INTERNATIONAL ENERGY AGENCY

ENERGY TECHNOLOGY PERSPECTIVES 2006

In support of the G8 Plan of Action

Scenarios & Strategies to 2050

OECD

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INTERNATIONAL ENERGY AGENCY

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, and 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.

FOREWORD

At their Gleneagles Summit in July 2005, leaders of the G8 addressed the serious and long-term challenges of secure and clean energy, climate change, and sustainable development. Agreeing to act with resolve and urgency, they adopted a Plan of Action and launched a dialogue with other significant energy consumers. The G8 leaders asked the IEA to play a major role in delivering the Plan of Action and to be a partner in the dialogue. A similar sense of urgency was shown by Energy Ministers of the IEA in their meeting two months earlier, when they asked the IEA to help bridge the gap between what is happening and what needs to be done.

The G8 leaders and Energy Ministers asked the IEA to advise on alternative energy scenarios and strategies aimed at a clean, clever and competitive energy future. Specifically, the Energy Ministers have requested the IEA to focus on the opportunities that efficient and emerging energy technologies can deliver. *Energy Technology Perspectives: Scenarios and Strategies to 2050* is a specific response to these requests.

The book provides a comprehensive and detailed analysis of the key energy technologies of the next 50 years. Our scenario analysis shows that global CO_2 emissions could be returned to current levels by 2050 and that the growth of oil demand could be cut in half. Energy efficiency is of paramount importance in archiving these results. The analysis also shows that decarbonising power generation through CO_2 capture and storage, renewables, and, in those countries where it is accepted, nuclear, will be essential.

The analysis demonstrates that a more sustainable energy future is within our reach. Many of the technologies needed are already available or close to commercialisation. But it will require substantial effort and investment by both the public and private sectors for them to be adopted by the market. Pathways need to be opened up to enable these technologies to deliver their full potential. Urgent action is needed to stimulate R&D, to demonstrate and deploy promising technologies, and to provide clear and predictable incentives for low carbon options and diverse energy sources. We also need closer energy technology collaboration between developed and developing countries.

The IEA is breaking new ground with this book, which is expected to become a regular biennial publication of the IEA. It is based on our best analysis and we are grateful for the many comments and contributions provided by the IEAs extensive energy technology collaboration network and other distinguished experts. Nevertheless, we recognise that looking far into the energy future is not as clear as gazing into a crystal ball; we may still have a lot to learn. We hope that this book will provide a focus for discussion and debate in energy circles, among both policy makers and investors, as well as in the G8 dialogue.

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

Claude Mandil
Executive Director

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SUMMARY AND POLICY IMPLICATIONS

This publication is a response to the Group of Eight (G8) leaders at their Gleneagles Summit in July 2005, and to the International Energy Agency's Energy Ministers who met two months earlier. Both groups called for the IEA to develop and advise on alternative scenarios and strategies aimed at a clean, clever and competitive energy future.

Secure, reliable and affordable energy supplies are fundamental to economic stability and development. The threat of disruptive climate change, the erosion of energy security and the growing energy needs of the developing world all pose major challenges for energy decision makers. They can only be met through innovation, the adoption of new cost-effective technologies, and a better use of existing energy-efficient technologies. *Energy Technology Perspectives* presents the status and prospects for key energy technologies and assesses their potential to make a difference by 2050. It also outlines the barriers to implementing these technologies and the measures that can overcome such barriers.

The Outlook to 2050 and the Role of Energy Technology

The world is not on course for a sustainable energy future. Oil prices at historical highs raise concerns about the long-term balance of supply and demand. CO_2 emissions have increased by more than 20% over the last decade. Indeed, if the future is in line with present trends as illustrated by the *World Energy Outlook 2005* Reference Scenario, CO_2 emissions and oil demand will continue to grow rapidly over the next 25 years. This is after taking account of energy efficiency gains and technological progress that can be expected under existing policies. Extending this outlook beyond 2030 shows that these worrisome trends are likely to get worse. In the Baseline Scenario prepared for this study, CO_2 emissions will be almost two and a half times the current level by 2050. Surging transport demand will continue to put pressure on oil supply. The carbon intensity of the world's economy will increase due to greater reliance on coal for power generation – especially in rapidly expanding developing countries with domestic coal resources – and the increased use of coal in the production of liquid transport fuels.

But this alarming outlook can be changed. The Accelerated Technology scenarios (ACTs) – that form the backbone of this book – demonstrate that by employing technologies that already exist or are under development, the world could be brought onto a much more sustainable energy path. The scenarios show how energy-related CO_2 emissions can be returned to their current levels by 2050 and how the growth of oil demand can be moderated. They also show that by 2050, energy efficiency measures can reduce electricity demand by a third below the Baseline levels. Savings from liquid fuels would equal more than half of today's global oil consumption, offsetting about 56% of the growth in oil demand foreseen in the Baseline scenario.

The substantial changes demonstrated in the ACT scenarios are grounded in:

- Strong energy efficiency gains in the transport, industry and buildings sectors.
- Electricity supply becoming significantly decarbonised as the power-generation mix shifts towards nuclear power, renewables, natural gas and coal with CO_2 capture and storage (CCS).
- Increased use of biofuels for road transport.

Nevertheless, even in the ACT scenarios, fossil fuels still supply most of the world's energy in 2050. Demand for oil, coal (except in one scenario) and natural gas are all greater in 2050 than they are today. Investment in conventional energy sources will, therefore, remain essential.

In all five of the ACT scenarios, demand for energy services is assumed to grow rapidly, especially in developing countries. The scenarios do not imply that the growth in demand for energy services is constrained in developing or developed countries. Rather they show how this demand can be met more intelligently and with lower CO_2 emissions through the implementation of a wide range of policies including increased research, development and demonstration (RD&D) efforts and deployment programmes, as well as economic incentives to advance the uptake of low-carbon technologies. The policies considered are the same across all five ACT scenarios. What varies are assumptions about how quickly energy efficiency gains can be achieved, about how quickly the cost of major technologies such as CCS, renewables and nuclear can be reduced, and about how soon these technologies can be made widely available. A sixth scenario, TECH Plus, illustrates the implications of making more optimistic assumptions on the rate of progress for renewables and nuclear electricity generation technologies, as well as for advanced biofuels and hydrogen fuel cells in the transport sector.

The costs of achieving a more sustainable energy future in the ACT scenarios are not disproportionate, but they will require substantial effort and investment by both the public and private sectors. None of the technologies required are expected – when fully commercialised – to have an incremental cost of more than USD 25 per tonne of avoided CO_2 emissions in all countries, including developing countries. For comparison, this cost is less than the average price for CO_2 permits under the European trading scheme over the first four months of 2006. A price of USD 25 per tonne of CO_2 would add about USD 0.02 per kWh to the cost of coal-fired electricity and about USD 0.07/litre (USD 0.28/gallon) to the cost of gasoline. The *average* cost per tonne CO_2 emissions reduction for the whole technology portfolio, once all technologies are fully commercialised, is less than USD 25. However, there will be significant additional transitional costs related to RD&D and deployment programmes to commercialise many of the technologies over the next couple of decades. The import price of oil will be lower, as reduced demand will put less pressure on more expensive supply options. This cost reduction may not be apparent to consumers, however, since most of it will be balanced by the increased cost of promoting low-carbon technologies.

There are large uncertainties when looking 50 years ahead. The ACT scenarios illustrate a range of possible outcomes based on assumptions that are more, or less, optimistic with regard to cost reductions achieved by technologies such as renewables, nuclear and CCS in power generation. Yet, despite all the uncertainties, **two main conclusions** from the analysis seem robust. First, technologies do exist that can make a difference over the next 10 to 50 years. Second, none of these technologies can make a sufficient difference on their own. Pursuing a portfolio of technologies will greatly reduce the risk and potentially the costs, if one or more technologies fail to make the expected progress.

The following discussion summarises the key technologies identified by the ACT scenarios that help build a portfolio for a sustainable energy future.

Energy Efficiency in Buildings, Industry and Transport

Accelerating progress in energy efficiency is indispensable. The recent slowdown in energy savings in OECD countries must be reversed. This is indeed possible; there is still significant scope for adopting more efficient technologies in buildings, industry and transport. In non-OECD countries, the potential for improvement is even greater, as rapidly expanding economies offer enormous opportunities for investment in energy-efficient technologies.

In many countries, new **buildings** could be made 70% more efficient than existing buildings. Some of the exciting new technologies that can contribute to this transformation have not yet been commercialised, but most have. Windows are now available with three times the insulation value of their predecessors. Modern gas and oil furnaces have attained 95% efficiency. Efficient air conditioners use 30% to 40% less energy than the models of ten years ago. District heating, heat pumps and solar energy can all save energy. Improved lighting could yield cost-effective savings of 30% to 60%. Major improvements have been made in refrigerators, water heaters, washing machines and dishwashers. Stand-by power (leaking electricity) absorbs about 10% of residential electricity in IEA countries, but technologies exist that can substantially reduce this consumption. New technologies such as “smart” metering, micro combined-heat-and-power generation, fuel cells and solar photovoltaics are opening up new ways to provide energy services.

In **industry** there is huge potential to reduce energy demand and CO_2 emissions through improved efficiency of motors, pumps, boilers and heating systems; increased energy recovery in materials-production processes; increased recycling of used materials; adoption of new and more advanced processes and materials; and a higher efficiency of materials use. The biggest sources of industrial CO_2 emissions are the iron and steel industry (26%), the production of other minerals such as cement, glass, and ceramics (25%), and chemicals and petrochemicals (18%). New cutting-edge industrial technologies with substantial potential to save energy and CO_2 emissions include: advanced membranes that can replace distillation in some petrochemical processes; “direct casting” in iron and steel; and the use of bio-feedstocks in the petrochemical industry to replace oil and natural gas.

Improving energy efficiency in the **transport** sector is of special importance, since this sector consumes the bulk of oil products and has the fastest growing emission profile. The efficiency of conventional gasoline and diesel vehicles can be substantially improved. Promising technologies include hybrid vehicles and advanced diesel engines. Turbochargers, fuel injection and advanced electronic methods of engine control can help cut fuel consumption. New materials and more compact engines lead to lighter and more fuel-efficient vehicles. Large efficiency gains are also possible in vehicle appliances, especially air conditioning. Some practical measures, such as ensuring that tyres are correctly inflated, can make a surprisingly significant difference.

Energy efficiency gains are a first priority for a more sustainable energy future. In the ACT scenarios, improved energy efficiency in the buildings, industry and transport sectors leads to between 17% and 33% lower energy use than in the Baseline scenario by 2050. Energy efficiency accounts for between 45% and 53% of the total CO_2 emission reduction relative to the Baseline in 2050, depending on the scenario. In a scenario in which global efficiency gains relative to the Baseline are only 20% by 2050, global CO_2 emissions increase by more than 20% compared to the other ACT scenarios.

Clean Coal and CO_2 Capture and Storage Technologies

CO_2 capture and storage technologies (CCS) can significantly reduce CO_2 emissions from power generation, industry and the production of synthetic transport fuels. CCS could reduce CO_2 emissions from coal and natural gas use in these sectors to near zero. The cost of CCS is high, but it could fall below USD 25 per tonne of CO_2 by 2030. When the captured CO_2 can be used for enhanced oil recovery (EOR), costs could be lower and even negative in some cases. However, the global long-term potential for CO_2 EOR is small relative to global emissions from the power generation sector.

All the individual elements needed for CCS have been demonstrated, but there is an urgent need for an integrated full-scale demonstration plant. Particularly when used with coal, it is important that coal plants are highly efficient in order to limit the cost increase of using CCS. More efficient technologies for coal combustion are already available or in an advanced stage of development. These include high-temperature pulverised coal plants and integrated coal-gasification combined-cycle (IGCC).

In the ACT scenarios, CCS technologies contribute between 20% and 28% of total CO_2 emission reductions below the Baseline Scenario by 2050. Clean coal technologies with CCS offer a particularly important opportunity to constrain emissions in rapidly growing economies with large coal reserves, such as China and India. CCS is indispensable for the role that coal can play in providing low-cost electricity in a CO_2 constrained world. This is illustrated in a scenario where CCS is *not* included as an option. In this scenario, global coal demand is almost 30% lower than in the scenarios that include CCS and CO_2 emissions are between 10% and 14% higher.

Electricity Generation from Natural Gas

The share of natural gas in electricity generation remains relatively robust in all of the ACT scenarios, ranging from 23% to 28% of total generation in 2050. This represents a more than a doubling of gas-based electricity generation from 2003 levels. Ample reserves of gas exist to meet demand, but many factors will affect its actual availability and price. Natural gas emits only about half as much CO_2 as coal per kWh. The improved efficiency of gas-fired electricity generating plants is one of the success stories of modern power generation technologies. The latest combined-cycle gas plants reach efficiencies of around 60%. More widespread use of this technology can reduce emissions significantly. To achieve even higher efficiencies, new materials will be needed that can withstand very high temperatures.

Electricity Generation from Nuclear Power

Nuclear energy is an emission-free technology that has progressed through several "generations". "Generation III" was developed in the 1990s, with a number of advances in safety and economics, including "passive safety" features. Eleven countries, including those OECD countries with the largest nuclear power sectors, have joined together to develop "Generation IV" nuclear power plants. Three key issues present major obstacles to nuclear energy's further exploitation: their large capital cost; public opposition due to the perceived threats of radioactive waste and nuclear accidents; and the possible proliferation of nuclear weapons. The development of Generation IV reactors aims to address these issues.

Assuming that these concerns are met, increased use of nuclear power can provide substantial CO_2 emission reductions. In the ACT scenarios, nuclear accounts for 16% to 19% of global electricity generation in 2050. The increased use of nuclear power relative to the Baseline Scenario accounts for 6% to 10% of the emissions reduction in 2050. In a scenario with more pessimistic prospects for nuclear, its share of electricity generation drops to 6.7%, the same level as in the Baseline. In the more optimistic TECH Plus scenario, nuclear power accounts for 22.2% of electricity generation in 2050.

Electricity Generation from Renewables

By 2050, the increased use of renewables such as hydropower, wind, solar and biomass in power generation contributes between 9% and 16% of the CO_2 emission reductions in the ACT scenarios. The share of renewables in the generation mix increases from 18% today, to as high as 34% by 2050. In a scenario with less optimistic assumptions about cost reductions for renewable technologies, their share of generation is 23% in 2050. On the other hand, in the TECH Plus scenario, which is more optimistic for both renewable and nuclear technologies, the share of renewables reaches more than 35% by 2050.

Hydropower is already widely deployed and is, in many areas, the cheapest source of power. There is considerable potential for expansion, particularly for small hydro plants. Hydropower remains the largest source of renewable generation in all the ACT scenarios.

The costs of **onshore and offshore wind** have declined sharply in recent years through mass deployment, the use of larger blades and more sophisticated controls. Costs depend on location. The best onshore sites, which can produce power for about USD 0.04 per kWh, are already competitive with other power sources. Offshore installations are more costly, especially in deep water, but are expected to be commercial after 2030. In situations where wind will have a very high share of generation, it will need to be complemented by sophisticated networks, back-up systems, or storage, to accommodate its intermittency. In the ACT scenarios, power generation from wind turbines is set to increase rapidly. In most of the scenarios, wind is second to hydropower as the most important renewable source.

The combustion of **biomass** for power generation is a well-proven technology. It is commercially attractive where quality fuel is available and affordable. Co-firing a coal-fired power plant with a small proportion of biomass requires no major plant modifications, can be highly economic and can also contribute to CO_2 emission reductions.

The costs of high-temperature **geothermal** resources for power generation have dropped substantially since the 1970s. Geothermal's potential is enormous, but it is a site-specific resource that can only be accessed in certain parts of the world for power generation. Lower-temperature geothermal resources for direct uses like district heating and ground-source heat pumps are more widespread. RD&D can further reduce the costs and increase the scope of geothermal power.

Solar **photovoltaic (PV)** technology is playing a rapidly growing role in niche applications. Costs have dropped with increased deployment and continuing R&D. Concentrating solar power (CSP) also has promising prospects. By 2050, however, solar's (PV and CSP) share in global power generation will still be below 2% in all the ACT scenarios.

Biofuels and Hydrogen Fuel Cells in Road Transport

Finding carbon-free alternatives in the transport sector has proven to be a greater challenge than in power generation. Ethanol derived from plant material is an attractive fuel with good combustion qualities. It has most commonly been blended with gasoline (10% ethanol and 90% gasoline), but Brazil has successfully introduced much higher blends with only minor vehicle modifications. Ethanol from sugar cane is produced in large volumes in Brazil, and it is fully competitive with gasoline at current oil prices. Today's ethanol production uses predominately starch or sugar crops, limiting the available feedstock, but new technology could enable lignocellulosic biomass feedstocks to be used as well. This is currently one of the cutting edge areas of energy technology research.

The use of hydrogen from low-carbon or zero-carbon sources in fuel-cell vehicles could practically decarbonise transport in the long run. But a switch to hydrogen will require huge infrastructure investments. In addition, although recent advances in hydrogen fuel-cell technologies have been impressive, they are still very expensive.

The increased use of biofuels in transport accounts for around 6% of the CO_2 emission reductions in all the ACT scenarios, while the contribution from hydrogen is very modest. In the TECH Plus scenario, however, hydrogen consumption grows to more than 300 Mtoe per year in 2050 and accounts for around 800 Mt of CO_2 savings, while the fuel-efficiency impact of fuel cells adds another 700 Mt CO_2 of savings. Hydrogen and biofuels provide 35% of total final transport energy demand in 2050 in the TECH Plus scenario, up from around 13% in the ACT scenarios and 3% in the Baseline scenario. This returns primary oil demand in 2050 back to about today's level.

Beyond 2050

Bringing CO_2 emission levels in 2050 back to current levels, as illustrated by the ACT scenarios, could offer a pathway to eventually stabilise CO_2 concentrations in the atmosphere. But for this to happen, the trend of declining CO_2 emissions achieved by 2050 would have to continue into the second half of the 21^{st} century. In approximate terms, the ACT scenarios show how electricity generation can be significantly decarbonised by 2050. Decarbonising transport, a more difficult task, would need to be accomplished in the following decades.

The more ambitious technology assumptions of the TECH Plus scenario, result in CO_2 emissions being reduced by 16% below current levels by 2050. This outcome could be achievable, but it would be risky to rely on the even faster rate of technical progress assumed in this scenario. The TECH Plus scenario could also be regarded as providing an idea of the trends that may be developed more strongly, and perhaps with more certainty, in the second half of the century.

Implementing the ACT Scenarios: Policy Implications

It will take a huge and co-ordinated international effort to achieve the results implied by the ACT scenarios. Public and private support will be essential. Unprecedented co-operation will be needed between the developed and developing nations, and between industry and government. The task is urgent. It must be carried out before a new generation of inefficient and high-carbon energy infrastructure is locked into place. The effort will take decades to complete and it will require significant investments. Yet, the benefits will be substantial, and not only for the environment. Lower energy consumption, together with reduced air pollution and CO_2 emissions could help lift possible constraints that concerns about energy supply and environmental degradation may otherwise impose on economic growth.

Implementing the ACT scenarios will require a transformation in the way power is generated; in the way homes, offices and factories are built and used; and in the technologies used for transport. In the end, it is the private sector that will have to deliver the changes required. But the market on its own will not always achieve the desired results. Governments have a major role to play in supporting innovative R&D and in helping new technologies to surmount some daunting barriers. Government, industry and consumers will have to work hard together.

Energy Efficiency Is Top Priority

Improving energy efficiency is often the cheapest, fastest and most environmentally friendly way to meet the world's energy needs. Improved energy efficiency also reduces the need for investing in energy supply. Many energy efficiency measures are already economic and they will pay for themselves over their lifetime through reduced energy costs. But there are still major barriers to overcome. Consumers are often ill-informed. Few are concerned with energy efficiency when buying appliances, homes or cars. Even business management tends to give energy efficiency a low priority in decision making. There are also opportunities for energy efficiency that consumers never see because the manufacturers of refrigerators, televisions or cars do not always take full advantage of the technologies that exist to make their products more energy efficient. A wide range of policy instruments are available, including public information campaigns, non-binding guidelines, labels and targets, public-sector leadership in procurement, binding regulations, standards, and fiscal and other financial incentives.

Governments should work to help industry and consumers to adopt and demand advanced technologies that will deliver the same or better services at lower costs.

Well-focused R&D Programmes Are Essential

There is an acute need to stabilise declining budgets for energy-related R&D and then increase them. More R&D in the private sector is critical. Some forward-looking companies are increasing their commitments, but this trend needs to continue and broaden. For technologies that are already commercial, the private sector is best placed to tailor ongoing research and development to the market's needs.

Nevertheless, government–funded R&D will remain essential, especially for promising technologies that are not yet commercial. Government R&D budgets in IEA countries are well below the levels that they reached in response to the oil price shocks of the 1970s and have been static or in decline over the past decade. Budgets for energy R&D and deployment programmes need to be reviewed if the results of the ACT scenarios are to be realised. Some of the areas with the greatest potential include advanced bio-fuels, hydrogen and fuel cells, energy storage and advanced renewables. There are also some interesting areas of basic science – especially bio-technologies, nano-technologies and materials – which could have far-reaching implications for energy in the long term.

The Transition from R&D to Technology Deployment Is Critical

The deployment phase can require considerably more resources than the R&D phase. Several new technologies that are already on the market need government backing if they are to be mass deployed. Many renewable energy technologies are in this position. The "valley of death" that new technologies face on the way to full commercialisation must be bridged. Experience shows that new technologies benefit from cost reductions through "technology learning" as deployment increases. Governmental deployment programmes can also activate R&D by private industry by creating expectations of future markets for the new technology.

There is a particularly urgent need to commercialise advanced coal-fired power plants with CO_2 capture and storage. If this is done, coal can continue to play a major role in the energy mix to 2050, significantly reducing the costs of shifting to a more sustainable energy future. To accelerate the introduction of CCS, at least 10 full-scale integrated coal-fired power plants with CCS are needed by 2015 for demonstration. These plants will cost between USD 500 million and USD 1 billion each. The projects can only be accomplished if governments strengthen their commitment to CCS development and deployment and work closely with the private sector. Involvement of developing countries with large coal reserves, such as China, will be crucial in this process. Similar initiatives will be needed to commercialise Generation IV nuclear technology.

Governments Need to Create a Stable Policy Environment that Promotes Low-carbon Energy Options

New energy technologies may be more expensive, even after full commercialisation, than those they are designed to replace. For example, CCS technologies will not make a significant impact unless lasting economic incentives to reduce CO_2

emissions are put in place. The ACT scenarios include widespread implementation of technologies with an incremental cost of up to USD 25 per tonne of CO_2 in 2050. This could be achieved in many ways, such as national or international cap-and-trade schemes, but also through national fiscal or regulatory action. Incentives are needed in developed as well as in developing countries. Incentives for energy-intensive industries will have to be internationally co-ordinated to avoid the risk that factories might relocate to lightly regulated regimes, thereby actually increasing global CO_2 emissions.

Non-economic Barriers Must also Receive Attention

There are a range of other barriers that are not economic or technical that can delay or prevent innovation and market deployment of new energy technologies. These barriers can take many forms, including planning and licensing rules, lack of information and education, health and safety regulations, and lack of co-ordination across different sectors. All these need attention if the potential of promising technologies is to be realised.

Collaboration between Developed and Developing Countries Will be Needed

By 2050, most of the world's energy will be consumed in developing countries, many of which are experiencing rapid growth in all energy consuming sectors. Developing countries will therefore also need to consider energy security and CO_2 abatement policies. A significant transformation of the global energy economy is required to meet the legitimate aspirations of developing countries' citizens for energy services, to secure supplies and to ensure sustainability. Developed countries have an important role to play in helping developing economies to leapfrog the technology development process and to employ efficient equipment and practices through technology transfer, capacity building and collaborative RD&D efforts. Fast-growing developing countries offer opportunities to accelerate technology learning and bring down the costs of technologies, such as energy-efficient equipment.

Part 1 TECHNOLOGY AND THE GLOBAL ENERGY ECONOMY TO 2050

Chapter 1 INTRODUCTION

Secure, reliable and affordable energy resources are fundamental to economic stability and development. The threat of disruptive climate change, the erosion of energy security and the growing energy needs of the developing world, all pose major challenges to energy decision makers. Innovation and the adoption of new energy technologies, and a better use of existing technologies will be required to meet these challenges.

This book deals with those challenges. It describes the key energy technologies of the future. It provides analysis of their status and prospects. It outlines the barriers to their implementation and the measures that may be needed to overcome them. It explores how they can change our energy future.

The International Energy Agency's *World Energy Outlook* (WEO 2005) projects that unless current policies change global energy-related CO_2 emissions will grow by more than 50% from 2003 levels by 2030 and oil demand by 45%. Fossil fuels will meet 85 % of the world's incremental energy needs. The *WEO* further foresees that most of the new CO_2 emissions and increased demand for energy will come from developing countries. Even in the Alternative Policy Scenario of the *WEO* 2005, which analyses impact of policies and measures under consideration, global CO_2 emissions rise 28% over current levels.

World leaders have looked at this and other similar projections and concluded that a new pathway is needed to a future that will meet the universally recognized goals of energy security, economic prosperity and environmental protection.

At their July 2005 summit in Gleneagles, United Kingdom, leaders of the Group of Eight (G8) countries addressed energy issues in these terms: "We will act with resolve and urgency now to meet our shared and multiple objectives of reducing greenhouse gas emissions, improving the global environment, enhancing energy security and cutting air pollution in conjunction with our vigorous efforts to reduce poverty."

The IEA Ministerial meeting communiqué from May 2005, also addressed pathways to a sustainable energy future. The Ministers concluded: "We can and will achieve a sustainable and secure energy future through stronger actions now to curb our growing energy import dependence as world reserves narrow to fewer sources; lessen our economic vulnerability to high and volatile energy prices, including through increased energy efficiency measures; and reduce the environmental impact of the world's growing reliance on fossil fuels."

The themes identified in the G8 and IEA communiqués are also being given priority by other organisations and groups. Innovative technologies can play a vital role in reducing energy consumption, boosting economic growth, reducing greenhouse gas emissions and improving energy security.

This book addresses many of the challenges identified in the IEA Ministerial communiqué and is also part of the IEAs response to the request made by G8 leaders to provide "advice on alternative energy scenarios and strategies aimed at a clean, clever and competitive energy future". It is intended to be a key reference for policy makers and others interested in existing and emerging clean energy technologies, policies and practices.

The technology review draws upon the IEAs extensive store of data and analysis. It further profits from IEAs unique international network for collaboration on energy technology. More than five thousand experts from 39 countries participate in the IEAs Committee on Energy Research and Technology (CERT), its Working Parties and in 40 Implementing Agreements. The analysis in this book has benefited from numerous contributions from network members. A description of this network is included in Annex A.

The objectives of this book are to:

- Review and assess the status and prospects for key energy technologies in electricity generation, road transport, buildings and industry.
- Examine, through scenario analysis, the potential contributions that these energy technologies can make to improve energy security and reduce the environmental impacts of energy provision and use.
- Discuss strategies on how to help these technologies make this contribution.

The book has two major components:

Part I: *Technology and the Global Energy Economy to 2050* presents a set of scenarios to 2050 in Chapter 2. They include five Accelerated Technology scenarios (ACT) that investigate the potential of energy technologies and best practices aimed at reducing energy demand and emissions, and diversifying energy sources. The scenarios illustrate the impact of a wide range of policies and measures that overcome barriers to the adoption of these technologies. A sixth scenario, TECH Plus, analyses the impact of more optimistic assumptions on certain key technologies. Chapter 3 presents strategies that suggest how promising energy technologies can help the world to move towards a more sustainable energy future.

Part II: *Energy Technology Status and Outlook* provides a detailed review of the status and prospects of key energy technologies in separate chapters covering electricity generation, road transport, buildings and appliances, and industry. It highlights the potential and costs for these technologies and discusses the barriers that they must overcome before their full potential can be harvested.

Chapter 2 SCENARIOS TO 2050: ENERGY DEMAND, SUPPLY AND CO_2 EMISSIONS

Key Findings

In the absence of new policies, global energy demand and CO_2 emissions will more than double by 2050.

- *In the Baseline Scenario, global CO_2 emissions grow rapidly, oil and gas prices are high, and energy-security concerns increase as imports rise. Energy use more than doubles, while CO_2 emissions rise by an unsustainable 137% from 24.5 Gt in 2003 to 58 Gt in 2050. Most of the growth in energy demand, and hence emissions, comes from developing countries.*

- *Coal demand in 2050 is almost three times higher than in 2003; gas demand increases by 138% and crude oil demand increases by 65%. The carbon intensity of the world economy increase due to greater reliance on coal for power generation and an increased use of coal in the production of liquid transport fuels.*

Energy technologies can bring the world's energy sector onto a more sustainable path.

- *The five Accelerated Technology (ACT) scenarios in this study demonstrate that the use of technologies that already exist or are under development can return global energy-related CO_2 emissions towards today's level by 2050.*

- *The significant changes in the ACT scenarios result from strong energy efficiency gains in transport, industry and buildings; from the substantial decarbonisation of electricity supply as the power generation mix shifts towards nuclear power, renewables, natural gas, and coal with CO_2 Capture and Storage (CCS); and through increased use of biofuels for road transport.*

- *Despite these changes, fossil fuels still supply between 66% and 71% of the world's energy in 2050. Demand for oil, coal (except in the scenario where CCS is not available) and natural gas are all greater in 2050 than they are today. Investment in conventional energy sources thus remains essential.*

- *Improved energy efficiency accounts for between 31% and 53% of the CO_2 emissions reductions in the ACT scenarios; CO_2 capture and storage for between 20% and 28% (in the scenarios it is assumed to be available); fuel switching for between 11% and 16%; the use of renewables in power generation for between 5% and 16%; nuclear for between 2% and 10%; biofuels in transport for about 6%; and other options for between 1% and 3%.*

- *The ACT scenarios show that more energy efficient end-use technologies can reduce total global energy consumption by 24% by 2050 compared to the Baseline. Electricity demand is reduced by one-third below the Baseline level in 2050, which halves electricity demand growth between 2003 and 2050. Savings of oil are equivalent to more than half of today's global oil consumption, offsetting 56% of the growth in oil product demand expected in the Baseline Scenario. The growth in oil demand is moderated by improved efficiency, the increased use of biofuels in the transport, and fuel switching in buildings and industry sectors.*

- *A sixth scenario, TECH Plus, is based on more optimistic assumptions on the rate of progress for renewable and nuclear electricity generation technologies, for advanced biofuels, and for hydrogen fuel cells. Given these assumptions, CO_2 emissions could fall by about 16% below current levels in 2050. Hydrogen and biofuels provide 34% of total final transport energy demand in 2050, returning primary oil demand in 2050 to about today's level.*

Beyond 2050.

- *Bringing global CO_2 emission levels in 2050 back to current levels, as illustrated by the ACT scenarios, could offer a pathway to eventually stabilise CO_2 concentrations in the atmosphere. However, the trend of declining CO_2 emissions achieved by 2050 would have to continue in the second half of this century. In approximate terms, the ACT scenarios show how electricity generation can be substantially decarbonised by 2050. Decarbonising transport, which is more difficult, would need to be achieved in the following decades. The more radical changes in the TECH Plus scenario could be regarded as providing an indication of the trends that may develop more strongly and perhaps with more certainty, in the second half of the century.*

The Accelerated Technology and TECH Plus Scenarios

In the *World Energy Outlook 2005 (WEO 2005)* Reference Scenario, which includes enacted or committed energy and climate policies, global energy-related CO_2 emissions increase very rapidly from 24.5 Gt in 2003 to 37.4 Gt in 2030. The *WEO 2005* Alternative Policy Scenario analyses the potential impact of policies and measures under consideration that are aimed at addressing environmental and energy-security concerns. In this scenario, CO_2 emissions are 16% lower than in the Reference Scenario in 2030. CO_2 emissions still rise 28% over current levels and although both oil and gas demand grow more slowly, import dependence is still higher in 2030 than today in most importing regions. The CO_2 emissions growth in the Reference Scenario is unsustainable, and the improvement in the Alternative Policy Scenario, although a start, will not move the world onto a sustainable path.

The Accelerated Technology scenarios investigate the potential of energy technologies and best practices aimed at reducing energy demand and emissions, and diversifying energy sources. The scenarios focus on technologies which exist today or which are likely to become commercially available in the next two decades. The results of the ACT scenarios illustrate the impact of a wide range of policies and measures aimed at overcoming barriers to the adoption of these technologies. The public and the private sectors both have major roles to play in creating and disseminating new energy technologies. In addition to the ACT scenarios, a scenario with more optimistic assumptions about the rate at which certain technological barriers are overcome, the TECH Plus scenario, is considered.

The increased uptake of cleaner and more efficient energy technologies in the ACT scenarios is driven by the following main types of policies:

- *Increased support for the research and development (R&D)* of energy technologies that face technical challenges and need to reduce costs before they become commercially viable.
- *Demonstration programmes* for energy technologies that need to prove they can work on a commercial scale and under relevant operating conditions.
- *Deployment programmes* for energy technologies which are not yet cost-competitive, but whose costs could be reduced through learning-by-doing. These programmes would be phased out when the technology becomes cost-competitive.
- *CO_2 reduction incentives* to encourage the adoption of low-carbon technologies. In the ACT scenarios, policies and measures are assumed to be put in place that would lead to the adoption of low-carbon technologies with a cost of up to USD 25 per tonne of CO_2. The ACT scenarios are based on the incentives being in place from 2030 in all countries, including developing countries. The incentives could take many forms – such as regulation, pricing, tax breaks, voluntary programmes, subsidies or trading schemes.
- *Policy instruments to overcome other commercialisation barriers* that are not primarily economic. These include enabling standards and other regulations, labelling schemes, information campaigns, and energy auditing. These measures can play an important role in increasing the uptake of energy efficient technologies in the buildings[1] and transport sectors, as well as in non-energy intensive industry branches where energy costs are low compared to other production costs.

This study analyses five different ACT scenarios. The scenarios, each of which assumes the same set of core efforts and policies described above, vary *only* in that they assume *different rates of progress* in overcoming technological barriers, achieving cost reductions and winning public acceptance for a technology. In the ACT scenarios, the technology areas where different assumptions are made are (1) the progress in cost reductions for renewable power generation technologies; (2) constraints on the development of nuclear power plants; (3) the risk that CO_2 capture and storage (CCS) technologies will not be commercialised by 2050; and (4) the effectiveness of policies to increase the adoption of energy efficient end-use technologies.

These scenarios are not forecasts of the future, even if the analysed policies were to be implemented. They are illustrations of possible outcomes based on a thorough analysis of today's knowledge about the characteristics and potential of current

1. The buildings sector comprises the residential and service sectors.

technologies and those that will be available in the future. They are put forward to help frame the issues and debate, providing insights into future developments and to aid in planning for the future. Actual outcomes will depend on factors that cannot be accurately predicted, including the success of research programmes and of industry in improving technology, reducing costs and marketing their products.

A description of each of the five ACT scenarios follows. In addition, there is an ambitious TECH Plus scenario, in which more significant technical progress and cost reductions are assumed for certain technologies.

ACT Map

The ACT Map scenario is relatively optimistic in all the four technology areas mentioned above. Its assumptions are realistic in the light of the current knowledge of the technologies and historic experience with technological progress. However, it should be noted that significant uncertainties surround each of the four areas identified. The other scenarios are mapped against the results of this scenario. The key features of the Map scenario are:

- Barriers to the capture and storage of CO_2 are overcome, although costs remain high.
- Cost reductions for renewable energy technologies, such as wind and solar, continue with increasing deployment (through technology learning effects).
- Expansion of nuclear power generation capacity becomes more acceptable, as problems related to waste management and nuclear weapon proliferation are addressed.
- Progress in energy efficiency is accelerated due to successful implementation of best practices and policies that lead to the adoption of more-efficient technologies in the transport, buildings and industrial sectors.
- Biofuels become an increasingly viable alternative to petroleum products in the transport sector. New technologies such as ethanol from ligno-cellulosic feedstocks, increased crop yields and the increased feedstock availability due to agricultural sector restructuring all contribute to reduced costs for biofuels.
- Significant progress is made to reduce the costs of hydrogen fuel-cell vehicles (FCVs), but costs remain high and hydrogen makes only a minor contribution to the transport sector in this scenario.

ACT Low Renewables

This scenario explores the impact of slower cost reductions for wind and solar energy technologies. In this scenario, costs decline more slowly than in the ACT Map scenario.

ACT Low Nuclear

This scenario reflects the limited growth potential of nuclear if public acceptance remains low, nuclear waste issues are not satisfactorily addressed and non-proliferation issues remain significant.

ACT No CCS

This scenario explores what would happen if the technological issues facing CCS are not solved and CCS technologies do not become commercially available.

ACT Low Efficiency

This scenario assumes that energy-efficiency policies are less effective than in the Map scenario. Global average energy savings are 0.3% per year lower than in the Map scenario. Supply-side technology assumptions remain as they are in Map. However, the mix of technologies and fuels change due to higher demand in this scenario.

TECH Plus

The TECH Plus scenario makes more optimistic assumptions about the progress for promising energy technologies. This scenario is to some extent speculative, in that it assumes more progress in overcoming technological barriers (cost-related and otherwise) than is considered likely in the ACT scenarios.

This scenario assumes much more optimistic cost reductions from R&D, technology development and learning-by-doing, while still retaining the same CO_2 reduction incentive and level of policy efforts as in the ACT scenarios. Specifically, the scenario assumes greater cost reductions for fuel cells, renewable electricity generation technologies, biofuels and nuclear technologies compared with the ACT Map scenario. In this scenario, the shares of renewable and nuclear energy in electricity generation both increase, and hydrogen FCVs gain significant market share by 2050. Technology progress lowers the cost of biofuels production from a wider range of feedstocks, resulting in a more rapid uptake of ligno-cellulosic ethanol. This scenario assumes that trade, agricultural and energy policies advance the international trade in biofuels, which also boosts the global biofuel uptake.

Table 2.1 ▸ **Overview of scenario assumptions for ACT and TECH Plus scenarios**

	Technologies					
	Renewables	Nuclear	CCS	H_2 fuel cells	Advanced biofuels	End-use efficiency
Scenario						
Map						
Low Renewables	Pessimistic					
Low Nuclear		Pessimistic				
No CCS			No CCS			
Low Efficiency						Pessimistic
TECH Plus	Optimistic	Optimistic		Optimistic	Optimistic	

Box 2.1 ▶ The Energy Technology Perspectives Baseline Scenario

The Energy Technology Perspectives (ETP) Baseline Scenario was developed by extending the World Energy Outlook (WEO) 2005 *Reference Scenario from 2030 to 2050. As in the WEO Reference Scenario, the ETP Baseline includes the effects of technology developments and improvements in energy efficiency that can be expected on the basis of government policies already enacted. Many of these policies will have an effect beyond the 2030 timeframe because of the long lifetime of much of the energy-using capital stock. The lifespan for power plants is forty years or more, while building structures may last sixty years, a century or longer. Other factors will also affect technology development beyond 2030, especially rising oil and gas prices. Energy prices have implications both for energy efficiency and for the relative shares of fuels. In the Baseline Scenario, oil prices increase from USD 39 per barrel in 2030 (in 2004 dollars) to USD 60 per barrel in 2050. At these prices, substitutes for conventional oil, such as tar sands, as well as transport fuels produced from gas and coal will begin to play a larger role. This will occur against the backdrop of a change in the pattern of economic growth after 2030, as population growth slows and the economies of developing countries begin to mature.*

All the ACT scenarios and the TECH Plus scenario are based on the same macro-economic assumptions as in the Baseline Scenario developed for this study (see Box 2.1). World economic growth in the Baseline and ACT scenarios is a robust 2.9% per year between 2003 and 2050. Per capita incomes grow by 2% per year on average, ranging from 1% per year in the Middle East to 4.3% per year in China.

Energy prices in each of the ACT and TECH Plus scenarios respond to changes in demand and supply in that scenario. The interaction between availability of energy resources, the energy technologies used, the demand for energy services and energy prices is captured in the energy system model used for this analysis (see Box 2.2). In the Baseline, as in all the ACT scenarios and the TECH Plus scenario, the underlying demand for energy services is the same. Thus, this analysis does not consider scenarios for reducing the demand for energy services (such as by reducing indoor room temperatures or restricting personal travel activity).

CO_2 Emission Trends

Without new policies, global energy-related CO_2 emissions will increase very rapidly (Figure 2.1). In the *WEO 2005* Reference Scenario, CO_2 emissions increase from 24.5 Gt in 2003 to 37.4 Gt in 2030. In the ETP Baseline Scenario, the growth in CO_2 emissions continues through to 2050, reaching 58 Gt CO_2. CO_2 emissions in 2050 are an unsustainable 137% higher than in 2003. The rapid growth in emissions after 2030 is the result of an increasing share of coal

Box 2.2 ▶ The IEA Energy Technology Perspectives Model

The primary tool used for the analysis of the ACT scenarios is the IEA Energy Technology Perspectives model (ETP). This global 15-region model permits the analysis of fuel and technology choices throughout the energy system, from energy extraction through fuel conversion and electricity generation to end-use. The model's detailed representation of technology options includes about 1 000 individual technologies.

The ETP model belongs to the MARKAL family of bottom-up modelling tools (Fishbone and Abilock, 1981). MARKAL has been developed over the past 30 years by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA Implementing Agreements (ETSAP, 2003). The ETP-MARKAL model uses cost-optimisation to identify least-cost mixes of energy technologies and fuels to meet energy-service demand, given constraints like the availability of natural resources.

For this study, the ETP model has been supplemented with detailed demand-side models for all major end-uses in the industry, buildings and transport sectors. These models were developed to assess the effects of policies that do not primarily act on price. These demand-side models explicitly take into account capital-stock turnover and have been used to model the impact of new technologies as they penetrate the market over time.

in the energy mix.[2] This is due to increased use of coal in electricity generation, expansion of coal-based transport fuel production and rapid economic growth in developing countries that have large coal reserves.

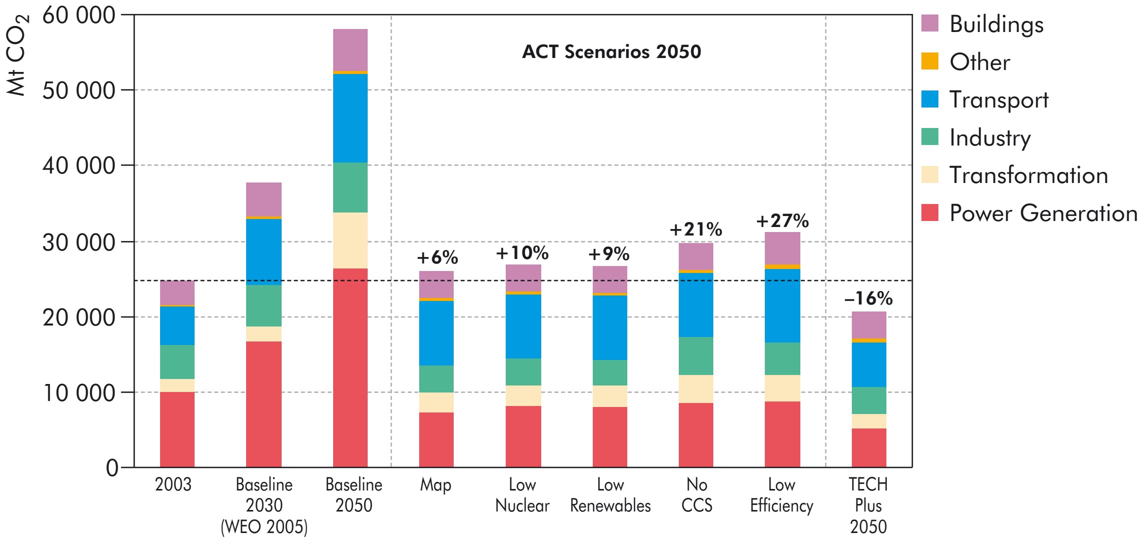
In the Baseline Scenario, oil demand[3] increases by 93% between 2003 and 2050, from 3 646 Mtoe to 7 027 Mtoe, resulting in significant pressure on oil supply. Gas demand increases by 138%, from 2 244 Mtoe in 2003 to 5 349 Mtoe in 2050. Coal demand increases by 192%, from 2 584 Mtoe in 2003 to 7 532 Mtoe in 2050.

These energy use and CO_2 emissions trends can be mitigated by clean-energy technologies, best practices and policy actions. The ACT scenarios illustrate that it is possible to move the energy system to a more sustainable basis over the next half century using technologies that are available today or which could become commercially available in the next decade or two. Significant CO_2 emission reductions are achieved in all of the ACT scenarios. In the Map scenario, emissions return to about today's level by 2050, or 6% higher than in 2003.[4] In the four remaining ACT scenarios – Low Nuclear, Low Renewables, No CCS and Low Efficiency – CO_2 emissions are higher than in the Map scenario, ranging between 9% and 27% above the 2003 level (Figure 2.1).

2. The adoption of CCS in the Baseline Scenario remains minimal.
3. Including conventional and non-conventional oil, and synfuels from coal and gas.
4. 2003 is the latest year for which the IEA has detailed statistics on CO_2 emissions from energy use at the time this publication went to press. An unofficial IEA estimate suggests that global CO_2 emissions have increased by 8% between 2003 and 2005, implying that emissions in the Map scenario are just below 2005 levels.

Only in the TECH Plus scenario are CO_2 emissions lower in 2050 than in 2003. In this scenario, more optimistic assumptions about reductions in the cost of nuclear, renewables, hydrogen fuel cells and the production of ethanol from cellulosic feedstocks leads to greater use of these technologies and fuels, and is the only scenario where there is significant penetration of hydrogen. CO_2 emissions in this scenario are 21% below the Map scenario and 16% below 2003 levels by 2050.

Figure 2.1 ▶ **Global CO_2 emissions in the Baseline Scenario, ACT scenarios and TECH Plus scenario**



Key point

CO_2 emissions can be returned towards current levels by using a portfolio of technologies.

All of the ACT scenarios, except the Low Efficiency scenario, yield significant energy-security benefits. Oil demand in the ACT scenarios is 27% less than in the Baseline Scenario in 2050, except in the Low Efficiency scenario, where it is 20% lower. In the Map scenario, oil demand reaches 5 126 Mtoe in 2050, although this is 27% below the Baseline Scenario, it is still 41% higher than in 2003. Gas demand in the Baseline Scenario reaches 5 349 Mtoe in 2050, while in the ACT scenarios it ranges from 3 746 Mtoe to 4 513 Mtoe in 2050. Gas demand ranges from 30% lower than the Baseline Scenario in 2050 in the Map scenario to 16% lower in the Low Efficiency scenario. Coal demand in the Baseline Scenario reaches 7 532 Mtoe in 2050, while in the ACT scenarios it ranges from 55% to 72% lower than in the Baseline Scenario in 2050. Coal demand in 2050 ranges from 2 111 Mtoe in the No CCS scenario to 3 417 Mtoe in the Low Efficiency scenario.

The energy security benefits of the TECH Plus scenario are even more significant than in the ACT scenarios. Oil demand in 2050 in the TECH Plus scenario, at 4 135 Mtoe, is just 13% higher than the 2003 level and is 41% lower than in the Baseline

Scenario. Gas demand in 2050 is 3 697 Mtoe, or 31% lower than in the Baseline Scenario in 2050. Coal demand in 2050 is 2 655 Mtoe, or 65% lower than in the Baseline Scenario in 2050.

