunisia.

OECD Asia
Japan and Korea.

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

OECD North America
United States, Canada and Mexico.

OECD Oceania
Australia and New Zealand.

OECD Pacific
Japan, Korea, Australia and New Zealand.

Organization of the Petroleum Exporting Countries
Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Sub-Saharan Africa
Africa excluding North Africa.

Transition Economies
Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Serbia and Montenegro, the former Yugoslav Republic of Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus, Gibraltar and Malta.

Average Conversion Factors

Coal	1 Mtoe = 2.0003 million tonnes
Oil	1 Mtoe = 0.0209 mb/d
Gas	1 Mtoe = 1.2073 bcm

These are world averages for the period 2004 to 2030. Region-specific factors are used to convert Mtoe data in this publication to other units.

ACRONYMS

APS	Alternative Policy Scenario
BAPS	Beyond Alternative Policy Scenario
CCGT	combined-cycle gas turbine
CCS	CO_2 capture and storage
CCT	clean coal technology
CDM	Clean Development Mechanism (under the Kyoto Protocol)
CDU	crude distillation unit
CHP	combined heat and power; when referring to industrial CHP, the term co-generation is sometimes used
CNG	compressed natural gas
CO_2	carbon dioxide
DIC	Deferred Investment Case
DME	dimethyl ether
E&P	exploration and production
EOR	enhanced oil recovery
EPACT	Energy Policy Act (in the United States)
EPC	engineering, procurement and construction
ESCO	Energy Service Company
EU	European Union
EU CAP	European Union Common Agricultural Policy
EU ETS	European Union Emissions Trading Scheme
FAO	Food and Agriculture Organization of the United Nations
FDI	foreign direct investment
FFV	flex-fuel vehicle

GDP	gross domestic product
GHG	greenhouse gas
GTL	gas-to-liquids
HIV/AIDS	Human Immunodeficiency Virus/Acquired Immunodeficiency Syndrome
IAEA	International Atomic Energy Agency
IAP	indoor air pollution
ICE	internal combustion engine
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IMF	International Monetary Fund
IOC	international oil company
IPP	independent power producer
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MDG	Millennium Development Goal
MSC	multiple service contract
NEA	Nuclear Energy Agency
NIMBY	not-in-my-backyard
NGL	natural gas liquid
NOC	national oil company
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PPP	purchasing power parity
PSA	production-sharing agreement

RS	Reference Scenario
TFC	total final consumption
UNDESA	United Nations Department of Economic and Social Affairs
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
USGS	United States Geological Survey
WB	World Bank
WEM	World Energy Model
WHO	World Health Organization
WTI	West Texas Intermediate

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