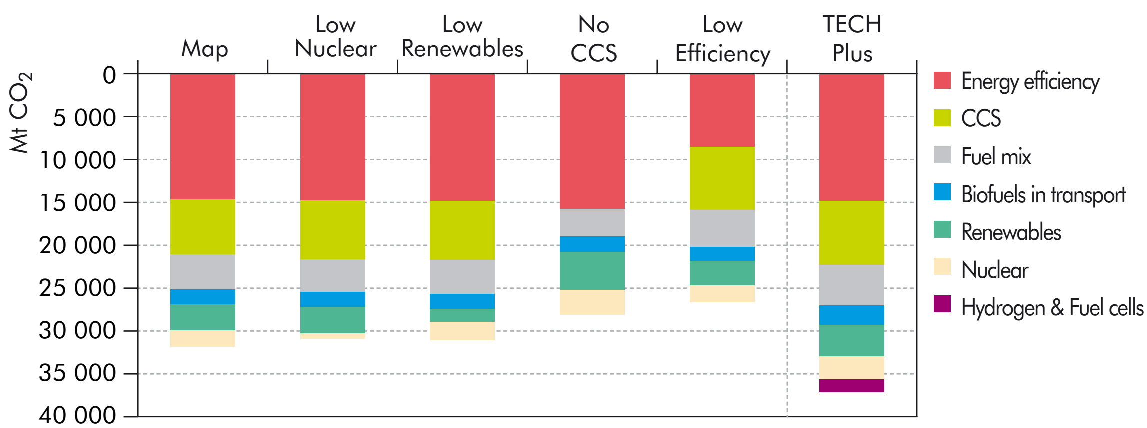
Reductions in CO_2 Emissions by Contributing Factor[5]

End-use Energy Efficiency

Energy efficiency improvements in the end-use sectors are the single largest contributor to CO_2 emission reductions in the ACT scenarios (Figure 2.2 and Figure 2.3). Except for the Low Efficiency scenario, energy efficiency improvements contribute between 45% and 53% of the emission reductions in the ACT Scenarios (Table 2.2). In the Low Efficiency scenario, this share falls to 31%.

Figure 2.2 ▶ CO_2 emission reductions by contributing factor in the ACT and TECH Plus scenarios

(reduction below Baseline Scenario in 2050)[6]



Key point

Energy efficiency plays the most important role in CO_2 emission reductions, accounting for up to 53% of total CO_2 emission reductions.

5. When calculating the contribution of the different factors discussed in this section, the impact of saved electricity has been allocated to the end-use efficiency category using the 2003 CO_2 emission intensity for power generation. This means that the end-use efficiency improvements are not affected by the reduction in the power generation CO_2 emission intensity between 2003 and 2050. The impact of the reduction of this intensity is accounted for by the factors related to power generation in Figures 2.2 and 2.3, and in Table 2.2. Similarly, the reduction in emissions from fuel transformation due to lower production of carbon intensive coal- and gas-to-liquids are allocated to the increased use of biofuels and improved energy the efficiency in the transport sector.

6. The fuel mix category includes CO_2 emission reductions from changes in the fuel mix in the power generation, industry and buildings sectors. A significant part of these reductions derive from the substitution of gas and renewables for coal, and more use of electricity where the CO_2 intensity of power generation is low. Similarly, the energy efficiency category includes the impact of efficiency improvements in the power generation, industry, transport and buildings sectors. The hydrogen savings include the end-use efficiency contribution of fuel cells.

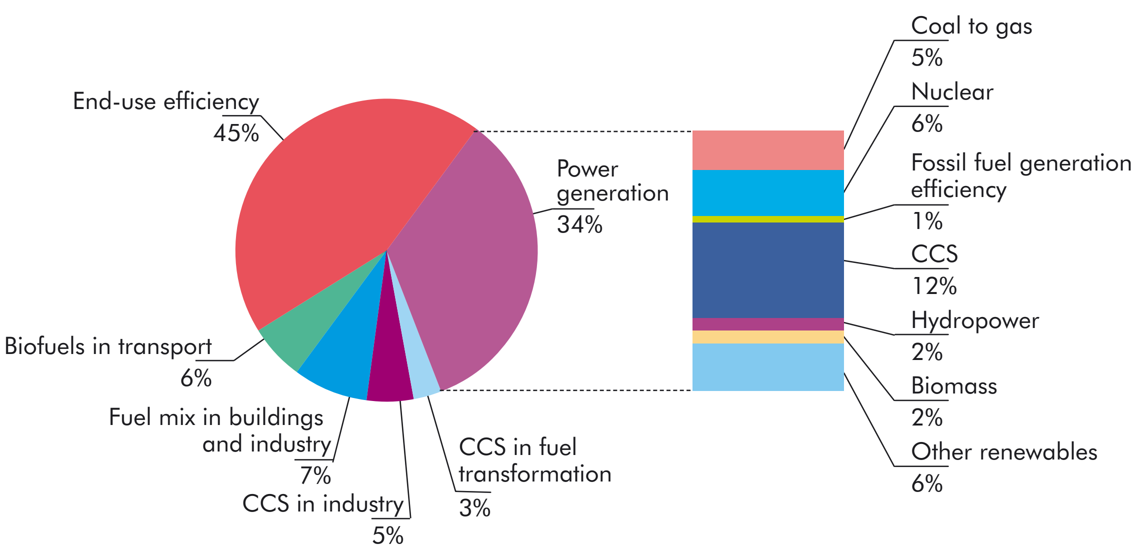
Final energy demand in 2050 is 3 280 Mtoe (23%) lower in the Map scenario than in the Baseline Scenario. Of this difference, around 24% occurs in industry, 23% in the transport sector, 18% in the services sector and 34% in the residential sector.

Energy efficiency in the final demand sectors accounts for 39% of the CO_2 emission reductions in the TECH Plus scenario, which yields a slightly higher reduction in absolute terms than in the Map scenario. In addition to this, the fuel efficiency impact of fuel cell vehicles (FCVs) accounts for another 2% of the total savings.

Power Generation

The impact of switching from coal-fired to gas-fired power generation contributes between 5% and 7% of the total reduction in CO_2 emissions relative to the Baseline Scenario, while improved power-generation efficiency accounts for an additional 1 to 3% depending on the scenario.[7] Nuclear technologies play an important role in reducing CO_2 emissions in all scenarios except Low Nuclear, with a share of the total CO_2 emission reduction ranging from 6% in the Map to 10% in the No CCS scenario. Increased use of renewables in power generation contributes 9% of the reduction in the Map scenario and 16% in the No CCS scenario. Assuming more modest cost declines for renewables, as in the Low Renewables scenario, means the share of reductions from renewable generation technologies falls to 5%.

Figure 2.3 ▶ **Reduction in CO_2 emissions in the Map scenario by technology area**
(share of reduction below Baseline Scenario in 2050)



Key point

Improved efficiency of end-use technologies contributes 45% of the reduction in CO_2 emissions.

7. The contribution from improved generation efficiency is affected by the reduction in thermal efficiency that occurs with the use of CCS.

The competition among options in the power sector depends primarily on economic considerations, but it is also influenced by a number of other factors. In general, the mix of capital, operating and fuel costs will determine which technology is most competitive to meet new capacity needs. But other issues, such as the availability of capital and land-use policies, can limit the contribution of individual technologies or raise their costs in certain regions.

CO_2 Capture and Storage

The use of CO_2 capture and storage in the industrial, fuel transformation and power generation sectors accounts for 20 to 28% of the CO_2 savings, except in the No CCS scenario. CCS at coal-to-liquids and gas-to-liquids plants, at refineries, and in the production of hydrogen contributes between 3% and 5% of the CO_2 emissions reduction depending on the scenario, while CCS in industry contributes 4 to 6%. The greatest potential for the application of low-cost CCS is in power generation, where CCS contributes between 12% and 18% of the CO_2 emission reductions depending on the scenario.

Fuel Switching in End-use Sectors

Fuel switching to less carbon-intensive fuels in buildings and industry contributes between 6% and 10% of the CO_2 emissions reduction depending on the scenario. The share of coal consumed in industry in the Map scenario in 2050 is 9%, two percentage points lower than in the Baseline Scenario. The share of coal in the buildings sector is unchanged, at roughly 1%. The share of oil use in industry in 2050 declines from 25% in the Baseline Scenario to 19% in the Map scenario, while its share is unchanged in the buildings sector. In 2050, the share of gas use in industry increases from 25% in the Baseline Scenario to 32% in the Map scenario.

Electricity increases its share in total final consumption from 16% in 2003 to 21% in 2050 in the Map scenario, despite significant energy efficiency gains. This is due to the rapid growth in electric end-uses such as appliances. There is also an impact from the increased use of electricity as a substitute for fossil fuels, particularly for heat pumps, and in countries where the CO_2 intensity of power generation is low.

In 2050, the share of renewables in industry increases from 8% in the Baseline Scenario to 12% in the Map scenario. In the buildings sector, the increase in the renewables share is from 15% to 18%. Most of the increase in the buildings sector is due to the increased use of solar hot water heating systems. The greater efficiency of biomass use, particularly in developing countries, in the ACT scenarios allows greater energy service demands to be met from an equivalent quantity of biomass.

Biofuels, Hydrogen and Fuels Cells

In the transport sector, biofuels and fuel cells using hydrogen offer two of the few opportunities to reduce the carbon intensity of the fuel mix. The contribution to CO_2 emission reductions from the increased use of biofuels in transport is around 6% in all the ACT scenarios, while the contribution from hydrogen is negligible.

However, in the TECH Plus scenario, hydrogen consumption grows to over 300 Mtoe per year in 2050. Hydrogen accounts for around 800 Mt of CO_2 savings in the TECH Plus scenario, while the fuel efficiency impact of fuel cells adds another 700 Mt CO_2 of savings. Biofuels' share of the CO_2 emissions savings is 0.6 percentage points higher in this scenario, saving 500 Mt of CO_2 more than in the Map scenario. Energy demand in the transport sector is 7% lower than in the Map scenario in 2050, due to more efficient fuel cell vehicles.

Hydrogen and biofuels provide 34% of total final transport energy demand in 2050 in the TECH Plus scenario, up from 13% in the Map scenario and 3% in the Baseline Scenario. In the TECH Plus scenario, demand for oil products (including synfuels from coal and gas) in the transportation sector is just 20% higher in 2050 than in 2003, while the total primary demand for oil, (which does not include synfuels from coal and gas), in 2050 is only 5% higher than in 2003.

These results are impressive, but it should be kept in mind that this scenario requires major technological advances in hydrogen production and storage, as well as in fuel cells. Without strong government support and technological breakthroughs, the energy-security benefits of this scenario will not be realised.

Carbon Dioxide Emission Trends by Scenario

Increased energy efficiency is essential to the savings in the ACT scenarios. This is underscored by the Low Efficiency scenario, in which measures to promote the adoption of more efficient end-use technologies are assumed to be less effective than in the other scenarios. The result is that the rate of energy efficiency improvement is on average 0.3% per year less than in the other ACT scenarios. Emissions in the Low Efficiency scenario are 20% higher than the Map scenario by 2050, or 27% higher than in 2003. Electricity demand in this scenario is 14% higher than in the Map scenario. Additional gas-fired generation accounts for 44% of the increase in generation, coal with CCS for 21%, renewables for 14% (of which biomass is 4%) and nuclear 10%. With no change in the assumptions about the incentives for CO_2 emission reduction, most of the remaining (non-electricity) increase in demand in the final end-use sectors is satisfied by fossil fuels.

In the No CCS scenario, CO_2 emissions are 21% higher in 2050 than in 2003. In the absence of CCS technologies, the share of coal-fired generation drops by more than 10 percentage points. Just over half of this is picked up by gas-fired generation. Nuclear gains the next largest share; then hydro and other renewables account for the rest (Table 2.3). CO_2 emissions increase not only from electricity generation, but also in industry and the fuel transformation sector.

In the Low Nuclear scenario, nuclear energy increases by only 18% between 2003 and 2050, compared to a 103% increase in the Map scenario. Nuclear energy contributes about 10% of all electricity produced in 2050 in this scenario, compared to 17% in the Map scenario. The difference is mainly made up for by increased coal-fired capacity, of which a little more than half is equipped with CCS, by more gas-fired generation and by a modest increase in renewables. Total global emissions in this scenario are 4% higher in 2050 than in the Map scenario and 10% higher than in 2003.

Table 2.2 ▶ **Reduction in CO_2 emissions below the Baseline in the ACT and TECH Plus scenarios by contributing factor, 2050**

CO_2 emission reductions in 2050 by contributing factor (Mt CO_2)						
Scenarios	Map	Low Nuclear	Low Renewables	No CCS	Low Efficiency	TECH Plus
Fossil fuel mix in power generation	1 623	1 445	1 623	1 675	1 804	1 974
Fossil fuel power generation efficiency	251	280	328	821	364	263
Nuclear	1 922	593	2 133	2 928	1 968	2 677
Hydropower	513	506	23	582	382	464
Biomass power generation	537	557	97	725	567	577
Other renewables power generation	1 966	2 060	1 397	3 192	1 927	2 676
CCS in power generation	3 983	4 450	4 471	0	4 787	4 370
CCS in fuel transformation	1 043	1 043	1 043	0	1 123	1 727
CCS in industry	1 460	1 460	1 460	0	1 480	1 460
Fuel mix in buildings and industry	2 484	2 324	2 327	1 560	2 562	2 746
Increased use of biofuels in transport	1 794	1 794	1 794	1 805	1 611	2 306
Hydrogen and fuel cells in transport	0	0	0	0	0	1 523
End-use efficiency	14 478	14 612	14 589	15 036	8 223	14 658
Total reduction	***32 053***	***31 125***	***31 283***	***28 324***	***26 807***	***37 420***
Total CO_2 Emissions in 2050	**25 969**	**26 897**	**26 738**	**29 698**	**31 214**	**20 602**
CO_2 Emissions Relative to 2003	**+ 6%**	**+ 10%**	**+ 9%**	**+ 21%**	**+ 27%**	**–16%**

Shares of CO_2 emission reductions in 2050 by contributing factor (%)						
Scenarios	Map	Low Nuclear	Low Renewables	No CCS	Low Efficiency	TECH Plus
Fossil fuel mix in power generation	5.1	4.6	5.2	5.9	6.7	5.3
Fossil fuel generation efficiency	0.8	0.9	1.0	2.9	1.4	0.7
Nuclear	6.0	1.9	6.8	10.3	7.3	7.2
Hydropower	1.6	1.6	0.1	2.1	1.4	1.2
Biomass power generation	1.7	1.8	0.3	2.6	2.1	1.5
Other renewables power generation	6.1	6.6	4.5	11.3	7.2	7.2
CCS power generation	12.4	14.3	14.3	0.0	17.9	11.7
CCS coal-to-liquids	3.3	3.4	3.3	0.0	4.2	4.6
CCS industry	4.6	4.7	4.7	0.0	5.5	3.9
Fuel mix buildings and industry	7.7	7.5	7.4	5.5	9.6	7.3
Increased use of biofuels in transport	5.6	5.8	5.7	6.4	6.0	6.2
Hydrogen and fuel cells in transport	0.0	0.0	0.0	0.0	0.0	4.1
End-use efficiency	45.2	46.9	46.6	53.1	30.7	39.2
Total	**100**	**100**	**100**	**100**	**100**	**100**

In the Low Renewables scenario, CO_2 emissions in 2050 increase by 3% over the Map scenario. Roughly half of the reduced renewable capacity is replaced by gas-fired generation, slightly more than a quarter by coal (of which most is equipped with CCS), with nuclear accounting for the rest.

The TECH Plus scenario, with its more optimistic assumptions about cost improvements for certain key technologies, results in CO_2 emissions in 2050 that are 16% lower than the 2003 level. In this scenario, coal demand increases by just 3% between 2003 and 2050 and primary oil demand by 5%. This is in contrast to nuclear energy, which increases by 202% between 2003 and 2050, and non-hydro renewables which increases by 307%.

Table 2.3 ► ***Electricity generation shares in the Baseline, ACT and TECH Plus scenarios, 2050***

		ACT Scenarios					
	Baseline	**Map**	**Low Nuclear**	**Low Renewables**	**No CCS**	**Low Efficiency**	**TECH Plus**
	(percentage)						
Coal	47.1	26.9	30.4	29.5	16.5	27.6	20.9
Coal	*47.1*	*12.6*	*14.3*	*13.3*	*16.5*	*12.4*	*5.7*
Coal CCS	*0.0*	*14.3*	*16.1*	*16.2*	*0.0*	*15.2*	*15.2*
Oil	3.3	2.3	2.3	2.2	2.0	2.0	2.2
Gas	27.6	22.6	25.7	26.9	28.2	25.4	19.5
Nuclear	6.7	16.8	9.8	18.0	19.0	16.0	22.2
Hydro	9.5	15.4	15.5	14.0	16.0	13.4	15.3
Biomass	2.0	4.5	4.6	3.0	4.8	4.4	5.1
Other renewables	3.9	11.4	11.8	6.4	13.5	11.2	14.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Regional Analysis

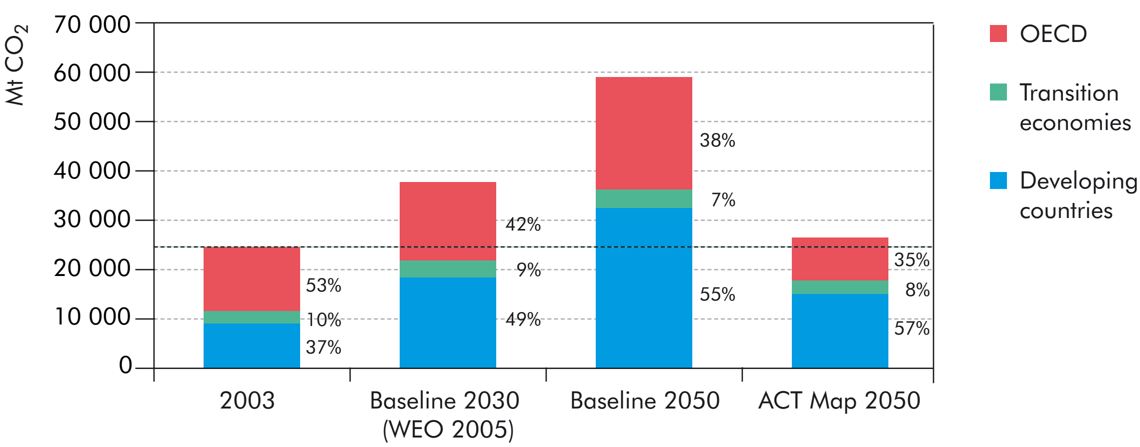
In the Map scenario, global CO_2 emissions in 2050 are 55% lower than in the Baseline Scenario (Table 2.4). CO_2 emissions in the OECD are 60% (13 177 Mt CO_2) lower than in the Baseline Scenario, and account for 41% of the worldwide reduction below the Baseline Scenario. CO_2 emissions in transition economies are 42% (1 670 Mt CO_2) lower than in the Baseline Scenario. Developing countries' CO_2 emissions are 54% (17 207 Mt CO_2) lower than in the Baseline Scenario in 2050, and they account for 54% of the global reduction. In the No CCS scenario, the reduction in CO_2 emissions below the Baseline Scenario in 2050 is 55% in the OECD, 31% in transition economies and 47% in developing countries.

In the Baseline Scenario, emissions from developing countries overtake those from the OECD between 2020 and 2025. Developing countries' CO_2 emissions increase from 37% of the global total in 2003 to 49% in 2030 and 55% in 2050 (Figure 2.4). Meanwhile, the OECD share of global CO_2 emissions declines from 53% in 2003 to 38% in 2050. In the Map scenario the OECD share of emissions declines further to 35% in 2050, that of developing countries' increases to 57% and the transition economies' share moves to 8% in 2050. The OECD share of emissions in the Map scenario is lower than in the Baseline Scenario because its emissions reductions exceed those of the developing countries.

Table 2.4 ► CO_2 emissions by region in the Baseline, Map and No CCS scenarios, 2003 and 2050

	Baseline Scenario		ACT Scenarios			
			Map	No CCS	Map	No CCS
	2003	2050			Reduction below Baseline Scenario in 2050	
	(Mt CO_2)	(Mt CO_2)	(Mt CO_2)	(Mt CO_2)	(%)	(%)
OECD	12 969	21 949	8 772	9 943	–60	–55
Transition economies	2 543	3 953	2 283	2 734	–42	–31
Developing countries	9 020	32 120	14 913	17 021	–54	–47
World	24 532	58 022	25 968	29 698	–55	–49

Figure 2.4 ► CO_2 emissions by region in the Baseline and Map scenarios



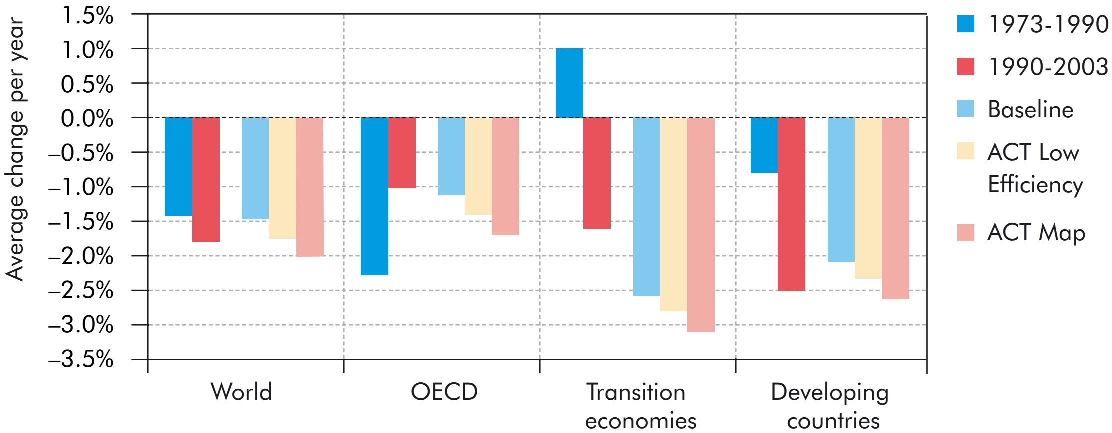
Key point

The growth in CO_2 emissions is concentrated in developing countries.

Impact of Changes in Energy Efficiency and the Fuel Mix

The ACT scenarios demonstrate the important role energy efficient end-use technologies can play in reducing CO_2 emissions. Improved energy efficiency in the ACT scenarios (except in the Low Efficiency scenario) increases the decline in global final energy consumption per unit GDP to 2% per year on average between 2003 and 2050.[8] This is more than the decline in global final energy intensity of 1.4% per year between 1973 and 1990 and than the 1.8% per year between 1990 and 2003 (Figure 2.5). In the Baseline and Low Efficiency scenarios, the annual decline rate for the period 2003 to 2050 is 1.4% and 1.7%, respectively.

Figure 2.5 ► ***Changes in final energy consumption per unit of GDP, by region, for the Baseline, Map and Low Efficiency scenarios, 2003-2050***



Key point

Outside the OECD, the decline in global final energy intensity in the Map scenario exceeds historical reduction rates.

There are important differences in the rate of decline between regions. OECD countries achieved a rapid decline in energy intensity following the oil price shocks of the 1970s. However, after 1990, the rate of reduction slowed considerably and averaged only 1% per year through to 2003, or less than half the rate between 1973 and 1990. In the OECD, this slower rate of final energy intensity reduction continues in the Baseline Scenario. In the Map scenario, the decline in final energy intensity is much more significant, at 1.7% per year. The

8. There are only small differences in final energy per GDP across the ACT scenarios; the Map scenario is thus used to illustrate the results in all ACT scenarios in this section. The important exception is the Low Efficiency scenario, where the rate of the decline in energy intensity is on average 0.3% less than in the other scenarios.

energy intensity of the transition economies declines by more than in the OECD in all scenarios, reflecting the significant energy efficiency potential in these countries.[9] Many developing countries have experienced rapid economic growth in recent years and have also seen their energy consumption relative to GDP decline rapidly with the modernisation of their economies. In the Baseline Scenario, the strong decline in energy intensity continues, but at a slower rate than between 1990 and 2003. The introduction of more energy efficient end-use technologies in the Map scenario increases the decline in energy intensity in developing countries to a rate slightly higher than in recent years.

While changes in energy efficiency are usually the most important driver of changes in energy consumption per GDP, it is not the only factor. Changes in economic structure, such as a shift from the production of raw materials to less energy-intensive manufactured products, often play an important role. After 1973, the economic structure of many OECD countries became less energy intensive. This implies that the reduction in energy intensity observed between 1973 and 2003 overestimates energy efficiency improvements (IEA, 2004). On the other hand, in some non-OECD countries, the structure has become *more* energy intensive as the production of raw materials such as steel and cement has increased rapidly.

The economic outlook that underlies this study assumes that the global economy shifts towards a less energy-intensive structure between 2003 and 2050. The rate of reduction in energy intensity in the Baseline and ACT scenarios presented in Figure 2.5 therefore, to some extent, overestimates the real rate of energy efficiency improvement. However, comparing the change in energy intensity between 2003 and 2050 *among* the different scenarios does provide a good measure of differences in energy efficiency improvement across scenarios, since the economic structure is the same in all scenarios. Hence the 0.3% per year lower rate of decline in energy intensity in the Low Efficiency scenario compared to the Map scenario represents less progress in improving energy efficiency.

Declining energy intensities have an important impact on the decoupling of CO_2 emissions from economic growth. In the Baseline Scenario, the global average annual growth in CO_2 emissions between 2003 and 2050 is 1.1 percentage points lower than GDP growth. This decoupling is smaller than between 1973 and 2003 when the annual growth rate in CO_2 emissions was 1.5% less than GDP (Figure 2.6).

To better understand what is behind this development, changes in CO_2 emissions per unit of GDP (CO_2/GDP) can be decomposed into changes in energy intensity (TFC/GDP)[10] and changes in the CO_2 intensity of the fuel mix (CO_2/TFC):

$$CO_2\,/TFC = CO_2\,/TFC * TFC/GDP$$

Figure 2.6 shows that all the decoupling of CO_2 emissions per GDP that took place between 1973 and 2003 was a result of declining energy intensities; the CO_2 intensity of the fuel mix (CO_2/TFC) in 2003 was virtually the same as in 1973. On

9. Interpretation of historical intensity trends in transition economies is difficult due to the significant restructuring that these economies have undergone.

10. TFC: Total Final energy Consumption.

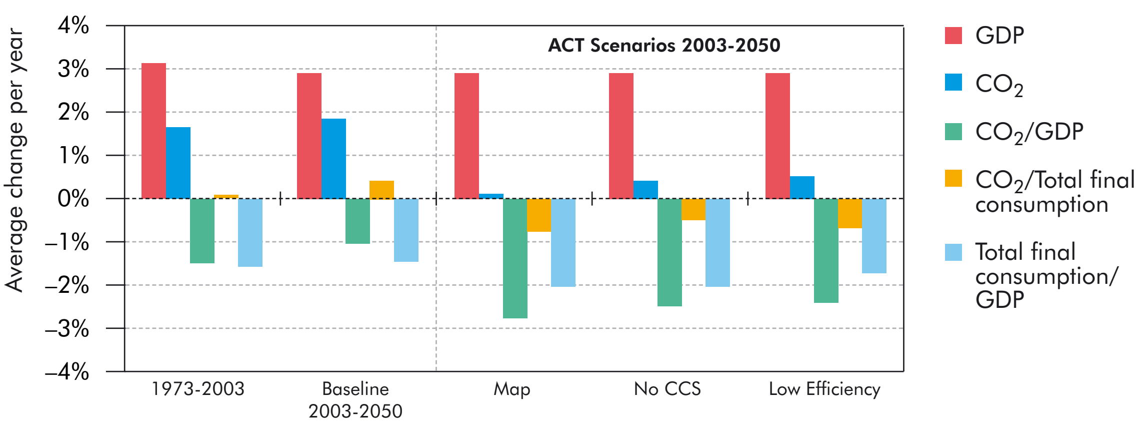
the other hand, in the Baseline Scenario the growing share of coal increases the CO_2 intensity of the fuel mix by on average 0.4% per year out to 2050. At the same time, the energy intensity declines by 1.4% per year, slightly less than it did on average between 1973 and 2003, with the net result that the CO_2 emissions per GDP in the Baseline falls by half a percentage point less per year compared to 1973-2003 period.

In the Map scenario, CO_2 emissions per GDP decline at an average annual rate of 2.7% between 2003 and 2050. CO_2 emissions are almost completely decoupled from GDP growth in this scenario. Almost three-quarters of this decoupling is due to the decline in energy intensity, and the rest to a reduction in the CO_2 intensity of the fuel mix.

In the Low Efficiency and the No CCS scenarios, CO_2 emissions per unit of GDP decline at an annual rate of 0.4% and 0.3% less than in the Map scenario respectively. In the Low Efficiency scenario, the reduced decoupling is due to the lower rate of decline in final energy intensity, while in the No CCS scenario it is due to the lower rate of decline in the CO_2 intensity of the energy mix.

Figure 2.7 shows the changes in GDP and CO_2 emissions by region, as well as changes in energy intensity and the CO_2 intensity of the fuel mix. In the Map scenario, CO_2 emissions decline by 0.8% per year in OECD countries and by 0.2% per year in transition economies. Only emissions in developing countries increase in this scenario, at 1.1% per year. The strong reductions in CO_2 emissions per GDP are due to greater improvements in energy efficiency, as well as the decline in the CO_2 intensity of the energy mix. This latter factor is driven by fuel switching in the end-use

Figure 2.6 ► ***Changes in CO_2 emissions and GDP in the Baseline, Map, No CCS and Low Efficiency scenarios, 2003-2050***
(including decomposition of changes in CO_2 emissions per GDP into changes in CO_2 intensity of the fuel mix and energy intensity)



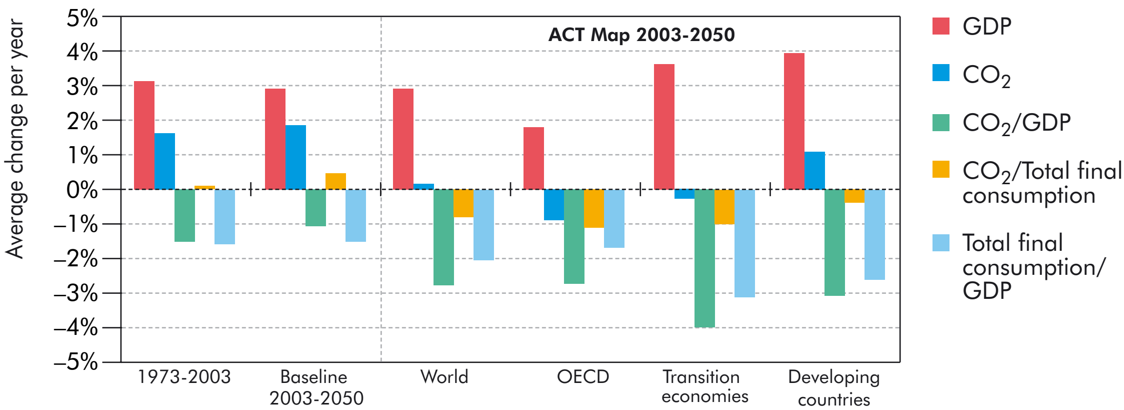
Key point

Strong reductions in CO_2 emissions per unit of GDP in the ACT scenarios are driven primarily by accelerated energy efficiency improvements.

sectors and by the large reduction in CO_2 emissions from the power generation sector. The relative impact on CO_2 emissions per GDP from decarbonising final energy consumption is more important in OECD countries than in transition and developing economies.

Figure 2.7 ► **Growth in CO_2 emissions and GDP in the Baseline and Map scenarios, by region, 2003-2050**

(including decomposition of changes in CO_2 emissions per GDP into changes in CO_2 intensity of the fuel mix and energy intensity)



Key point

Energy efficiency plays a more important role in reducing CO_2 emissions per GDP outside OECD.

Cost Implications of the ACT and TECH Plus Scenarios

Most of the technologies included in the ACT scenarios have higher upfront investment costs than incumbent technologies. However, many technologies offer cost savings on a life-cycle basis because of lower fuel or other variable costs. This is particularly true for many demand-side technologies. Furthermore, promising new technologies that are more expensive initially could provide future costs savings if learning-by-doing effects reduce costs below cost-competitive levels. Other technologies may need substantial investments in R&D and demonstration, but may give significant returns on these investments when the technology becomes cost-competitive in the future.

The most important cost components of accelerating the uptake of clean and efficient technologies in the ACT scenarios are:

- Investment in R&D.
- Investment in demonstration projects for technologies that need to be proven on a commercial scale.

- Support for deployment programmes to reduce the cost of new technologies via technology learning.
- The increased costs due to investment in technologies that would not be cost-effective without the assumed sustained CO_2 emission reduction incentive of USD 25 per tonne CO_2.

While this study assumes that many technologies will be improved through increased R&D efforts, it does not quantify the amount of investment that would be needed for R&D activities. What is clear, however, is that achieving the results in the ACT scenarios would require the declining trend in energy R&D expenditures observed in OECD countries to be reversed. Governments must be prepared to increase their R&D funding and also look at ways to stimulate R&D efforts in the private sector. Among its other benefits, money spent on targeted R&D often reduces the need for economic support for demonstration and deployment activities.

Certain technologies in the ACT scenarios will require economic support for demonstration before they can be mass deployed. This is particularly important for CCS technologies. To achieve the significant market shares for CCS technologies envisaged in many of the ACT scenarios, some 10 to 15 demonstration plants need to be built over the next 10-15 years. The incremental investment cost of the CCS plant will be in the order of USD 250-500 million each. The total investment cost of this demonstration programme would be USD 2.5-7.5 billion.

Table 2.5 presents the increased investment cost for power generation in the Map scenario relative to the Baseline. These costs are calculated as the difference in cumulative investment costs accrued for each technology over the time period to 2050. The costs exclude investment in R&D and demonstration, but include the costs for deployment programmes.

The additional investment costs for renewable, nuclear and CCS plants are to a large extent offset by avoided investment in fossil-fuel generation capacity. These avoided investments depend on two factors: first, significant demand-side savings reduce the need to build new capacity; second, some of the fossil-fuel-based capacity built in the Baseline is replaced by other capacity in the Map scenario. As a net result, the total additional power generation investment cost amounts to USD 3.4 trillion over the period 2005 to 2050, or about 0.1% of global GDP in 2003. If energy efficiency did not reduce electricity demand below the Baseline Scenario, then the additional cumulative investment needs would be about USD 2.9 trillion higher than this.

The additional power generation investment costs include the cost of deployment programmes needed to bring the cost of certain technologies down to a point where they become cost-competitive with the assumed CO_2 emission reduction incentive of USD 25 per tonne CO_2. In the Map scenario, the total deployment costs or "learning investments" amount to USD 720 billion over the period 2005-2050.[11] This is less than 10% of the USD 7.9 trillion additional investment costs in renewables, nuclear and CCS technologies. However, most of the deployment support will be needed

11. The deployment costs are estimated as the gap between the actual investment cost and what would be the "competitive" investment cost that makes that technology economic in each year, multiplied by the investments each year, and summed over the period up to the point when the technology becomes cost competitive.

Table 2.5 ▶ **Cumulative increase in power generation investment in the Map scenario, 2005 to 2050**
(increase over the Baseline Scenario)

Power plants	Additional investment cost (USD trillion)
Wind	3.6
Solar	0.9
Geothermal	1.1
Nuclear	1.4
CCS*	0.9
Total additional investment in renewables, nuclear and CCS	7.9
Reduced investment in fossil fuel power plants	–4.5
- of which due to lower electricity demand	*–2.9*
Total	**3.4**

*Only the CCS costs, excluding the power plant.

over the next two to three decades and they would thus represent a significant investment, which would have to be borne, at least to some degree, by governments.

Table 2.4 does not take into account the avoided investment in transmission and distribution networks due to lower demand and the wider use of distributed generation, which can be quite substantial (see Box 2.3). A rough estimate suggests that cumulative investment costs in transmission and distribution networks in the Map scenario would be around USD 4.3 trillion *lower* than in the Baseline scenario.[12] This would more than offset the additional power generation investment costs in the Map scenario and suggests that the net investment costs for electricity supply would be around USD 0.9 trillion *lower* than in the Baseline.

The improved end-use energy efficiency in the Map scenario leads to substantial reductions in investment needs for power generation capacity (USD 2.9 trillion) and transmission and distribution (USD 4.3 trillion). The cost of the more energy efficient technologies included in the Map scenario vary substantially among end-uses and world regions. The global average investment cost of these demand side technologies can be estimated to be about USD 0.03/kWh. This implies additional investment costs on the demand side of about USD 8.9 trillion out to 2050. Adding this to the 0.9 trillion reduction in supply-side investment, yields total additional investment needs for the electricity supply and demand-side of around USD 8 trillion.

The Map scenario results in a significant reduction in coal and gas use in the electricity sector due to demand reductions and the increased use of renewables and nuclear. The total cumulative savings in coal and gas use for electricity generation amount to about USD 10.8 trillion over the period to 2050. Roughly two-thirds of

12. This assumes an avoided investment cost equivalent to USD 0.3 per kWh of reduced electricity demand.

these savings are the result of reduced electricity demand and the rest is due the replacement of fossil-fuel capacity by renewables and nuclear.

The monetary savings from the reduction in coal and gas use can not be directly compared to the additional investment in the Map scenario. The investment costs must be paid for up front, but the savings of fuel will accrue over the life of the technology. To take this difference in timing into account, both the investment costs and the monetary savings from reduced fuel use were discounted using a 5% discount rate. When discounted back to 2003, the net investment needs for electricity supply are USD 0.3 trillion *lower* in the Map scenario than in the Baseline, while the demand-side investments would be USD 1.8 trillion *higher*. Discounted fuel savings amount to USD 1.4 trillion, yielding a *net additional* discounted cost of only USD 100 billion for the electricity system in the Map scenario. These costs exclude the costs for accelerated R&D and demonstration efforts.

This relatively small increase in net discounted costs for the electricity sector in the Map scenario illustrates, to a large extent, that the additional costs in the ACT scenarios can be regarded as transitional, leading to significant economic as well as environmental and security benefits in the longer term.

The changes in the ACT and TECH Plus scenarios imply a shift in the distribution of the costs and benefits of the Baseline Scenario. The producers of coal, gas and oil would see their markets grow more slowly, while those of nuclear and renewable power plants would see their markets expand more rapidly. The benefits of lower

Box 2.3 ▶ Investment costs in the *WEO 2004* Alternative Policy Scenario

The policies included in the Alternative Scenario of WEO 2004, *reduce global primary energy demand in 2030 by almost 10% compared to the Reference Scenario (IEA, 2004). At 1.2% per year, the average annual rate of demand growth is 0.4 percentage points less than in the Reference Scenario. Oil demand is reduced by 11%, gas by 10%, and coal by almost a quarter. While, electricity demand is down 12%, or 3 100 TWh, generation from nuclear and renewables is much higher.*

In the Alternative Scenario, larger capital needs on the demand side are entirely offset by lower needs on the supply side. Savings in electricity-supply investment account for more than two-thirds of the overall reduction in investment. 80% of the reduced investment in electricity supply is from lower capital needed for transmission and distribution networks, which is almost USD 1.2 trillion lower than in the Reference Scenario over the 2003-2030 period. This is mainly due to lower electricity demand, but also due to the wider use of distributed generation.

On the demand side, consumers need to invest USD 2.1 trillion more in end-use technology than in the Reference Scenario. Almost two-thirds of this additional investment, or USD 1.5 trillion, is needed in OECD countries, where the capital cost of more efficient and cleaner technologies is highest. Transportation will absorb more than half of the total additional demand-side investments foreseen. The forthcoming World Energy Outlook 2006 *will include a detailed analysis of the impact of policies and measures under consideration on energy demand and supply in the Alternative Policy Scenario, as well as a detailed assessment of the impact on coal, oil, gas and electricity prices; and the investment requirements.*

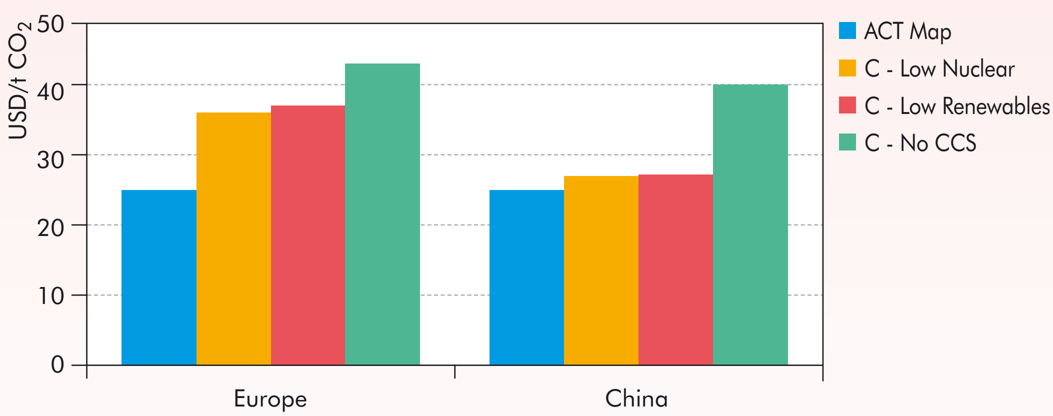
Box 2.4 ▶ The impact of technology assumptions on marginal CO_2 emission abatement cost

The differences in technology assumptions across the ACT scenarios affect the cost of achieving a certain emission reduction. The CO_2 reduction incentive assumed in the ACT scenarios represents the maximum additional cost that the market would be willing to pay for low-carbon technologies and thus is the marginal abatement cost. Since all ACT scenarios have the same CO_2 reduction incentive of USD 25 per tonne, the marginal cost is also the same. However, the level of emission reduction varies as a consequence of the differences in technology assumptions among the scenarios. A separate set of model runs was conducted to show how the marginal cost of meeting the same emissions reduction level by 2050 varies with different technology assumptions.

These runs used the same scenario assumptions on technology as in the equivalent ACT scenarios. For each scenario, however, regional emissions were constrained to equal those of the Map scenario. The difference in the marginal cost of CO_2 emissions reduction in these constrained scenarios gives an indication of the value or costs of the different assumptions made for key technologies.

Figure 2.8 shows that there is little difference in the marginal cost between the Low Nuclear and Low Renewables scenarios in Europe and China in 2050. These two scenarios would add USD 11-12 per tonne of CO_2 to the marginal cost of emissions reduction in Europe, but only USD 2-3 per tonne of CO_2 in China. The impact of the No CCS scenario on the marginal emissions reduction cost is more significant. The absence of CCS would increase the marginal costs by nearly USD 18 per tonne of CO_2 in Europe and by around USD 15 per tonne of CO_2 in China. This analysis shows that CCS is a crucial technology for achieving economic CO_2 reductions in both regions. Renewables and nuclear power are also important, but the economic impact if these are less available is much greater in Europe than in China.

Figure 2.8 ▶ Estimated marginal emissions abatement cost by scenario, 2050



Key point

The absence of CCS significantly increases the marginal cost of CO_2 emissions reduction.

Note: The C-Low Nuclear model run is the ACT scenario of the same name constrained to have the same regional emissions as the ACT Map scenario. The same is true for the C-Low renewables and C-No CCS model runs. The marginal cost for the ACT scenarios is equal to the level of the CO_2 reduction incentive of USD 25 per tome of CO_2.

energy bills, improved local and global environmental outcomes, improved prospects for some energy technology markets, and lower fuel supply prices (in some cases) will be offset to some extent by increased investment costs, higher consumer prices and slower growth in the markets for some energy technologies.

In the ACT and TECH Plus scenarios, consumers and power generators need to invest more upfront in energy efficient technologies and high capital-cost plants in order to reduce their fuel bills in later years. The time preference of individual actors and the discount rates they use to evaluate decisions will have an important role in determining the cost of this transition. In many cases investments in energy efficiency can be made that are least-cost over the life of the equipment with a consumer's discount rate, in other cases governments will have a role to play in ensuring that technologies are evaluated using social discount rates to take into account the benefits of CO_2 reduction.

The ACT and TECH Plus Scenarios: Beyond 2050

In the ACT scenarios, CO_2 emissions rise before they are returned towards current levels by 2050. This is a huge improvement on the Baseline Scenario, but CO_2 concentrations in the atmosphere will continue to rise out to 2050 and be significantly higher than the current level of 375 parts per million (ppm). This is because CO_2 remains in the atmosphere for some time and so concentrations build up even if emission rates stay fairly constant.

The eventual stabilisation of CO_2 concentrations in the atmosphere *at any level* will require the reduction of emissions to very low levels - certainly far below current levels. The lower the level for stabilization that is sought, the sooner the decline in global net CO_2 emissions needs to begin. Even after stabilization of the atmospheric concentration of CO_2 and other greenhouse gases, it is expected that surface air temperatures will continue to rise by a few tenths of a degree per century for a century or more and sea levels will continue to rise for many centuries.

There is no universal agreement as to the maximum concentrations of CO_2 in the atmosphere that can be regarded as sustainable. Levels of about 550 ppm are sometimes quoted as the lowest that can now realistically be aimed for. This is still more than twice the pre-industrial level and could lead to an increase of global temperatures by 2 degrees Celsius by 2100. The Map, Low Nuclear and Low Renewables scenarios could all be on the pathway towards a stabilisation of CO_2 concentrations at a 550 ppm level. The emissions in these scenarios up to 2050 are below the Intergovernmental Panel on Climate Change (IPCC) B1 scenario contained in the Special Report on Emission Scenarios (SRES), which results in CO_2 concentrations in 2100 of 550 ppm (IPCC, 2001).

However, achievement of the ACT scenarios, while making an important start on the path to sustainability, will not guarantee this goal is reached if further progress is not made after 2050. The declining trend in CO_2 emissions would need to be continued through the second half of the century. The CO_2 emission reductions in the ACT scenarios are largely achieved through energy efficiency gains and the substantial decarbonisation of power generation. These trends would need to continue over the next fifty years, with the complete decarbonisation of electricity, and the more difficult task of decarbonising transport would need to be accomplished. The more technologically optimistic TECH Plus scenario may be regarded as foreshadowing these developments.

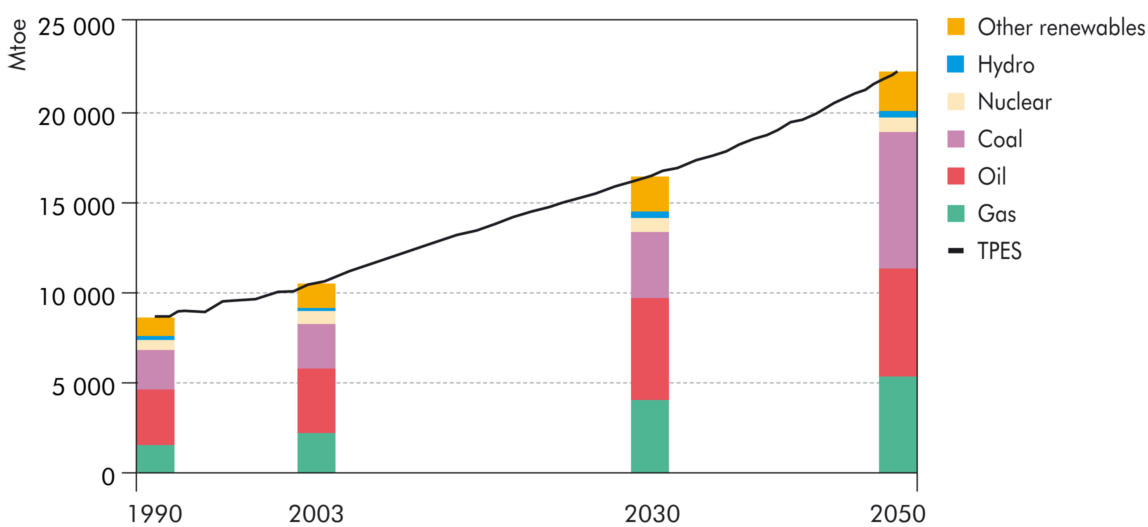
Developments beyond 2050 and the various pathways over this century to stabilise emissions could lead to differences in the technology and energy mix indicated by the ACT and Tech Plus scenarios in the latter part of the period to 2050. If it is anticipated that the power generation sector will be completely decarbonised sometime after 2050, then it may make sense to alter the balance of investment in energy infrastructure and consuming technologies before 2050. For instance, switching to electricity in industry and households before 2050 (given the long-lived nature of some capital equipment) could provide additional emission reductions if the power generation sector is expected to be almost completely decarbonised after 2050.

Energy Demand by Fuel

In the Baseline Scenario, total primary energy supply (TPES) grows at 1.6% on average per year, from 10 579 Mtoe in 2003 to 22 112 Mtoe in 2050 (Figure 2.9). This rate of growth is less than the 2.1% per year that occurred between 1971 and 2003, but it still represents an increase of 109% in primary energy demand between 2003 and 2050.

Between 2003 and 2050 the production of coal triples, that of natural gas more than doubles and that of oil almost doubles (including synfuels). By 2050, coal becomes the predominant fuel and accounts for 34% of primary energy use in 2050. It surpasses oil demand in absolute terms between 2030 and 2050. Oil's

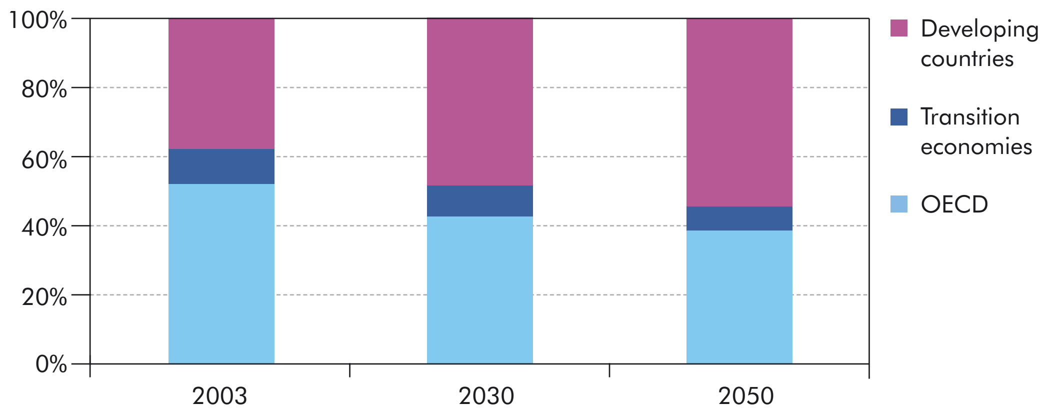
Figure 2.9 ▶ ***World total primary energy supply by fuel in the Baseline Scenario***



Key point

Primary energy use more than doubles between 2003 and 2050, with a very high reliance on coal.

Figure 2.10 ▶ **Primary energy use share by region in the Baseline Scenario**



Key point

By 2050, 55% of primary energy use is in developing countries.

share of TPES declines from 34% in 2003 to 27% in 2050. Natural gas increases its share from 21% in 2003 to 24% in 2050. Non-fossil fuels account for just 15% of demand in 2050, down from 20% in 2003. Of the non-fossil fuels, nuclear's share declines from 6% in 2003 to 4% in 2050, other renewables from 11% in 2003 to 9%, while hydro remains at 2%.

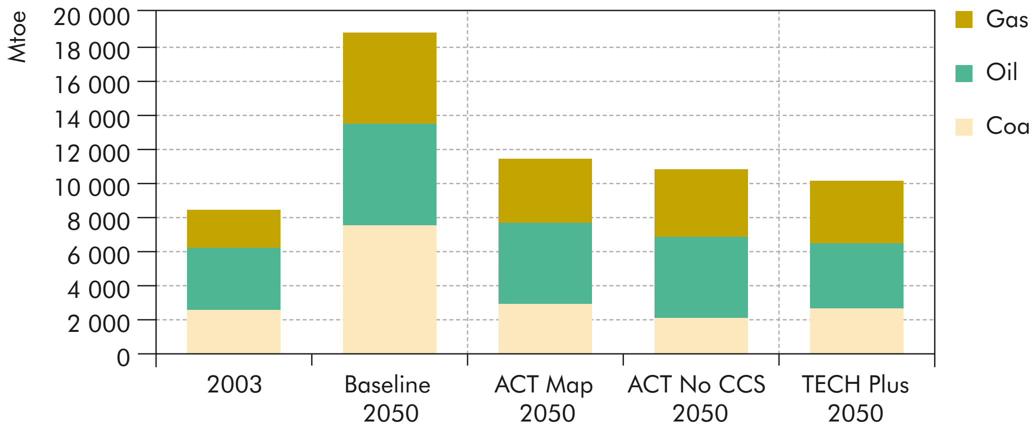
Fossil fuel's share of total demand increases from 80% in 2003 to 85% in 2050, despite the growth in nuclear and renewable energy. It follows that concerns about energy security will continue, as well as concerns associated with the continued growth in CO_2 emissions.

In the Baseline Scenario, the share of developing countries in global energy demand rises considerably, from 38% in 2003 to 54% in 2050 (Figure 2.10). OECD countries' share of primary energy use falls from just over half in 2003 to 38% in 2050.

In the Map scenario, primary energy use in 2050 is 58% higher than in 2003, at 16 762 Mtoe. This is 24% lower than that in the Baseline Scenario in 2050. Primary energy use varies little among the ACT scenarios, except in the Low Efficiency scenario where it is 14.6% higher.

The use of fossil fuels in 2050 is significantly lower in all the ACT scenarios than in the Baseline Scenario, ranging from 28% lower in the Low Efficiency scenario to 42% lower in the No CCS scenario (Figure 2.11). The reduction in fossil fuel use can be attributed to energy efficiency gains and fuel switching. The use of carbon-free fuels increases much faster than does total primary energy supply. Primary oil supply in the ACT scenarios is from 7% to 21% lower and gas demand is between 16% and 30% lower in 2050. The import dependency of most of the importing regions decreases significantly in the ACT scenarios.

Figure 2.11 ▶ World fossil-fuel supply by scenario



Key point

By 2050 total fossil fuel use in the Map scenario is 39% lower than in the Baseline Scenario, while coa use is reduced by 61%.

Table 2.6 ▶ Changes in primary energy supply by fuel in the Map, No CCS and TECH Plus scenarios, 2050[13]

	Map Scenario		No CCS		TECH Plus	
	(difference from Baseline Scenario in 2050)					
	(%)	(Mtoe)	(%)	(Mtoe)	(%)	(Mtoe)
Coal	–61	–4 620	–72	–5 421	–65	–4 878
Oil	–20	–1 209	–21	–1 237	–36	–2 165
Gas	–30	–1 602	–25	–1 360	–31	–1 651
Nuclear	72	585	85	687	156	1 264
Hydro	11	41	9	36	14	51
Renewables	71	1 455	78	1 599	137	2 822
Total	–24	– 5 350	–26	–5 696	–21	–4556

13. Oil refers to primary oil supply and therefore excludes the synfuel produced from coal-to-liquids and gas-to-liquids. The primary energy consumption from producing these fuels is reported under coal and gas.

In the TECH Plus scenario, fossil fuel use is 46% lower than in the Baseline Scenario in 2050. Primary oil supply is 36% lower than in the Baseline Scenario in 2050, coal demand is 65% lower and gas demand is 31% lower.

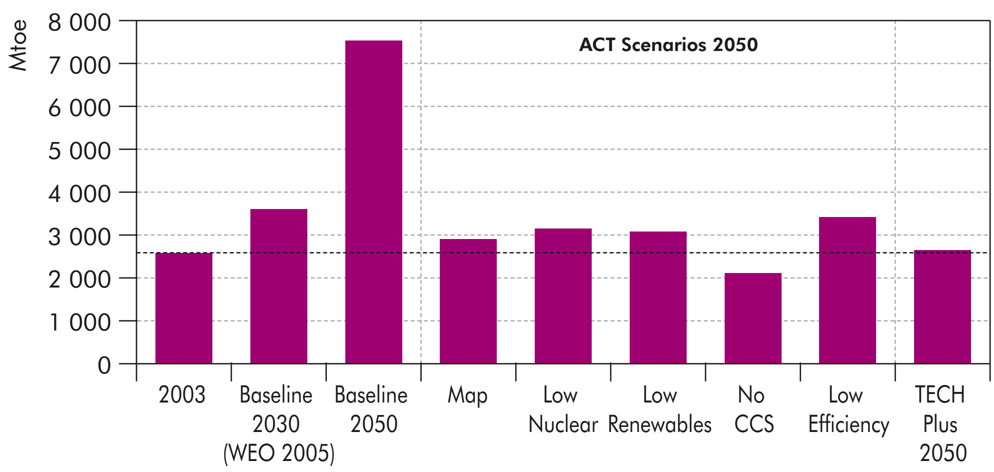
The lower demand for fossil fuels in the ACT scenarios and TECH Plus scenario also lead to lower oil and gas prices. If this were the only impact on final energy prices, some of the potential savings would be taken back, the so-called "rebound effect". In fact, however, the lower fossil fuel prices are largely offset by the impact of the CO_2 reduction policies and incentives. A CO_2 reduction incentive of USD 25 per tonne translates into a premium on oil of USD 10/bbl and on coal of USD 65 per tonne of coal. The end result of these interactions (lower demand, lower upstream prices for oil and gas, and the CO_2 reduction incentive of USD 25 per tonne) is that there is no substantial rebound effect for these fuels.

Coal

In the Baseline Scenario, coal demand is almost three times higher in 2050 than in 2003 (Figure 2.12). Coal demand increases from 2 584 Mtoe in 2003 to 7 532 Mtoe in 2050. Coal's share of total demand grows from 24% in 2003 to 34% in 2050. Between 2030 and 2050, coal eclipses oil as the single most important fuel.

Coal's strong growth in the Baseline Scenario is driven by three distinct factors. First, as oil demand grows and pressure on conventional oil supplies increases, so does the oil price. High oil prices make coal-to-liquids (CTL) economic, and the production of synfuels from coal increases dramatically after 2030. In 2050, nearly

Figure 2.12 ▶ **World coal supply by scenario, 2003-2050**



Key point

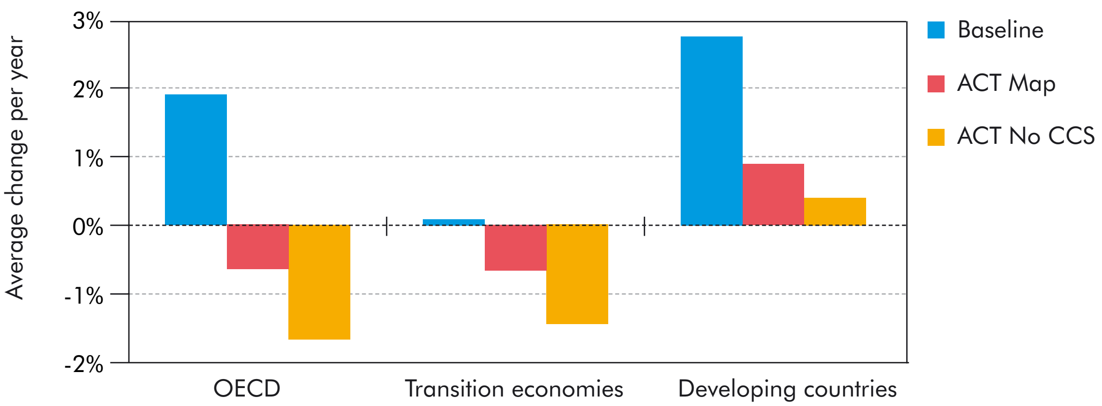
Strong reduction in coal demand in all scenarios relative to the Baseline, particularly in No CCS where coal demand drops below today's level by 2050.

1 800 Mtoe of coal is being consumed by CTL plants, predominantly in the OECD and a few developing countries. Second, the increasing demand for natural gas, the increasing length of supply chains and pressure on gas reserves, leads to higher gas prices. As a result, more new coal-fired electricity generating plants are built. Third, energy-intensive industrial production grows rapidly in developing countries, especially China and India. These countries have large coal reserves, but limited reserves of other energy resources, so much of the increase in energy demand in these countries will be met by coal, either directly or in the form of coal-based electricity generation.

Coal demand in the Map scenario, at 2 912 Mtoe in 2050, is just 13% higher than in 2003. This is predominantly the result of lower electricity demand in the Map scenario, but also the increased use of zero-emission technologies and fuels in power generation. Coal demand in 2050 varies in the ACT scenarios from a low of 2 111 Mtoe in the No CCS scenario to 3 417 Mtoe in the Low Efficiency scenario. Across the ACT scenarios, coal use in 2050 ranges from 18% less than in 2003 in the No CCS scenario to 32% higher in the Low Efficiency scenario. In the TECH Plus scenario, coal demand in 2050 is 3% higher than the 2003 level.

Coal demand in the Baseline Scenario grows most rapidly in developing countries, at 2.8% on average per year between 2003 and 2050 (Figure 2.13). Growth in OECD countries is a robust 1.9% per year. In the Map scenario, coal demand in the OECD *declines* by 0.6% per year, while *growth* in developing countries is reduced to 0.9% per year. In the No CCS scenario, coal demand is significantly reduced below the Map scenario, as nuclear, renewables and gas-fired generation increase their share of electricity generation. In this scenario, coal demand *declines* by 1.7% per year in the OECD and 1.5% per year in transition economies, while demand *growth* in developing countries is reduced to 0.4% per year.

Figure 2.13 ► ***Changes in world coal demand by region in the Baseline, Map and No CCS scenarios, 2003-2050***



Key point

Outside developing countries, coal demand drops in the ACT scenarios, particularly without CCS.

Oil

Oil demand in the Baseline Scenario increases by 93% between 2003 and 2050, from 3 646 Mtoe in 2003 to 7 027 Mtoe in 2050. Pressure on conventional oil supplies results in significant growth in the production of non-conventional oil (heavy oil, tar sands and shale oil). The balance of the increase in demand is met by synfuels produced from coal and gas, which increase from very low levels today to 1 039 Mtoe in 2050. The primary supply of oil (which excludes synfuels from coal and gas) grows by 65% between 2003 and 2050, from 3 639 Mtoe to 5 988 Mtoe. The demand for liquid fuels (defined as including oil products, synfuels and biofuels) increases by a total of 96% between 2003 and 2050 (Figure 2.14). Liquid fuel demand grows the most rapidly in the transport sector, at 1.9% on average per year, followed by the buildings sector at 1.3% per year and the industrial sector at 1.1% per year. Liquid fuel use continues to be concentrated in the transport sector, with virtually all of the growth in demand in OECD countries being driven by increases in transport.

Oil demand in the Map scenario in 2050 is 27% less than in the Baseline Scenario, reaching just 5 126 Mtoe. The increased use of biofuels accounts for about one-fifth of the reduction in demand, while improved efficiency and fuel switching accounts for the rest. Primary oil supply (excluding synfuels) grows by just 31% in the Map scenario between 2003 and 2050, to reach 4 780 Mtoe in 2050. This is 1 209 Mtoe (20%) less than in the Baseline Scenario in 2050. Synfuels from coal and gas are reduced by about two-thirds below the Baseline Scenario and contribute 346 Mtoe in 2050. Liquid fuel demand is 22% lower in 2050 in the Map scenario than in the Baseline Scenario.

In the TECH Plus scenario, the increased use of biofuels and the improved average fuel efficiency of the vehicle fleet means that oil demand is only 4 135 Mtoe in 2050, or 41% lower than the Baseline Scenario. In the TECH Plus scenario, primary oil demand, at 3 825 Mtoe in 2050, is only 5% higher than 2003 levels in 2050.

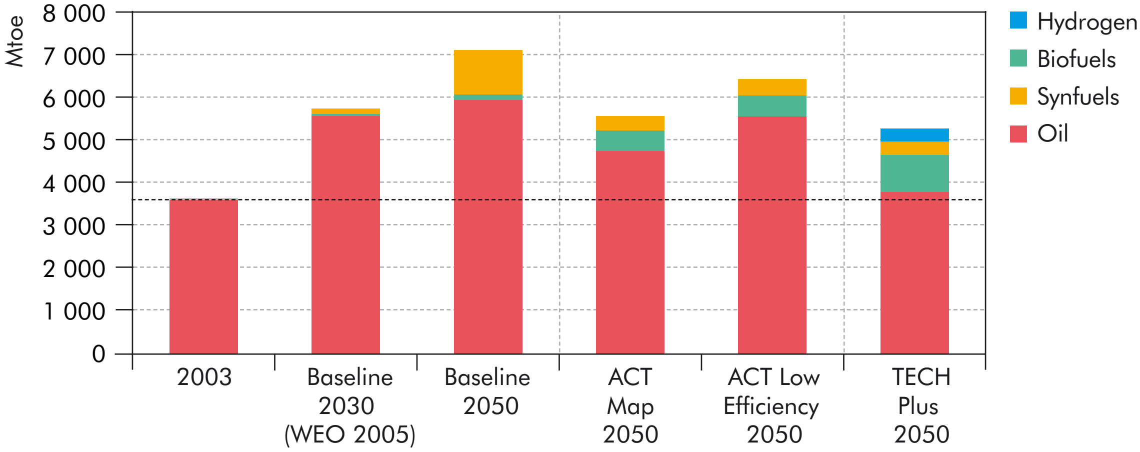
Figure 2.14 also presents the demand for oil, biofuels, synfuels and hydrogen. In the Baseline Scenario, synfuels make up 14.5% and biofuels 1.7% of liquid fuels in 2050. In the ACT scenarios, the share of synfuels drops to around 6% of total supply, while biofuels provide 9%.

Oil still accounts for the majority of fuel consumption in the transport sector in all the ACT scenarios, and a substantial oil dependency remains. Very large investments, especially in the Middle East, will be required to meet demand growth and maintain secure supplies of transport fuels.

In the TECH Plus scenario, biofuels account for 16% and hydrogen for 6% of 2050 demand for liquid fuels and hydrogen. In this scenario, synfuel's share declines to around 6%. However, the consumption of hydrogen alone does not reflect the full contribution of hydrogen, because fuel cell vehicles using hydrogen are two to three times more fuel efficient than conventional gasoline vehicles in 2050.

In the Map scenario, the demand for oil products and synfuels is reduced by 1 901 Mtoe, or 27%, from the level in the Baseline Scenario. This is equivalent to about 42 million barrels per day (Mb/d) of oil (Figure 2.15). The reduction is a result of

Figure 2.14 ▶ **World liquid fuel and hydrogen supply by scenario, 2003, 2030 and 2050**



Key point

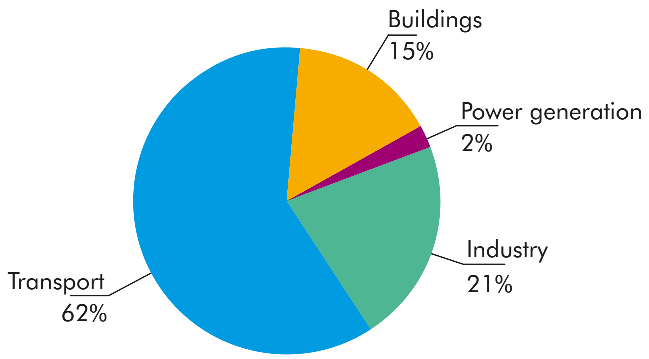
Primary oil demand in 2050 is in all ACT scenarios below the 2030 Baseline level, and is returned to around today's level in the TECH Plus scenario.

improved efficiency and switching to less carbon-intensive fuels in the building sector; improved vehicle fuel efficiency; the increased use of biofuels in the transportation sector; and improved energy efficiency, fuel-switching and the use of biomass as a substitute for some oil feedstock in the industrial sector.

Primary oil supply in the Baseline Scenario grows most rapidly in developing countries, at 2% on average per year, followed by the transition economies at 0.8% per year and by OECD countries at 0.3% per year. Faster population growth and the rapid growth in vehicle ownership contribute to faster growth in developing countries. In contrast to the situation in OECD countries, there are also significant increases in demand for oil products in sectors other than transport. This reflects the relatively poor energy infrastructure in many developing countries, which makes oil products an attractive option for power production, residential and commercial consumers. It also reflects the strong growth in the output of the industrial sectors of many developing countries.

The share of non-OECD countries in oil demand increases from 40% in 2003 to 57% in 2050 in the Baseline Scenario (Figure 2.16). The non-OECD countries share reaches 61% in the TECH Plus scenario because of the more-rapid adoption of hydrogen fuel cell vehicles in OECD countries in this scenario.

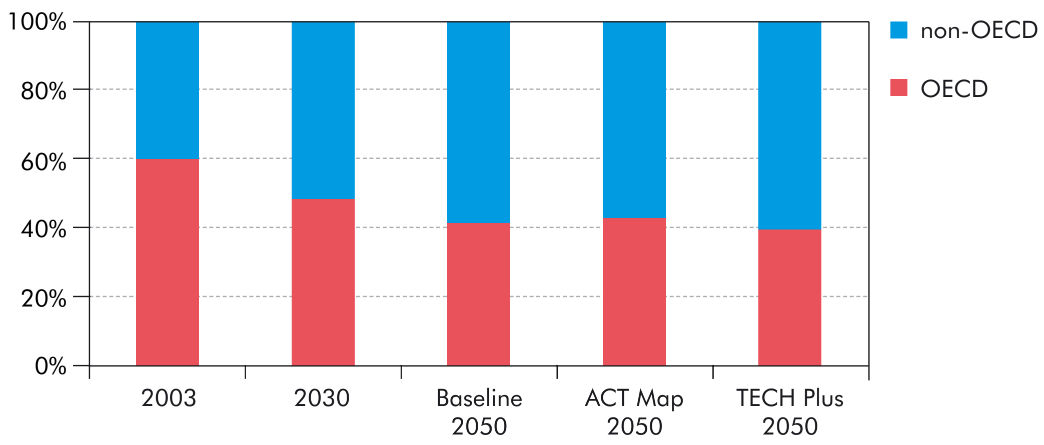
Figure 2.15 ▶ Reduction in oil demand by sector in the Map scenario, 2050 [14]



Key point

Savings below the Baseline Scenario in 2050 are around half of current total oil demand.

Figure 2.16 ▶ Share of world primary oil demand in OECD and non-OECD countries by scenario, 2003-2050



Key point

Oil demand is increasingly concentrated in developing countries.

14. Includes conventional oil, non-conventional oil, and synfuels from coal and gas.

Box 2.5 ▶ Oil supply and prices

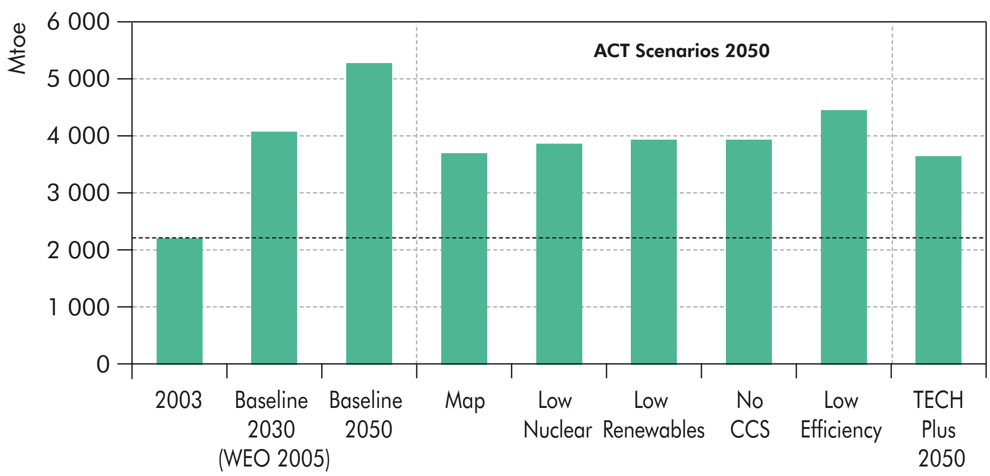
The assumed price trends in the Baseline Scenario reflect the WEO 2005 assumptions until 2030. After 2030, the price needed to meet demand over the period to 2050 is based on an analysis of conventional and non-conventional oil resources and their potential contribution to supply. Oil has to compete with other options for liquid fuel supply, including biofuels and synfuels from oil and gas.

In the WEO 2005 Reference Scenario, the IEA crude oil import price in 2030 is USD 39/bbl (in 2004 US dollars). In the Baseline Scenario of this study the price increases to about USD 60/bbl in 2050, as conventional oil supplies give way to more expensive non-conventional supplies. However, the reduced demand in the ACT scenarios lowers the call on more expensive non-conventional oil supplies and reduces the crude oil price by between USD 5 and USD 15 per barrel in 2050, depending on the scenario. The net effect on consumer prices in these scenarios is limited however, since the CO_2 emission reduction incentive of USD 25 per tonne CO_2 translates into about USD 10 per barrel of oil.

Natural Gas

Primary demand for natural gas in the Baseline Scenario grows at 1.9% on average per year between 2003 and 2050, rising from 2 224 Mtoe to 5 349 Mtoe (Figure 2.17). Global gas use by the electricity generation sector increases at 2.4% per year, from 832 Mtoe in 2003 to 2 504 Mtoe in 2050. Gas used in other

Figure 2.17 ▶ World gas supply by scenario, 2003-2050



Key point

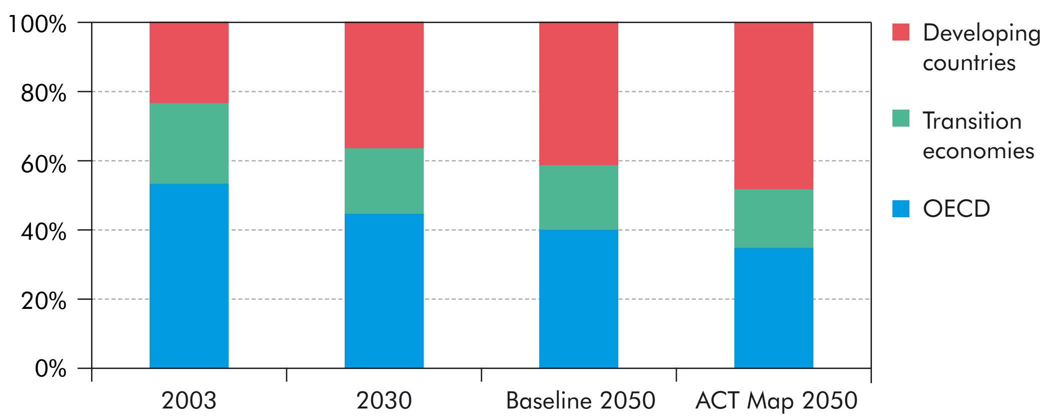
Despite significant reductions below the Baseline Scenario in 2050, gas demand in the ACT scenarios and TECH Plus scenario is still between 65% and 101% higher than today's level.

transformation activities grows at 1.8% per year from 221 Mtoe in 2003 to 517 Mtoe in 2050. Most of this increase is for gas-to-liquids plants. Gas demand in the final consumption sectors grows at 1.4% per year, with little difference between the sub-sectors at the global level.

Global natural gas use in the Map scenario grows by 1.1% per year on average, with total consumption reaching 3 746 Mtoe in 2050. This is 1 602 Mtoe less than in the Baseline Scenario in 2050, but still 67% higher than in 2003. About three-quarters of the reduction occurs in the electricity generation sector, due to reduced electricity demand and a drop in gas' share of electricity generation from 28% to 23%. Gas demand ranges from a low of 3 746 Mtoe in the Map scenario to a high of 4 513 Mtoe in the Low Efficiency scenario. Gas demand in the other scenarios does not vary much and remains in a relatively narrow band between 3 918 Mtoe and 3 989 Mtoe. Gas demand in the TECH Plus scenario, at 3 697 Mtoe in 2050, is 1% lower than in the Map scenario in 2050.

Primary demand for natural gas in developing countries increases by more than fourfold in the Baseline Scenario, from 532 Mtoe in 2003 to 2 345 Mtoe in 2050, or 3.2% per year on average. By 2050, developing countries will consume more gas than will the OECD, with slightly more than half of the growth in demand coming from electricity generation. Demand for gas in OECD countries grows at 1.2% per year, from 1 189 Mtoe in 2003 to 2 058 Mtoe in 2050. As in the developing countries, slightly more than half of the increase in OECD demand comes from electricity generation. Gas demand in the transition economies grows at 1.3% per year between 2003 and 2050. In the Baseline Scenario, developing countries increase their share of global gas demand from just under one-quarter in 2003 to 44% in 2050 (Figure 2.18). In the Map scenario, developing countries' share of gas demand reaches 48% in 2050.

Figure 2.18 ***Share of world gas demand by region, 2003-2050***



Key point

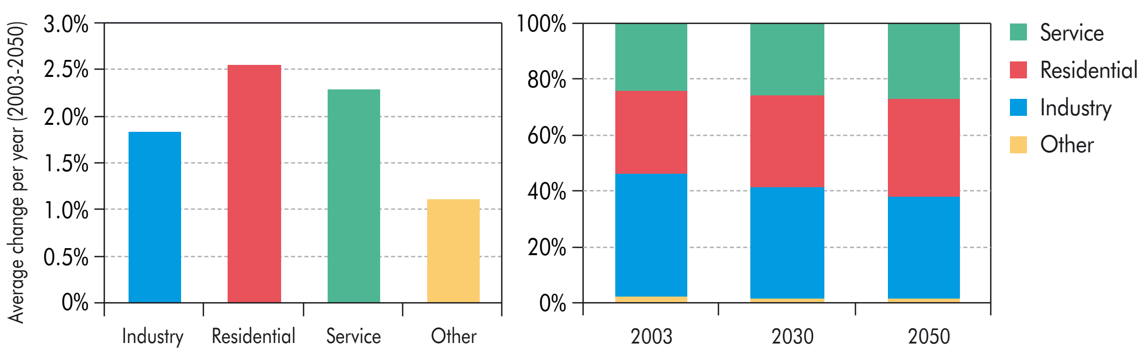
By 2050 developing countries will consume more than the OECD.

Electricity

Electricity demand growth in the Baseline Scenario is on average 2.2% per year between 2003 and 2050, making electricity the fastest growing component in total final demand. Electricity demand increases from 1 433 Mtoe (16 661 TWh) in 2003 to 4 010 Mtoe (46 631 TWh) in 2050. Electricity's share of final demand increases from 16% in 2003 to 23% in 2050. These trends are driven by rapid growth in population and incomes in developing countries, by the continuing increase in the number of electricity consuming devices used in homes and commercial buildings, and by the growth in electrically driven industrial processes in industry.

Electricity demand growth in the residential sector, at 2.6% per year on average between 2003 and 2050, is a fraction higher than in the services sector, where it is 2.5% per year in the Baseline Scenario (Figure 2.19). Electricity demand in industry grows at a more modest 1.8% per year, although electricity is still the fastest growing fuel in the sector. Industry's share of global electricity demand declines from 44% in 2003 to 37% in 2050, while the residential sector increases its share from 30% to 35%, and services from 24% to 27%.

Figure 2.19 **Electricity demand growth by sector (2003–2050) and share of demand by sector (2003, 2030, 2050) in the Baseline Scenario**



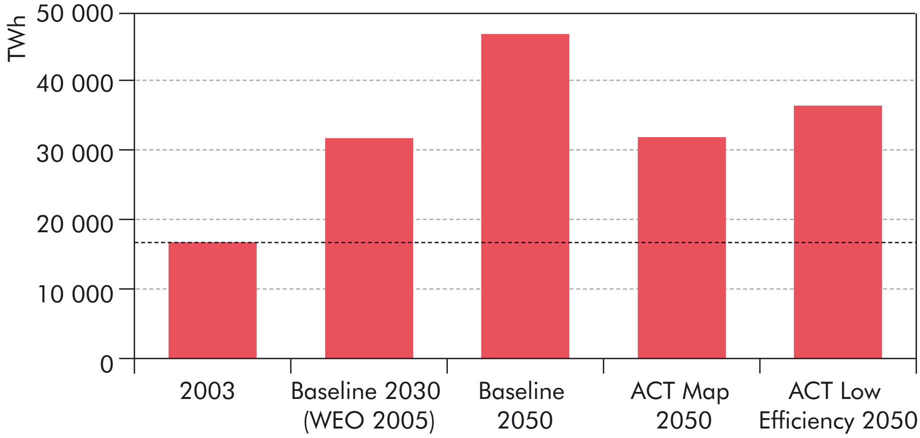
Key point

Electricity demand growth is strong in the residential and service sectors.

Baseline electricity demand in developing countries grows on average 3.6% per year, three times faster than in OECD countries. This is due mainly to the higher population growth in developing countries and the rapid increases in GDP and per capita incomes. Between now and 2050, millions of people will gain access to electricity in developing countries.

In the Map scenario, global electricity demand growth is reduced to on average 1.4% per year, with demand reaching 2 732 Mtoe (31 776 TWh) in 2050 (Figure 2.20). The reductions in electricity demand result in electricity demand growth in the Map scenario being just half that of the Baseline Scenario to 2050. This is despite fuel switching to electricity where it offers low-cost CO_2 emissions reduction opportunities, for example heat pumps in households and more electrical-intensive production processes in industry. Electricity demand in 2050 is 32% below the Baseline Scenario level. About 56% of the reduction in electricity demand occurs in the buildings sector, while industry accounts for 26% of the savings. These reductions in electricity demand contribute significantly to the total emissions savings attributable to end-use efficiency. In the Low Efficiency scenario, electricity demand in 2050 is 14% higher than in the Map scenario, at 3 124 Mtoe (36 335 TWh).

Figure 2.20 ▶ **Electricity demand in the Baseline, Map and Low Efficiency scenarios, 2003, 2030 and 2050**



Key point

In the ACT Map scenario, electricity demand in 2050 is 32% lower than the Baseline Scenario.

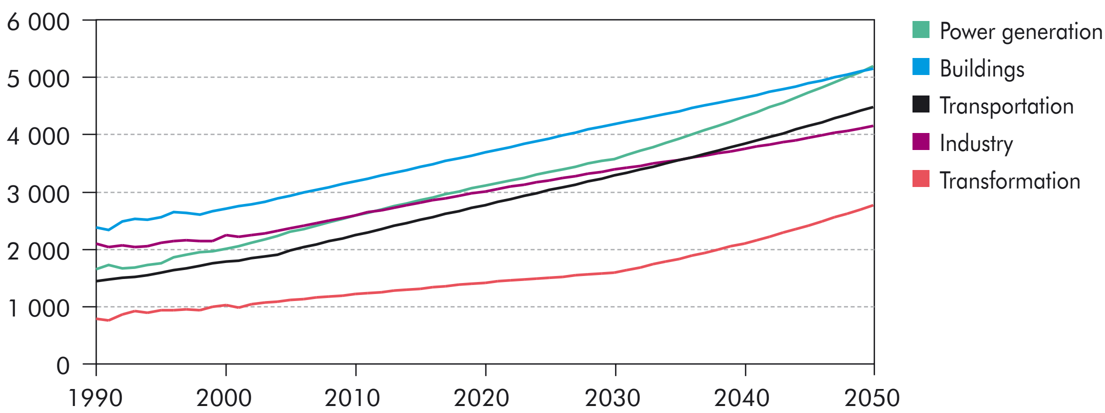
Energy Demand and CO_2 Emissions by Sector

Energy use increases in all sectors in the Baseline Scenario. The net energy consumed in the electricity generation sector (including heat plants) accounts for about half of the overall growth in primary energy (Figure 2.21). Growth in energy used for fuel transformation accelerates from an average annual growth rate of 1.4% between 2003 and 2030 to 2.8% per year between 2030 and 2050. This is due to the increased production of synfuels from coal and gas. Synfuel production typically achieves process efficiencies of 50 to 60%, while oil refineries (the main consumer in this sector prior to 2030) are from 85 to 95% efficient at converting crude to oil products.

Energy consumption in the transport, buildings and industry sectors increases on average 1.4% per year between 2003 and 2050 in the Baseline Scenario, somewhat less than the 1.7% per year between 1971 and 2003. Driven by continued strong population and income growth in developing countries, transportation demand increases on average by 1.8% per year between 2003 and

2050. Energy use in the buildings sector grows on average by 1.4% per year, with around 70% of this growth coming from developing countries. Energy consumption in the industrial sector grows slightly more slowly, at on average 1.2% per year. About 64% of the growth in industrial energy consumption occurs in developing countries.

Figure 2.21 **Energy use by sector in the Baseline Scenario[15]**



Key point

Power generation and the fuel transformation sector drive the acceleration in the growth in total energy demand.

In the Map scenario, the growth in the net energy consumption of the electricity generation and heat sector is about 70% between 2003 and 2050. The net energy consumption in the electricity generation sector is 28% lower in the Map scenario than in the Baseline Scenario in 2050. Energy consumption in the fuel transformation sectors increases from 1 103 Mtoe in 2003 to 2 154 Mtoe in 2050. This is 22% less than in the Baseline Scenario in 2050.

In the fuel transformation sector (refineries, coal-to-liquid, gas-to-liquid, etc.), the amount of energy consumed is lower than in the Baseline Scenario in both the Map and Low Efficiency scenarios. However, in the TECH Plus scenario, the reduced energy consumption and losses at refineries due to lower oil product demand is more than offset by increased energy consumed in the manufacture of biofuels and hydrogen.

Energy consumption in the industry, buildings and transport sectors grows on average 0.9% per year in the Map scenario, from 7 287 Mtoe in 2003 to 10 895 Mtoe in 2050. This is 23% less than in the Baseline Scenario in 2050. In the Map scenario, the transport sector still has the most rapid growth, at 1.4% per year on average and reaches 3 705 Mtoe in 2050. This is 767 Mtoe (17%) less than in the Baseline Scenario in 2050.

15. The power generation sector includes heat plants.

Final consumption in the industrial sector grows at 0.8% on average per year in the Map scenario, reaching 3 339 Mtoe in 2050, or 19% less than the Baseline Scenario. The rate of growth in energy consumption in the buildings and appliances sector is reduced to 0.5% on average per year between 2003 and 2050, with demand reaching 3 428 Mtoe in 2050. This is one-third less than the Baseline Scenario in 2050. This sector alone accounts for about two-thirds of the savings in electricity.

Table 2.7 ▶ **World energy consumption by sector and scenario[16]**

	Baseline Scenario		ACT Scenarios 2050		
	2003 (Mtoe)	2050 (Mtoe)	Map (Mtoe)	Low Efficiency (Mtoe)	TECH Plus (Mtoe)
Electricity and heat plants	2 180	5 177	3 712	4 716	3 929
Other fuel transformation	1 003	2 761	2 154	2 398	2 975
Industry	2 326	4 138	3 339	3 682	3 339
Transport	1 895	4 472	3 705	4 232	3 461
Buildings and appliances	2 733	5 142	3 428	3 764	3 428
Difference from Baseline Scenario in 2050 (%)					
Electricity and heat plants			–28	–9	–24
Other fuel transformation			–22	–13	8
Industry			–19	–11	–19
Transport			–17	–5	–23
Buildings and appliances			–33	–27	–33

Note : In this table buildings and appliances includes agriculture (298 Mtoe in 2050).

The buildings sector has the largest reduction below the Baseline Scenario in percentage terms in each of the three world regions in the Map scenario, with savings ranging from 32% to 36% in 2050 (Table 2.8). Savings in transportation by region in the Map scenario vary from 10% to 20% below the Baseline Scenario in 2050, while savings in industry range from 21% to 25%. Absolute savings in the industry sector in the ACT scenario are highest in developing countries, at 447 Mtoe. In the transport sector, absolute savings are about the same in OECD (378 Mtoe) and developing countries (354 Mtoe). In the buildings sector, absolute savings are highest in developing countries, reflecting the large difference in population between OECD and developing countries.

16. The energy consumption by electricity and heat plants is net of electricity and heat generated. Electricty and heat generated are included in the sectors where it is used. The table excludes non-energy use.

In the Baseline Scenario, CO_2 emissions from electricity and heat plants increase by 164% between 2003 and 2050, as electricity demand growth is met by substantial new coal-fired power generation. Electricity and heat plants account for 45% of total CO_2 emissions in 2050 and transport for one-fifth. CO_2 emissions from fuel transformation increase over fourfold to 7 603 Mt in 2050 due to the increase in synfuel production from gas and coal. Transport sector CO_2 emissions more than double between 2003 and 2050, while buildings sector CO_2 emissions increase by two-thirds and industrial CO_2 emissions by 45%.

Table 2.8 ▶ Reduction in final energy consumption below the Baseline Scenario by region in the Map scenario in 2050

	Difference from the Baseline Scenario in 2050 (Mtoe)			
	World	OECD	Transition economies	Developing countries
Industry	–799	–322	–90	–387
Transport	–767	–378	–34	–354
Buildings and appliances	–1 715	–630	–149	–936
	Difference from the Baseline Scenario in 2050			
	World	**OECD**	**Transition economies**	**Developing countries**
Industry	–19%	–20%	–22%	–18%
Transport	–17%	–20%	–10%	–16%
Buildings and appliances	–33%	–36%	–33%	–32%

In the Map scenario, the substantial decarbonisation of electricity generation reduces CO_2 emissions from electricity and heat plants by 72% below the Baseline Scenario in 2050. In the fuel transformation sector, the reduction in synfuel production from coal contributes to the 65% reduction below the Baseline Scenario level of emissions in 2050. CO_2 emissions in the buildings sector are 35% less than the Baseline Scenario in 2050, transport sector CO_2 emissions are 28% less and industry CO_2 emissions 54% less.

The decarbonisation of electricity generation in the Map scenario results in its share of CO_2 emissions declining to 28% in 2050, from 45% in the Baseline Scenario. The difficulty in decarbonising the transport sector results in its share of emissions in the Map scenario increasing to 33% in 2050. The additional use of biofuels and the introduction of hydrogen in significant quantities reduces transports share to 29% in the TECH Plus scenario.

Table 2.9 ▶ **CO_2 emissions by sector and by scenario, 2003 and 2050**[17]

	Baseline Scenario		ACT scenarios 2050		
	2003	2050	Map	Low Efficiency	TECH Plus
	(Mt CO_2)	(Mt CO_2)	(Mt CO_2)	(Mt CO_2)	(Mt CO_2)
Electricity and heat plants	9 946	26 294	7 324	8 751	5 119
Other fuel transformation	1 718	7 603	2 696	3 451	2 074
Industry	4 490	6 512	3 501	4 363	3 501
Transport	5 122	11 733	8 486	9 866	5 946
Buildings and appliances	3 255	5 469	3 552	4 373	3 550
Share of CO_2 emissions (%)					
Electricity and heat plants	41	46	29	28	25
Other fuel transformation	7	13	11	11	10
Industry	18	11	14	14	17
Transport	21	20	33	32	29
Buildings and appliances	13	9	14	14	18
Difference in CO_2 emissions from the Baseline Scenario in 2050 (%)					
Electricity and heat plants			–72	–67	–81
Other fuel transformation			–65	–55	–73
Industry			–46	–33	–46
Transport			–28	–16	–49
Buildings and appliances			–35	–20	–35

Electricity Generation

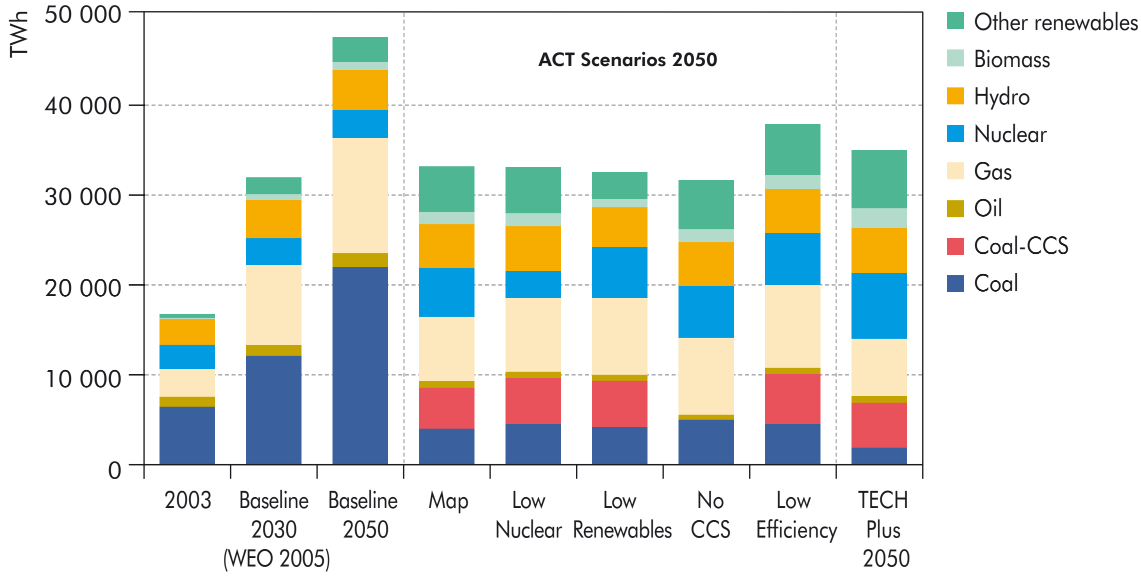
In the Baseline Scenario, global electricity production almost triples between 2003 and 2050 (Figure 2.22). Coal-based generation in 2050 is more than three-times higher than today's level and accounts for more than half of the increased production between 2003 and 2050 (Figure 2.23). The capacity of gas-fired power plants quadruples and they account for about a third of increased global production. Hydro and non-biomass renewables (mostly wind) contribute about 6% each to the new capacity required, while biomass and nuclear each account for around 2% of the increased capacity.

In the ACT scenarios, significant savings in electricity demand in the buildings and industry sectors reduce the required growth in production capacity. Electricity demand in 2050 ranges between 81% higher than the 2003 level in the No CCS scenario to 118% higher in the Low Efficiency scenario. Electricity generation in the TECH Plus scenario is 4% higher than the Map scenario in 2050 due to increased electricity demand to power decentralised electrolysers to produce hydrogen.

17. Table 2.9 does not allocate electricity emissions to the end-use sectors. See Table 2.2 for the reduction below the Baseline Scenario with electricity demand reductions allocated to the end-use sectors.

2

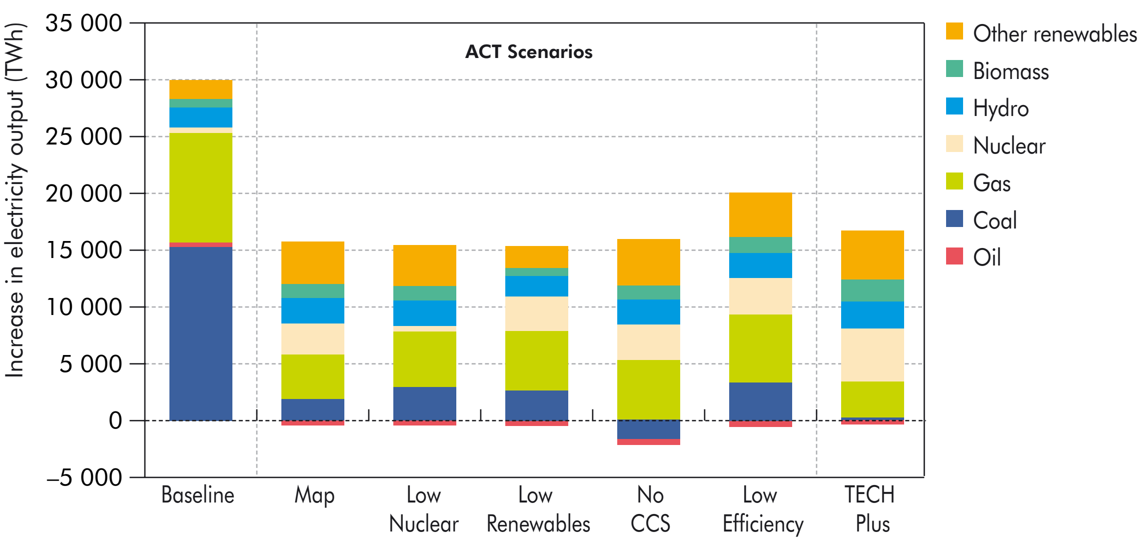
Figure 2.22 ▶ **Global electricity production by fuel and scenario, 2003, 2030 and 2050**



Key point

In the Map scenario nuclear, hydro and other renewables account for about half of total generation in 2050.

Figure 2.23 ▶ **Growth in electricity production by fuel and scenario, 2003-2050**



Key point

Growth in coal-fired capacity is substantially reduced in the ACT and TECH Plus scenarios.

The CO_2 emission reduction incentives and other measures introduced in the ACT scenarios significantly change the electricity generation mix relative to the Baseline Scenario (Table 2.10). Depending on the scenario, it generally results in nuclear, renewables and to some degree gas becoming more attractive compared to coal-based power plants.

Coal

Coal-fired generation is dramatically lower than in the Baseline Scenario in all the ACT scenarios. The share of coal is the lowest in the No CCS scenario, where it constitutes only 16.5% of the global power generation mix in 2050, compared to 47% in the Baseline Scenario. In this scenario, coal-fired generation is 4 988 TWh in 2050, which is 77% lower than in the Baseline Scenario and a quarter lower than the 2003 level. In all the other ACT scenarios coal-fired plants (with and without CCS) retain significant market shares, ranging from 26.9% to 30.4% in 2050. By 2050, output from coal-fired plants in the ACT scenarios ranges from 8 551 TWh to 10 029 TWh, of which plants equipped with CCS constitute between 53% and 55% depending on the scenario. In the TECH Plus scenario, coal-fired generation is 6 879 TWh, but only 1 877 TWh of this is without CCS.

Gas and Oil

The share of gas in total generation remains relatively robust in all of the ACT scenarios. By 2050, the share of gas in the Baseline Scenario is 27.6%, up from 19.4% in 2003. In the ACT scenarios, the share ranges from 22.6% in the Map scenario to 28.2% in the No CCS scenario. While gas-based generation in the ACT scenarios is between 28% and 44% lower than in the Baseline Scenario by 2050, it increases significantly from the 2003 production level of 3 225 TWh. In the Map scenario, gas-based generation reaches 7 192 TWh by 2050, while in the Low Efficiency scenario it reaches 9 229 TWh. In the TECH Plus scenario, gas-fired generation is around half the Baseline Scenario level in 2050, at 6 425 TWh or 20% of electricity generation.

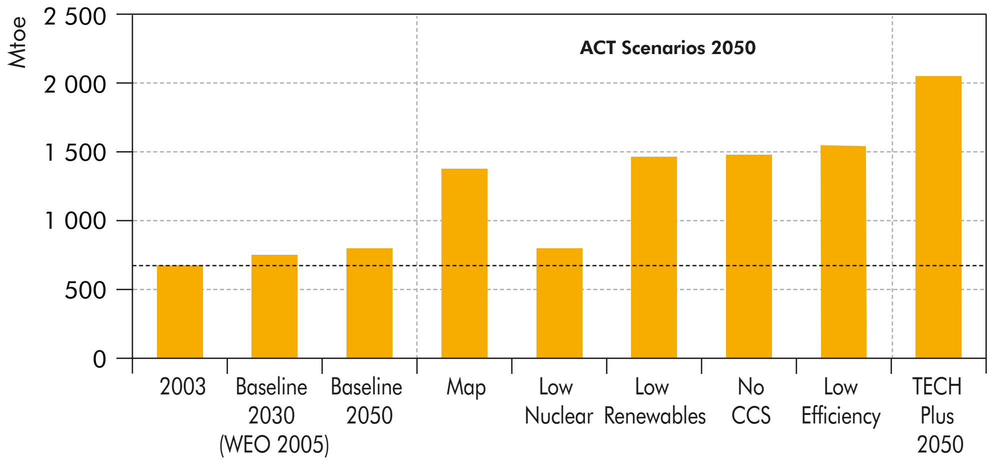
The share of electricity generation from oil declines in all scenarios between 2003 and 2050. In the Baseline Scenario the share is 3.3%, while in the ACT scenarios and TECH Plus scenario oil retains a share of around 2% of global electricity production.

Nuclear

In the Baseline Scenario, nuclear electricity generation increases from 2 635 TWh in 2003 to 3 107 TWh in 2050 (Figure 2.24). Achieving this growth will require significant investment in new capacity, because virtually all of today's capacity will have to be replaced by 2050.

Nuclear plants, which account for 6.7% of electricity output in 2050 in the Baseline Scenario, substantially increase their share of generation in the ACT scenarios (except for in the Low Nuclear scenario). In the Low Efficiency scenario, nuclear's share of generation is 16%, which increases to 19% in the No CCS scenario. In the Low Nuclear scenario, growth in nuclear capacity is the same as in the Baseline

Figure 2.24 World nuclear energy use by scenario, 2003-2050



Key point

Nuclear energy use in 2050 is 103% higher than in 2003 in the Map scenario and 177% higher in the TECH Plus scenario.

Scenario, but due to lower total demand the nuclear share by 2050 is actually higher (9.8% of total generation). In the Map scenario, global nuclear generation reaches 5 338 TWh by 2050. This is just over twice the 2003 level and 72% higher than in the Baseline Scenario in 2050. Nuclear electricity production varies from a low of around 3 100 TWh in the Low Nuclear scenario to a high of around 5 814 TWh in 2050 in the Low Efficiency scenario.

There are a number of challenges that need to be overcome if nuclear is to play an even greater role by 2050 than the ACT scenarios indicate. However, as discussed in Chapter 4, there are nuclear technologies under development that could help overcome these challenges. If these technologies become economic, then the contribution from nuclear by 2050 would be even more important than in the ACT scenarios. The TECH Plus scenario includes more optimistic assumptions for nuclear (and also for other technologies) that reflect these new nuclear technologies having become cost competitive. In this TECH Plus scenario, electricity generation from nuclear plants increases 177% between 2003 and 2050, with generation reaching around 7 300 TWh in 2050. In this scenario, nuclear accounts for 29% of the increased output between 2003 and 2050, and provides 22% of total electricity generation in 2050. In addition, the equivalent of around 665 TWh of nuclear generation is used to produce hydrogen via the sulphur/iodine (S/I) thermochemical cycle. Nuclear plant capacity in 2050 in the TECH Plus scenario is therefore around three times higher than in 2003.

Hydropower and Biomass

In the Baseline Scenario, hydropower production increases from 2 645 TWh in 2003 to 4 420 TWh in 2050. However, despite the optimistic outlook for small hydro in particular, its share of electricity generation declines from 16% in 2003 to 9% in

Table 2.10 Global electricity production (2050) and share of increased output (2003 to 2050) by type and scenario

	2003	Baseline	Map	Low Nuclear	Low Renewables	No CCS	Low Efficiency	TECH Plus
Electricity generation output in 2050 (TWh)								
Coal	6 681	21 958	8 551	9 626	9 322	4 988	10 029	6 879
-of which CCS	*0*	*0*	*4 545*	*5 102*	*5 127*	*0*	*5 516*	*5 001*
Oil	1 152	1 531	733	721	695	605	727	726
Gas	3 225	12 881	7 192	8 138	8 500	8 524	9 229	6 425
Nuclear	2 635	3 107	5 338	3 103	5 688	5 743	5 814	7 300
Hydro	2 645	4 420	4 896	4 897	4 424	4 836	4 869	5 019
Biomass	210	933	1 430	1 457	948	1 451	1 599	1 678
Other Renewables	113	1 800	3 623	3 736	2 022	4 081	4 065	4 869
Total	***16 661***	***46 631***	***31 776***	***31 664***	***31 600***	***30 228***	***36 335***	***32 896***
Share of electricity generation output in 2050 (%)								
Coal	40.1	47.1	26.9	30.4	29.5	16.5	27.6	20.9
-of which CCS	*0.0*	*0.0*	*14.3*	*16.1*	*16.2*	*0.0*	*15.2*	*15.2*
Oil	6.9	3.3	2.3	2.3	2.2	2.0	2.0	2.2
Gas	19.4	27.6	22.6	25.7	26.9	28.2	25.4	19.5
Nuclear	15.8	6.7	16.8	9.8	18.0	19.0	16.0	22.2
Hydro	15.9	9.5	15.4	15.5	14.0	16.0	13.4	15.3
Biomass	1.3	2.0	4.5	4.6	3.0	4.8	4.4	5.1
Other Renewables	0.7	3.9	11.4	11.8	6.4	13.5	11.2	14.8
Total	***100***	***100***	***100***	***100***	***100***	***100***	***100***	***100***
Share of the increase in power generation output 2003-2050 (%)								
Coal (incl. CCS)	–	51.0	12.0	19.1	17.2	0.0	16.7	1.2
Oil	–	1.3	0.0	0.0	0.0	0.0	0.0	0.0
Gas	–	32.2	25.6	31.8	34.3	33.5	29.9	19.2
Nuclear	–	1.6	17.4	3.0	19.8	19.7	15.8	28.0
Hydro	–	5.9	14.5	14.6	11.6	13.9	11.1	14.2
Biomass	–	2.4	7.9	8.1	4.8	7.9	6.9	9.6
Other Renewables	–	5.6	22.6	23.5	12.4	25.1	19.7	27.8
Total	**–**	***100***	***100***	***100***	***100***	***100***	***100***	***100***

2050 in the Baseline Scenario. In the ACT scenarios, except for the Low Renewables scenario, electricity production from hydropower is roughly 10% higher than in the Baseline Scenario by 2050. This somewhat modest increase is due to the limited additional sites that can be utilised for large-scale hydro development. However, the reduced demand for electricity in the ACT scenarios means that hydropower's share of generation in the ACT scenarios ranges from between 13% and 16%. In the TECH Plus scenario, hydro generation is around 14% higher than in the Baseline Scenario in 2050.

Electricity production from biomass and other combustible renewables increases significantly from current levels both in the Baseline Scenario and in the ACT scenarios. By 2050, the biomass share of electricity output is 2% in the Baseline Scenario, 3% in the Low Renewables scenario and around 4.5% in all other ACT scenarios. In the TECH Plus scenario, the share of biomass reaches 5.1% in 2050.

Other Renewables

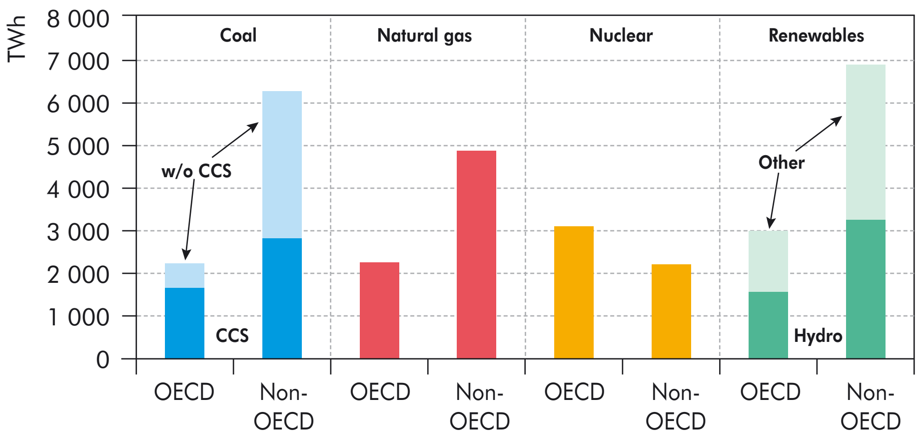
Other renewables, which includes wind, solar, geothermal, tidal and wave, are the area of electricity production that grows the fastest, although they start from a very low base. By 2050, electricity production from other renewables in the Baseline Scenario reaches 1 800 TWh, up from 113 TWh in 2003. In the Map scenario, the production from these renewable sources is twice that of the Baseline level in 2050 and even higher in the other ACT scenarios. One exception is the Low Renewables scenario, where more pessimistic assumptions on future cost reductions for other renewables leads to production being just 10% higher than the Baseline level in 2050. Wind is by far the most important generation source in this category. In the Map scenario, wind accounts for about two-thirds of the 3 620 TWh generation from other renewables. The remaining share is split almost equally between solar and geothermal, with a very minor contribution from tidal and wave power.

In the TECH Plus scenario, the more optimistic assumptions for cost improvements, particularly for wind and solar, cause electricity generation from other renewable sources to grow at 8% per year on average between 2003 and 2050 to reach 4 869 TWh in 2050, or 15% of total electricity generation.

Electricity Generation by Region

In the Map scenario, non-OECD regions account for over 90% of the increase in electricity generation between 2003 and 2050, with generation reaching 20 752 TWh in 2050, which is about twice the OECD level. Almost a third of generation in non-OECD regions is coal-based, of which 45% is from plants equipped with CCS (Figure 2.25). Another third is from renewables of which hydro contributes almost half. The remainder is from gas (24%) and nuclear (11%). In OECD regions total coal-fired generation in the Map scenario declines by 1 580 TWh between 2003 and 2050, and coal only constitutes 21% of total generation in 2050, of which plants with CCS provide three-quarters. Gas-fired generation in OECD increases 560 TWh from 2003 levels and reaches the same level as coal by 2050. Nuclear contributes about 28% of OECD generation, hydro accounts for 15% and non-hydro renewables for 13%.

Figure 2.25 ▶ Electricity generation by fuel in the Map scenario in OECD and non-OECD regions, 2050



Key point

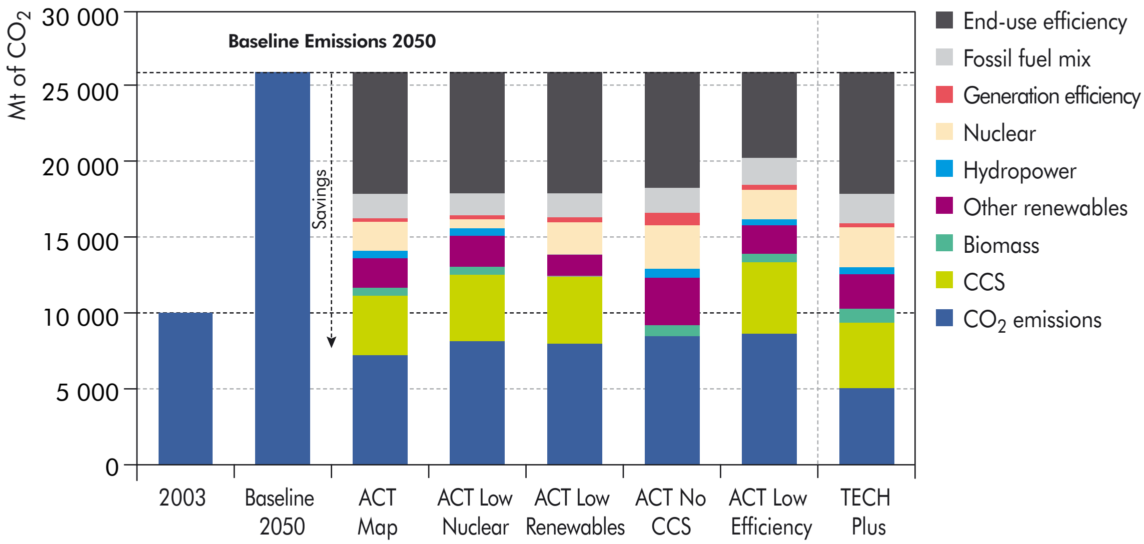
In 2050, almost three-quarters of all coal-fied capacity is in non-OECD countries.

Carbon Dioxide Emissions from Electricity Generation

In the Map scenario, CO_2 capture from power plants amounts to 3.7 Gt CO_2 in 2050. Of this amount, 20% is captured from plants that are retrofitted with CCS technology, applied primarily to coal-fired plants with oxy-firing. About 2.2 Gt CO_2 is captured from coal-fired integrated gasification combined-cycle (IGCC) units and dedicated steam cycles with post-combustion capture. In 2050, half of all coal-fired power plants are equipped with CO_2 capture, including around three-quarters of plants in OECD countries, around half in transition economies and 45% in developing countries. In addition to the 3.7 Gt CO_2 captured at power plants, another 0.3 Gt CO_2 is captured from biomass-fuelled plants, notably black liquor gasifiers in the pulp and paper industry. There is no significant capture from gas-fired plants. This is due to CCS not being cost-effective for these plants at the assumed CO_2 reduction incentive level of USD 25 per tonne CO_2.

The changes in the electricity generation mix in the ACT scenarios have a profound effect on CO_2 emissions from the electricity generation sector. While emissions from electricity generation in the Baseline Scenario increase by 164% over the period 2003 to 2050, emissions in 2050 are below 2003 levels in all ACT scenarios (Figure 2.26). Of the ACT scenarios, emissions are the lowest in the Map scenario, at 26% below the 2003 level. In this scenario, electricity demand is 32% lower in 2050 than in the Baseline Scenario and accounts for 43% of the reduction in emissions from the electricity generation sector. CCS contributes another 21% to the emission savings, while the increased use of nuclear, the increased use of other renewables and the switch from coal to gas each contribute around 10%. Improved generation efficiency, the increased use of hydropower and biomass account for the rest.

Figure 2.26 CO_2 emissions from electricity generation and source of reduction, 2003-2050



Key point

CO_2 emissions from electricity generation are below the 2003 level in all ACT scenarios.

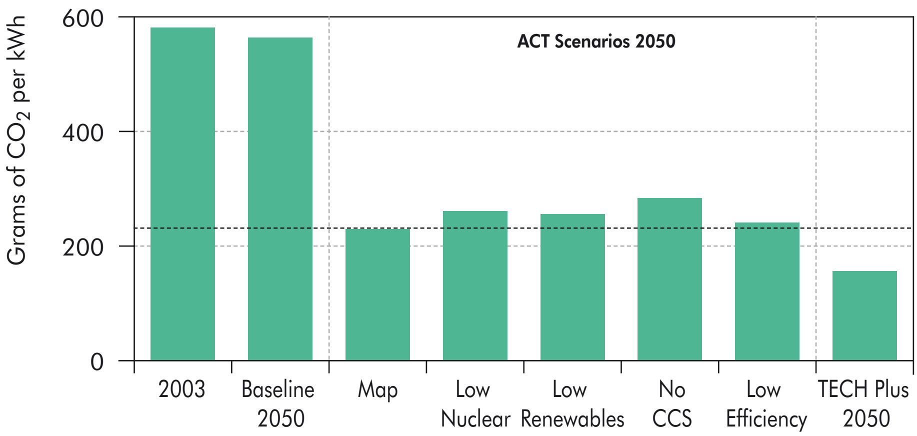
The contribution to CO_2 emission reductions from nuclear and renewables increase in the No CCS Scenario, and thus dampen the impact on total emissions from CCS not being available. Similarly, the potential increase in emissions in the Low Efficiency scenario is somewhat moderated by the fact that a significant share of the additional power generation capacity needed in this scenario is met by coal plants equipped with CCS and to some degree more use of nuclear and renewables.

In the TECH Plus scenario, the increased use of nuclear and renewable generation technologies contribute to reducing CO_2 emissions from the electricity sector in 2050 to 49% below the 2003 level. Renewables and nuclear energy contribute 30% of the reduction in CO_2 emissions below the Baseline Scenario.

Despite the increasing shares of coal and gas in the Baseline Scenario, the CO_2 intensity of electricity generation declines, albeit marginally, between 2003 and

2050 (Figure 2.27). This is a result of improvements in generation efficiency for both coal and gas plants more than outweighing the impact of the fuel mix becoming more CO_2 intensive. In all ACT scenarios, power generation is significantly decarbonised. In the Map scenario, CO_2 emissions per kWh are about 60% lower than in the Baseline Scenario. Even in the No CCS scenario, 1 kWh of electricity generated results in only half the amount of CO_2 emissions that would have occurred in the Baseline Scenario. In the TECH Plus scenario, the CO_2 intensity of electricity generation is 73% lower than the 2003 level in 2050.

Figure 2.27 ***CO_2 intensity of electricity production by scenario, 2003 and 2050***

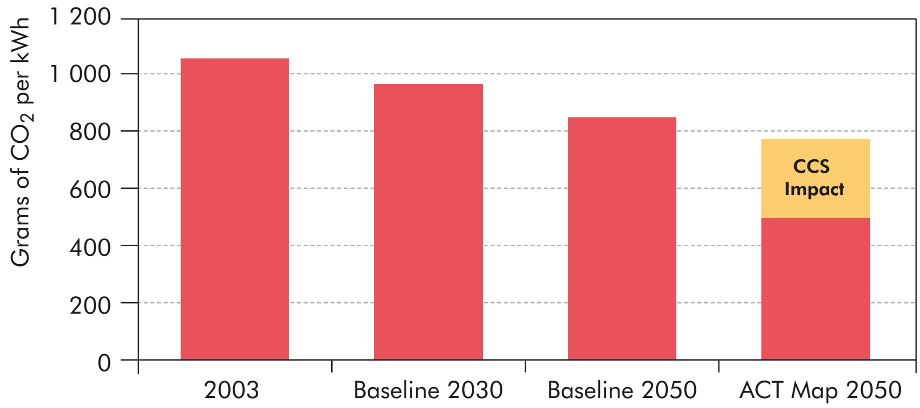


Key point

In the ACT scenarios, the global CO_2 intensity of power production is less than half the Baseline level in 2050.

The impact on CO_2 intensities from improved generation efficiency is illustrated for China in Figure 2.28. In the Baseline Scenario, these improvements reduce the CO_2 emitted per unit of electricity generated from coal-fired plants by 20% between 2003 and 2050. The average efficiency in China in 2003 was around 33%. As more efficient plants (mostly supercritical steam cycle) enter the stock, the average efficiency of the stock increases to 41% by 2050. In the Map scenario, the average efficiency is 45% due to the higher penetration of ultra-supercritical plants. By 2050, about 40% of coal-fired plants are equipped with CCS, which significantly reduces the CO_2 intensity of generation. However, the introduction of CCS also results in efficiency losses of 8 percentage points on average. In fact, the average stock efficiency of the plants without CCS is close to 48%. In China, the net effect of improved generation efficiency and CCS is to reduce per-kWh CO_2 emissions from coal plants by 42% in the Map scenario compared to the Baseline Scenario.

Figure 2.28 **CO_2 intensity of coal-fired electricity production in China, 2003-2050**



Key point

CO_2 emissions per kWh for coal-based generation in the Map scenario are more than 50% lower than in 2003 due to steady improvement in generation efficiency and the introduction of CCS.

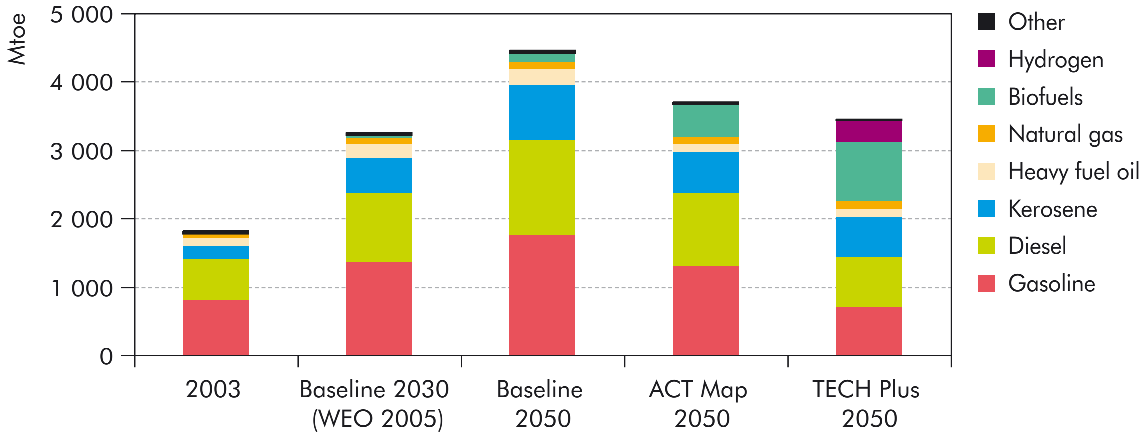
Transport[18]

In the Baseline Scenario, energy demand in the transport sector increases 136% between 2003 and 2050 (Figure 2.29). Global transport energy demand in 2050 is close to 4 500 Mtoe. Oil products provide 94% of this, of which synfuels produced from gas and coal via the Fischer-Tropsch process account for about a quarter. Biofuels, both biodiesel and ethanol, only contribute 3% or the equivalent of 2.6 Mb/d of oil. The balance is provided by gas, mostly used in gas pipelines, by electricity and some coal used for rail transport.

In the Map scenario, total transport energy demand in 2050 is 17% or 767 Mtoe below the Baseline Scenario, while in the TECH Plus scenario, fuel savings reach 1 011 Mtoe in 2050, or a 23% reduction from the Baseline level. Synfuels from gas and coal are 67% lower in the Map scenario and 70% lower in the TECH Plus scenario in 2050, compared to the Baseline Scenario. The share of synfuels declines to less than 9% in both scenarios. Biofuel production grows significantly in the Map scenario reaching about 480 Mtoe in 2050 (Figure 2.30). Biofuels' share of transport demand increases to 13% in 2050 in the Map scenario and to almost 25% in the more optimistic TECH Plus scenario.

18. The transport sector includes road, rail, air and water transport as well as energy used for pipelines. Only technologies in road transport have been considered in the ACT and TECH Plus scenarios. In 2003 road transport constituted about 80% of total transport demand. The only scenarios discussed in this section are the Map and TECH Plus scenarios. There are only minor differences for the transport sector in the other scenarios. The only exception is the Low Efficiency scenario, however, the implications for technology and fuel choices in the transport sector of the lower efficiency progress in this scenario were not assessed.

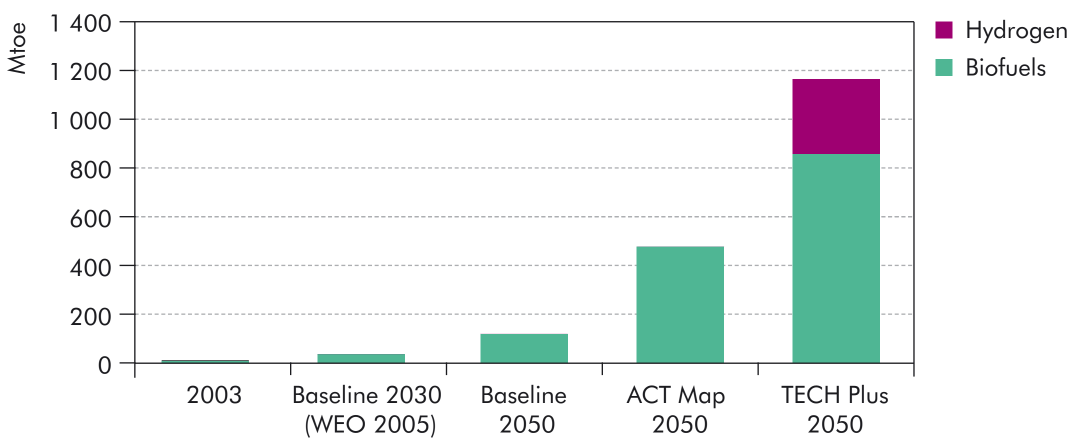
Figure 2.29 **Transport energy use in the Baseline, ACT and TECH Plus scenarios, 2003-2050**



Key point

Fuel efficiency and alternative fuels reduce diesel and gasoline demand 24% below the Baseline Scenario in the Map scenario and by 55% in the TECH Plus scenario.

Figure 2.30 **Global use of hydrogen and biofuels by scenario, 2003-2050**



Key point

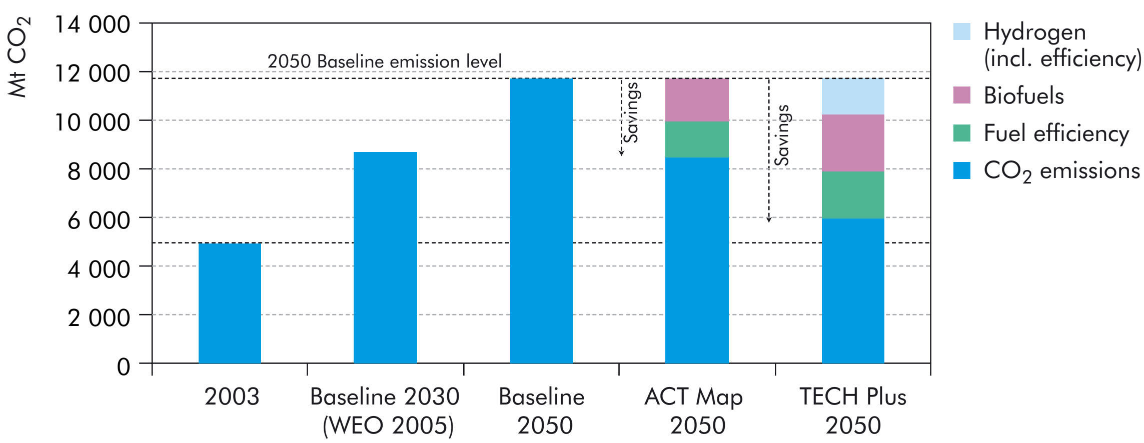
The use of biofuels grows rapidly in the Map and TECH Plus scenarios.

The contribution from hydrogen is minimal in the Map scenario, where it remains a niche fuel. In the TECH Plus scenario, additional reductions in the cost of fuel-cells, that represent breakthroughs in a number of areas, would allow hydrogen fuel-cell vehicles to penetrate the market significantly. In this scenario, hydrogen demand in the transport sector reaches 308 Mtoe in 2050, or 9% of total transport demand. However, the fuel consumption figures do not fully reflect hydrogen's benefits, as fuel-cell vehicles in 2050 are projected to be two to three times as fuel efficient as similar internal combustion engine vehicles.

CO_2 emissions in the Baseline Scenario in 2050 are at 11.7 Gt, about 2.3 times higher than the 2003 level (Figure 2.31). On a well-to-wheel basis, emissions increase even more rapidly due to the significant introduction of coal-based synfuels in the Baseline Scenario. These fuels produce very high well-to-wheel emissions, for example coal-to-liquids diesel emits about 2.1 times as much as petroleum diesel burned in a standard 2003 vehicle (Figure 2.32). If these upstream emissions were included transport related CO_2 emissions would reach 15.5 Gt by 2050.

Growth in CO_2 emissions, like growth in energy demand, varies by region. Developing countries show much steeper increases than do developed countries. In the Baseline Scenario, CO_2 emissions from transport in non-OECD countries increase by more than 300%, while OECD countries see an increase of about 50%. This is mainly due to differing rates of growth in transport activity, but also to the faster deployment of clean and efficient transport technologies in OECD countries.

Figure 2.31 ***CO_2 emissions in the transport sector in the Baseline, ACT Map and TECH Plus scenarios, 2003-2050[19]***

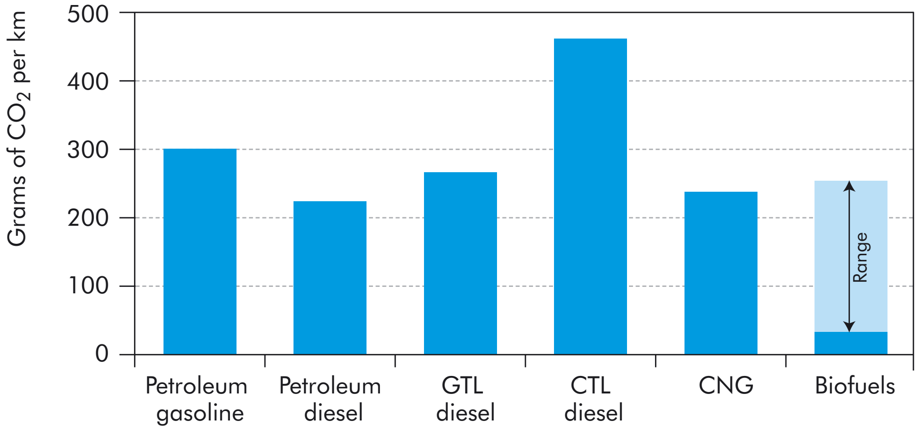


Key point

Improved fuel efficiency accounts for two-thirds and biofuels for one-third of the 28% CO_2 emissions reduction in the Map scenario

19. This figure excludes CO_2 emission reductions from the fuel transformation sector.

Figure 2.32 **Well-to-wheel CO_2 emissions by fuel source in the transport sector, 2003**[20]



Key point

Some biofuels offer very large well-to-wheel CO_2 emissions savings, but there is currently a wide range.

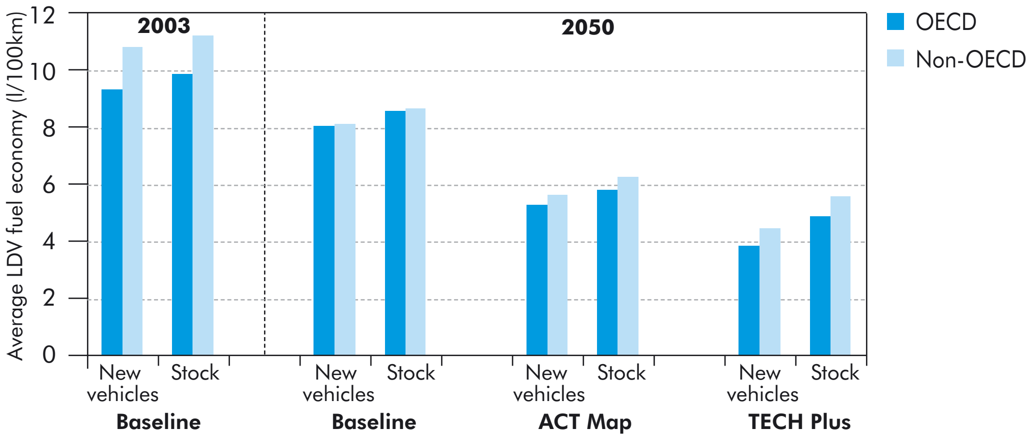
In the Map scenario, CO_2 emissions are 28% (3.2 Gt CO_2) lower than the Baseline level. Slightly more than two-thirds of this reduction is due to improved fuel efficiency, while the rest is the result of the increased use of biofuels. The reduced demand for oil products in this scenario and the introduction of a USD 25 per tonne of CO_2 emission reduction incentive lead to a dramatic drop in synfuels production, reducing emissions in the fuel transformation sector by another 3 Gt (not included in Figure 2.31).

The increased use of biofuels and the introduction of hydrogen fuel cell vehicles reduce emissions even further in the TECH Plus scenario. By 2050, transport CO_2 emissions are only half of emissions levels in the Baseline, but are still 16% higher than in 2003. In the TECH Plus scenario, about a quarter of the reduction in transport CO_2 emissions below the Baseline Scenario in 2050 is due to the use of hydrogen in fuel-cell vehicles including the marginal fuel efficiency improvement in the stock of LDVs due to the lower fuel intensity of hydrogen FCVs. The balance is due to improvements in internal combustion engine vehicles, including hybrids, and to the use of biofuels.

There are important reductions in the fuel intensity of light duty vehicles (LDV) in the Baseline Scenario. In the OECD regions, the average fuel-intensity of the vehicle stock in 2050 is some 13% lower than it was in 2003. In non-OECD regions it is 23% lower (Figure 2.33). These gains are achieved in spite of a growing trend towards larger vehicles and increased ancillary equipment.

20. The calculations are based on 2003 vehicle technology standards. CNG = compressed natural gas. The production of biofuels using today's technologies has very different well-to-wheel CO_2 emissions, depending on the feedstock, crop yield, agricultural methods and the conversion process used. On a well-to-wheel basis, bioethanol from sugar cane will emit, per kilometre, about one-tenth the CO_2 emissions of an equivalent vehicle using petroleum gasoline. The environmental benefits of vehicles running on bioethanol from grain are much less than this.

Figure 2.33 **Fuel intensity of new light-duty vehicles and stock**[21]



Key point

Average fuel intensity of the vehicle stock is 40% lower than the 2003 level in the Map scenario and 50% lower in the TECH Plus scenario.

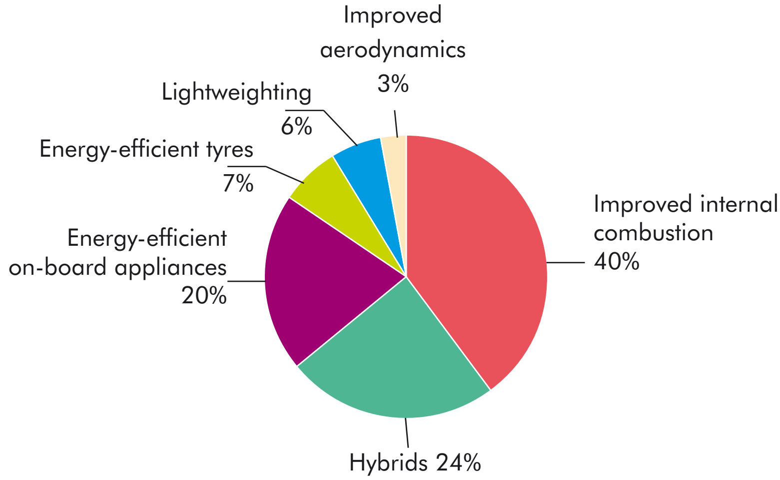
The improved fuel economy of LDVs provide most of the CO_2 emission reductions in the Map scenario relative to the Baseline. In the Map scenario, the average fuel intensity of the light-duty vehicle stock in 2050 is more than 40% lower than the 2003 level. This improvement in the energy intensity of LDVs restricts the growth in energy consumption of LDVs between 2003 and 2050 to 50%, despite a 149% increase in global light-duty vehicle kilometres over this period.

In the TECH Plus scenario, the fuel intensity of light-duty vehicles in 2050 is reduced to about half the 2003 level. The additional improvements over the Map scenario come mostly from the introduction of hydrogen fuel cell vehicles. Hydrogen fuel cell vehicles are projected to make up some 30% of the vehicle fleet in this scenario. These vehicles offer large efficiency improvements over conventional gasoline vehicles, but the gains over full-hybrids are much less, which explains the relatively modest reduction in fuel intensity compared to the Map scenario.

In the Map scenario, several improvements in combustion technologies and internal combustion engine controls help improve efficiency (Figure 2.34). New spark-ignition engines will offer the same power and lower consumption thanks to the combination of size reductions, the use of turbochargers, variable-valve control and advanced combustion technologies. Improved spark-ignition engines will run leaner, necessitating exhaust gas recirculation systems, but will require less fuel with respect to the current stoichiometric engines, even if they will need to be equipped with NO_X after-treatment. The use of high-octane ethanol is another contributing factor to better efficiencies. Improvements in fuel efficiency due to advanced gasoline engines are expected to yield savings of 210 Mtoe by 2050 in the Map scenario.

21. LDV = Light-duty vehicle.

Figure 2.34 **Contribution to the LDV energy efficiency in the Map scenario**



Key point

Improvements in conventional combustion technologies are crucial to improving the efficiency of light-duty vehicles.

Turbocharged diesel engines using the "common rail" direct injection system are an established technology and already offer 20% fuel savings over gasoline engines. Advanced technologies such as variable-valve control and fully-variable direct injection systems can further improve the fuel efficiency of compression ignition engines, even if stricter pollutant emission regulations will increasingly require active emissions controls (such as particulate filters and NO_X traps). In the Map scenario, improved fuel efficiency of diesel vehicles is expected to contribute 50 Mtoe of energy savings in transport by 2050.

Fuel savings due to improved aerodynamics, lightweight technologies, energy efficient tyres and more-efficient on-board accessories provide around 240 Mtoe of fuel savings in the Map scenario by 2050. Some of these solutions (*e.g.* better tyres and more-efficient air conditioning systems) are expected to achieve high market penetration rates (about 80%).

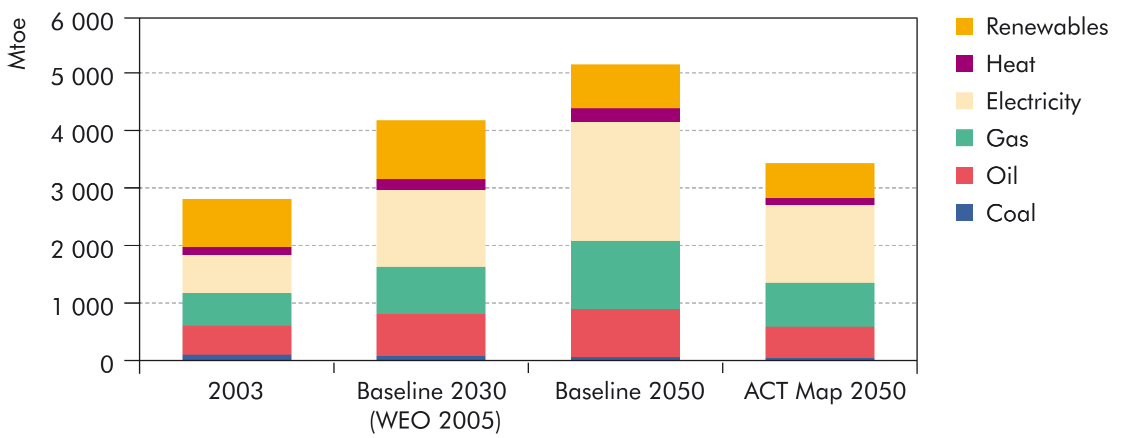
Vehicles with hybrid electric/internal combustion engine propulsion systems offer potentially large efficiency gains. Full-hybrid configurations by 2050 (if combined with technologies that improve the efficiency of powertrains and other technologies that reduce engine loads) could consume half as much energy as today's gasoline vehicles do. However, the rate of market deployment is likely to differ amongst vehicle classes, because of the high cost of some hybrid configurations. Full hybrid powertrains will first be introduced in large and expensive vehicles, while "light hybrid" solutions (hybridising just the starter-alternator) are expected to gain market share earlier in smaller vehicles.

In the Baseline Scenario, light and full hybrids each make up 10% of the light-duty vehicle stock in 2050. In the Map scenario, 85% of light-duty vehicles on the road in 2050 are powered by a full (20%), mild (20%) or light (45%) hybrid powertrain. Just over a third (35%) of medium freight trucks and 75% of buses would have hybrid engines in the Map scenario. The efficiency improvements derived from the hybridisation of the powertrain (i.e. from regenerative braking, smaller engine size and increasing the time spent in the ICEs optimal operating range) leads to about 265 Mtoe of fuel savings.

Buildings[22]

The buildings sector[23] consumed 2 571 Mtoe in 2003, or 35.3% of final energy consumption, with agriculture adding 162 Mtoe (Figure 2.35). Importantly, the buildings sector consumes about half of all electricity. In 2003, 32% of the building sector's global energy needs were met by renewables, mainly biomass and other traditional renewables in developing countries. Electricity accounted for 24%, natural gas for 22% and oil for 14%. In OECD countries, electricity accounts for 37% of consumption, natural gas for 35%, oil for 18% and renewables for 5%. Overall, energy consumption in the residential sector is almost 3.5 times as high as in the service (commercial) sector. In OECD countries, the difference is less pronounced, with the service sector consuming around 435 Mtoe (37%), while the residential sector consumes 725 Mtoe (63%).

Figure 2.35 **Global buildings sector energy consumption in the Baseline and Map scenarios**



Key point

Buildings energy consumption in 2050 is 35% lower in the Map scenario than in the Baseline Scenario.

22. The only ACT scenario discussed in this section is the Map scenario. There are only minor differences in the buildings sector in the other scenarios. The only exception is the Low Efficiency scenario, however, the implications for technology and fuel choices in the buildings sector of the lower efficiency progress in this scenario were not assessed.

23. The buildings sector includes the residential and services sectors, including the energy use of appliances in these sectors. The term "buildings" is used to cover these sectors, although strictly speaking not all energy in commercial and residential sectors is used within buildings. For example, in many developing countries, significant energy use for cooking and water-heating takes place outside. Note that the total consumption in Figure 2.35 includes agriculture, although no measures have been considered in this sector.

Table 2.11 ▶ ***Global energy consumption in the buildings sector in the Baseline Scenario***

	2003 (Mtoe)	2030 (Mtoe)	2050 (Mtoe)
Residential			
Coal	74	49	40
Oil	243	370	382
Gas	408	589	843
Electricity	337	714	1 105
Heat	114	145	146
Renewables	819	943	710
Total	1 994	2 809	3 224
Services			
Coal	15	12	10
Oil	116	227	287
Gas	151	228	340
Electricity	267	552	850
Heat	20	35	88
Renewables	7	41	44
Total	577	1 094	1 620

Global energy consumption in the residential sector grows on average at 1% per year in the Baseline Scenario (Table 2.11). This reflects a modest growth in the number of households through 2050 and the saturation of demand for heat and hot water in most of the OECD and the transition economies. Saturation in the ownership of major electrical appliances also contributes to the modest overall growth in these two regions. But growth in demand for air conditioning rises, as does the use of a number of other electrical devices. Energy consumption in the service sector grows more strongly, at 2.2% per year. This increase is driven by strong growth in commercial floor space, particularly in developing regions. Electricity consumption in the services sector increases to 850 Mtoe in 2050 and represents 52% of all consumption in the sector. The use of heat and renewables in the services sector grows strongly, but from low levels.

In the Baseline Scenario, energy use in the buildings sector increases by 88% between 2003 and 2050, or 1.4% per year. Continued economic growth leads to more commercial floor area, and the number of households continues to expand. Electricity consumption increases at 2.5% per year, raising its share in the buildings sector from 24% in 2003 to 40% in 2050, largely at the expense of renewables. This reflects the growing share of electric appliances and other electrical uses. By 2050, 59% of final electricity use is accounted for by the buildings sector. The use of renewables in the buildings sector declines by 0.2% per year, reflecting the increased use of commercial fuels (rather than biomass) in developing countries. The renewables share of consumption drops from 32% to 16%. Coal use in buildings continues to decline, but the rate of decline slows somewhat after 2030.

In the Map Scenario, energy consumption in the building sector in 2050 is 1 715 Mtoe lower than in Baseline Scenario (Table 2.12). The residential sector accounts for 66% of these savings. District heating is 49% lower in the Map scenario than in the Baseline Scenario, reflecting the big potential for energy savings in buildings heated with district heat in transition economies. Electricity demand is 35% lower than in the Baseline Scenario and savings in electricity account for 42% (713 Mtoe) of all savings in the buildings sector. The reduction in renewables below the Baseline Scenario in 2050 is 154 Mtoe, or 20%. Reduced biomass demand is the result of programmes to install improved cook stoves in developing countries and improvements in building envelopes around the world. In addition, some of the reduced biomass consumption in developing countries comes as a result of increased use of solar hot water heating. Table 2.12 reports the net change from increased solar heating and reduced biomass use.

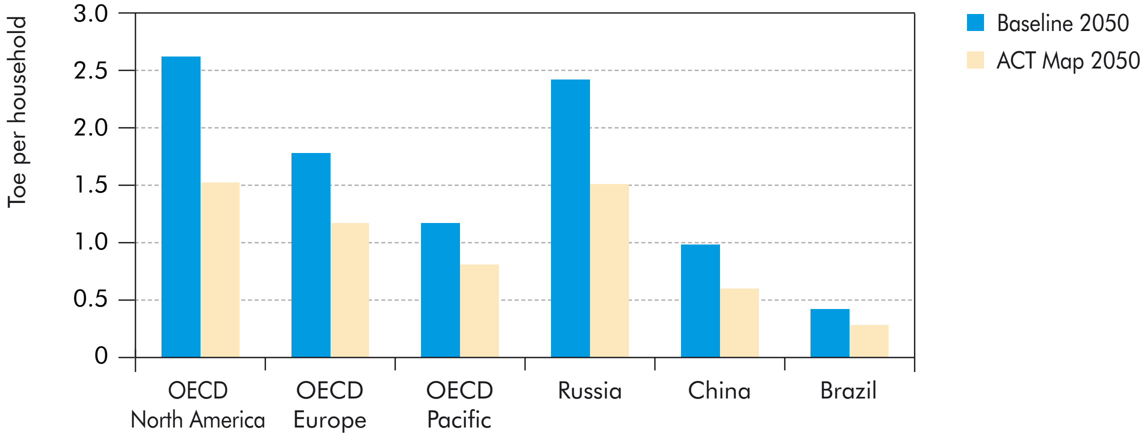
Table 2.12 ► ***Reduction in global buildings energy consumption in the Map scenario***
(reduction below the Baseline Scenario)

	Map Scenario 2050 (Mtoe)	2050 (%)
Coal	–24	–39
Oil	–284	–34
Gas	–424	–36
Electricity	–713	–35
Heat	–116	–49
Renewables	–154	–20
Total	**–1 715**	**–33**

There is limited growth in energy consumption per household in the OECD in the Baseline Scenario. The relatively stable per household energy consumption reflects saturation of ownership of major household appliances in developed countries and the already high comfort levels for space heating. Efficiency improvements in these areas tend to offset the demand growth from new appliances. In developing countries, the reduced share of biomass (with low end-use efficiency) in the household energy mix helps to offset, to some extent, the growth in electricity demand. The absolute level of energy consumption per household depends not only on the efficiency of energy use, but also varies significantly by region depending on climate, with cold climate countries having much higher energy consumption needs than warm climate countries (Figure 2.36).

In the Map scenario, adoption of more efficient technologies results in per household energy consumption declining by between 0.5% and 1.9% on average per year between 2003 and 2050, depending on the region. This represents a reduction below the Baseline Scenario level in 2050 of between 26% and 42%, again depending on the region.

Figure 2.36 **Energy consumption per household in the Baseline and Map scenarios, 2050**



Key point

The Map scenario results in significantly reduced energy consumption per household.

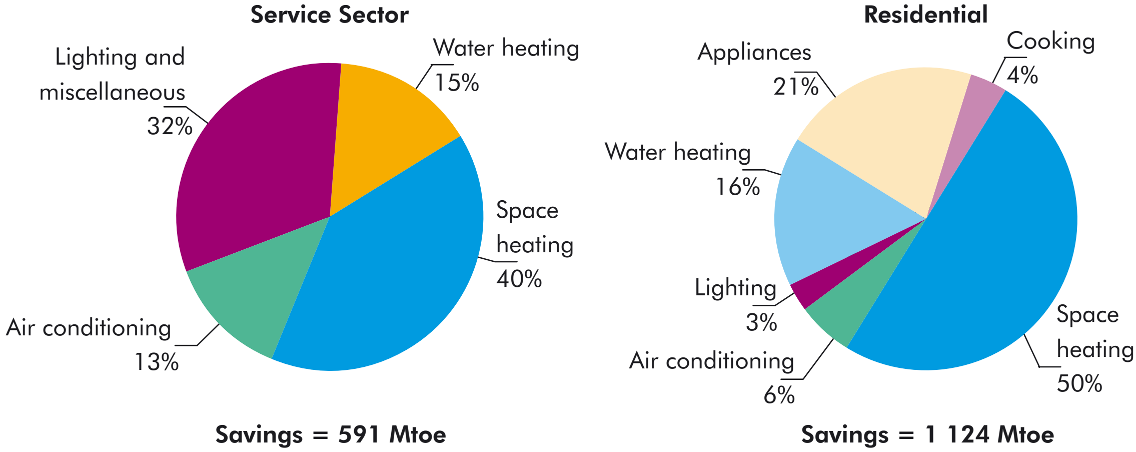
By 2050, the residential sector accounts for about 1 124 Mtoe of the total reduction in energy consumption below the Baseline Scenario. The savings are almost twice as large as those in the service sector, which are 591 Mtoe (Figure 2.36). In percentage terms, however, service-sector energy consumption is reduced by 36%, while residential-sector savings are 35%.

Half of all energy savings in the residential sector come from space heating (Figure 2.37). This reflects the impact of more energy efficient regulations for new buildings and energy efficient retrofits of the existing building stock, as well as improvements in heating systems and their operation. Appliances account for about one-fifth of the savings. Significant savings come from reduced standby power losses ("leaking electricity") and from reductions in the consumption of a myriad of small electric appliances. Water heating accounts for about 16% of total energy savings in the Map scenario. Lighting and air conditioning show significant percentage reductions in consumption below the Baseline scenario (37% for lighting). Together they account for 9% of the total energy savings in households. More energy efficient technologies for cooking were only considered in non-OECD countries. Still cooking contributes 4% of total global energy savings in the residential sector.

Savings in the service sector look somewhat different. Space heating still accounts for the largest share, at 40%, but the savings from lighting and other electrical end-uses are more important than in the residential sector. Lighting and miscellaneous electrical end-uses account for 32% of the energy savings. Of this 32%, ventilation, office equipment, motors and other building services account for two-thirds, while lighting contributes to about one-third.

The 35% reduction in electricity consumption below the Baseline Scenario in 2050 accounts for 42% of all energy savings in the building sector. The residential sector

Figure 2.37 ▸ Buildings sector energy savings in the Map scenario by end-use, 2050
(reduction below the Baseline Scenario)



Key point

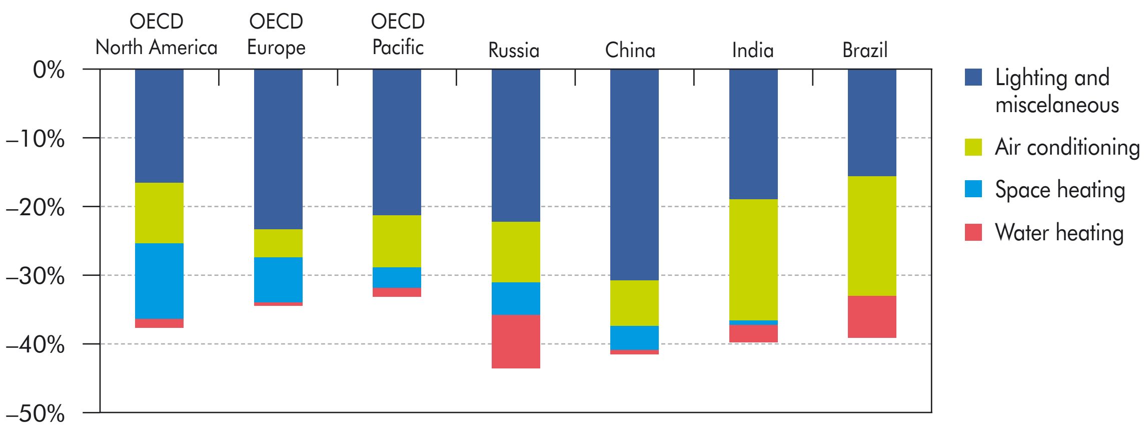
Energy savings in residential buildings are almost twice as large as those in the service sector

contributes 62% of the electricity savings, of which more than half are in developing countries.

In the service sector, electricity consumption is 32% lower than in the Baseline Scenario in 2050. Lighting and other miscellaneous electrical end-use account for 58% of all electricity savings in the service sector, with air conditioning accounting for 21%, space heating 17% and water heating 4%. The importance of cooling and space heating in the total savings of electricity vary significantly by region, depending on whether it is a hot or cold climate (Figure 2.38).

The consumption of coal, oil and natural gas in the buildings sector produced 38% of the sector's total direct and indirect CO_2 emissions in 2003. CO_2 emissions from electricity and heat generation for the sector accounted for 62% of the total direct and indirect emissions (Figure 2.39). The upstream CO_2 emissions for electricity in 2030 and 2050 are calculated using the 2003 CO_2 intensity of electricity and heat so that the changes in CO_2 emissions from electricity use are only due to the end-use efficiency changes in the buildings sector. In the Baseline Scenario, CO_2 emissions attributable to the building sector increase by 139% between 2003 and 2050. In the Map scenario, the CO_2 emissions from coal, oil and gas consumed in the buildings sector are 35% lower in 2050 than in the Baseline Scenario. The emissions from coal are reduced by 40%, those of gas by 35% and those of coal by 34% below the Baseline Scenario in 2050. The upstream CO_2 emissions attributable to heat and electricity consumption in the Map scenario are 38% lower than the Baseline Scenario in 2050. This is despite fuel switching to electricity where it offers energy efficiency benefits, such as heat pumps for some households. Total CO_2 emissions from the buildings sector, including those for electricity and heat, are 37% lower than in the Baseline Scenario in 2050 and total savings are about 7.8 Gt CO_2.

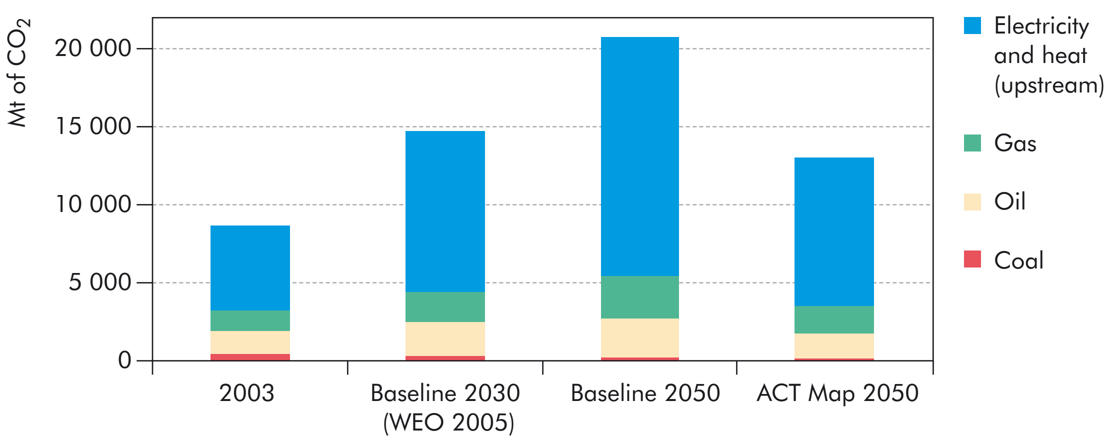
Figure 2.38 **Service sector electricity savings in the Map scenario by region, 2050**
(reduction below the Baseline Scenario)



Key point

The importance of the various end-uses in total electricity savings varies by region depending on the climate.

Figure 2.39 **Building sector CO_2 emissions by source and by scenario, 2003-2050[24]**



Key point

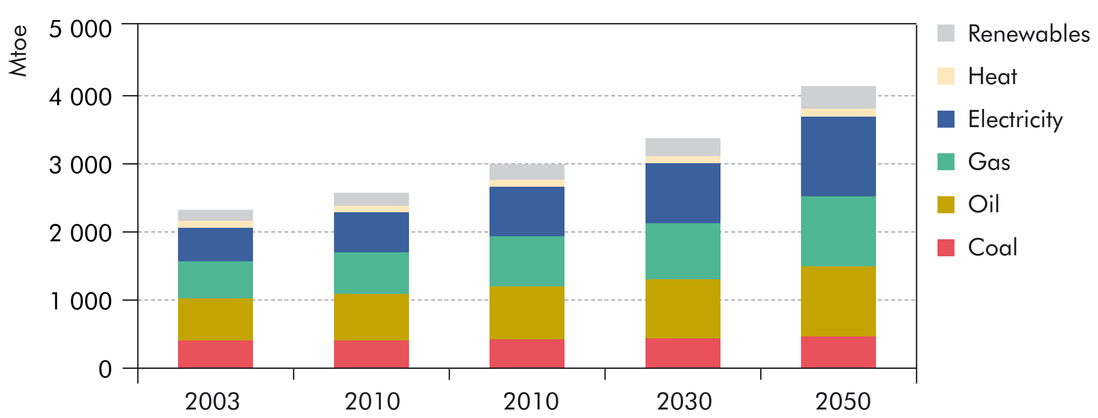
The main CO_2 emission reductions for buildings are due to savings of electricity .

24. Upstream electricity emissions are allocated using the 2003 CO_2 emissions intensity for the electricity generation sector. The change in CO_2 emissions from upstream electricity generation over time in this figure therefore only reflects energy efficiency improvements in the industry sector and not improvements in the power generation CO_2 intensity.

Industry[25]

In the Baseline Scenario, energy consumption in industry grows from 2 326 Mtoe in 2003 to 4 138 Mtoe in 2050 (Figure 2.40). These figures exclude blast furnaces and coke ovens operated in industry, which are accounted for in the transformation sector. These activities add around 200 Mtoe of fuel use in 2003, virtually all of it in the form of coal. In the Baseline Scenario, the share of gas in industrial energy use remains high in the transition economies through 2050.

Figure 2.40 **Industrial energy use in the Baseline Scenario[26]**



Key point

Industrial energy use grows by 78% in the Baseline Scenario between 2003 and 2050.

The industrial energy mix changes appreciably between 2003 and 2050 in the Map scenario, with the use of coal and oil declining, while natural gas and biomass gain share. However, even with the efforts in the Map scenario, industrial energy use in 2050, at 3 339 Mtoe, is still 44% higher in 2050 than in 2003.

In the Map scenario in 2050, global industrial energy demand (including coke ovens and blast furnaces) is 20%, or 894 Mtoe, lower than in the Baseline Scenario (Table 2.13). Reduced electricity consumption accounts for 335 Mtoe of energy savings, oil for 382 Mtoe and coal for 276 Mtoe. The use of gas and renewables increases by 7%. Almost half of the energy reduction occurs in developing countries and two-fifths in OECD countries.

25. The only ACT scenario discussed in this section is the Map scenario. There are only minor differences in the industry sector in the other scenarios. The only exception is the Low Efficiency scenario, however, the implications for technology and fuel choices in the industry sector of the lower efficiency progress in this scenario were not assessed.

26. This figure excludes the transformation sector component of industry activities, about 200 Mtoe in 2003.

Table 2.13 ▶ Industrial energy consumption and savings in the Map scenario, 2050

	OECD (Mtoe)	Transition economies (Mtoe)	Developing countries (Mtoe)	World (Mtoe)
Coal	55	16	213	285
Oil	260	41	345	646
Gas	434	144	492	1 071
Electricity	302	70	464	836
Heat	20	40	55	115
Biomass	199	9	179	387
Total	**1 271**	**320**	**1 748**	**3 339**
Coal use in coke ovens and blast furnaces	**150**	**75**	**320**	**555**
Change compared to Baseline Scenario (including coke ovens and blast furnaces)				
Coal	–31%	–36%	–28%	–29%
Oil	–38%	–39%	–36%	–37%
Gas	–1%	–5%	13%	4%
Electricity	–34%	–30%	–25%	–29%
Heat	–8%	–16%	15%	–2%
Biomass	16%	358%	15%	18%
Total	**–21%**	**–23%**	**–18%**	**–20%**

The highest percentage reduction is for oil (37%), followed by coal (29%) and electricity (29%). Recycling of plastic waste increases, and more natural gas is used as a substitute to oil as a feedstock. The reduction in coal use can be attributed to fuel substitution and improvements in the efficiency of both iron- and steel-making and steam generation and use. In general, the fuel substitution is from coal to natural gas and renewables.

The reduction in electricity use can largely be attributed to the higher efficiency of motor systems. In addition, aluminium smelters, chlorine plants and electric-arc furnaces achieve a higher efficiency than in the Baseline Scenario due to introduction of new technologies.

The percentage reduction is highest in the transition economies, followed by OECD countries and developing countries. The significant savings in transition economies can be explained by the current low energy efficiency of their industries.

Total coal use for steel making declines from 700 Mtoe in the Baseline Scenario in 2050 to 550 Mtoe in the Map scenario. Existing energy efficiency measures, such as residual-heat recovery technologies in blast furnaces, coke ovens, basic oxygen furnaces, sintering plants and hot stoves are more widely applied. Larger furnaces, pre-reduction of iron ore during sintering, more reactive coke and top-gas recycling all reduce coal and coke use. The injection of waste plastic and its use in coke ovens increases. Direct reduced iron (DRI) will increasingly be produced at locations with cheap stranded gas reserves, reducing the coal-based production of pig iron in large integrated plants. New technologies such as coal-based integrated smelt reduction and DRI production processes will reduce the coal and coke demand per tonne of iron and steel product.

The remainder of the reduced coal demand is to a large extent accounted for by less coal use in boilers, notably in China and India. More efficienct boilers, better coal quality due to washing and better operation of the boilers all play an important role. More natural gas is substituted for coal, notably in small-scale boilers in urban environments. This development is driven by local air pollution concerns.

The chemical industry contributes more than other industrial sectors to the total reduction in demand for fossil fuels. Important efficiency gains are also achieved in sectors such as iron and steel, cement, and paper and pulp production. The other industry sub-sectors category accounts for half the total reduction in energy use in industry.

Efficiency improvements in the iron and steel industry in Russia, China and Brazil are roughly of the same magnitude as in the OECD. In India, 25% less energy will be required to produce one tonne of steel than is the case in the Baseline Scenario. In China, the efficiency of the production of non-metallic minerals, especially cement, increases considerably. This sub-sector provides more than a third of the country's total savings in industrial energy use.

Improving industrial energy efficiency in developing countries will depend on the availability of capital and on technology transfer from OECD countries. Factories and plants in developing countries rarely achieve the best practice levels that are realised in OECD countries. This is often because they lack sufficient scale, technological know-how and/or capital.

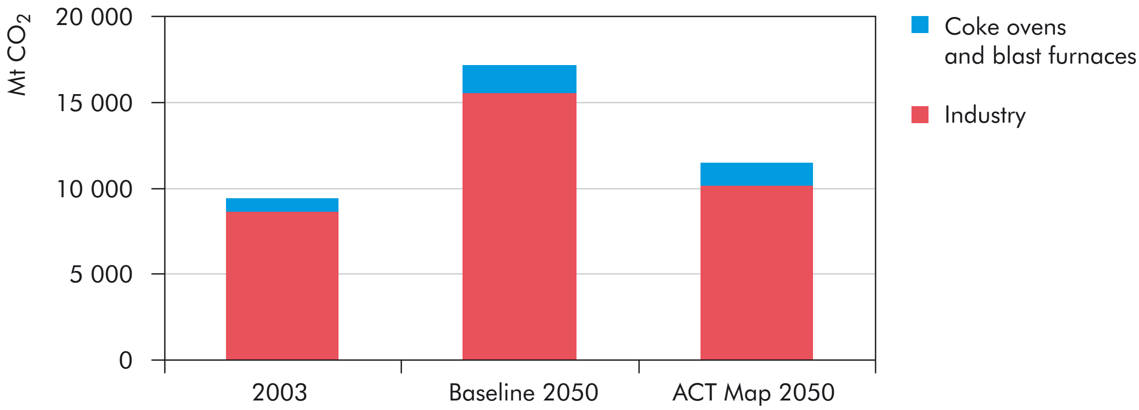
Apart from energy efficiency measures based on existing technology, a large number of potential options for mitigating CO_2 emissions from industry have been considered in the ACT scenarios. They include energy and feedstock substitution, materials and product efficiency, CO_2 capture and storage, process innovation, energy and materials efficiency, and the use of more combined heat and power generation.

In the Baseline Scenario, industrial CO_2 emissions including the upstream emissions from electricity and heat generation, and coal use in coke ovens and blast furnaces increase by 82% between 2003 and 2050, reaching 17.2 Gt CO_2 in 2050 (Figure 2.41). In the Map scenario, emissions are reduced to 11.5 Gt CO_2. Therefore CO_2 emissions are 33% less than in the Baseline Scenario in 2050. However, this still represents a 21% increase compared to the 2003 level.

The total CO_2 emission reduction in the industrial sector in the Map scenario is about 5.4 Gt CO_2, with about another 0.3 Gt CO_2 attributable to reduced fuel use in coke ovens and blast furnaces, which is accounted for in the transformation sector. This is net of the increased CO_2 emissions from the increased use of CHP and the secondary effects from other sectors that increase CO_2 emissions somewhat.

Of this 5.7 Gt CO_2, energy efficiency based on existing technology and process innovation accounts for 46% of the savings in the Map scenario compared to the Baseline Scenario (Figure 2.42), while 27% of the reduction in 2050 can be

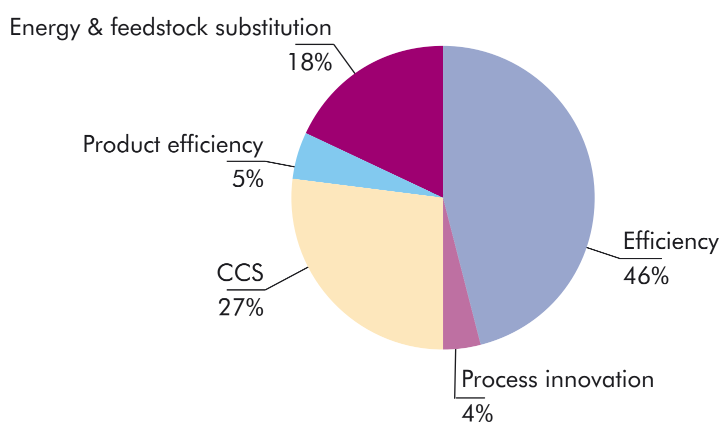
Figure 2.41 ▶ **Industrial CO_2 emissions in the Baseline and Map scenarios, 2003 and 2050**[27]



Key point

Industrial emissions in the Map Scenario are reduced by 5.4 Gt CO_2 in 2050 compared to the Baseline Scenario.

Figure 2.42 ▶ **Industrial CO_2 emission reductions in the Map scenario by 2050 compared to the Baseline Scenario**[28]



Key point

Efficiency gains account for half of the total CO_2 reduction in the Map scenario.

27. This figure includes upstream electricity emissions. These are allocated using the 2003 CO_2 emissions intensity for the electricity generation sector. The change in CO_2 emissions from upstream electricity generation over time in this figure therefore only reflects energy efficiency improvements in the industry sector and not improvements in the power generation CO_2 intensity. The coal use in coke ovens and blast furnaces is presented separately, as this is accounted for in the fuel transformation sector.

28. This figure includes savings from coke ovens, blast furnaces and steam crackers. It also includes CO_2 emission reductions in power generation due to reduced electricity demand in industry.

attributed to CO_2 capture and storage. About 20% of this capture takes place in ammonia plants, 30% in iron and steel production, 25% in cement kilns, and the remainder in other processes such as furnaces. CO_2 capture is also applied to black liquor gasifiers in pulp production (about 0.3 Gt per year in 2050), but these savings are accounted for under power generation. Changes in the energy fuel mix and feedstock substitution account for 18% of all CO_2 emission reductions and include switching to less carbon intensive energy sources and feedstocks. Of the total savings, 5% can be attributed to the more efficient use of basic materials (product efficiency), which reduces the need for primary materials production. This includes new materials of higher strength such as new steel qualities that allow product lightweighting. Innovations in industrial processes contribute 4% of the savings.

Cogeneration of heat and power and the increasing need for ammonia to produce fertiliser for bioenergy production actually increase CO_2 emissions from industry, but they contribute to significant emissions reductions in other sectors. In theory, there exists a potential for further CO_2 emissions reductions using more CCS (e.g. in cement kilns) and through the use of electricity and hydrogen. But the costs of these options usually exceed USD 50 per tonne CO_2. An ambitious policy for industry with CO_2 emissions reduction incentives equivalent to that level is only feasible if the issue of carbon leakage due to industry relocation is dealt with (see Box 2.6).

Box 2.6 ▶ Carbon Leakage

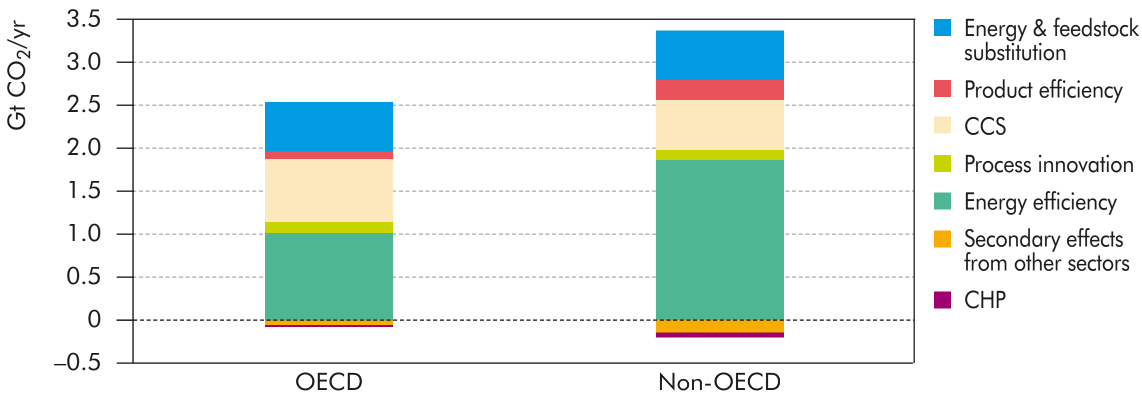
Government policies that lead to higher energy prices may cause industry to relocate to countries with lower energy prices. If this happens, CO_2 reductions in one country can result in increased emissions in another country. In the worst case, the increase will exceed the reduction. This may happen when an industry relocates from an OECD country to a developing country where the process efficiency is lower, due to the lower price of energy. This has potentially significant economic and environmental costs, since the real or perceived risk of industry relocation can have a negative impact on investment.

Modelling studies give different estimates of the severity of the relocation effect. It is clear, however, that certain energy-intensive industries are very sensitive to energy prices and have indeed relocated as a response to higher energy prices. Sixteen ammonia plants in the United States have closed permanently over the past five years, primarily as a result of rising natural gas prices. Five more plants are currently idle. As a result, ammonia production in the United States fell by more than 6 million tonnes, or 34%, in just five years.

The US fertiliser industry, which once supplied 85% of its internal needs from domestic production, now imports nearly 45% of its nitrogen supplies. This effect was caused by a natural gas price increase of about USD 4 per GJ. This price rise is equivalent to the increase in natural gas prices that would ensue from a CO_2 reduction incentive of USD 70 per tonne of CO_2. Since there is little experience yet of very ambitious CO_2 policies, the anecdotal evidence must be treated with caution. The continuing opening of world markets has already increased the risk of carbon leakage. This observation must be kept in perspective. Relocation for energy-price reasons alone will be limited to the energy-intensive heavy industries. It is not an issue for the energy-extensive light industries.

Figure 2.43 shows the breakdown of CO_2 emissions reductions in the OECD region and the rest of the world by source of the reduction. By 2050, more than half the reductions are in non-OECD countries, as the potential for energy efficiency is more significant in developing countries and transition economies.

Figure 2.43 ▶ **CO_2 emissions reduction in the Map scenario in the OECD and non-OECD, 2050**[29]



Key point

Total savings in developing countries and transition economies exceed those in the OECD by 2050.

Energy and feedstock substitution results in global savings below the Baseline Scenario in 2050 of 1.2 Gt CO_2, while product efficiency contributes 0.3 Gt CO_2. Energy efficiency contributes savings of 2.9 Gt CO_2, CCS 1.5 Gt CO_2 and process innovation 0.2 Gt CO_2. This is offset by the increase in CO_2 emissions in industry of 0.3 Gt CO_2 , due to the increased use of CHP and the increased energy needed to produce ammonia for fertilisers used in the production of biofuels for the transport sector. However, both these increases yield substantially higher reductions in CO_2 emissions in the electricity generation and transport sectors.

29. Note this figure includes upstream savings in the electricity sector and coke ovens, blast furnaces and steam crackers in the transformation sector. The reduction is below the Baseline Scenario in 2050.

Chapter 3 TECHNOLOGY STRATEGIES FOR A MORE SUSTAINABLE ENERGY FUTURE

Key Findings

- *The Accelerated Technology scenarios demonstrate that employing technologies that exist today or are under development can shift the world onto a path towards a more sustainable energy future. Most, perhaps all, of the energy technologies included in these scenarios, however, face barriers of different kinds that must be overcome before their full potential can be realised.*

- *Well focused R&D programmes are essential to overcome the technical and cost barriers facing many new energy technologies. There is an acute need to stabilise declining budgets for energy-related R&D and indeed start increasing support. Increased R&D in the private sector will also be pivotal.*

- *Several emerging technologies need government support if they are to bridge the "valley of death" that new technologies face on the path to full commercialisation. Deployment programmes can be very efficient in reducing costs via "technology learning" effects. These programmes may also activate R&D by private industry by creating expectations of significant future markets. However, the deployment phase can require considerably more resources than the R&D phase and in some cases it may be more cost effective to increase R&D resources in order to reduce the need for deployment support.*

- *New energy technologies may be more expensive, even after harvesting "technology learning" effects, than those they are designed to replace. For example, CO_2 capture and storage (CCS) technologies will not be installed unless there are lasting economic incentives to reduce CO_2 emissions. Governments need to foster a stable and predictable regulatory and policy environment that gives credit for low carbon technologies.*

- *Today there are many energy technologies, particularly on the demand side, that are economic and will pay for themselves through reduced energy costs. Yet, there are still barriers to overcome, as many consumers do not take into consideration energy costs when they buy appliances, homes or cars. As well, manufacturers of refrigerators, televisions, cars, etc., do not always take advantage of the technology opportunities that exist to make their products more energy efficient. A wide range of policy instruments are available to address these barriers, including information campaigns, standards, voluntary agreements, labels, targets, public sector leadership through procurement and practice, regulation, and financial incentives.*

- *Policies such as these would help harvesting the significant low-cost potential of a wide range of existing efficient technologies in the buildings, industry and transport sectors. In all these sectors there are also important opportunities to develop and deploy new cutting-edge technologies. Many of these technologies can be expected to start making a significant contribution in the next decade or two, while others such as hydrogen fuel cell vehicles will need breakthroughs before they are ready for mass deployment.*

- *Electricity generation can be significantly decarbonised by 2050 by shifting the generation mix towards renewables, nuclear, natural gas and clean coal with CCS. But these technologies all face challenges in expanding their market share. Renewable energy options range from mature technologies such as hydro and biomass to technologies that are rapidly growing in some markets, but still need further cost reductions to reach their full potential (e.g. wind). Other technologies would benefit from further R&D (e.g. solar and geothermal). Nuclear power's further exploitation faces three key issues: their high capital costs; public concerns about radioactive waste and nuclear accidents; and the proliferation of nuclear weapons. Natural gas technologies emit only half as much CO_2 as coal technologies, but are very sensitive to changes in gas prices. CCS technologies require further R&D and, maybe most urgently, require large-scale demonstration to reduce costs and to prove the safety and integrity of CO_2 storage.*

Introduction

It will take a major, co-ordinated international effort to achieve the results implied by the ACT scenarios presented in Chapter 2. Public and private support will be essential. Co-operation between developed and developing nations, and between industry and government will be needed. The task is urgent, as it must be carried out before a new generation of inefficient and high-carbon energy infrastructure is locked into place. The task will take decades to complete and it will require significant investment. Yet, the benefits will be substantial, not only for the environment. Lower energy consumption, reduced pollution and CO_2 emissions could help reduce concerns about energy supply and environmental degradation that may otherwise impose constraints on economic growth.

Implementing the ACT scenarios will require a transformation in the way power is generated; how homes, offices and factories are built and used; and in technologies used for transport. In the end, it is the private sector that will have to deliver the changes required. But the market on its own will not always achieve the desired results. Governments have a major role to play in supporting innovative R&D and in helping new technologies to surmount some daunting barriers

This chapter sets out strategies to achieve the more sustainable energy future illustrated by the ACT scenarios. It starts with a general discussion of the barriers to energy technology uptake. It then reviews each major technology's potential, costs, barriers to further uptake and how to overcome these barriers.

Barriers to Technology Uptake

Most, perhaps all, of the energy technologies considered in this book face barriers they must overcome before their full potential can be harvested. The barriers can be classified under three broad headings: technical barriers; cost barriers; and other barriers not primarily related to costs and technical issues.

Technical Barriers

Some energy technologies are not yet ready for the market. Further research and development (R&D) may be needed to resolve technical problems. Typically government funding is essential in the early phase of a technology's development, while industry's engagement increases as the technology gets closer to market introduction. When a technology is technically proven, demonstration projects may be required to show that it works on a commercial-scale and under relevant operating conditions.

Cost Barriers

Most new energy technologies initially have higher costs than the incumbent technologies. Costs can be reduced by further R&D and usually fall, sometimes significantly, as a result of the "technology learning" effect (see Box 3.1). Deployment programmes may be needed to achieve these cost reductions. Although the costs of the technologies will be reduced by R&D and learning, some technologies like CO_2 capture and storage, can only be cost competitive if credit is given for the CO_2 emission reductions.

Another group of technologies, on the demand-side, are those that have higher capital costs than less efficient incumbent technologies, but which have significantly lower life-cycle costs due to their lower energy bills. These technologies face a "first cost" barrier to market acceptance, which is partly associated with a lack of information and awareness of their life-cycle cost benefits. The energy performance of these technologies is usually of secondary importance in the purchase decision. This lowers the probability that the market will gravitate to the least-cost option. The likelihood of market actors trying to minimise energy-costs is further weakened by numerous split incentives. For example, a large proportion of buildings and energy-using capital equipment is often not purchased by those who will be paying the energy bill. Priority is therefore usually given to minimising the initial capital investment, rather than the energy or life-cycle costs.

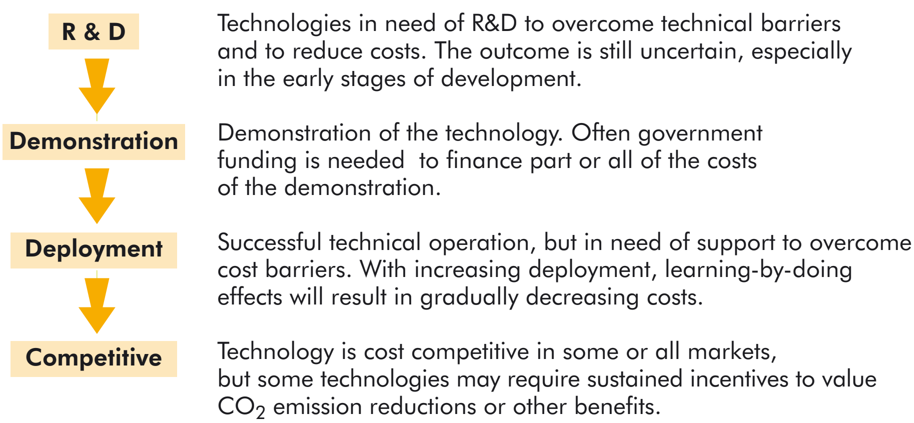
Box 3.1 ▶ Technology learning

The process of technology learning – in which production costs decrease and technical performance increases as cumulative installed capacity rises – can make new technologies available at lower costs (Boston Consulting Group 1968, OECD/IEA, 2000). The prospect that a given technology will be produced and sold on the market can stimulate private industry R&D ("learning-by-searching") and improvements in the manufacturing process ("learning-by-doing"). Feedback from the market may suggest avenues for improving a technology, reducing its costs or tailoring some of its features to consumers' needs ("learning-by-using"). These benefits are only reaped when technology is utilised by the market. The rate of technology improvement is therefore usually a function of the rate of technology adoption. The benefits of technology learning are typically shared on a global level. This emphasises the need for international collaboration on technology development and deployment.

A new energy technology will typically go through several stages to overcome technical and cost barriers before it becomes cost-competitive (Figure 3.1). Even if a technology is technically proven after the R&D and demonstration stage, costs may still be too high for the market. This is often referred to as the "valley of death" that new technologies face on the way to full commercialisation. Programmes aimed at taking the technology through the deployment phase can require considerably more resources than the R&D phase. In some cases prolonging the R&D phase to reduce the market entry cost for the technology may lead to reduced overall costs, as long as the increased R&D expenses are lower than the reduction in deployment costs.

While governments play an important role in stimulating deployment, the costs of the programmes are often borne by the private sector. For example, governments may establish codes or minimum standards that require the market to invest in certain technologies, often at a higher initial cost, but which will result in the reduced cost of the technologies as the deployment increases. The expectation of large future markets stimulated by deployment programmes may also have the important benefit of activating additional R&D by private industry. With a market in sight, industry will step up their efforts, set research priorities and find ways to cut costs.

Figure 3.1 ▶ ***Stages in technology development***



Other Barriers

There are a range of other barriers that can delay or prevent the market deployment of technologies. These include such diverse factors as public acceptance, planning and licensing, financing, lack of information, structure and incentives.

Public Acceptance

Although most surveys of public opinion show the public to be supportive of action to reduce greenhouse gas emissions and combat climate change, this does not invariably translate into ready uptake of cleaner technologies. At the individual level, this reluctance to adopt new technologies may be due to the higher up-front costs of more efficient options (*e.g.* hybrid vehicles) or reluctance to change behaviour patterns (*e.g.* such as avoiding standby losses). But some technologies face opposition from whole sections of the general public. Wind farms, energy from waste plants, nuclear plants and new hydro schemes have all run into vociferous objections at local or national levels. Although such barriers may be reduced by better information, educating the public, and more experience with the technologies, there will always be those who consider that the savings in greenhouse gases do not justify the local environmental consequences caused by a wind farm, hydro scheme or nuclear power plant.

Planning and Licensing

Obtaining the necessary permission can be a problem, especially for electricity generation technologies. The process can be cumbersome and protracted if there is strong public concern about the new installation. The process can prove particularly difficult for new entrants into the market with little experience. Many of the procedures have been designed with conventional technologies in mind and may not lend themselves to dealing with issues raised by new forms of power generation. Electricity grids are designed on a model of large central power stations transmitting electricity to a distribution network that progressively reduces voltage to the final consumer. This can be a real obstacle to the uptake of technologies that are better suited to a distributed generation model.

Financing

Financing is often a problem for new energy technologies, because banks and investors are wary of putting money into technologies that have yet to prove themselves. This risk may make financing more difficult and more expensive to obtain. For technologies that are already struggling to achieve cost competitiveness with the incumbent technologies, this can be a serious barrier. Many renewables projects are relatively small, certainly in comparison to a conventional power station, and the transaction costs for the finance institution inevitably become a larger proportion of the financing package, further driving up the costs.

Lack of Information and Education

Many technologies have not fulfilled their potential simply because the benefits that they offer have not been fully appreciated. This is particularly true for a number of the energy-efficient demand-side technologies reviewed in the buildings and appliances chapter of this book. Many of these technologies offer significant life-cycle cost savings, but remain under-utilised due to a lack of understanding of their cost benefits. Other technologies have not fulfilled their potential because of a lack of supporting infrastructure, such as installers and service engineers, even though the technology may be fully competitive. The development of technologies should be accompanied by training, education and deployment programmes so that they can compete in the market in the same way as incumbent technologies. Minimum standards and codes can ensure that the worst performing products are weeded out of the market, so that the consumer only has a choice between more efficient options.

Structure and Incentives

A distinction needs to be drawn between the factors influencing adoption of centralised energy supply systems and those applying to decentralised energy-demand technologies. Utilities plan their supply portfolios to minimise costs and generally have the necessary knowledge and skills to make an optimum decision. Demand-side technologies are more numerous, more diffused and are far more subject to knowledge, awareness and financing barriers.

Split incentives to minimise energy costs apply in the industrial, transport and buildings sectors. Most motors are not sold directly to industrial end-users, but are incorporated into equipment produced by manufacturers who may wish to minimise product costs at the expense of their final efficiency. In the buildings sector, a building may be commissioned by a developer, designed by an architect, built by a contractor and then fitted with energy service equipment by a variety of different contractors. Each of these actors usually wishes to minimise costs and time. This may create a disincentive to minimise whole building energy performance costs. In industry, it is common for the capital expenditure budget to be managed independently of the operational budget. The manager of the capital expenditure budget needs to be given the correct incentives to minimise life-cycle costs, otherwise the increase in energy costs in the operational budget can easily exceed the savings in capital expenditure.

Another common split incentive occurs when the domestic and commercial building stock is not owner-occupied. Depending on the country, this can account for a very high percentage of the building stock. In such cases, the owner (landlord) has an incentive to minimise the capital costs even if this results in increasing the operating costs borne by the tenant. Even in owner-occupied buildings, the period of time that any one owner may own the energy-using capital (be it a building, appliance or industrial plant) is often less than its useful life and hence there is little incentive to make energy saving investments that will minimise the life-cycle costs of the equipment. This is compounded in numerous situations where the length of ownership is not known in advance. Another complication is that many consumers, particularly those on lower incomes, can be capital-constrained and may not have the option to purchase the lowest life-cycle option. Given these factors, it is not surprising that typical investments in demand-side capital are not as well cost-optimised over the life time of the capital as are supply-side investments. Minimum standards and codes can help address these split incentives by eliminating the poorest performing products from the market.

Table 3.1 illustrates, for each group of technologies included in the ACT and TECH Plus scenarios, the main barriers facing the technology today and the policy instruments that are the most crucial to stimulate its market uptake at this time. It should be noted that the table focuses on the most important barriers/policy instruments and is *not* an exhaustive list. Many technologies for which R&D is not listed as a key barrier could still benefit from further research. Similarly, technologies for which cost it not listed as a main barrier may well achieve further cost reductions. The table represents broad categories of technologies for which cost is an issue across many different markets. Typically the barriers and their relative importance vary depending on specific market conditions. They also vary among

Table 3.1 ▶ ***The main barriers faced by key technologies in the ACT and TECH Plus scenarios and policy instruments to overcome them***

	Barriers	Technical		Cost		Cost-effective, but facing other barriers
	Policy Instruments	R&D	Demons-tration	Deploy-ment	CO_2 reduction incentive	Regulation/ information/ other
Sector	**Technologies**					
Transport - vehicles	Vehicle fuel economy improvements				•	●
	Hybrid vehicles	•		●	•	
	Ethanol flex-fuel vehicles				●	
	Hydrogen fuel cell vehicles	●	●	●	●	
	Non-engine technologies				•	●
Transport-fuels	Biodiesel				●	
	Ethanol (grain/starch)				●	•
	Ethanol (sugar)				●	•
	Ethanol (cellulosic)	●	●	•	●	
	Hydrogen	●	●	●	●	
Industry	Co-generation technologies				•	•
	Motor systems					●
	Steam systems				•	●
	Energy efficiency in existing basic materials production processes				•	•
	Process innovation in basic materials production processes	●	●	•	•	
	Fuel substitution in basic materials production processes				●	
	Materials/product efficiency	•	●	•		●
	Feedstock substitution	●	●	•	•	
	CO_2 capture and storage	●	●	•	●	
Buildings & appliances	Heating and cooling technologies	•			•	●
	District heating and cooling systems				•	●
	Building energy management systems	•	•	•	•	●
	Lighting systems	•	•	•	•	●
	Electric appliances			•	•	●
	Reduce stand-by losses		•			●
	Building envelope measures	•	•	•	•	●
	Solar heating and cooling		•	•	●	●
Power generation	Hydro (small & large)				●	●
	Biomass	•	•	•	●	
	Geothermal	•	•	•	●	
	Wind (onshore & offshore)		•	●	●	•
	Solar photovoltaics	●	●	●	●	
	Concentrating solar power	•	●	●	●	
	Ocean energy	●	●	●	●	
	Combined-cycle (natural gas)*				●	
	Advanced steam cycles (coal)*		•	•	●	
	IGCC (coal)*	•	●	●	●	
	Fuel Cells	●	●	●	●	
	CCS+Advanced steam cycle w/flue-gas separation (coal)	•	●		●	
	CCS+Advanced steam cycle w/oxyfueling (coal)	●	●		●	
	CCS+Integrated Gasification Combined Cycle (coal)	●	●	●	●	
	CCS+Chemical absorption flue-gas separation (natural gas)	•	●		●	
	Nuclear-Generation II and III	•	•	•	●	●
	Nuclear-Generation IV	●	●	•	●	

* Importance of incentives to reduce CO_2 emissions reflects a situation where these efficient fossil fuel-based generation technologies compete with less efficient alternatives, not when they compete with carbon-free options.

General note to the table: ● denotes a barrier that is important today, while • denotes a barrier that is less important but still significant. No mark does not necessarily mean that the barrier is not relevant for the technology - for example are there technologies within almost all categories that would benefit from more R&D - but rather that it is overall less important compared to the barriers that are identified in the table.

different technologies within a category (*e.g.* compact fluorescent lighting systems are proven and available to the market, while advanced light emitting diode based lighting systems would benefit from more R&D). The column representing technologies that are cost-effective, but are facing other barriers, illustrates the situation of today's commercially available technologies. Technologies that may become cost-effective in the future, if they overcome technical and cost barriers, may still face other barriers to their market uptake.

Overcoming Barriers

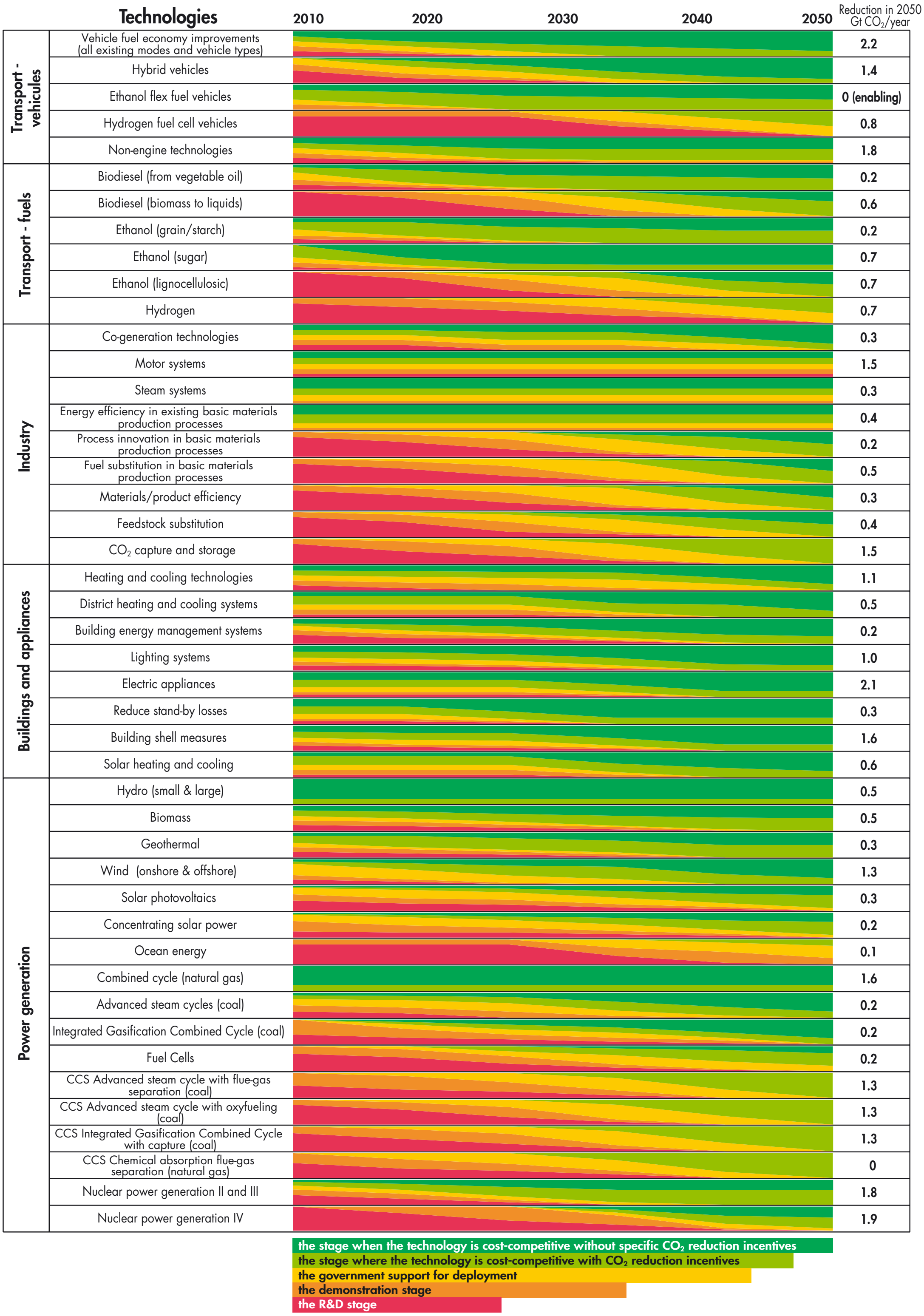
The results in the ACT and TECH Plus scenarios are driven by assumptions about technology costs and performance, and how these are affected by different policies aimed at overcoming the barriers listed in Table 3.1. Some technologies will need continued R&D efforts over many years before they are ready for demonstration and large-scale market deployment. Others have already overcome technical barriers, but need support from deployment programmes to reduce costs via learning-by-doing before they can become cost-competitive. Many technologies, even after harvesting cost reductions from learning-by-doing effects, may still require economic incentives to achieve market uptake. The contributions from many of the technologies in the ACT scenarios are fully or partly dependent on sustained long-term economic incentives to reduce CO_2 emissions. In this study it is assumed that an incentive equivalent to USD 25 per tonne CO_2 is introduced in all countries from 2030 onward.

Figure 3.2 illustrates how different technologies included in the ACT scenarios are assumed to move from their current status and through relevant stages towards cost-competitiveness under the policy and market conditions included in the ACT and TECH Plus scenarios. This assumes that the needed actions to support R&D, demonstration and deployment take place. In the figure, the red sections represent the R&D stage, orange the demonstration stage, yellow the government support for deployment, light green the stage where the technology is cost-competitive with CO_2 emission reduction incentives and dark green the stage when the technology is cost-competitive even without CO_2 emission reduction incentives. The figure also indicates the potential the technologies have to reduce CO_2 emissions by 2050 in the ACT Map scenario.

The figure gives a simplified picture of technology development for a sometimes broad group of technologies within each category. Technology options can require several kinds of support simultaneously and thus be in different technology stages at the same time. Similarly, differences in market conditions and other factors could imply that a technology which is cost competitive in one market may need deployment support in another.

All the technologies included in Figure 3.2 contribute to emission reductions in one or more of the ACT scenarios or in the TECH Plus scenario, with some offering savings of more than 1 Gt CO_2/year. It would, however, be a mistake to focus exclusively on those technologies with the highest abatement potential, since these are often the ones that face the most difficult transition to full deployment. A portfolio

Figure 3.2 ▶ ***Transition through technology stages towards cost-competitiveness in the ACT scenarios.***



Note: The CO_2 reduction effect allocated to each technology accounts only for their direct benefits; it does not account for the fact that certain technologies enable CO_2 emission reductions from other technologies. For example, advanced high-efficiency coal-fired power plants are essential for the widespread introduction of CO_2 capture and storage. The total CO_2 emission reduction potential may not match those in Table 2.2 due to rounding errors. The reductions attributable to Nuclear Generation IV, hydrogen and fuel cells refer to the TECH Plus scenario, for all other categories the reductions refer to the ACT Map scenario.

approach will be needed if savings are to be maximised, with action taken to realise the reductions available with little effort, as well as pursuing those technologies that face greater challenges, but which offer the promise of significant savings in the future.

The following sections describe, sector by sector, in more detail, the contribution each technology makes to emission reductions in relevant scenarios.[1] The sections also discuss the barriers faced by each technology in order to make this contribution and outlines possible ways to overcome them.

For each technology category, the relevant section of Figure 3.2 is repeated to illustrate how the technologies in question are assumed to move from their current status through the relevant stages towards cost-competitiveness. This assumes that the needed actions to support R&D, demonstration, and deployment in the ACT and TECH Plus scenarios take place.

For each technology area there is also a table indicating the potential for CO_2 emission reduction by 2015, 2030 and 2050 for each technology relative to the Baseline Scenario in the Map scenario. The reductions are illustrated by a category ★ (< 0.1Gt CO_2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt).

Power Generation from Fossil Fuels

Two-thirds of the world's electricity is currently produced from fossil fuels. In the Baseline Scenario a major expansion of coal-fired generation is anticipated, notably in developing countries. The ACT scenarios suggest that coal and gas can continue to play an important role even in a CO_2 constrained world. Improving the efficiency of fossil-fuel power plants is one way to reduce CO_2 emissions per unit of electricity produced. This will be essential for CO_2 capture and storage (CCS). Fuel switching from coal to gas can reduce CO_2 emissions per kWh generated by between 50% and 75%, because natural gas has less carbon than coal and natural gas combined cycle (NGCC) power plants are more efficient than coal-fired power plants.

CO_2 capture and storage can prevent CO_2 reaching the atmosphere. It offers the potential to reduce CO_2 emissions from fossil fuel plants by between 85% and 95%. This option can be applied to coal and gas-fired power plants. CO_2 capture and storage in combination with biomass use would go even further and actually remove CO_2 from the atmosphere, rather than just avoiding its release from fossil fuels.

More gas-fired generation, the improved efficiency of fossil fuel-fired power plants and the use of CCS contribute about 18% of the reduction in CO_2 emissions in the

1. The first section discusses supply-side technologies in power generation and is split into three areas: fossil fuels, renewables and nuclear.

Map scenario and 9% in the No CCS scenario (Figure 3.3). In the Map scenario, CCS accounts for 12% of the total reduction in emissions below the Baseline Scenario in 2050.

Table 3.2 presents the CO_2 emission reductions by technology option and summarises the technology deployment path. NGCC plant are available today and can play an important role in the short- to medium-term. Switching from coal-fired generation to gas-fired generation results in substantial emissions reductions. This option is only attractive where gas prices allow generation costs lower than for coal, including the CO_2 reduction incentive. High-efficiency coal-fired power plants are also available today, but even further efficiency gains are possible. Advanced steam cycles are already deployed today, while IGCC still needs further development. However, by 2050 the use of both is of similar importance. Fuel cells are different in that they are a gas-based decentralised technology that make most sense in cogeneration applications. Costs need to come down further, but they do not have a "guaranteed" market, despite their efficiency, as other competing cogeneration technologies are under development.

Table 3.2 indicates that CO_2 capture and storage could be applied by 2030, but development and demonstration of more efficient and cheaper CCS technologies are needed. Moreover, CCS only makes economic sense if it is used at efficient power plants. The deployment of CCS will therefore depend on investment patterns and its introduction will be a slow process that will take decades. CCS for gas-based processes can make sense in locations where gas prices are low or where gas-fired power plants are the only CO_2 source for enhanced oil recovery (a particularly valuable use of CO_2). The use of CCS at gas-fired power plants will therefore likely be limited at an incentive level of 25 USD per tonne CO_2.

Most of the emerging technologies considered in this study reach the stage where they start becoming cost-effective, at least in some markets, between 2015 and 2030 (Figure 3.4). This is important in order to achieve a substantial uptake by 2050. For some technologies, particularly CCS, predictable long-term CO_2 emission reduction incentives will be essential.

Figure 3.3 ▶ ***Share of fossil power generation technologies in global CO_2 emission reductions relative to Baseline in the Map and No CCS scenarios, 2050***

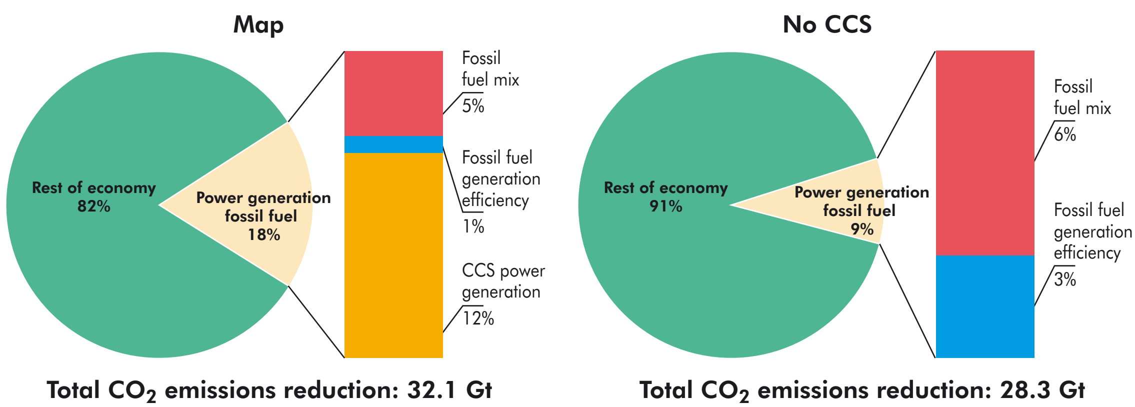
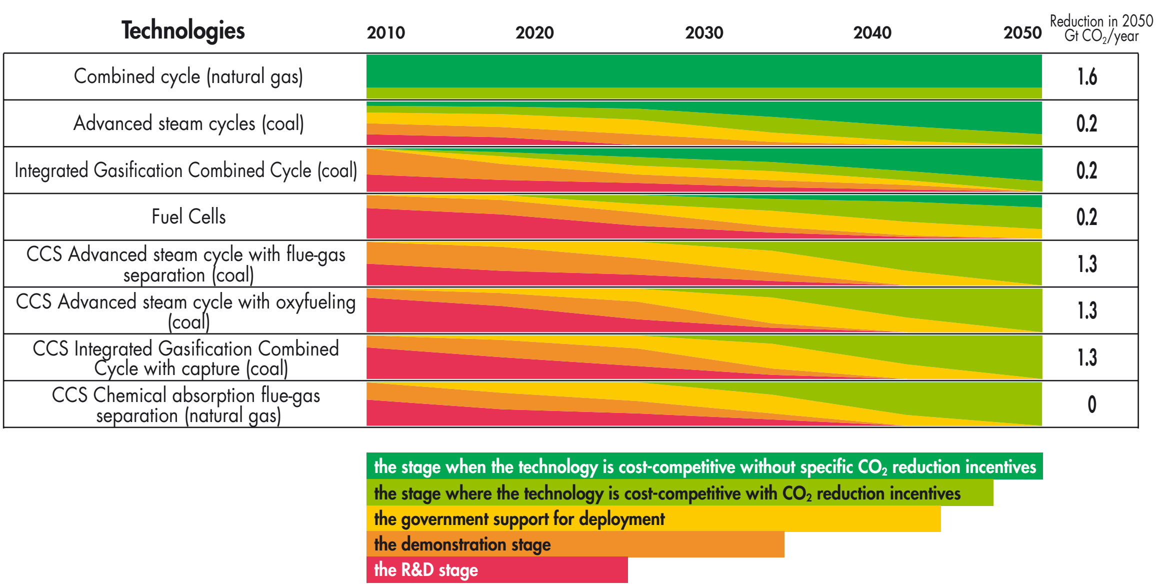


Table 3.2 ▶ **CO_2 emission reductions in ACT scenarios below the Baseline due to fossil power generation technologies**

Technologies	2015	2030	2050	Gt CO_2/year
Combined cycle (natural gas)	★★	★★★	★★★★	1.6
Advanced steam cycles (coal)	★	★★	★★	0.2
Integrated Gasification Combined-Cycle (coal)		★	★★	0.2
Fuel Cells		★	★★	0.2
CCS Advanced steam cycle with flue-gas separation (coal)		★★	★★★★	1.3
CCS Advanced steam cycle with oxyfueling (coal)		★★	★★★★	1.3
CCS Integrated Gasification Combined-Cycle (coal)		★★	★★★★	1.3
CCS Chemical absorption flue-gas separation (natural gas)				0.1

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt). The CO_2 emission reduction in the last column refers to the Map scenario.

Figure 3.4 ▶ **Pathways towards cost-competitiveness for fossil power generation technologies**



Natural Gas Combined-Cycle

Potential

The increased share of natural gas in the power generation mix due to NGCC technologies provide between 5% and 7% of total CO_2 emissions reduction in the ACT scenarios by 2050. The Baseline Scenario assumes a strong expansion of gas fired power generation. In the ACT scenarios, gas-fired generation is lower than in the Baseline Scenario, but the use of coal-fired power plants decreases by even more, so the share of gas in power generation increases. The increased use of NGCC plants can have an impact in the short-term, as it is commercially available now, and over the medium-term to 2030.

NGCC is a mature technology. The F-class combined-cycle gas turbine (200 MW range) was first introduced in the 1990s, with many of its features being taken from jet-engine technology. Since then, the technology has progressed with cooling systems and materials developments, including single crystal airfoils, higher compression ratios, and higher firing temperatures. As a result, efficiencies have now reached 60% on a lower heating value (LHV) basis. In comparison, the world average efficiency of gas-fired power plants was just 42% in 2003. The replacement of existing gas-fired power plants with the latest designs can therefore reduce CO_2 emissions. It is unlikely that the global average efficiency for gas-based generation will ever reach that of NGCC plants because the use of gas in less efficient stand-alone turbines for peak loads is likely to remain attractive.

Costs

Thermal efficiencies close to 60% (LHV) have been achieved, and capital costs are much lower (USD 450-600 per kW) than for a typical coal-fired plant (USD 1 000-1 200 per kW).

NGCCs emit less than half as much CO_2 as coal-fired plants per unit of electricity generated, so fuel switching leads to significant emission reductions. However, the total cost of generation using NGCC is much more dependent on fuel prices than other technologies. The CO_2 reduction costs of a switch from coal to gas, therefore also depend on the gas price.

Barriers

The principal barrier to the further expansion of NGCC technology is uncertainty about future natural gas prices. Fuel costs account for 60 to 85% of total generation costs for NGCCs, much higher than for other power generation technologies. An increase in fuel prices would therefore have a more serious impact on the economics of an NGCC plant than on other technologies. A significant "dash for gas" across the world, motivated by lower capital costs and reduced emissions would almost certainly lead to higher gas prices and could undermine the economics of NGCC.[2] Even if a major expansion could be achieved without undue impact on gas prices, an over-reliance on natural gas would raise concerns in many countries about energy security and diversification, as dependence on gas imports rises.

Overcoming Barriers

Continuing R&D by the industry can be expected to result in even higher efficiencies, with commensurate CO_2 savings and reduced costs, during the period up to 2050. A combination of NGCC with CCS technologies would lead to further CO_2 savings, although this is likely to be a costly CO_2 mitigation option.

2. Tight gas supplies, notably in North America and Europe, have already seen pressure on prices at regional levels.

Of all the technologies described in this book, NGCC is one of the least in need of action by governments to overcome obstacles. However, measures aimed at boosting gas production, through improved technology, would help to minimise increases in the price of gas and associated security and diversity considerations for NGCC.

Supercritical Steam Cycle (SCSC) and Ultra-Supercritical Steam Cycle (USCSC)

Potential

Two-thirds of all coal-fired plants are older than 20 years. These plants have an average net efficiency of 29% and emit 3.9 Gt CO_2 per year. If all of these plants were to be replaced by plants with efficiencies of 45%, the new plants would emit 36% less CO_2 for a reduction of 1.4 Gt CO_2 per year. The replacement of this older capital stock could be carried out before 2030.

Advanced steam cycle technologies are already widely adopted in the Baseline Scenario. Therefore, their contribution to the additional emissions reduction in the ACT scenarios is limited. They constitute a key enabling technology for the economic use of CO_2 capture and storage at coal-fired plants.

Costs

Supercritical steam cycle (SCSC) technology is commercially available and existing projects have been financed by private capital. In Europe and Japan, SCSC is the technology of choice for new coal plants and in China, it accounts for half of all new orders (more than 40 GW in 2003).

Ultra-supercritical steam cycle (USSC) plants operating at temperatures around 700°C still need further R&D. The costs of ultra-supercritical steam cycle plants are expected to be between 12 and 15% higher than the cost of a sub-critical steam cycle plant. However, due to the reduced coal and flue-gas handling, the balance-of-plant costs are 13 to 16% lower than in a supercritical plant. Given the relatively early stage of development of these technologies, uncertainty surrounding the fabrication and building costs with new materials could alter these impacts.

Barriers

The best coal-fired plants that are in use today achieve 45 to 47% efficiency. Advanced cycle technologies aim to improve efficiencies up to around 50 to 55% (*i.e.* as much as 20 percentage points above today's average of 35%) by operating at higher temperatures than conventional steam plants. Such improvements would bring major CO_2 emission savings. However, operating at much higher temperatures requires the development of materials that can withstand extreme conditions. These are not readily available at acceptable costs. Current steel alloys reach their limit at a temperature of about 600°C. Other materials, such as ferritic (up to 650°C) and austenitic steels (up to 700°C), which were the focus of research in the 1990s have not yielded satisfactory results. Nickel alloys, originally developed for gas turbines can withstand temperatures up to 750 °C, but they cost much more than ferritic and austenitic steels.

Overcoming Barriers

Major R&D efforts are needed, especially with regard to materials, if plants that can operate at what are considered today to be extreme temperatures are to be successfully developed. Hand in hand with finding these new materials, R&D is needed to reduce costs. The additional costs imposed by expensive new materials can be mitigated, at least in part, by improvements in plant design to reduce the amount of the plant that is exposed to the most extreme conditions and which require special materials. Novel plant designs such as two-pass, inverse-twin-tower and horizontal-boiler concepts can reduce investment costs.

The R&D effort in materials science and plant design should not be left entirely to industry. The potential savings in the cost of electricity generation (without any economic benefit for reducing the CO_2 emissions) from efficiency gains are probably insufficient to motivate private investment. In addition, much of the research needed, especially with regard to materials, is basic research that has usually been the domain of the public sector.

Integrated Gasification Combined-cycle (IGCC)

Potential

IGCC systems are among the cleanest and most efficient clean-coal power-production technologies and have the advantage that they can process all carbonaceous feedstocks, including coal, petroleum coke, residual oil, biomass and municipal solid waste. IGCC could potentially achieve higher efficiencies than steam cycles and could become a key enabling technology for CCS given that the CO_2 capture cost at IGCC plants is lower than in coal-fired steam cycles. It is not yet clear if the total power generation cost will be lower.

Costs

Today, the capital costs of IGCC plants are approximately 20% higher than conventional plants. Current demonstration IGCC plants have efficiencies of 45%, but efficiencies around 50% are expected to be achieved by 2020 and may be even higher in later decades. It could be anticipated that second-generation IGCC plants may have similar electricity costs as pressurised fluidised-bed combustion and supercritical plants.

Barriers

The high capital costs and a number of technical issues stand in the way of the widespread adoption of IGCC plants. Substantial R&D is needed to make IGCC plants available. Although the fuel flexibility and high efficiency make IGCC plant very attractive, these benefits do not presently outweigh the costs of capital and operational reliability.

Overcoming Barriers

More research is needed to overcome a range of technical issues related to gasifier size and maintenance requirements (a key issue for plant availability over the year), heat transfer after the gasifier, hot gas clean-up, gas composition and combustion, waste-water treatment and the degree of process integration. IGCC will benefit from technological progress in gas turbines and from progress in oxygen production technologies.

IGCC will not be taken up widely until there has been sufficient evidence from demonstration projects that the technology can provide satisfactory levels of plant availability and economic levels of capital cost compared to conventional steam cycles.

Fluidised Bed Combustion (FBC and PFBC)

Potential

Fluidised bed combustion is a mature technology and can thus make a contribution in the short to medium term. If other newer fossil technologies fulfil their potential, fluidised bed technologies are likely to be superseded after 2020. However, this technology may play a role for certain types of low quality feedstocks.

Costs

There are two basic types of fluidised beds – "bubbling" and "circulating" – and hybrid systems have also evolved from these two basic approaches. Fluidised beds are particularly suited to the combustion of low-quality coal. There are hundreds of atmospheric circulating fluidised bed (CFBC) units operating worldwide, with a significant number of medium sized plants around 300 MW_e. The power generation efficiency of CFBC units is generally of the same order as that of conventional pulverised coal plants firing similar coals, because they use steam turbine cycles employing similar conditions. Efficiency can be improved by moving to supercritical cycles or using pressurised fluidised beds (PFBC).

Barriers

Fluidised bed combustion is in use today and is particularly suited to burning low-grade coal. Efficiency needs to be improved if further CO_2 savings are to be achieved. Fluidised bed combustion at elevated pressure (PFBC), typically 12 bar, can result in efficiencies of up to about 44% (LHV).

Moving to supercritical cycles would improve the efficiency of fluidised bed combustion. A 460 MWe supercritical unit is under construction in Poland and is due to be commissioned in 2006. This is expected to have a thermal efficiency of 43% (LHV). Larger 600 MW_e supercritical CFBC units are under consideration. Second-generation PFBC cycles are under development, but have not yet reached demonstration scale.

Overcoming Barriers

The key requirement for this technology is further R&D and, critically, demonstration in order to drive down costs, while delivering improved efficiencies. Reliability will be an important feature of demonstration programmes to show that plant availability is not compromised by the increased sophistication needed to deliver the improved efficiency.

The absence of any current private sector interest in producing and promoting PFBC technology could foreclose this as a technology option.

CO_2 Capture and Storage Technologies (CCS)

Potential

The ACT scenarios demonstrate that CCS in power generation may contribute as much as 4.8 Gt CO_2 (in the Low Efficiency scenario) to emission reductions by 2050. In fact, one of the key findings of this analysis is that CCS technologies enable coal to play a significant role even in a CO_2 constrained world.

Costs

If a CCS plant were to be built today with current best available technology, abatement costs would be around USD 50 per tonne of CO_2 avoided. While the prospects for cost reductions are good, costs need to drop by more than half if CCS is going to have the impact that the ACT scenarios indicate.

Barriers

There are major R&D and demonstration gaps to be bridged over the next few years if CCS technologies are to be developed in time for their potential to be realised. Although many components of some capture options are proven technologies, demonstrating that they work in full-scale applications still remains a critical task. CCS technologies also face uncertainties regarding the retention in underground CO_2 storage and the legal aspects of such storage. The public acceptance of CCS remains an issue. The biggest obstacle is still high costs. A fossil fuel station fitted with CCS will be more costly than the same station without the additional CCS technology. As a consequence, CCS technologies require that credit is given for CO_2 reductions if they are to become commercially viable.

Overcoming Barriers

To develop CCS technologies, significant technology development and demonstration efforts are necessary, and must be accompanied by the *simultaneous,* rather than the sequential, development of legal, regulatory and policy frameworks, and by improved public awareness and acceptance.

At the same time, an appropriate environment must be put in place to encourage private sector involvement. On the capture side, the current activities of oil and gas companies are encouraging. The real challenge is the introduction of widespread CO_2 capture in power production, where the marginal costs are quite high. Investment costs for CO_2 capture from a single power plant are in the order of hundreds of millions of dollars. Even for a power company which owns several power plants, such additional investment poses a major financing challenge. Linkage of power plants and storage sites will imply the development of extensive CO_2 pipeline "backbones", to which capture plants and storage installations can be connected. On the storage side, the best sites and optimal storage approach need to be identified and storage retention needs to be assured.

The development new power production technologies are often a co-operative effort by the power generation sector, manufacturers of power plant technologies and the government. Public-private partnerships will be needed, as power producers need a clear indication that CO_2 emission reductions will be sufficiently rewarded over the life of their investment, which is in the order of decades not years. Governments will have to establish credible long-term policy goals that create the basis for investment in CCS.

Rapid advances in CO_2 capture technology could potentially unlock large CO_2 mitigation opportunities at relatively low costs. Power producers need reliable technology that is proven on a commercial scale. If appropriate investments are to be made from 2015-2020 and onwards, CCS technologies need to have been demonstrated on a commercial scale by this date.

This tight schedule may require that less efficient technologies be combined with CCS by 2015, instead of waiting for more advanced and less costly technologies. It may also require the construction of power plants by 2015 that are suited for retrofit a decade later (so-called "capture-ready" power plants).

Despite the risk of technical problems and higher costs than if demonstration plants were built and operated first, new power plants could be fitted with CO_2 capture technology now, if incentives were high enough. CO_2 storage technologies face more of a time delay, due to the need to demonstrate safety and security before large-scale implementation.

With CO_2 capture, governments must address the present shortage of sizeable demonstration projects in order to advance technological understanding, increase efficiency and drive down costs. This will require increasing RD&D and investment in early commercialisation of CCS and power plant technologies. By 2015 at least 10 major power plants fitted with capture technology should be operating. These plants would each cost between USD 500 million and USD 1 billion, of which half would be the additional cost for CCS.

Demonstration of the safety and integrity of CO_2 storage is a critical factor for development of this technology. A large amount of data gathered from demonstration projects will be needed to establish suitable legal and regulatory frameworks, to attract financing, and to gain public acceptance. Storage demonstration projects should fully utilise early opportunities created by enhanced oil recovery (EOR) projects and sources of cheap CO_2 from industrial processes and fuel processing.

Power Generation from Renewables

The potential of hydropower for electricity generation was recognised more than a century ago. The possibility of using other forms of renewable energy to produce electricity on a significant scale has only come to the fore in recent decades. New power generation technologies play a key role in this development. Using renewables to generate electricity has several advantages – a non-exhaustible energy source, potential for lower reliance on imported fossil fuels and no CO_2 emissions.[3]

3. Burning biomass does produce CO_2, but this has been previously absorbed by plants from the atmosphere. Biomass is therefore "carbon neutral", provided sufficient re-planting takes place. Methane emissions from hydropower reservoirs in the tropics should be accounted for. Other types of renewable power generation equipment may generate small amounts of CO_2 during the equipment production process. Various studies suggest that these emissions are of secondary importance.

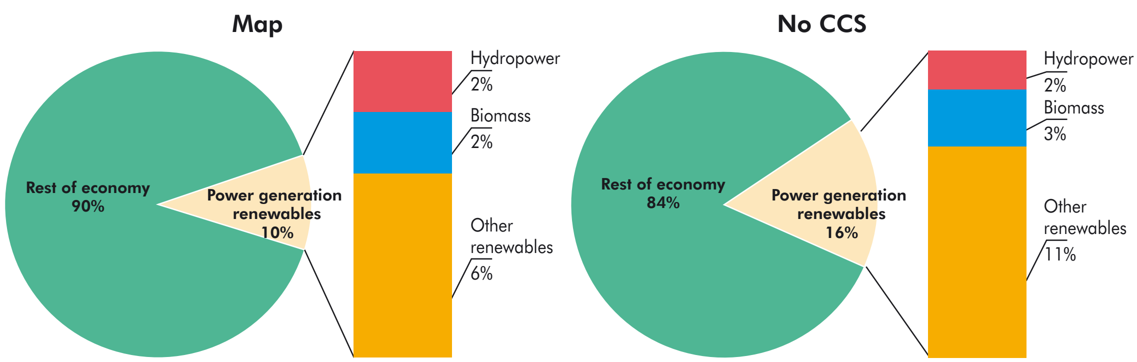
The deployment of renewables is a key element of any strategy to substantially reduce CO_2 emissions. The principal obstacle facing renewables' rapid expansion for electricity generation is their cost. While certain types of renewable electricity such as hydro, geothermal, biomass and wind are already cost-competitive at certain locations based on good quality or low-cost resources, other types of renewables cannot yet compete with bulk electricity generation in most parts of the world. These technologies are at different stages of maturity and proximity to economic viability, and they face different transition barriers, which may also vary by region. A significant share of the potential for expanding the existing low-cost options is already included in the Baseline Scenario.

Hydropower contributes about 2% of the reduction in CO_2 emissions in the ACT scenario. However, the major growth in renewables foreseen in the ACT scenarios comes from non-hydro renewables – wind, biomass, solar and geothermal. In the Map scenario, biomass accounts for around 2% of the CO_2 emission reductions and the other non-hydro renewables 6% (Figure 3.5). In the No CCS scenario, more biomass and other non-hydro renewables partly make up for the absence of CCS.

Table 3.3 shows the importance of various renewable power generation options in emission reductions and the contribution they can make over time. All except ocean energy play an important role by 2050. Hydropower already plays a key role in power generation and will continue to expand substantially. It contributes relatively little to emissions reductions below the Baseline Scenario, because there is already substantial growth in the Baseline Scenario and the potential for additional use in the ACT scenarios is therefore limited.

Biomass and wind can start to make a substantial contribution in the next decade, as many of the technology options for these two renewable sources are already cost competitive in many markets. Many renewable power generation technologies are based on a range of technologies that are adapted to local circumstances. While certain technologies may be ready for more widespread deployment, others will require more R&D. As a consequence, different stages in the pathway overlap in time (Figure 3.6). For example, geothermal from dry hot-rock sources requires more R&D, demonstration and deployment, while better quality geothermal resources are already in use and have been producing electricity for decades.

Figure 3.5 ► ***Share of renewable generation technologies in global CO_2 emission reductions relative to Baseline for ACT Map and ACT No CCS scenarios, 2050***



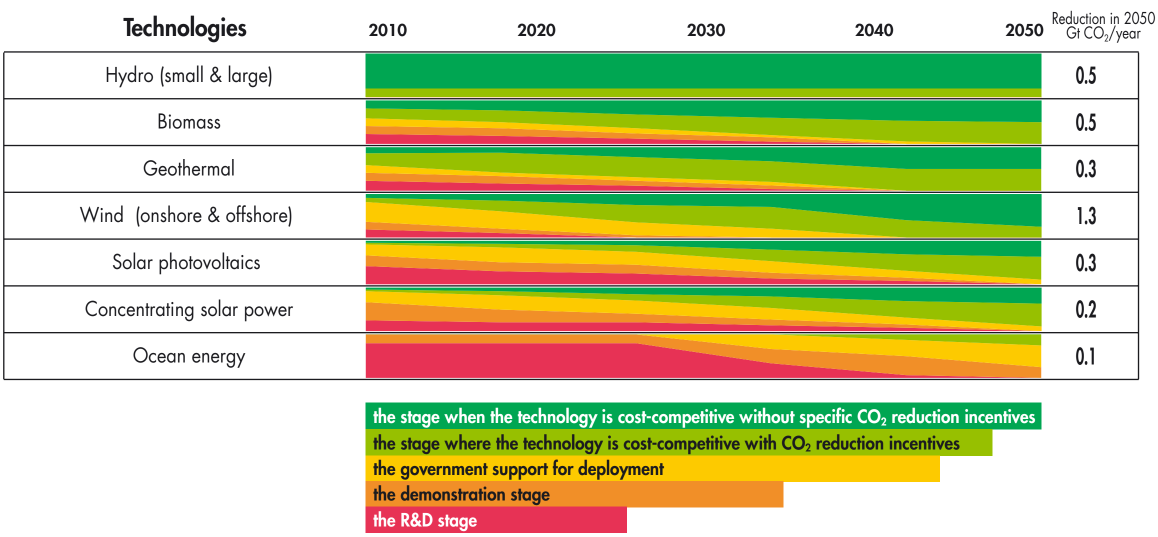
Total CO_2 emissions reduction: 32.1 Gt   **Total CO_2 emissions reduction: 28.3 Gt**

Table 3.3 ▶ **CO_2 emission reductions in the ACT scenarios below the Baseline due to renewable power generation technologies**

Technologies	2015	2030	2050	Gt CO_2/year
Hydro (small & large)	★	★★★	★★★	0.5
Biomass	★★	★★	★★★	0.5
Geothermal		★★	★★	0.3
Wind (onshore & offshore)	★★	★★★	★★★★	1.3
Solar photovoltaics		★	★★	0.3
Concentrating solar power		★	★★	0.2
Ocean energy			★★	0.1

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt). The CO_2 emission reduction in the last column refers to the Map scenario.

Figure 3.6 ▶ **Pathways towards cost-competitiveness for renewable power generation technologies**



Hydropower

Potential

The IEA estimates the world's total technical feasible hydro potential at 14 000 TWh/year, of which about 8 000 TWh/year is currently considered economic. At present about 808 GW of capacity is operating or under construction, with estimated average annual generation of around 7 080 TWh. Most of the remaining potential for development is in Africa, Asia and Latin America. Most of the economic hydropower potential is taken up by 2030 in the Baseline Scenario and thus limits the additional use in the ACT scenarios. So far, 5% of global hydropower potential has been exploited through small-scale sites. The technical potential of small hydropower worldwide is estimated at 150-200 GW.

Costs

Existing large hydropower plants are in many cases some of the lowest cost electricity generation sources in today's energy market, primarily because most plants were built many years ago and their costs have been fully amortised. For new large plants, generating costs are in the range of USD 0.03 - USD 0.04 per kWh. The costs of small hydropower (*i.e.* < 10MW) are estimated to be in the range of USD 0.02 to more than USD 0.10 per kWh, with the lowest costs occuring in favourable resource areas. Once the high up-front capital costs are written off, the plant can provide power at even lower cost, as such systems commonly operate without major replacement costs for 50 years or more.

Barriers

Much of the low-cost hydro resources have already been developed, especially in IEA countries, limiting the scope for further expansion. Environmental and social concerns are the major barriers to exploitation of the world's remaining hydro power potential. Increasing water demand for various uses can limit hydropower expansion and reduce the water available for existing plants. Construction of dams for large hydro schemes has significant environmental impacts and may involve relocation of large populations. Even smaller "run of the river" schemes are not without difficulty, *e.g.* with regard to the safe passage of fish. Remoteness from the grid can also be an issue for hydro plants, particularly small ones. There are some technological barriers related to the need to widen the range of head and flow that can be accommodated at reasonable costs.

Overcoming Barriers

Hydropower is a mature and commercially competitive technology. However, there is need for both public and industry R&D to improve designs and control systems and to help alleviate the environmental and social concerns. Optimising electricity generation from hydropower and incorporating this as part of integrated water-management systems will be increasingly needed. For small hydropower systems, recent design efforts have focused on the environmental integration into river systems in order to minimise environmental damage. The range of applications for this technology can be extended to make it suitable for application in rapidly expanding non-OECD markets.

There remain contentious issues that are not easily solved by technology fixes. The siting of storage dams raises very difficult issues, because new reservoirs may threaten the livelihoods or existence of whole communities. Expansion of large hydropower requires stable legal frameworks and a proper sharing of the burden and benefits of hydropower with local populations. Social acceptability also requires transparent decision processes. Upstream river valleys are often ecologically valuable and indispensable habitat for certain animals and plants. A careful trade-off of various environmental impacts will be needed.

Geothermal

Potential

Existing geothermal power plants are limited to geologically active areas producing steam or hot water from a natural reservoir at sufficient temperatures; this potential has been largely exploited. The potential of new geothermal technologies, such as hot dry rock, is huge and as yet untapped, but is also primarily concentrated in geologically active areas. In the ACT scenarios, the share of geothermal in the global power generation mix ranges from 2 to 3% in 2050.

Costs

The costs of geothermal power plants have dropped substantially from the systems built in the 1970s. Generation costs at current plants in the United States are as low as USD 0.015 to USD 0.025 per kWh. Based on the analysis in this study it is estimated that new geothermal plants can deliver power at USD 0.03-USD 0.08 per kWh in the coming decades, depending on the quality of the resource. Up-front investment for resource exploration and plant construction make up a large share of overall costs. Drilling costs alone can account for as much as one-third to a half of the total cost of a geothermal project. Generation costs per kWh for hot dry rock systems in Europe are currently in the range of USD 0.20-0.30 per kWh.

Barriers

Major challenges to expanding geothermal energy include long project development times and the risk and costs of exploratory and production drilling. The project risks are high, because of the uncertainty of developing reservoirs which can sustain long-term fluid and heat flow. Saline fluids and escaping fluids from some aquifers present environmental hazards.

Overcoming Barriers

High financial risks can be offset by government policies to underwrite or share the risks at both the reservoir-assessment and drilling stages, as is done in some countries that are developing geothermal resources today.

Near-term R&D efforts are focused on ways to enhance the productivity of geothermal reservoirs and to use more marginal areas, such as reservoir rocks that contain ample heat, but are insufficiently permeable to water. R&D for new approaches, for improving conventional approaches and for producing smaller modular units will allow economies of scale in the manufacturing process.

Hot dry rock geothermal systems are at an early stage of research and there are still significant technical and cost problems to be overcome. This requires further government-funded research and close collaboration with industry if the technology is to fulfil its promise and contribute to electricity generation as foreseen by the ACT scenarios. Geothermal generation can benefit from technology developments in oil and gas production, such as horizontal wells, expandable solid tube technology, rock fracturing and improved seismic technology.

Bioenergy

Potential

While biomass (*e.g.* wood, wood waste, dung, bagasse, black liquor etc) use increases in absolute terms, its share declines in the Baseline scenario from 9% today to 7% in 2050. In the ACT scenarios, new bioenergy technologies increase the share of bioenergy in the global supply to 15%. For electricity, the market share in 2050 is 2% in the Baseline Scenario rising to 3.0 to 6.5% in the ACT scenarios. This contribution is important, but small compared to the total global biomass potential.

Electricity production from biomass based on steam cycles is a well-established technology. Biomass is a fuel with similar characteristics as coal, so the same technologies can be applied. An important option is co-firing biomass in coal-fired power plants. After minor modifications, biomass can substitute up to 10% of total energy input in a coal-fired power plant. This can be considered a proven technology. However, biomass grinding and pollutants require more attention, as they may affect plant operation. New technologies such as biomass integrated gasifier/gas turbine (BIG/GT) and IGCC are being developed, but are still costly and the uptake has been slow. IGCC is now being developed for black liquor, a biomass by-product of chemical pulp production. In addition to these large-scale applications, small-scale biomass cogeneration technologies have important potential. Biomass can be an important fuel in district heating systems in regions where sufficient resources are available at low cost.

Costs

Additional investments for co-firing biomass with coal are between USD 50 to USD 250 per kW_e. The power generation cost ranges from USD 0.02 per kWh if the biomass is free, to USD 0.05 per kWh for biomass that is available at USD 3/GJ. Biomass combustion for heat and the cogeneration of heat and power is a commercial technology in the district heating systems of northern Europe. Electricity from such cogeneration is sold at competitive prices on the electricity spot markets, *i.e.* around USD 0.04 per kWh. The overall production cost depends on the value of the heat produced. The electricity production costs are typically USD 0.10 to USD 0.13 per kWh for innovative technologies and a delivered biomass price of USD 3/GJ, with costs declining depending on the value of the heat sold and if lower cost biomass is available. The potential for cost reductions are limited by the potential to collect sufficient amounts of biomass for large-scale plants without increasing the delivered biomass cost beyond the benefits of larger economies-of-scale.

Barriers

Conventional biomass technologies can be economically competitive, but may still require deployment support to overcome perceived drawbacks and gain public acceptance. In particular, energy from burning municipal waste can face problems with public perceptions about emissions, especially of dioxins, and the concern that incineration of waste may be an "easy option" that will detract from efforts on waste minimisation and recycling that lie at the heart of most national waste management strategies. The primary barrier to the increased use of biomass on a larger scale is the cost of the systems required for dedicated feedstock production, harvesting, and transportation, as well as for fuel conversion technologies.

The availability of sufficient amounts of low-cost feedstocks is an issue. Biomass collection systems, new fast growing crops and biorefineries that maximise the economic yield of biomass products including electricity production from residues need further development.

Overcoming Barriers

For other renewables, their development can be understood as pathways for individual technologies, but the development of biomass-based energy requires consideration of the pathway for the entire *system* of biomass production, transportation and power generation.

Most of today's biomass plants rely on residues from forestry, agriculture and industry, and municipal waste. Although there are still untapped resources, major feedstock expansion will require dedicated energy crops, which can also provide new economic opportunities for farmers and forestry owners. There can be a "chicken-and-egg" problem if farmers are reluctant to plant energy crops without an established market, while investors are wary about financing biomass power stations without a secure fuel supply chain. The costs of biomass transportation imply that any market will be local. This requires a new type of business structure than the power generation sector is used to.

Biomass integrated gasifier/gas turbine (BIG/GT) systems are still in the RD&D phase. There are encouraging developments in IGCC technology for coal, black liquor and bagasse that may help to reduce the cost of BIG/GT using dedicated energy crops. A lack of economies of scale implies that this technology will always be more expensive than large-scale IGCC. The bio-refinery concept for biomass feedstocks has the potential to meet a significant proportion of energy demand in the future and may allow lower cost electricity production. R&D efforts are focusing on reducing the costs of dedicated plantations, ways of mitigating the potential environmental impacts of bio-refineries and creating an integrated bioenergy industry, thereby linking bioenergy resources with the production of a variety of energy and material products.

Wind energy

Potential

National deployment programmes have increased the wind power capacity in IEA countries from 2.4 GW in 1990 to 28.1 GW in 2002, amounting to a 23% annual average growth rate. Of these, 600 MW is off-shore, all in Europe. In the ACT scenarios, wind power produces 4 to 10% of all electricity in 2050, second only to hydropower among the renewable energy technologies. In the Baseline Scenario the share of wind power in total electricity production is only 2%, reflecting the sensitivity of generation costs to technology learning advances that government-accelerated deployment policies help accelerate.

Costs

The average price for large, modern on-shore wind farms is about USD 1 000/kW electrical power installed. Off-shore installations can be between 35 and 100% more expensive. Any potential costs for grid integration and back-up capacity are not included in these estimates. Production costs at the very best on-shore sites have dropped to USD 0.03 to 0.04/kWh. Lower average wind speeds increase electricity costs. Taking into account differences in sites, capital costs and wind speed ranges results in a very high variation in the cost of wind in different countries and locations, from between just USD 0.03/kWh through to USD 0.20/kWh. In most markets wind is not competitive today, but it is helped by favourable feed-in tariffs. Technology learning will further reduce costs, but CO_2 reduction incentives help bridge the gap between fossil-fuelled power plants and wind.

Barriers

The costs of electricity from wind have to be further reduced to make wind power cost competitive in most regions. As costs approach competitive levels, other factors such as public acceptability of wind farms, intermittency and the impact on grid stability, pose other limiting factors for increased market penetration by wind energy.

Overcoming Barriers

The various deployment policies used to promote wind energy over the last three decades have been largely successful. They have led to a dramatic reduction in costs, advances in the size and reliability of turbines, and raised public awareness of renewables. The 23% annual growth rate since 1990 is remarkable. Indeed it is this very expansion that has brought forward new obstacles. Intermittency and power quality are not serious issues when wind forms only a small part of the total generating capacity of the system. The rapid expansion and technical advances has meant that wind farms now use much bigger turbines and are inevitably more visually intrusive, and this has in some cases resulted in problems with public acceptance.

Going offshore may alleviate concerns about despoiling the landscape, and since the wind regime is more stable, reduces intermittency problems. There is a considerable additional cost, both in the turbines (which must withstand more hostile environments), higher foundation and installation costs, and additional expenditure to transmit the electricity back to land and connection to the grid. This option is limited to coastal areas with favourable wind regimes, such as the North Sea.

Part of the solution to intermittency and grid stability may lie with the development of more sophisticated grid management systems, demand-side management systems and electricity storage systems, for example underground compressed air storage, rather than with wind turbines themselves. Systems with significant hydro components can also help reduce some of these problems, by allowing reduced water draw from reservoirs when wind generation is available.

Solar

Potential

Solar photovoltaic (PV) is a modular technology that can be used for centralised as well as decentralised production of electricity. It is already commercial in certain niche markets such as off-grid applications in remote areas. The potential is huge, but unless there is a technological break-through it is not expected to become ready for mass deployment before 2030.

Concentrating solar power (CSP) utilises direct normal insolation, so the optimal region for this technology is the "sun belt" on either side of the equator. This technology has particular relevance to arid regions in southern Europe, Africa, the Middle East, western India, western Australia, the Andean Plateau, north-eastern Brazil, northern Mexico and the south-west United States. Except for in some niche markets, CSP is closer to mass market deployment than solar PV.

In the ACT scenarios, the total share of solar electricity production ranges from 1 to 2% by 2050, but reaches 3% in the TECH Plus scenario.

Costs

At the end of the 1960s, a solar PV module cost about USD 100 000 per kilowatt peak production capacity (kWp). Today, the price of a solar module is between USD 2000 and USD 3000 per kWp. In grid applications, the cost of the balance of system (BOS), *i.e.* mountings, converters and electrical connections, is the same as for the PV module. The cost of electricity depends on the level of insolation. For example, in the Mediterranean area solar PV electricity can be produced at a cost of between USD 0.35 and USD 0.45 per kWh. The cost of concentrating solar power generated with up-to-date technology at superior locations is between USD 0.10 and USD 0.15 per kWh. Industry goals are to reduce the cost of CSP systems to between USD 0.05 and USD 0.08 per kWh within 10 years and below USD 0.05 in the long term, but such objectives can only be reached with additional R&D efforts.

Barriers

The principal barrier for solar technologies is cost. R&D efforts will be needed to bring the cost down to competitive levels. For solar thermal, large-scale deployment is needed to reduce costs through technology learning. As solar is an intermittent energy source, the integration within the electricity supply system requires attention if large amounts of solar PV are introduced. CSP plants offer guaranteed electricity supply due to fossil fuel back-up or heat storage at low additional costs.

Overcoming Barriers

New types of solar generation PV panels are under development such as thin-film on glass technology. These new technologies can reduce the module cost substantially. The goal is to bring the cost down to less than USD 500/kWp. The cost for PV modules is about the same as for all other needed system components together. Cost reductions for other system components are therefore as important as for the modules. In order to reach markets for mass deployment, total investment costs for grid-connected PV-systems must come down to USD 1000/kWp. At the learning rates seen so far, and with deployment rates growing at 15% per year, solar PV will not reach this level until 2030 or later. The learning investments that are required to reach this goal are very large, in the order of USD 100 billion, and are much larger than for any of the previously described renewables technologies. This argues for furthering R&D efforts and concerted action among governments on deployment policies.

The huge market potential for mass deployment and the strong evidence that technology development for PV reacts predictably to stimulation by deployment incentives may justify such large investments. The existence of niche markets which place a higher value on PV technology means that much of the learning investments will be funded by the market, limiting the need for government support.

Solar PV poses several challenges for government deployment policies, which must be credible and stable over a long time horizon, as well as stimulate niche markets and learning investments from industry and the private sector. The long time horizon and the large learning investments make the international aspect more important. Presently, most of the deployment is happening in Japan, Germany and the United States. It is unlikely that a single country or small group of countries can carry PV systems to mass global deployment. There is evidence to suggest that uncoordinated deployment incentives may over-stimulate the market, unnecessarily increasing costs and learning investments.

Concentrating solar power is ready for deployment in two of its three alternatives: parabolic trough and power towers, while parabolic dishes still need more R&D efforts. The costs are still too high, so the development of appropriate deployment support policies is a critical issue for the future of solar thermal-power plants. Spain has shown one way forward by introducing a feed-in tariff for electricity from CSP. Systems that integrate CSP with fossil-fuelled steam cycles may play a role at an earlier stage. CSP and PV are especially attractive in regions where the electricity demand peak is linked to summer day air-conditioning demand.

Ocean Energy

Potential

Proposed technologies use different types of ocean energy, like waves, tides, marine currents, thermal energy and salinity gradients. Some, like waves, have a wide applicability and large potential whilst for others such as tidal currents, the potential is limited by available sites. In the ACT scenarios, ocean energy technologies have only marginal importance in the period up to 2050.

Costs

Certain tidal barrage energy systems have been operating economically for decades. The number of sites for such systems is limited and their environmental impact is controversial. New systems based on different technology concepts are still in a R&D stage and it is premature to provide production costs. The cost will vary widely, depending on the resource quality, and grid connection must be added to the production cost.

Barriers

Cost, technology and financial risks are important barriers. The risk is augmented by the fact that even pilot projects need to be relatively large-scale to withstand rough off-shore conditions. The prospects for tidal barrages are good in certain locations, but site-specific environmental impacts need careful assessment.

Overcoming Barriers

Ocean energy is still at the R&D stage but one which has received relatively little R&D funding over the last twenty years. This position seems to be changing with interest growing in several countries, as evidenced by the establishment of the IEA Ocean

Energy Implementing Agreement. Several concepts are envisaging full-scale demonstration prototypes around the British coast.

Ocean energy technologies must solve two major problems concurrently: proving the energy conversion potential and overcoming a very high technical risk from a harsh environment. Currently, wave energy and marine (tidal) current energy are the two main areas under development and they will probably be the focus of future research and development in the sector. The IEA Ocean Energy Systems Implementing Agreement is developing projects expected to be operational in 2007. These projects are expected to require support to allay costs of at least USD 300 per MWh.

Nuclear Power Generation

In the ACT and TECH Plus scenarios, nuclear power accounts for between 10 and 22 % of electricity generation in 2050. This represents a 20 to 165% increase from present production levels. The lower share occurs in the Low Nuclear scenario, while it reaches the high of 22% in the TECH Plus scenario. As all plants that are in use today will reach their end of life before 2050, these figures imply a massive re-investment programme.

Nuclear energy is a CO_2-free power generation source that has the potential to make a significant contribution to CO_2 emissions reductions if it can successfully resolve public acceptance issues. In the Map scenario, nuclear contributes around 6% of the total emissions reductions below the Baseline Scenario in 2050 and 10% in the No CCS scenario (Figure 3.7).

Table 3.4 indicates that nuclear power generation plays a key role in CO_2 emission reductions by 2050. Certain generation II and III technologies are ready for mass deployment. Other generation III+ and generation IV technologies will require demonstration, a slow process that may mean they are not ready for commercial deployment for 2-3 decades. Generation IV technologies will only contribute substantially from 2030 onward, while Generation II and Generation III and III+ can make a contribution before that (Figure 3.8). All nuclear technologies will benefit

Figure 3.7 ▶ ***Share of nuclear power generation in global CO_2 emission reductions relative to Baseline for ACT Map and ACT No CCS scenarios, 2050***

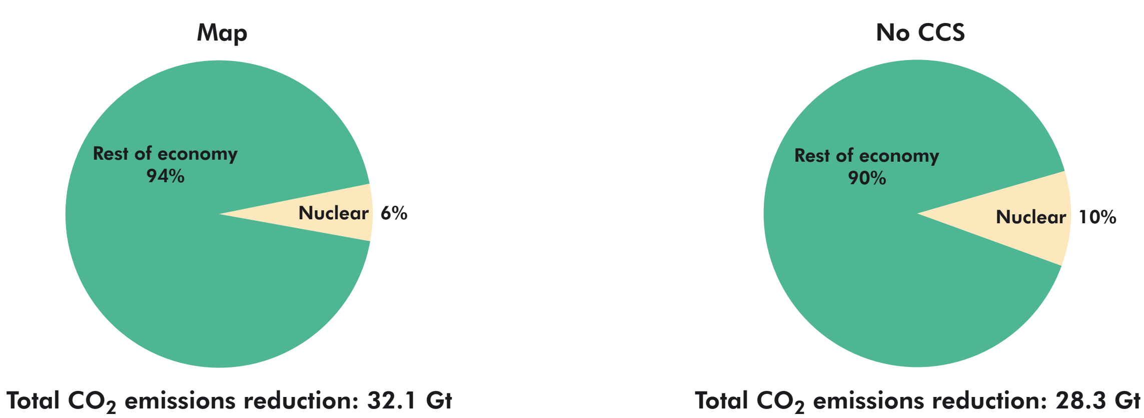
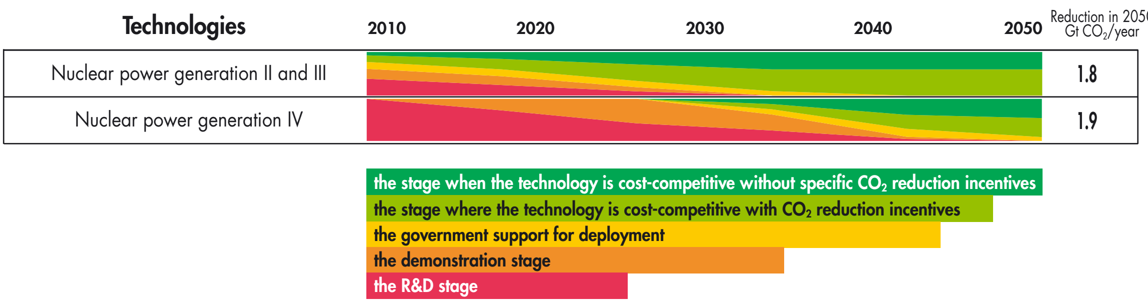


Table 3.4 ▶ **CO_2 emission reductions in the ACT and TECH Plus scenarios below the Baseline due to nuclear power generation technologies**

Technologies	2015	2030	2050	Gt CO_2/year
Nuclear power generation II and III	★★	★★★	★★★★	1.8
Nuclear power generation IV		★★	★★★★	1.9

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO_2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt). The CO_2 emission reduction in the last column refers to the Map scenario for generation II and III and the TECH Plus scenario for Generation IV.

Figure 3.8 ▶ ***Pathways towards cost-competitiveness for nuclear power generation technologies***



from more R&D and demonstration in the field of waste treatment, decommissioning and new more efficient fuel cycles. Thorium reactors and fast breeders may be needed in the long-term if uranium reserves are not to be a constraint on expansion.

Nuclear power generation is virtually free of greenhouse gas emissions and is suitable for large-scale centralised power stations that lie at the heart of most electricity grids. Yet in spite of its benefits, the share of the world's electricity coming from nuclear generation has remained static at around 16% for many years and only 30 countries worldwide deploy this option. Nuclear energy has attracted increasing attention in recent years given its CO_2 emission benefits. Some countries, however, have adopted a policy of not developing nuclear.

Nuclear fission technologies are generally classified into four generations. The first generation were mainly prototypes that are now coming to the end of their life and have been or are about to be decommissioned. Generation II and III are in commercial operation today. Generation III+ are reactors that can be applied by 2010 and Generation IV is foreseen to be commercial by 2030. Generation III and III+ are reactors that are candidates for near-term deployment.

Nuclear fission: Generation III and Generation III+

Potential

Generation III reactors include the advanced boiling water reactor (ABWR) and the advanced pressurised water reactor (APWR). These reactors have been built and are in operation. The French and Finnish programmes focus on the European pressurized water reactor (EPR). Generation III+ include the pebble bed modular reactor (PBMR) and the AP1000. Both have passive safety features. The PBMR is gas-cooled and can be built in small, modular units of 100-200 MW. A demonstration is planned in South Africa for 2011, with commercialisation from 2015. The AP1000 design, a third-generation light water reactor, is currently under consideration for use in China. It is an upscale version of the proven AP600 design. It is likely that a number of reactor designs will co-exist.

Costs

Estimates suggest that the overnight (*e.g.* the cost without interest during construction) investment cost for Generation III+ may drop below USD 1 500/kW. At a 10% discount rate the levelised cost of electricity ranges from USD 47-62 per MWh with a five-year construction period, which is about USD 5-20 per MWh above that of coal or gas-fired power plants in most world regions. Serial production may enable further cost reductions. The technology is already competitive in Japan and Korea due to the higher fossil fuel prices in these regions. A CO_2 reduction incentive could close the gap in other world regions.

Barriers

Although each generation represents an improvement over its predecessor, nuclear fission technologies continue to face barriers, namely:

- Public acceptance problems related to nuclear weapons proliferation, waste management and safety issues.
- Investment costs based on current technology (including working capital during construction period, waste treatment and decommissioning) are high.
- New reactor types with potentially lower unit capacity cost need to be proven on a commercial scale, a process that takes decades. Larger reactors reduce investment cost per unit of capacity, but increase project investment costs. Certain new reactor designs are of a smaller unit size.
- Rapid expansion (more than a doubling of capacity over more than 50 years) will put pressure on uranium reserves and may encourage the use of thorium or fast breeder reactors in the long term, which will create new technology challenges.

The degree to which nuclear technologies can overcome these barriers will determine the extent to which nuclear can contribute to the energy mix of the future and how much it will contribute to reduced CO_2 emissions. Some governments have taken policy decisions not to employ, or to phase out, nuclear power.

Overcoming Barriers

Continued technology development (see Generation IV reactors below) and demonstration programmes could help overcoming the barriers facing nuclear generation, of which the most important is public acceptance. Nuclear investment would also benefit from predictable long term CO_2 emission reduction incentives.

Nuclear Fission: Generation IV

Potential

Generation IV reactors are not expected to be available until around 2030 but could, as demonstrated in the TECH Plus scenario, provide up to 1.9 Gt of CO_2 emissions reduction by 2050.

Costs

The costs are as yet unknown, but the ambition of the Generation IV reactors is to develop a future generation of nuclear energy systems that will provide competitively priced and reliable energy products.

Barriers

Generation IV faces the same barriers as other nuclear technologies, namely costs, safety, waste disposal and proliferation. This is recognised by the Generation IV International Forum and its 11 members (Argentina, Brazil, Canada, Euratom, France, Japan, Korea, South Africa, Switzerland, the United Kingdom and the United States), and it is the intention to address all these issues in their development programme.

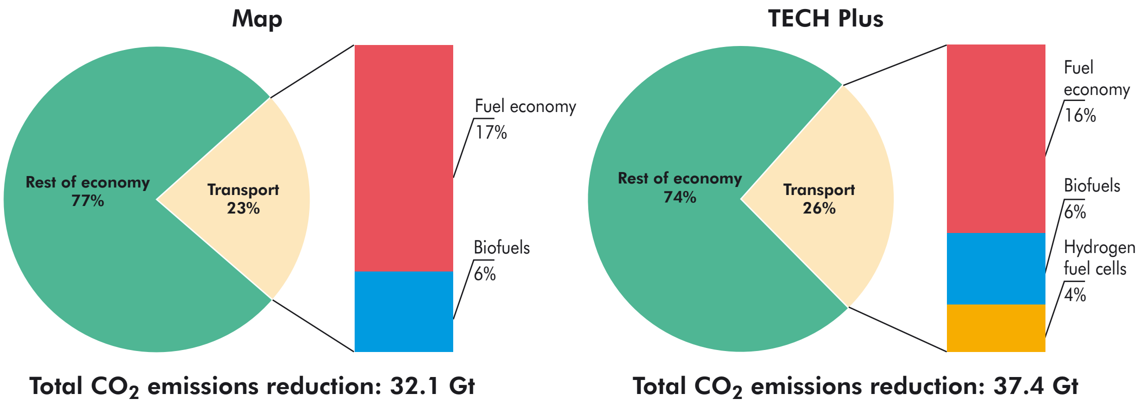
Overcoming Barriers

The commitment of the Generation IV International Forum to address the well known barriers to the deployment of nuclear power offers the best potential that these obstacles can be removed, or lowered, and thus for allowing Generation IV reactors to play their part in emission reductions after 2030.

Transport

Transport vehicle technologies and fuels contribute 23% of total emission reduction in the Map scenario and 26% in the TECH Plus scenario (Figure 3.9). In the Map scenario improved fuel economy from increased use of hybrids and from improvements in engine and non-engine components contribute a little more than two-thirds of the transport savings. The rest is from biofuels including biodiesel, grain and sugar-based bioethanol and lignocellulosic ethanol. In the TECH Plus scenario, the overall contribution from biofuels increases due to higher penetration of lignocellulosic ethanol, although its share of CO_2 emission reductions remains the same. In this scenario hydrogen fuelled fuel-cell vehicles contribute 4% of the total global emission reduction. The total reduction attributable to hydrogen fuel cell vehicles comes from both using CO_2-free hydrogen as a fuel and through the high efficiencies fuel-cell vehicles offer relative to other vehicle alternatives. Fuel cell vehicles have about 30% of the global market share by 2050 and this limits the total fuel economy improvement for other vehicles. This explains the slightly lower share for fuel economy improvements in TECH Plus relative to Map. These figures do not take into account any possible modal switches induced by the CO_2 emissions reduction incentives.

Figure 3.9 ▶ ***Share of road transport in global CO_2 emission reductions relative to Baseline in the Map and TECH Plus scenarios, 2050***



The contribution to emission reductions from each technology by 2015, 2030 and 2050 is shown in Table 3.5. By 2015 options to improve the fuel economy of internal combustion engines (variable valve control, direct injection and improved combustion technologies) and non-engine fuel saving measures (increased use of

Table 3.5 ▶ ***CO_2 emission reductions in the Map and TECH Plus scenarios below the Baseline due to transport technologies***

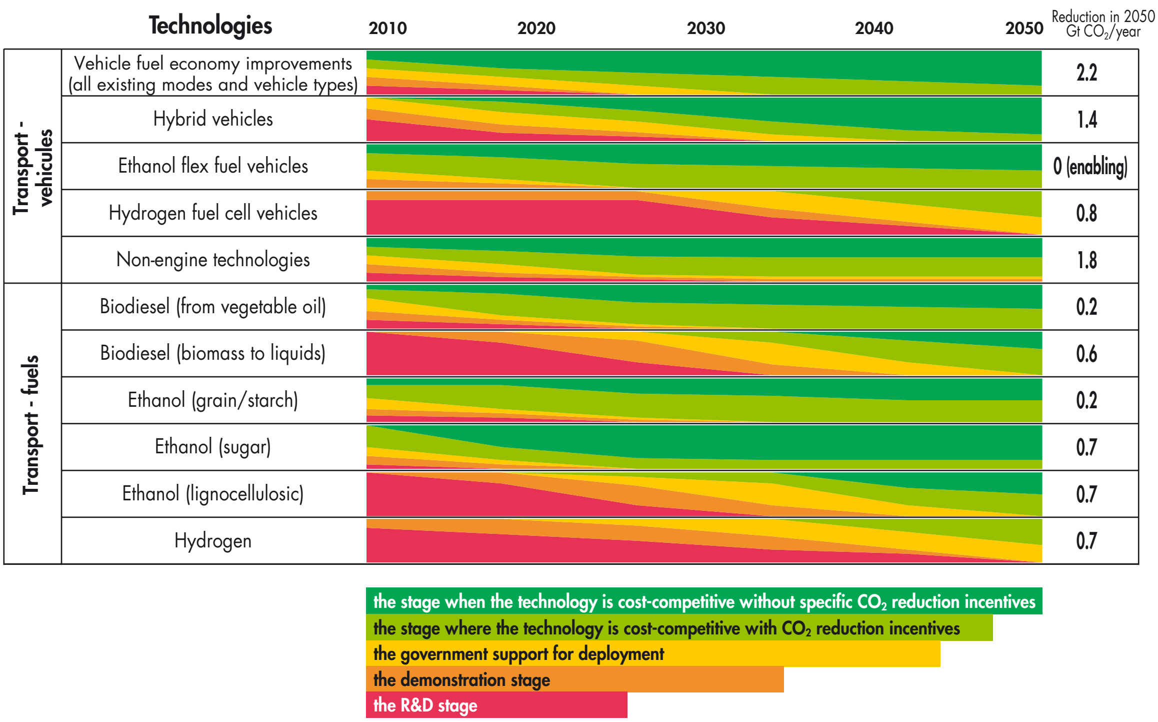
	Technologies	2015	2030	2050	Gt CO_2/year
Transport – vehicles	Vehicle fuel economy improvements (all existing modes and vehicle types)	★★	★★★★	★★★★	2.2
	Hybrid vehicles	★★	★★★	★★★★	1.4
	Ethanol flex fuel vehicles				0 (enabling)
	Hydrogen fuel cell vehicles		★	★★★	0.8
	Non-engine technologies	★★	★★★	★★★★	1.8
Transport - fuels	Biodiesel (from vegetable oil)	★	★★	★★	0.2
	Biodiesel (biomass to liquids)		★	★★★	0.6
	Ethanol (grain/starch)	★	★★	★★	0.2
	Ethanol (sugar)	★★	★★★	★★★	0.7
	Ethanol (lignocellulosic)		★★	★★★	0.7
	Hydrogen		★	★★★	0.7

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO_2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt).The CO_2 emission reduction in the last column refers to the Map scenario, expect for lignocellusic ethanol, hydrogen and fuel cells, which are based on the TECH Plus scenario.

energy-efficient tyres, lighter materials and more efficient air conditioners and lighting) dominate. By 2030, increased use of hybrid powertrains and biofuels start to have a significant impact. In the long-run, further improvement of the technologies in these two categories plays a key role in reducing emissions.

The different relative contributions the various technologies make over time reflect the different barriers facing each technology. Significant R&D efforts are needed to improve performance and reduce costs for fuel cell vehicles and the production of hydrogen and lignocellulosic ethanol before these technologies can make a significant impact (Figure 3.10). On the other hand, many options to improve fuel economy are available today and they can thus make a difference in the short run with the right policy incentives. The following sections discuss the barriers facing the more widespread use of each technology and fuel category and how they can be overcome.

Figure 3.10 ▶ Pathways towards cost-competitiveness for transport technologies



Incremental Improvements in the Fuel-economy of Vehicles (Engine and Non-engine Components)

Potential

This is a category of technologies rather than a single technology. It includes improvements in the efficiency of such engine components as the transmission and drive train. It also includes reducing the vehicle's weight and improving its aerodynamics, as well as increasing the efficiency of such auxiliary systems as air conditioners and tyres.

Costs

The costs of these improvements vary, but many of them already result in lower life-cycle costs. It is also possible that the wider deployment of these improvements will lead to cost reductions that expand the range of fuel reduction options that are cost-effective without the CO_2 reduction incentives.

Barriers

Consumers can buy more efficient vehicles, but they tend to buy cars on the basis of many factors, of which fuel economy is just one of them, and is seldom the most important one. There is little attention to potential fuel savings from the majority of customers, who tend to account only for the savings occurring over the first three to four years of the vehicle's life.

Although substantial efforts have been made to improve fuel efficiency, the engine improvements have generally been offset by larger, more powerful vehicles and by adding energy-consuming features such as climate control systems. The increasing market share of vehicles like SUVs, especially in North America and to a growing extent in Europe, is underpinning this trend. The global nature of the automotive industry means that co-ordinated international efforts to improve fuel efficiency could be more effective than a unilateral approach, but this approach is likely to be more difficult and time consuming.

Overcoming Barriers

Voluntary measures and regulatory mechanisms aim to improve fuel efficiency, and they can be combined, but they do not deliver the same results. Regulation is a sharper tool. Voluntary agreements commit auto-makers to deliver vehicles that meet specific efficiency standards, but the auto-makers do not generally face sanctions if they fail to fulfil the agreement. Regulatory standards, on the other hand, require auto-makers to meet specific efficiency standards by a certain date, and they do face sanctions if they fail to conform. Minimum performance targets, which are raised when technology improves, are already in use in some countries. Another possible option could be to include CO_2 emissions from vehicles in emission trading schemes, where they exist, either with an "upstream" regime that rest on the carbon content of the fuel, or with a regime that would assign responsibility to auto-makers for the emissions of all cars sold (IEA, 2005).

Auxiliary energy use is usually not included in the test drive cycles and therefore not reported in fuel efficiency estimates. Consideration of such auxiliary use in the test cycles would create an incentive for better fuel efficiency.

Incentives like labelling schemes, tax reductions (for efficient vehicles) or tax increases (for fuels or inefficient vehicles) and improved information would encourage the public to purchase more efficient vehicles with lower emissions, and send signals to the auto manufacturers to develop them.

Hybrid Vehicles

Potential

Full hybrid vehicles are currently about 25 to 30% more efficient than conventional gasoline vehicles in urban drive cycles. So-called "mild" and "light" hybrid vehicles are less efficient, but they still offer efficiency improvements of 5 to 20%. Hybrids save the most fuel in urban driving situations and are expected to gain a large share of the medium freight- truck and bus market by 2050. Although hybrid technology can be used in any vehicle, from cars to large trucks and buses, its benefits are lowest for long-haul, heavy-duty diesel trucks.

Costs

Full-hybrid gasoline vehicles are estimated to cost about USD 3 000 more than conventional gasoline light-duty vehicles, but this difference is expected to narrow over time, especially if the cost of the batteries is reduced. Mild hybrid vehicles cost an additional USD 2 000 and light hybrids cost USD 500-1 000, respectively. Hybrids could also be combined with diesel engines to achieve even higher efficiencies, but this would require additional investments. At this stage, diesel hybrids do not appear set to penetrate the market on a large scale before 2015, although there is some upside potential.

Barriers

High costs are the most important barrier to the uptake of hybrid vehicles. The long-term development of the cost of hybrid drive systems are uncertain and will depend primarily on the evolution of battery technology.

Hybrid vehicles are currently only available in a few models with gasoline engines. They have not, to date, reached the point of full mass market deployment. Full mass deployment and the critical mass it might generate, will require a wide range of hybrids in all vehicle classes.

Overcoming Barriers

R&D is still needed to improve performance and lower costs, but the main focus should be on promoting deployment in order to reduce costs via technology learning and to build consumer demand. If full hybrid vehicles are going to come into widespread use, they will initially need a financial subsidy that partially covers their incremental cost. The cost differential for "light" hybrid solutions (*e.g.* where only the starter motor is hybridised) is lower. Even if light hybrids offer lower fuel efficiency improvements, they can be more suitable for mid-size and small vehicles.

Minimising the incremental cost of hybrids, in order to ensure a rapid uptake, may necessitate that "light" hybrid solutions are used where the incremental cost would otherwise be prohibitive. This would also allow lower levels of subsidies or fee-bates to have a greater impact. In the longer term, the incremental price of hybrid vehicles is expected to decline with technology learning. Policy measures could then focus on advanced hybrid solutions, including plug-in hybrids

An important consideration is that hybrid systems will not necessarily improve a vehicles fuel economy if the hybrid systems are used to power more energy hungry auxiliary vehicle systems or to boost a vehicle's power. At the present time, hybrids have been promoted on the basis of their better fuel economy, but new hybrid models have superior performance than their non-hybrid equivalents and much of the potential fuel economy improvement can be lost. Incentives for the uptake of hybrids will therefore have to be carefully designed so that they reward only hybrids that offer fuel efficiency improvements in their class.

Grain and Sugar-based Ethanol

Potential

The CO_2 emissions profile of ethanol production depends heavily on the type of feedstock used and the production process. CO_2 emissions can be reduced by as much as 90% with the use of ethanol from sugar cane. Sugar cane ethanol is widely used in Brazil. Estimates of CO_2 emissions from grain-based ethanol vary widely. A recent study (Farrel *et al.*, 2006) gives a greenhouse gas emission reduction potential of 13% as the "best point estimate" for US production, while one litre of grain-based ethanol displaces 0.95 lires of oil consumption (these values depend on location and on the energy sources used in the ethanol production plant).

Costs

Ethanol production costs vary by region, depending on the type of feedstock and the conversion technology, as well as on biomass yields, land costs, labour costs and the availability of capital. Sugar-cane ethanol produced in Brazil costs about USD 0.30 per litre of gasoline equivalent. Corn-based ethanol produced in the United States costs around USD 0.60 per litre, and European ethanol based on wheat costs about USD 0.70-0.75 per litre of gasoline equivalent. The production costs depend on the feedstock costs, which are driven by production volume and competing food needs. The widespread use of ethanol derived from food crops may result in rising food prices worldwide.

Barriers

The supply of grain or sugar cane is limited by the amount of available agricultural land and by competing uses. Some regions are well endowed with biomass, but others are not. The ethanol market today is characterised by a regionalised structure. While ethanol ocean transport costs less than USD 0.02-0.03 per litre, import tariffs exceed USD 0.10 per litre in many countries. The development of an international ethanol fuel market would require the reduction of the trade barriers. Such a market would create opportunities for sugar cane producers in developing countries like Brazil, India, Thailand and other tropical countries where it would be an incentive for the development of an export industry.

Transportation of biomass crops presents logistical barriers that may be difficult to overcome and may limit the maximum size of conversion facilities, thereby limiting the potential for cost reductions due to economies of scale.

The production of biofuels on a massive scale may be a cause of deforestation and release of soil carbon, if pastureland or forest land is used for production. Such issues must be considered when the benefits of ethanol from food crops are evaluated and measures should be designed to minimse the overall life-cycle emissions.

While small amounts of ethanol can be mixed with gasoline, a high ethanol share would require dedicated infrastructure and widespread introduction of flex-fuel vehicles.

Overcoming Barriers

A minimum share of biofuels, as in Brazil and Europe, can help to bring ethanol and other biofuels into the market. Fuel standards can mandate the replacement of methyl tertiary butyl ether (MTBE) with ethanol as a gasoline additive, or they can set minimum thresholds for the use of ethanol in the fuel. Such obligations would create a market for ethanol fuel. Fuel tax exemptions to spur demand for ethanol could be a valuable complement to production incentives.

Ethanol (Lignocellulosic)

Potential

Lignocellulosic ethanol has the potential to reduce CO_2 emissions by 70% or more compared to gasoline. Ethanol from cellulose also reduces the potential competition for the use of land between farmers and energy producers.

Costs

Lignocellulosic ethanol is estimated to cost slightly less than USD 1 per litre of gasoline equivalent, which is around twice the cost of petroleum gasoline at USD 60 per barrel. Costs would continue to come down with large-scale production, possibly reaching USD 0.45-50 per litre gasoline equivalent.

Barriers

Lignocellulosic ethanol faces a combination of technological and logistical challenges. Additional research and development is needed, particularly on the process of breaking feedstock material down into sugars and in the fermentation of five-carbon sugars. No large-scale plants are currently in operation, but there are eight demonstration plants with a capacity ranging from 1 to 40 million litres a year that are expected to come on-stream in 2006 and 2007. These pilot plants will only use the six-carbon sugar fraction; fully commercial plants will need to scale up by a factor of 5 to 10.

Large-scale plants will face some logistical challenges, as one of the disadvantages of the biomass feedstock is its dispersed nature. Cellulosic ethanol can be produced from a wide variety of feedstocks (corn stalks, bagasse, rice straw, grasses and wood, for example), but the question remains of how to harvest all of this biomass and deliver it to the ethanol plant at a reasonable cost. Corn stover and bagasse are early candidates, but as production expands, feedstock supply may become an issue.

Overcoming Barriers

The development of lignocellulosic ethanol requires that the range of feedstocks is expanded and the introduction of advanced conversion technologies (e.g. enzymatic hydrolysis of lignocellulosic feedstocks) and new yeasts and micro-organisms that can convert five-carbon sugars. A process system optimisation is needed where preparation, hydrolysis, fermentation, ethanol separation and residue treatment are jointly optimised. Co-production of ethanol, electricity and other products in a "biorefinery" concept may help to enhance the process economics.

If the technology is to move towards mass deployment, full-scale demonstration plants will have to be supported in the years to come. Effective policies should help manufacturers with the investment costs of new ethanol production units through investment tax credits, production tax credits or loan guarantees. These deployment incentives can be phased out as the technology matures.

Biodiesel

Potential

Conventional biodiesel (from vegetable oils and animal fats) could reduce CO_2 emissions by 40 to 60% over conventional diesel fuel. The actual benefit depends on several factors (*e.g.* crop yields, the use of fertilisers and the CO_2 displacement due to the production of other by-products). Conventional biodiesel production from oil crops such as rapeseed and soy uses three times as much land per unit of energy delivered as sugar crops for ethanol. The cropland requirements pose a significant barrier to the widespread use of biodiesel. However, Fischer-Tropsch (FT) synthesis of biodiesel could use wood as a feedstock and thus not face the same land use constraints.

Biodiesel can be used in conventional vehicles without any significant modifications. The low sulphur content of biodiesel gives it an advantage compared petroleum based diesel fuels.

Costs

Current biodiesel production costs (between USD 0.70 and USD 1.2 per litre of diesel equivalent) are well above those of petroleum diesel. Biodiesel from waste oil feedstocks from restaurants ("yellow grease") is almost competitive with petroleum diesel, but its production potential is limited. FT-biodiesel is currently not economic. Other technologies such as hydrothermal liquefaction are under development but currently still in the R&D stage.

Barriers

Cost is a major barrier for conventional biodiesel, together with its high land requirements. The conventional production process for biodiesel is well-established. The current production capacity is small, with two-thirds of production concentrated in Europe. Production of oil from soybeans and palm oil are environmentally controversial.

If 5% of diesel fuel used in the United States and Europe were to be replaced by biodiesel, it would use 60% of current US soy production and over 100% of EU oil-seed production. The limitations on feedstocks are such that biodiesel's use will probably be limited to conventional- diesel-biodiesel blends of 5%. Fischer-Tropsch biodiesel could increase the biodiesel production potential substantially due to the much higher yields per hectare.

The use of biodiesel requires no modifications in conventional vehicles that use it, and the low sulphur content of biodiesel favours it in an environment where clean fuels receive strong government support. The benefits of biodiesel blending for low sulphur diesel are such that biodiesel production from vegetable oil and animal grease in hydrocracking units attached to refineries has now reached the demonstration phase.

Overcoming Barriers

To overcome the limitations in feedstocks, research and development into biodiesel production using lignocellulosic feedstocks should be given priority.

The use of blends can be encouraged by schemes that require fuel suppliers to provide blends that contained a specified percentage of biodiesel. Tax breaks could also be granted to encourage blending. Given its low sulphur content, fuel standards targeting sulphur emissions may help increase the market penetration of biodiesel.

Hydrogen Fuel Cell Vehicles

Potential

Fuel cells vehicles would emit zero or close to zero CO_2 if they are fuelled by hydrogen produced from fossil fuels with CO_2 capture and storage, from nuclear power, or from renewable energy. Non-hydrogen powered fuel cells for transportation applications (powered by methanol, ethanol or gasoline) received a lot of attention a decade ago, but this attention has waned. Current attention is focused on hydrogen fuel cell vehicles.

Costs

Current fuel cells cost significantly more than their market competitors for both automotive and stationary applications. Among all fuel cell technologies, proton exchange membrane (PEM) fuel cells are particularly suited to powering passenger cars and buses, and have now been installed in demonstration vehicles. PEM fuel-cell drive systems cost more than USD 2 000/kW. Estimates indicate that if fuel cell cars were mass-produced (and hence were to benefit from technology learning), the cost of fuel cell drive systems could be reduced to USD 100/kW. This implies that the costs of the fuel cell stacks must fall below USD 50/kW to make them competitive with internal combustion engines. At this moment it is not yet clear if these cost targets can be met.

Per unit of energy, hydrogen is more expensive than gasoline. However, because of the high efficiency of fuel cell vehicles, the fuel costs are on par with or even lower than gasoline per kilometre driven.

Barriers

The most important barrier to the widespread introduction of hydrogen is the cost of fuel cell vehicles. Significant technological and economic challenges need to be overcome before fuel cell vehicles become viable for mass-production.

The performance of fuel cell vehicles will depend on progress in hydrogen storage, stack life and other factors. Major technical advances and significant cost reductions are necessary in all areas. Once the various technical issues have been resolved, fuel cell vehicles will still face competition from other options such as biofuels.

Before full-scale development of the hydrogen production and infrastructure begins, international quality and safety standards must be established for the use of hydrogen as a fuel. An appropriate on-board storage system must also be chosen, as it will have a particular impact on the characteristics of the refuelling infrastructure.

Overcoming Barriers

More R&D is needed in order to develop vehicle designs that can meet the economic and technical criteria. A stack cost of USD 50/kW for fuel cells poses a particular challenge. It is premature to develop an extensive infrastructure since the technology for the on-board hydrogen-storage is still unclear. At this stage, governments may establish quality and safety standards for the use of hydrogen as a fuel and for on-board storage systems.

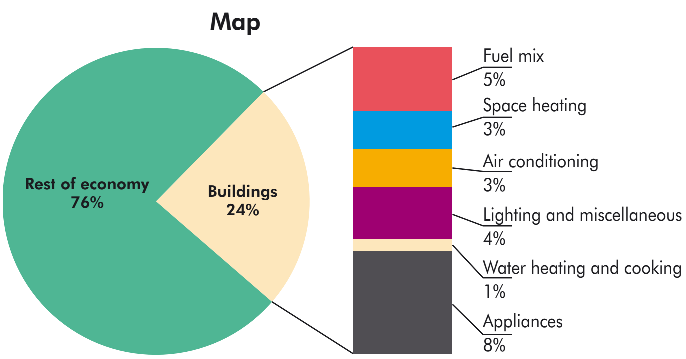
It is unlikely that market forces alone will result in the development of a hydrogen economy. Hydrogen fuel cells will only realise their full potential with the implementation of ambitious energy supply security policies and CO_2 emission reduction incentives.

Given the technical and cost barriers hydrogen vehicles are facing, they can only begin to enter vehicle fleets on a limited basis from 2020. Niche markets may be developed at an early stage in order to bring the cost down. Market development for fuel cell vehicles must be matched by the simultaneous development of a hydrogen infrastructure.

Buildings and Appliances

Buildings and appliances account for about 24% of the total CO_2 emission reductions below the Baseline Scenario in 2050 in the Map scenario. Given the generally high CO_2 emissions intensity of electricity generation, end-uses where significant electricity savings are made due to efficiency measures dominate the share of total savings. Lighting, appliances and air conditioning account for more than half of the total CO_2 emissions reduction in the building sector by 2050 (Figure 3.11).

Figure 3.11 ▶ **Share of buildings and appliances in global CO_2 emission reductions relative to Baseline in the Map scenario, 2050**



Total CO_2 emissions reduction: 32.1 Gt

Many of the technologies that offer significant energy efficiency opportunities are currently cost competitive and can contribute to reducing CO_2 emissions in the short- to medium-term (Figure 3.12). Although many of the technologies taken up in the ACT scenarios are commercially available, ongoing R&D is likely to continue to yield incremental improvements in some areas, while in the case of emerging technologies (e.g. light emitting diodes for lighting) the impact could be more significant.

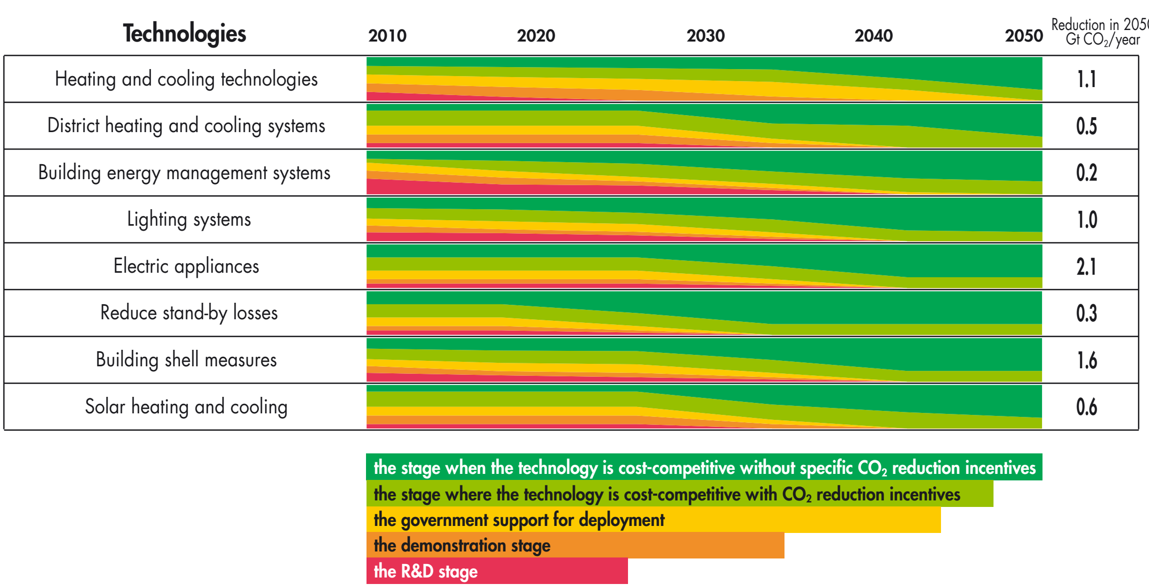
The CO_2 emissions reduction potential in the buildings sector in the short-to medium-term is therefore quite high compared to some other sectors (Table 3.6). Savings in many of the electricity end-uses, particularly lighting and appliances, can be achieved early and at low or even negative cost. Savings grow to 2050, with the largest contributions coming from heating and cooling technologies and building shell measures.

Table 3.6 ▶ ***CO_2 emission reductions in the Map scenario below the Baseline due to building and appliance technologies***

Technologies	2015	2030	2050	Gt CO_2/year
Heating and cooling technologies	★★	★★★	★★★★	1.1
District heating and cooling systems	★	★★	★★★	0.5
Building energy management systems	★	★★	★★	0.2
Lighting systems	★★	★★★	★★★★	1.0
Electric appliances	★★★	★★★	★★★★	2.1
Reduce stand-by losses	★★	★★	★★	0.3
Building envelope measures	★★	★★★	★★★★	1.6
Solar heating and cooling	★★	★★	★★★	0.6

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO_2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt).

Figure 3.12 ▶ ***Pathways towards cost-competitiveness for building and appliance technologies***



Building Envelope Measures

Potential

The energy performance of the building envelope is of fundamental importance, given the very long lifetimes of buildings. The design of the structure must take into account all types of climate conditions during a year. Its quality directly affects the performance of many energy efficient technologies, for example, the advantages of an improved heating system will be lost if the heat escapes from the building. The more severe the climate, the more important the roofs, wall, windows, doors and sub-structure will be. This is true for hot, as well as cold climates, since air conditioning is becoming a common feature in commercial buildings and residences.

Costs

There is a wide range of measures to improve the energy efficiency of buildings. The cost of the measures varies according to the type of measure, the type of building, individual conditions and the circumstances of the improvement. It is generally much more cost effective to improve energy efficiency when buildings are constructed than via retrofit. When retrofitting, the costs will typically be lower if the energy efficiency improvements are made when the building is renovated. The payback time for improvements in buildings can vary from 1 year or less up to 20 years or more. Due to the long lifetime of buildings and their components, even improvements with long payback times can be economically attractive.

In many cases, improvements to the building envelope will have a lower cost per saved kWh than the costs of a kWh delivered by a traditional heating or cooling system. These kinds of savings are cheaper for the owner, even in the short term. But typically the savings will require higher investments at the beginning while the savings will come in the following years. This creates a need for financing. Retrofitting high-rise residential buildings with energy efficiency in mind at the time of refurbishment can yield large energy savings at negative costs. The economics of retrofitting single-family or terraced houses is usually poorer, and costs can be in the range of USD 0.01-0.03/kWh depending on the region.

Barriers

Initial cost is the major concern for windows and doors, as well as for some of the major insulation works that require larger investments. When done in combination with renovation, replacement or other improvements the costs will be lower and the financing issue is less severe. There is, in general, insufficient awareness of the energy-saving potential of these building components and an even lower appreciation of their other benefits, such as security and sound proofing. Incorporating more energy efficient buildings components at the time of renovation, by reducing retrofit costs, can help to overcome some barriers such as financing, but buildings are only rarely retrofitted.

Most new buildings are built by builders or developers, and they are reluctant to go beyond the minimum legal requirements. No direct advantage accrues to them when they install better quality windows or improve the insulation. Most owners and renters of new property are far more interested in the initial costs than in the life-cycle costs.

Energy efficiency in buildings is a complicated topic; it involves insulation standards, windows, heating systems, cooling, lightning, other internal loads and how all of these interact. Energy efficiency is usually not a high priority in new or existing buildings. There is a need for a holistic approach and this is often not the case, since split incentives tend to work against this goal, while co-ordination between architects, advisers and installers can be difficult.

Buildings are very long-lived and their use, the comfort required and conditions of occupancy change over time. It is not always realised that the level of insulation in existing buildings may need to be increased and that optimal insulation level in buildings can bring benefits in warm climates as well as cold, because it reduces the need for cooling. However, many buildings are hard to retrofit, increasing the costs of extra insulation. There can also be a concern about finding qualified installers. Poor quality insulation or installation can lead to moisture problems and it can be difficult to check the obtained savings because comfort levels and the utilisation can change.

In many developing countries, there are no indigenous manufacturers of advanced insulating materials. This affects building code development and implementation, because there is a reluctance to import such materials, or because they are too expensive. In many countries, the lack of adequate enforcement of building codes and equipment standards leads to less than optimal installation practices.

Overcoming Barriers

There are many policy options available, but stringent building regulations are probably the most effective. Building codes should require optimum insulation, windows and doors for a given climate taking into account the life-cycle costs. Adequate training and ongoing information should be made available to builders. Building regulations should be designed both for new and existing buildings, and they should be revised regularly to take into consideration new technological developments, the cost of energy and climate policy. These revisions, in consultation with industry and interested parties, could gradually raise the requirements for energy efficient performance over time.

There has to be a good understanding of best practices by both the building trade and consumers, who need to understand how improved windows, doors and insulation can reduce energy consumption and costs, as well as the other potential benefits from warmer and drier buildings.

For windows, labelling of the thermal qualities has already started, and promises to replicate the benefits these types of schemes have achieved in other areas. Double- and triple-glazed windows, however, are often sold for reasons other than their energy efficiency, such as noise reduction. Linking the various benefits can be a useful way to convince consumers to invest in these items.

Market transformation programmes to promote more efficient windows have proven successful. Retrofitting public-sector buildings provides valuable signals to the public. Transformation programmes could include training of advisers, installers or other involved parts to meet the needs for a more holistic approach and in handling of life costs instead of initial costs. The installation of insulation can be further promoted through financial incentives and energy-service commitments on the part of energy distribution companies.

Certain options are suitable for countries that lack manufacturing capacity and are expanding their stock of buildings. In countries receiving foreign aid, consideration could be given to investing in plants to build energy efficient windows and doors in partnership with existing manufacturers. The lack of adequate production capacity can also be a concern in OECD countries. In such cases, governments can, by giving clear policy signals, help manufacturers overcome their reluctance to invest in new capacity.

While many of these technologies are mature and fully commercial, there is still on-going development. Industry does most of its own R&D, but governments should review industry policies and priorities to see how it can best support further development.

Heating and Cooling Technologies

Potential

These technologies range from conventional oil, gas and electric heating to heat pumps, thermal storage and air conditioning. In some cases, replacement of an old inefficient and maybe oversized boiler can reduce the total consumption by 30 to 35%. Electric heat pumps typically use about one-fourth to one-half as much electricity as electric resistance heaters. They can reduce primary energy consumption for heating by as much as 50% compared with fossil-fuel-fired boilers. The least-efficient portable air conditioner might have an energy efficiency ratio of less than 1.5 W/W (watts cooling output per watts power input), whereas the most efficient split room air conditioners can achieve more than 6.5 W/W. Further energy savings in both room and central air conditioning systems can be realised by optimising their partial-load performance through the use of variable speed drive compressors.

Costs

Important energy efficiency improvements can be achieved at little or no cost over the life-cycle of a product if a more efficient option is chosen at the end of the useful life of a heating or cooling technology. Replacing an old inefficient boiler early can be cost-effective in certain circumstances, but is usually a more expensive option. In Europe, the cost of installing a heat pump is about EUR 5 000, while they can be two to three times more efficient than conventional electric heating. In cold climates, heat pumps may offer significant cost savings over their life-time. An indicative range for the cost avoided through the installation of more efficient heating technologies is from a *negative* cost of USD 0.025/kWh for new installations in cold climates, to a cost of USD 0.02/kWh if retrofits are considered. More efficient cooling systems offer the potential for significant energy savings at low cost, as more efficient systems, although initially more expensive can have lower life-cycle costs. However, there will be a wide-range of costs, from a negative cost of energy saved up to USD 0.03/kWh.

Barriers

Heating and cooling technologies are generally mature, but they are continually being improved. For heating systems, the initial costs of the more energy-efficient systems are a major barrier. There has been a lack of good comparative information to help the consumer, but even if this were remedied, it might still be insufficient to overcome the "first-cost" barrier. The installation of more advanced systems can be a problem, adding to costs. Improvements in control systems are very important and have the potential to add to the savings of energy efficient heating devices, by ensuring that these only run when necessary.

For heat pumps, the barriers are quite similar in terms of initial cost and information. Installation issues are also very important. For thermal storage, there is a lack of confidence on the part of consumers about the technology. Initial high costs are again a major barrier.

There are many air conditioning products on the market, but there is often a lack of understanding of the most appropriate technology for a specific use.

Overcoming Barriers

The tightening of the thermal efficiency standards for new buildings and major refurbishments would help the introduction of more efficient heating and cooling technologies. New building codes could ensure, for example, that more efficient condensing boilers were installed. If such steps are taken, they should be supported by the training and certification of more installers in order to ensure that this does not become a bottleneck. The development of better heating controls, accompanied by measures to promote their deployment, could have a significant impact.

Improved, authoritative and comparative information is essential for all these technologies. It must be readily available from a variety of sources, including the fuel suppliers, installers and consumer groups. Financial incentives or financing solutions may be necessary where the cost of more efficient equipment is high.

Heat pumps are not currently widely deployed and the technology is not well understood by most of the public. Quality assurance, guarantees and advice programmes have a part to play. In countries where there are few installed heat pumps, demonstrations may be very useful. More R&D is needed to improve the technical performance of ground-source heat pump systems.

Thermal storage is an emerging technology in most countries and more R&D is required if this is to make a sizeable impact. Demonstrations, support for feasibility studies and international collaboration are all needed.

For air conditioning, improved information on the appropriate technology for specific needs is important. The best available technology still does not generally achieve a high market share. Improved information is particularly important in the design stage for public and commercial buildings. Minimum energy performance standards and labelling are important for standard mass-produced air conditioners. Care need to be taken in the design of building envelope measures in order to minimise the increase in internal heat loads from more stringent building codes.

District Heating and Cooling Systems

Potential

District heating offers the potential for significant CO_2 emission reductions. There exists significant potential in transition economies to greatly increase the efficiency of district heating systems, while the CO_2 emission benefits of extending district heating systems, although not negligible, are much smaller in nature.

Costs

There are a number of low-cost options for improving the energy efficiency of existing district heating systems in transition economies. Many of these systems do not achieve the efficiency of similar systems in OECD countries. Improving the system design and operation, replacing insufficient or low quality pipe insulation and improving the distribution system within the building can all yield significant energy savings. Improvements to existing district heating networks in transition economies can yield low-cost or even negative CO_2 emission abatement costs.

Barriers

The capital cost of establishing a new district heating system is the main barrier to its increased uptake. Combined heat and power (CHP) plants may provide the heat for a district heating network, but selling the electricity generated to the grid is not always straightforward, although it is important to maximising the CO_2 benefits of CHP plants. It is also important, because the economic viability of the whole programme may depend on selling electricity to the grid.

Overcoming Barriers

For the most part, the technology is commercial and it has been deployed for many decades in many countries. In spite of this, district heating is often overlooked as an option for new urban developments. Stronger environmental regulations, an improved regulatory framework and better information could help. It may be necessary to require developers to show they have considered district heating as an option before they are given authorisation to proceed. District heating should also be considered in climates where there is also a need for cooling, since in such regions district heating systems can provide major benefits throughout the year.

The resolution of the connection problems faced by CHP and other forms of distributed generation will aid district heating as well. Some financial support may be needed, particularly at the feasibility stage. The valuing of CO_2 reductions from district heating would improve the economics of district heating, make raising capital easier and could increase the development of district heating systems.

Some technical improvements are needed, in overall system operation, in the use of thermal storage and the in provision of cooling as well as heating. Further research is also needed on applying district heating to low heat-density areas and on the optimal sizing of networks.

Building Energy Management Systems

Potential

Energy management systems have been around for a long time, but improvements in control technology, improvements in sensors and the use of computers and telematics have changed the entire approach to managing buildings. It is now possible to manage centrally security, safety, air conditioning, lighting and ventilation. As the technology improves and becomes cheaper more and more household appliances could be managed through various types of energy management systems. In addition to reducing energy consumption and CO_2 emissions, such systems would also allow utilities to manage peak-load supply.

Costs

Distance metering and the monitoring of buildings are becoming increasingly sophisticated, at the same time as the costs for these kinds of systems are coming down. More complex systems will need interaction with different parts of the building, with heating installations, cooling and ventilation systems or other appliances. This can be complicated and more costly to do in existing buildings and will be easier by retrofitting. However, these kind of integrated systems would offer greater energy efficiency benefits.

Barriers

There is a general lack of awareness of the benefits that an integrated approach can bring, or even that technology is available today to provide sophisticated building and energy management systems. In many buildings, especially houses and apartments, control is limited to a room thermostat, and there is a lack of information about the energy savings which are possible with better systems. In many cases, there is also a lack of good distribution, installation and service support.

Overcoming Barriers

Various types of information programmes, including best-practice programmes, are essential in targeting primary audiences, including the public sector and commercial buildings. Regularly updated building codes should require architects and builders to seek out all possibilities for energy savings, including through the use of building energy management systems. This would lead to their increased use and contribute to reducing CO_2 emissions at low-cost.

More R&D and demonstrations are needed to integrate the various elements with one another. More understanding is also needed on how building energy management systems can be integrated into emergency demand response measures.

Lighting Systems

Potential

Numerous estimates show that the cost-effective CO_2 reduction potential ranges from 30 to 60 %. The IEA publication *Light's Labour's Lost* (2006), on which this study has drawn, projects that the cost-effective savings potential from energy efficient lighting deployed to 2030 is at least 38% of lighting related electricity consumption. This conservatively assumes no major advances occur in lighting technology. The same publication stresses the strong energy savings potential that is emerging from solid state lighting technologies, which include light emitting diodes (LEDs) and organic light emitting diodes (OLEDs). Both technologies are improving very rapidly and may allow far greater cost effective savings over the time frame to 2050, if not long before.

There is a general lack of awareness of the cost of lighting a building. Lighting accounts for about 13% of electricity consumption in the residential sector and 20 to 60% in the commercial sector. There is little understanding of all the benefits available from energy efficient lighting, including lower maintenance, lower CO_2 emissions, improved safety and improved productivity.

Costs

If new systems are being installed, the cost of efficient lighting is simply the additional cost that the more efficient system may have over the standard option. In many cases, however, efficient lighting systems last longer and have lower maintenance requirements than conventional lighting systems, so that even if their initial costs are higher, their life-cycle costs are often the same or lower than the standard option. If their lower energy costs are further taken into account, many efficient lighting solutions are significantly less costly than the standard systems. In fact, efficient lighting solutions are often so cost-effective that it frequently makes sense to prematurely retire old inefficient lighting systems and retrofit the efficient ones. Voluntary market transformation programmes, such as the European Greenlights programme, have provided numerous case-studies where retrofitted lighting systems had very short payback periods and internal rates of return on the investment of greater than 20%.

Barriers

Many residential and service sector consumers are discouraged from buying energy-efficient lighting systems such as compact fluorescent lights (CFLs) or T5 linear fluorescent lamps, because of their higher initial cost compared to standard lighting. However, the biggest barrier to the deployment of cost-effective energy efficient lighting is lack of awareness of the benefits it offers in terms of lower running costs (both energy and maintenance), often higher quality light and the lower CO_2 emissions. Without adequate awareness of the advantages end-users are not inclined to make a higher initial capital outlay. These problems are further compounded by the array of split incentives that apply to this sector. Building occupants often have little or no influence over the lighting systems that are installed; those who pay the energy bill are often not those who pay to procure the system.

Automatic lighting controls, which turn off lighting when no one is present and/or dim electric lighting in response to rising daylight, are one of the most cost-effective lighting energy saving technologies, but in this case their use is a purely additional cost, which is only justified by the energy savings they produce.

In some cases high-quality efficient lighting can not easily be distinguished from lower quality products due to a lack of adequate market surveillance and labelling. This problem particularly besets compact fluorescent lamps, where users are discouraged from returning to the technology if they invest in what they consider to be a relatively expensive light bulb only to find that it takes far too long to warm-up, burns out way too soon or flickers etc. Unfortunately "market poisoning" of this type can give a bad reputation to an entire class of products and damage the sales of high-quality goods.

The most energy efficient lighting of all is daylight, which is much more abundantly available than it used to be in many buildings, and which has been shown to offer advantages in worker and commercial performance productivity. Much more could be done through the appropriate deployment of architectural design and devices to exploit daylight, but this requires increasing knowledge about "daylighting" techniques.

Overcoming Barriers

There are many ways to increase the deployment of energy efficient lights. Most of these have already been used successfully, but they need to be more widely deployed. Equipment energy efficiency standards and labels can help remove the least efficient technologies from the market, while encouraging the adoption of more efficient technologies by making performance visible to end-users. The application of minimum lighting energy performance requirements in building codes can prohibit the installation of poor lighting designs. If building energy certification is adopted, the whole building energy rating will be raised by installing efficient lighting.

Initial cost barriers can be removed by a mixture of incentives for efficient lighting and disincentives, *e.g.* through raised sales tax for inefficient lighting. Financing for incentives can be provided by utility rebates, white certificate schemes, direct grants, third-party financing, ESCOs, etc. Technology and market-building procurement schemes, product quality policing, energy metering feedback schemes and many other mechanisms exist to help promote and build the market for energy efficient solutions. Fundamentally, awareness of the advantages of efficient lighting needs to be raised across the market so that more informed investment decisions can be made.

There is still much more to be done on the technology development side. International co-operation could be used. The IEA's Implementing Agreement on Energy Conservation in Buildings and Community Systems is a good example of such co-operation.[4] Much of the R&D for lighting is done by the private sector and governments should regularly monitor the situation so that this development continues to bring results.

Electric Appliances

Potential

The energy efficiency of many electric appliances has improved significantly over the last decade, mostly due to minimum efficiency standards and labelling schemes initially introduced in many OECD countries but increasingly being adopted more broadly. Broadening and tightening these standards is being discussed in many countries not least because a large cost-effective savings potential remains to be realised. In the ACT scenarios, savings of 37% are achieved with technologies that will offer the least life-cycle cost.

Costs

If new systems are being installed, the cost of efficient appliances is simply the additional cost that the more efficient appliance may have compared to the

4. See http://www.ecbcs.org/

conventional choice. In many cases this is very small or cannot be measured and payback periods are very short. In some cases the incremental investments are larger. However, when the value of avoided energy costs is considered, efficient appliances are significantly less costly than the standard systems.

Barriers

As with lighting, lack of awareness of cost-benefits and higher initial costs are the main barriers faced by efficient appliances and the energy consumed by appliances is a by-product of the service they provide and hence its minimisation is not the main motivation in the purchase decision. Depending on the appliance, consideration of the energy performance may be between the third and tenth most important factor that consumers express in their decision making hierarchy. In many cases this is because they are unaware of how important the energy costs may be in the overall cost of the service it provides (*e.g.* refrigerators often cost more to run over their life than the purchase price). A related problem is that consumers may have little idea of how large a difference in energy performance there can be between apparently similar products. For example, prior to the introduction of energy labelling in Europe, there was an eight-fold difference in energy efficiency among refrigerators on the European market, purely because energy performance was invisible to end-users and hence had no market value for manufacturers.

This example illustrates the importance of good comparative information with which to assess appliance options at the point of purchase. The technical barriers are relatively minor, although new technological breakthroughs come along all the time and governments can help stimulate this process. A decade ago, no one could have foreseen the dramatic spread of many appliances and office machines that are taken for granted today. The growth in the numbers and types of appliances will need to be matched by substantial improvements in efficiencies if CO_2 emissions from appliance use are not to rise steeply.

Overcoming Barriers

The policy framework has to be flexible enough to allow for innovation, because this is an area that is constantly evolving. There is a need for minimum energy performance standards, but such standards should be broadened to more products and they should reflect the globalisation of manufacturing. Steps should be taken to avoid the dumping of less efficient appliances in developing countries. Performance standards should be accompanied by labelling programmes, which are carefully designed to give consumers information in a way they can make use of at the time of purchase. Both performance standards and labels need to be reviewed regularly to keep up with and anticipate technological change. They need to be sufficiently ambitious to reward industry that is prepared to be innovative and produce highly efficient products.

Voluntary programmes are a possibility, but they have to be closely monitored to ensure they are achieving best practice. Most research on appliances is done by industry. Government should monitor that research and contribute where it is appropriate to develop promising energy saving technologies.

Reducing Standby Losses

Potential

Reducing standby losses provide a major opportunity for cost-effective energy savings, because so many energy using appliances can now be activated remotely and hence require a standby mode, yet this mode has often been found to use unnecessarily high levels of electricity. Standby power accounts for about 10% of residential electricity demand. Printers consume 30 to 40% of their full power requirement when they are idle. Television sets, music equipment and many other types of home equipment do likewise. Many products such as VCRs, DVDs and set top boxes are likely to use far more energy in the standby mode than they are in the operational mode because most of their time is spent in the standby mode. Standby losses can be reduced by up to 90%, depending on the appliance, by the adoption of simple low-cost technical solutions.

Costs

The cost of reducing standby power is often, but not always, minimal. Overall, even ambitious reductions in standby power will cost end-users less than USD 0.02 per kWh avoided, which is far less than most residential and commercial electricity tariffs and less than the cost of electricity generation.

Barriers

There are some technical barriers, especially for challenging end-uses, where arrangements have to be made between equipment manufacturers and entertainment service providers, such as for digital TV service decoders (set top boxes). But in general the means of avoiding standby power use are well known to industry. The main barriers are a "bundling" problem (the standby power is not the primary performance metric for any product, but very much a secondary one) and that it is, even today, almost completely invisible during the purchase decision. Relatively few energy labels currently address standby power and very few minimum energy performance standards include it. As a result consumers generally have no idea about how much energy products use when in standby mode.

Overcoming Barriers

If the equipment has a standby facility, the majority of consumers will continue to use it, regardless of public information campaigns. In the consumer's eyes, the convenience will usually outweigh the savings. The focus must therefore be on reducing the power drain of standby modes. Standards and labelling can greatly contribute to this. Market transformation programmes, in which a consensus is built up among stakeholders on market projections for energy consumption have proven valuable in some economies and much can be done to enhance industry engagement in this area.

Solar Heating and Cooling

Potential

Solar space heating and cooling systems take the sun's power and harness it to heat or cool buildings. Solar collectors absorb solar radiation and change it into heat energy. This thermal energy can then be used to provide hot water for space heating or cooling. The main collector technologies include unglazed, glazed flat plate and evacuated tubes. The technology may be considered mature, but it continues to improve.

Solar heating and cooling is already commercial in many applications, particularly for solar sanitary hot water, but its deployment is far below its potential in both OECD and non-OECD countries.

Costs

Solar water heating systems in Europe cost around EUR 2 500-6 000 depending on size and location, while solar cooling systems cost 1.5-3 times as much as conventional systems. Solar hot water heating systems can cost USD 1-2 per watt of capacity, with the cost of energy supplied varying depending on the location and sunshine hours per year. The United States R&D goal is to halve the cost of energy produced by a solar hot water system that delivers 2 500 kWh per year of energy to USD 0.04/kWh, substantially below the electricity tariff of residential customers.

Barriers

Information about total costs is often inadequate and high initial costs can be a barrier. Consumers often doubt that the heating system will operate effectively. In many countries, service, distribution and installation are poor, retarding the uptake of these technologies.

Overcoming Barriers

Building codes can be revised to encourage the use of solar heating and cooling. At the same time, training and accreditation programmes should be developed for installers so that consumers can have confidence in the performance of the technology over its lifetime.

Improved information and technical advice for consumers is also essential and could help inform their purchase decision. Financing schemes maybe important to help overcome the high initial cost of solar systems.

Demonstrations projects are useful in countries that have a low rate of market penetration. This is especially true in the commercial and public sectors, for hotels and for hospitals. Some countries have found that financial incentives can be successful. Third-party financing arrangements can also help, depending on the size of the installation. Another possibility is to allow solar hot-water systems to be counted against renewable portfolio obligations of electric utilities.

The installation of solar hot water heating has qualified for the Clean Development Mechanism under the Kyoto Protocol and that avenue of funding could be more widely utilised.

Biomass for Heating and Cooking

Biomass and waste currently provide 10% of global primary energy supply. More than 80% of this is used for heating or cooking. While the traditional use of biomass in developing countries is a major source of environmental pollution and health problems, it is also the only affordable fuel for the poor in large parts of the world. The biomass is often used inefficiently, though advanced technologies are applied in certain industrialised regions such as North America and Scandinavia. These technologies could be applied more widely and could help contribute to CO_2 emission reductions. However, biomass logistics and the inconvenience of solid fuels will probably limit this option to regions with ample biomass resources and relatively low population density. More efficient technologies for heating and cooking in developing countries can ease the burden of biomass collection, reduce fuel-wood bills, help to mitigate deforestation and free up biomass resources for other use. CO_2 considerations act as largely a secondary incentive in this priority area.

Industry

Industry consumes about 30% of the world's primary energy demand. The sector's fuel consumption is responsible for about 23% of total CO_2 emissions. Any improvement in the energy efficiency of industry will provide CO_2 emission reductions. Other options can increase the reduction potential further. Nine categories of options to reduce CO_2 emissions have been analysed in this study:

- Cogeneration technologies.
- Energy efficient motor systems.
- Energy efficient steam systems.
- Enhanced efficiency based on existing technologies for basic materials production.
- Enhanced efficiency based on process innovation for basic materials production.
- Fuel substitution.
- Materials/product efficiency.
- Feedstock substitution.
- CO_2 capture and storage.

In the Map scenario, total industrial CO_2 emissions are 5.4 Gt lower than in the Baseline Scenario, of which 2.4 Gt CO_2 are due to electricity savings that reduce emissions in the sector. Another 0.3 Gt CO_2 is accounted for in the fuel transformation sector. CCS accounts for 27% of industrial CO_2 emission reductions, while fuel and feedstock substitution account for 18% (Figure 3.13). Energy, product and process efficiency improvements account for 55%.

Table 3.7 provides an overview of the contribution of various options during the transition period from 2015 to 2050. Several options rely on technologies that are available today. If the remaining barriers can be removed in a timely fashion, these options could play an important role by 2015. Such options include better maintenance of steam systems and the retrofit of existing inefficient plants, or the closure of outdated small plants. These measures can be induced through proper energy pricing, better management systems, standards and regulations.

Figure 3.13 ▶ **Share of industry in global CO_2 emission reductions relative to Baseline in the Map scenario, 2050**

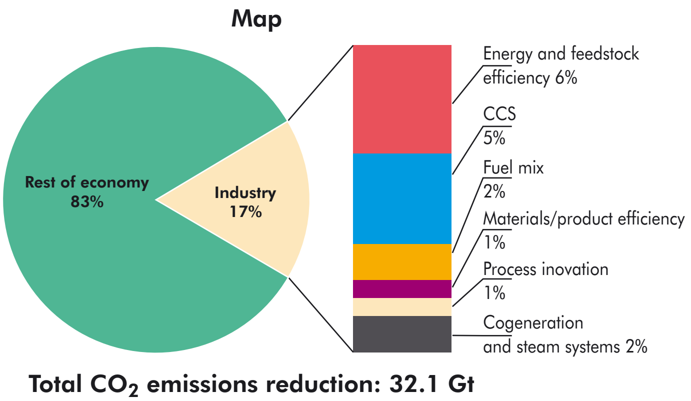


Table 3.7 ▶ **CO_2 emission reductions in the Map scenario below the Baseline due to industrial technologies**

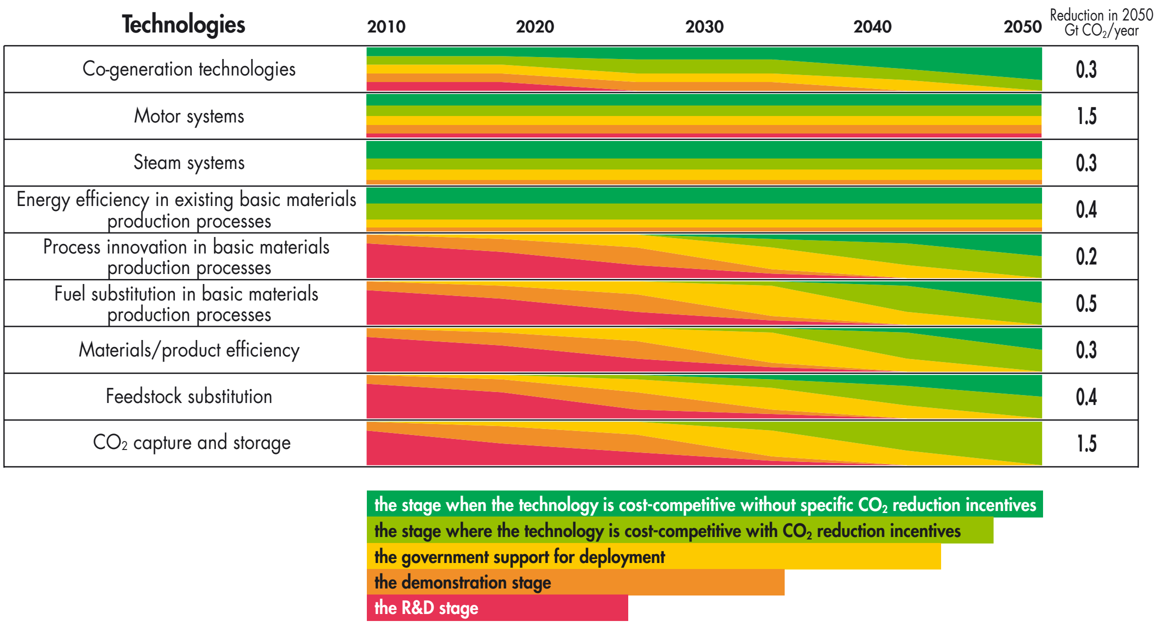
Technologies	2015	2030	2050	Gt CO_2/year
Co-generation technologies	★	★★	★★	0.3
Motor systems	★★	★★★	★★★★	1.5
Steam systems	★	★★	★★	0.3
Energy efficiency in existing basic materials production processes	★★	★★	★★★	0.4
Process innovation in basic materials production processes		★	★★	0.2
Fuel substitution in basic materials production processes		★★	★★★	0.5
Materials/product efficiency		★	★★	0.3
Feedstock substitution		★★	★★★	0.4
CO_2 capture and storage		★★	★★★★	1.5

Note: The reductions are illustrated by a category ★ (< 0.1Gt CO_2/yr of the total reduction), ★★ (between 0.1 – 0.3 Gt), ★★★ (between 0.3 – 1 Gt), ★★★★ (>1Gt).

Other options are further from market introduction. While some biomass feedstocks are already in use today (e.g. for detergents), others will require further R&D, such as new production routes for biopolymers. Where additional R&D is needed, the main uptake is projected for the 2030 to 2050 period. This is also a period with oil and gas prices that are considerably higher than in 2015, which further increases the potential uptake of all energy saving options.

Figure 3.14 elaborates the technology stages for each option category. Because the option categories are broad, it happens that all five occur at the same point in time. For example, in the case of cogeneration, certain systems are well proven and widely applied (for example, gas fired large-scale CHP units), while others are still in the R&D stage (for example, small-scale fuel cell units). For other options such as CCS and feedstock substitution, the emphasis is still clearly on R&D.

Figure 3.14 ▶ Pathways towards cost-competitiveness for industrial technologies



Cogeneration Technologies

Potential

Cogeneration (combined heat and power) is projected to quadruple in the ACT scenarios, but a large increase of cogeneration is already included in the Baseline scenario, so the additional increase is limited. Savings accrue primarily in the power sector. The fuel saving ranges from 10 to 25%, compared to stand-alone systems using the same fuel. CO_2 reductions may be more important if gas-based cogeneration replaces coal stand-alone systems. Savings in the ACT scenarios amount to 3 to 4 EJ per year (which translate into a CO_2 emission reductions of 0.2 to 0.4 Gt).

Costs

In many cases the introduction of cogeneration will result in substantial life-cycle cost savings and energy savings, but the additional investment costs can be several hundred dollars per kW of installed capacity. Abatement costs are estimated to be up to USD 25 per tonne CO_2. Gas is the preferred fuel for cogeneration units for a number of reasons, but coal or heavy oil residues may be used as well.

Barriers

In many parts of the world, industry is not yet allowed to feed electricity back into the grid. Where they are permitted to do so, plants may not be able to compete with centralised large-scale power production due to unfavourable feed-in tariffs. In certain countries where such problems have been solved, cogeneration contributes more than a quarter of total electricity production. Small- and medium-scale industries especially face higher fuel costs than large power producers.

Cogeneration requires that demand for heat and electricity is in close proximity. Although there are many industrial sectors where this will be the case, there are many others where it will not. In countries with a tradition of district heating, there may be opportunities available to supply heat, but these will still be limited.

Overcoming Barriers

Market liberalisation and non-discriminatory grid access would help level the playing field for cogeneration but still might not be sufficient to allow it to compete with large centralised production. The overall efficiency of cogeneration is very high, and a CO_2 incentive of some kind would reward this.

Motor Systems

Potential

Motor systems represent over half of industrial electricity use worldwide. The savings potential is in the order of 20 to 30%, or 5% in terms of total global electricity use. Part of this potential is realised in the Baseline Scenario, but the additional potential for savings is still significant (about 10 to 20%). The emission reduction potential is about 1.5 Gt CO_2 by 2050. Other electricity saving measures increase the potential electricity savings to the equivalent of 2.4 Gt CO_2 by 2050.

Costs

Cost will vary widely due to the large range of possible projects, depending on the specific case characteristics (*e.g.* efficiency gain, size, load factor, site-specific investment needs) and whether it is for a new motor or the variable speed control of existing motors. In many cases, important cost reductions can occur, but retrofits may be more costly than investments in new installations. As electricity prices are higher in the ACT scenarios than in the Baseline Scenario, the potential for cost-effective savings increases. However, CO_2 reduction costs are also affected by the decarbonisation of electricity production in the ACT scenarios. Therefore, the resulting range is quite wide, from a savings of USD 100 per tonne CO_2 to an additional cost of USD 100 per tonne CO_2. Over the long term, though, the major shares of these savings are cost-effective.

Barriers

Electricity costs are a secondary consideration in all but the most energy-intensive industries and there is a lack of awareness of potential energy-saving opportunities.

Industry focuses on production, not energy efficiency, and is reluctant to change systems that are familiar and which work satisfactorily. Often the budgets for energy efficiency investments and for paying energy bills are quite separate, so efficiency savings are less obvious. The market has tended to focus on components, not systems. Production managers generally do not have the expertise to provide solutions, even if they were to recognise the potential for energy savings.

Overcoming Barriers

Various mechanisms could be deployed to overcome the basic failure of appreciating energy inefficiencies. Encouraging industry to use energy service companies (ESCOs) would help. The ESCO could identify inefficiencies, and remedy them, leaving industry to concentrate on production. Voluntary agreements with industry can spur improved efficiency and may stimulate the greater use of ESCOs.

Energy management systems have improved greatly in recent years, but there is scope for further development. Software and off-the-shelf systems solutions would be particularly beneficial. Industry needs to be encouraged to develop these tools through government sponsored R&D programmes or other means. Ambitious standards for energy efficient motors are lacking in many parts of the world. Such standards could be extended to complete motor systems. If long-term benefits are to be realised, university courses and training programmes for plant designers and engineers should include an element on energy efficiency.

Steam Systems

Potential

Energy savings on the order of 10 to 20% are widely achievable and even more where pipe insulation is inadequate. The potential for additional emissions reductions, compared to the Baseline Scenario, is estimated at about 0.3 Gt CO_2.

Costs

In many cases, the introduction of steam system efficiency measures will result in substantial life-cycle cost savings. If a boiler needs replacement before the end of its life, however, the investment cost may be substantial. The CO_2 emission abatement costs for introducing steam efficiency measures are estimated to range from a cost saving of USD 25 per tonne CO_2 to roughly cost neutrality, while the cost of replacement with a new boiler is in the order of USD 25 per tonne CO_2. The costs are highly dependent on fuel prices.

Barriers

The barriers are much the same as for motors - lack of awareness of potential energy savings opportunities; split budgets for energy efficiency investments and energy bills; and a reluctance to change a working system.

Efficient boiler systems are based on well-established technologies. But inadequate attention to routine maintenance of some equipment, such as steam traps, valves, and heat transfer surfaces, significantly reduces the benefit derived. In many developing countries, the losses from steam supply systems remain substantial. Insulation is often non-existent in Russia, where low natural gas prices pose no incentive to increase efficiencies. In China, many small-scale boilers operate with considerable excess air and incomplete combustion of the coal.

Overcoming Barriers

Methods such as those proposed for motors can be used to promote the adoption of these technologies. It is important to ensure that the potential savings are not reduced by poor maintenance or lack of adequate insulation. Use of energy service companies (ESCOs), voluntary agreements and the inclusion of energy efficiency in the training of engineers and boiler operators should reduce or eliminate these problems.

In some cases, there are local factors effecting efficiency and these need to be addressed. For example, poor coal quality is the main factor in the low efficiency of Chinese boilers. Coal washing could therefore yield significant savings.

Enhanced Efficiency Based on Existing Technologies for Basic Materials Production

Potential

An important potential exists, especially in developing countries and transition economies, to improve the efficiency of basic materials production processes. For example, the energy efficiency of coke ovens and blast furnaces in China is considerably lower than in OECD countries. Also, small-scale pulp and paper mills in China and India use much more energy than is needed. Low natural gas prices in Russia result in a lack of efficiency incentives and therefore low efficiencies. Given the projected growth rate of industrial production between now and 2050, savings potentials are estimated to be around 20 EJ per year by 2050 (a 20 to 30% gain). This excludes the autonomous efficiency gains already included in the Baseline Scenario.

Costs

In many cases the introduction of energy efficiency measures will result in substantial life cycle cost savings, but where the equipment needs replacement before the end of its life, the investment cost may be substantial.

Barriers

When fuel prices are low, there is little incentive to act. Lack of capital or risk aversion may reduce the incentive to invest. In many developing countries advanced technologies are not readily available. Large-scale processes are usually more efficient than small-scale industries, but this may come at the expense of higher capital intensity and reduced labour intensity. Sheltered industries have limited incentive to invest. The long life span of industrial capital equipment reduces the potential for rapid efficiency gains. Lack of long-term CO_2 policy perspectives makes capital-intensive efficiency projects risky.

Overcoming Barriers

The use of ESCOs, which are fully aware of the possibilities and have the expertise to utilise them, could provide a way forward. Voluntary agreements, the development of energy management systems and the training of engineers also have a part to play. As well, fuel prices should reflect the importance attributed to their CO_2 emissions. Clear long-term CO_2 policy targets will convince industry that efficiency gains will result in competitive advantages.

Enhanced Efficiency Based on Process Innovation for Basic Materials Production

Potential

A number of emerging technologies can result in important efficiency gains. Many of these technologies will be cost-effective in the Baseline Scenario. The additional potential in the ACT scenarios, compared to the Baseline, is on the order of 3 EJ, or about 0.3 Gt of CO_2 savings.

Costs

In many cases, process innovation will result in substantial life-cycle cost savings and lower investment costs than for existing processes. However, new technologies will initially be more expensive than established ones, and deployment is needed to bring the cost down. CO_2 emissions abatement costs are expected to range from a cost saving of USD 25 per tonne CO_2 to an additional cost of USD 25 per tonne CO_2. Often important secondary benefits will occur, such as simplified production processes, increased production flexibility and reduced local environmental impacts that are hard to quantify.

Barriers

New technology needs to be demonstrated on a commercial scale. Industry is often reluctant to make substantial investments for pilot plants and demonstration projects pose important barriers. Management is reluctant to invest in new technologies that are not yet proven on a commercial scale. Often new technologies mature under special circumstances in a country or business environment with few other technology options. When new technology has been proven, it is likely to face the same barriers as other energy efficiency measures. These will be mitigated to a degree, because engineers involved in the demonstration projects will have the necessary knowledge, and so the technology will have champions as it emerges onto the market.

Overcoming Barriers

These technologies require more RD&D to bring them to the deployment stage. This will require improved co-operation between industry and government. International cooperation to share the burden of costly demonstration projects may be necessary.

Fuel Substitution in Basic-materials Production

Potential

Natural gas can be used as a substitute for coal and heavy oil products. In principle, the potential is very high (around 10 to 20 EJ), but in many cases the cost will be in excess of USD 50 per tonne CO_2, which is likely to be prohibitive. The additional savings that can be realised under the ACT scenarios are thus less than the theoretical potential. Additional potential may exist to use biomass or waste in parts of the world in certain sectors, for example in blast furnaces or cement kilns.

Costs

The costs of a switch from coal to gas can be low if inexpensive stranded gas can be used. This implies relocation by industry to places where such cheap gas resources exist. For example, if pig iron were replaced with imported direct reduced iron, such relocation could have economic consequences for individual countries. However, the global cost of abatement would be less than USD 25 per tonne CO_2.

Barriers

The main barriers are cost and an increased dependency on natural gas imports. The local availability of cheap coal will deter many from considering this option.

Overcoming Barriers

Fuel switching will be limited in the absence of CO_2 policies that place a value on carbon. In fact, higher oil and gas prices work in the opposite direction as they may favour industrial coal use. In certain regions, fossil fuels are subsidised through prices that are below market value (as is the case with natural gas in Russia). Continued trade liberalisation could accelerate the relocation of industry to places with cheap stranded gas resources. However, the CO_2-impact of the relocation can vary. A global emissions trading system, at least on a sector level, would help ensure that CO_2 emissions do not increase. Development of unconventional gas resources may help to disconnect the natural gas price from the oil price, a precondition to keeping gas as a competitive fuel for industry.

Materials and Product Efficiency

Potential

This option includes various approaches to make the same products using less material. Increased product life span and recycling can reduce the need for primary materials production, which reduces industrial energy use and CO_2 emissions. The potential savings are 5 EJ and include increased recycling and more efficient use of materials through product redesign. The carbon reductions are estimated by the ACT scenarios analysis to be 0.3 Gt CO_2.

Costs

The costs of such efficiency options vary widely. Cost savings are possible in certain cases, while in others, the additional costs can be high. In most cases, CO_2 policies will be of secondary importance. Environmental concerns related to waste policies, as well as economic factors, will dominate decision making.

Barriers

Improving the efficiency of materials or products requires a complex, life-cycle evaluation of options. The analysis will need to extend beyond the area of interest of an individual company or even an industry. Very few companies have interests that extend across the entire life-cycle, from derivation of raw materials, through to manufacture and on to product disposal or recycling. As a consequence, companies seldom have reason to consider the cycle as a whole, but only those particular steps in which they are engaged.

Overcoming Barriers

Life-cycle thinking is unlikely to emerge without governments taking measures, such as establishing producer responsibility throughout the product life-cycle. This type of action is more likely to be taken as a consequence of other environmental policies than to promote CO_2 savings. Nevertheless, there may be important incidental CO_2 savings as a result of the adoption of such policies, and environmental policies designed for these other purposes should be as "climate friendly" as possible without diminishing the main policy objective.

Feedstock Substitution

Potential

Feedstock substitution can save 5 to 10 EJ and achieve about 0.4 Gt of CO_2 emission reductions. This includes using biofuels as a substitute for petrochemical feedstocks and using bioplastics. The savings may occur throughout the life-cycle (as with waste combustion), but they should be credited to industry in order to create proper incentives.

Costs

In many cases, process innovation will result in substantial life-cycle cost savings and the investment cost will be lower than for existing processes. Cost will depend on technology development.

Barriers

At this moment, the cost for biomass feedstocks and biopolymers are considerably higher than for petroleum-based products. High oil prices increase the competitiveness of biomass, but the long-term oil price perspective is uncertain. Therefore, it is essential to reduce cost through R&D and technology deployment. Further cost reductions may imply the use of genetically modified crops, a sensitive issue in certain world regions.

Overcoming Barriers

More RD&D funding and CO_2 crediting systems for biomass feedstocks would work toward overcoming key barriers.

CO_2 Capture and Storage in Industry

Potential

The main potential for CO_2 capture and storage exists in power generation, but CCS is also applicable to large energy-intensive industrial facilities like ammonia plants, blast furnaces, cement kilns, black liquor gasifiers and furnaces in certain large-scale applications. Industrial capture in the ACT scenarios increases up to 1.45 Gt CO_2 in 2050.

Costs

The cost for CO_2 capture and storage in industry may in certain cases be lower than for power plants. For example, low-cost opportunities exist in ammonia production. Capture from blast furnaces could probably be implemented at a cost below USD 25 per tonne CO_2. The same applies to black liquor gasifiers in chemical pulp production processes. The cost for cement kilns and furnaces would be above USD 25 per tonne CO_2 based on current technology, but process re-design, notably oxy-firing, may allow further cost reductions to a level of USD 25 per tonne CO_2.

Barriers

New technology must be developed and a number of demonstration projects are needed. A better understanding is needed of the characteristics of CO_2 storage sites. Investments will only take place if credible long-term CO_2 policies are introduced. Industry relocation because of CO_2 policies is an issue that must be allowed for.

Overcoming Barriers

Financial support is needed for RD&D regarding industrial CO_2 capture. More proof of concept of CO_2 storage is needed. A credible long-term CO_2 policy outlook must be developed for such capture investments to materialise. In fact, there are interesting early opportunities for CCS in the industrial sector at cost levels below those in the power generation sector. These options should be developed at an early stage as they can help to establish CO_2 capture, transportation and storage technologies that can be applied to the power sector as well.

Part 2

ENERGY TECHNOLOGY STATUS AND OUTLOOK

Chapter 4 ELECTRICITY GENERATION

Key Findings

- *The share of power generation in total CO_2 emissions is projected to increase from 40% today to 45% in 2050.*

- *The existing electricity generation stock in OECD countries is aging and will need to be replaced in the next 10 to 20 years. This fact, combined with rapidly growing electricity demand in developing countries, implies that investment decisions taken over the next few years will have a huge long-term impact. The energy system could be locked into a fuel mix and emissions trajectory that may be difficult to change.*

- *Taking advantage of available clean coal technologies can make a significant contribution to containing the growth of CO_2 emissions from power generation. For example, advanced steam cycle or integrated gasification combined-cycle technology could raise average efficiency of coal-fired power plants from 35% today to more than 50% by 2050.*

- *Switching from coal to natural gas can reduce CO_2 emissions since natural gas is a less carbon-intensive fuel and natural gas-fired power plants can achieve higher efficiencies. As there is more uncertainty about future natural gas prices than of coal, the choice of switching from coal to gas is sensitive to natural gas prices.*

- *The largest users of fossil fuels for power generation are among the least efficient. China is the world's biggest user of coal for power generation, but has among the lowest efficiency. China could use some 20% less coal if its plants were as efficient as the average plant in Japan today. Russia is the world's largest user of natural gas for power generation. Russia could use a third less gas, if its plants were as efficient as the average plant in Western Europe today.*

- *Near-zero emissions can be achieved with CO_2 capture and storage. The costs vary, but in general, substantial financial incentives will be needed. Some CO_2 capture technologies are ready for demonstration, while others need more RD&D to reduce costs and improve performance. Coal plants with CO_2 capture and storage could be deployed for less than USD 25 per tonne of CO_2 emissions avoided. Sufficient proof of CO_2 retention in storage sites is essential for this technology.*

- *Renewable energy currently accounts for 18% of global electricity generation, most of it is large hydropower. Over the next four decades, wind, bioenergy and solar will increase their penetration, depending on how fast technologies improve and costs fall. Government policies aimed at technology learning can help to bring costs down.*

- *Nuclear represents 16% of global electricity production today. New reactors (Generations III and IV) enhance safety and mitigate waste-disposal problems. Nuclear power needs to see reductions in capital costs. If its main problems are resolved, nuclear energy could make a significant contribution to future electricity supply.*

- *Advances in grid management, with more intelligent management systems, will be needed to facilitate the expansion of distributed generation and permit more renewables to be brought into the grid. Greater efficiencies in transmission and distribution technologies will reduce system losses and CO_2 emissions.*

- *Fuel cells and other emerging decentralised power generation technologies require further RD&D. Natural gas fuel cells for distributed generation or back-up power are currently used in demonstration projects or niche applications. If their costs are reduced significantly, they could account for some 3% of global generating capacity in 2050.*

Overview

The electricity sector has been the main source of carbon dioxide (CO_2) worldwide for decades. Since 1971, the sector's CO_2 emissions have increased 170%. In 2003, electricity generation accounted for 40% of global CO_2 emissions, of which coal-fired electricity plants accounted for some 70%, natural gas-fired plants for about 20% and oil-fired plants for about 10%.

This chapter provides an overview of the status and prospects for the many advanced technologies that could help reduce CO_2 missions dramatically. It focuses on electricity generation. (Heat and cogeneration technologies are covered in more detail in Chapter 6, "Buildings & Appliances" and Chapter 7, "Industry".) Technologies such as integrated gasification combined-cycle (IGCC), advanced steam cycles and CO_2 capture and storage (CCS) can contribute to reducing CO_2 emissions from power generation. Policies which affect the fuel mix, such as supporting renewable-based generation, facilitating more nuclear generation and encouraging a switch to natural gas from coal, are important, as is research and development. R&D makes new technologies available, while investments can result in further cost reductions due to technology learning. The technologies that will be available 30 or 40 years from now could be radically different from those we use today.

While this chapter focuses on electricity generation, improvements to transmission and distribution networks are also necessary. Globally, generation accounts for about 45% of total electricity supply costs, distribution for 40% and transmission for the remainder. On average in OECD countries, generation accounts for more than half of total supply cost and in most countries it accounts for more than 60%.

Transmission typically accounts for 5 to 10% of supply costs. Both generation and transmission are highly technical undertakings and they are likely to be the areas where the greatest changes in technology will be concentrated. Improving demand-side energy efficiency is an important component of an emissions reduction strategy. Measures on the supply side to increase efficiency should be balanced with end-use energy efficiency improvements. (Technologies which improve end-use efficiency are examined in Chapter 6, "Buildings and Appliances" and Chapter 7, "Industry".)

The next section of this chapter looks at past trends in the global fuel mix and CO_2 emissions in the power generation sector. The following section provides a review of the barriers facing new technologies. The next four sections look at the status of different technology options for fossil-fuel based plants, CO_2 capture and storage, renewable energy-based generation and nuclear power. Each section examines prospects for improving efficiency and reducing CO_2 emissions. R&D needs and prospects for cost reduction are also reviewed. Advanced electricity networks and distributed generation are covered in the next section. (Micro-generation systems are covered separately in Chapter 6, "Buildings and Appliances".)

Global Electricity Generation and CO_2 Emissions

This section traces the evolution of the fuel mix and of CO_2 emissions in power generation over the last 30 years. Past trends provide insights about future developments. The existing stock in OECD countries is aging and will need to be replaced in the next 10 to 20 years. It takes decades to turn over the energy infrastructure in the power sector. This fact, combined with rapidly growing electricity demand in developing countries, implies that investment decisions taken over the next few years will have a huge long-term impact. The energy system could be locked into a fuel mix and CO_2 emissions trajectory that may be difficult to change.

The oil price shocks of the 1970s led to sharp reductions in the shares of oil-fired and natural gas-fired generation in OECD countries. The share of coal in the fuel mix increased during this period, but the largest gains were in nuclear power, whose share in the fuel mix of OECD countries rose from 4% in 1973 to 20% in 1985 (Table 4.1). This increase was bolstered by strong government support of the nuclear industry dating back to the 1950s.

In the period after 1985, fossil fuel prices were lower and environmental concerns were higher on the energy policy agenda. The mandated installation of pollution-control devices, especially in the European Union, raised the capital and operating costs of coal-fired plants. These factors, combined with a decline in gas-turbine capital costs and lower natural gas prices, increased the competitiveness of natural gas. In many OECD countries, most of the new plants built in the 1990s were fired by natural gas and in Europe the capacity of gas-fired plants tripled over the decade. Because of the high efficiency of natural gas combined-cycle (NGCCs) plants, the average efficiency of the power generation stock increased substantially.

Table 4.1 ▶ **Global electricity generation**

	1973	1985	2003	1973	1985	2003
	(TWh)			Share (%)		
OECD						
Coal	1 693	2 739	3 843	38	43	39
Oil	1 125	575	561	25	9	6
Gas	520	594	1 728	12	9	18
Nuclear	188	1 259	2 223	4.2	20	23
Hydro	912	1 174	1 242	21	18	13
Other renewables	14	45	266	0.3	0.7	2.7
Total	*4 454*	*6 388*	*9 863*			
Developing countries						
Coal	208	590	2 491	33	36	47
Oil	174	307	529	27	19	10
Gas	30	146	919	4.7	8.8	17
Nuclear	3	49	135	0.4	2.9	2.6
Hydro	219	544	1 137	35	33	22
Other renewables	2	11	55	0.4	0.7	1
Total	*636*	*1 646*	*5 264*			
Transition economies*						
Coal	434.	472	348	42	27	23
Oil	211	300	61	21	17	4
Gas	192	503	578	19	29	38
Nuclear	12	184	277	1.2	11	18
Hydro	150	256	269	15	15	18
Other renewables	23	23	3	2.2	1.3	0.2
Total	*1 021*	*1 738*	*1 535*			
World						
Coal	2 335	3 801	6 681	38	39	40
Oil	1 509	1 182	1 152	25	12	6.9
Gas	742	1 243	3 225	12	13	19
Nuclear	203	1 492	2 635	3.3	15	16
Hydro	1 282	1 974	2 645	21	20	16
Other renewables	40	80	323	0.6	0.8	1.9
Total	*6 111*	*9 772*	*16 661*			

* Transition economies include non-OECD Europe and the former Soviet Union.

Source: IEA, 2005b; IEA 2005c.

Environmental concerns, combined with a shortage of new sites, decreased the share of hydroelectric power in the late 1980s and 1990s. Nuclear power maintained its share, despite rising public concerns about safety and waste disposal. It benefited from higher capacity figures and improved plant operation. Overall, the oil price shocks of the 1970s did much more to reduce the share of fossil fuel-based generation than did the climate change policies of the 1990s.

From 1973 to 1985, the oil price shocks reduced the share of oil-fired generation in developing countries, but the share of natural gas-fired generation in those countries actually increased. Similarly, the emergence of environmental concerns in the late 1980s had much less impact on the share of coal in these countries. This was partly due to circumstances in China, as the world's largest coal user with a fast-growing economy, and partly to the fact that environmental concerns are less of a priority in most developing countries than poverty alleviation and economic development. Many developing countries have real concerns about rising CO_2 emissions, but they rarely have the resources to use the most advanced technologies.

In 1973, electricity demand in OECD countries was 4 450 TWh. In developing countries as a whole it was only 630 TWh. By 1985, the gap in demand had widened and electricity demand was nearly 4 800 TWh higher in OECD countries. In 1973, per capita electricity demand in developing countries was 587 kWh per capita, compared to 4 935 kWh per capita in OECD countries. Per capita demand has increased dramatically in both country groupings over the past twenty years, but in 2003, per capita electricity demand in developing countries was still an eighth of the level in OECD countries (1 103 kWh per capita compared to 8 543 kWh per capita in the OECD).

From 1985 to 2003, the share of hydropower declined in developing countries. Most of the decline was due to a drop in the annual growth rate for hydropower in Latin America, from 10% between 1973 and 1985 to 4% afterwards. Overall, the oil price shocks of the 1970s had only a modest impact on the fuel mix in developing countries and coal continued to dominate into the 1990s.

Changes in the fuel mix can have a significant effect on CO_2 emissions (Table 4.2). Between 1973 and 1985, coal-related CO_2 emissions grew by 3.6% per year in OECD countries, from 1.8 Gt to 2.8 Gt. Fuel-switching and the introduction of environmental standards in OECD countries reduced the rate of growth to 1.6% per year between 1986 and 2003, when annual emissions due to coal reached 3.7 Gt. Despite this slowdown in the average annual growth of coal-related emissions, total CO_2 emissions grew faster in the second period. In OECD countries, fossil fuel-based emissions grew by 1.9% per year from 1986 to 2003, compared to 1.5% from 1973 to 1985. Faster growth in the 1990s was due to higher energy demand. In developing countries, CO_2 emissions have grown by about 7% per year since 1973, where annual coal-related emissions grew from 0.3 Gt in 1973 to 0.7 Gt in 1985, and to 2.8 Gt in 2003. Worldwide, CO_2 emissions from electricity generation increased by more than 3 Gt between 1990 (the base year for reductions under the Kyoto Protocol) and 2003.

Power plants have a life span of 30 to 60 years. The replacement rate of the existing capital stock limits the rate at which new technologies enter the market. Many of the power plants entering the market from 2020 to 2050 will still be in use toward the end of the century. Thus, when capital stock does turn over or expand, a failure to choose advanced low-emissions technology will lock-in the future energy system with higher emissions.[1] Emissions growth can be moderated by putting more efficient technology into place as capital stock expands, particularly in the rapidly growing economies of the developing world.

1. Technology learning further emphasises the risk of lock-in and the need to use stock expansion or replacement to deploy new low-emissions technologies early on. Without market experience, no learning occurs, and the cost reductions and technical improvements required for mass deployment do not materialise.

Table 4.2 ▶ **CO_2 emissions from electricity generation (million tonnes of CO_2)**

	1973	1985	1990	2003	Average annual growth rate 1973-2003
OECD					
Coal	1 819	2 773	3 006	3 655	1.5%
Oil	806	420	474	385	–1.6%
Gas	282	316	409	819	5.5%
Other	1	5	24	58	7.2%
Total	*2 907*	*3 513*	*3 913*	*4 918*	*1.8%*
Developing countries					
Coal	265	661	1 050	2 830	7.9%
Oil	158	280	319	439	2.5%
Gas	24	109	167	495	8.7%
Other	0	0	0	2	–
Total	*446*	*1 051*	*1 536*	*3 766*	*7.1%*
Transition economies*					
Coal	547	625	690	588	–1.2%
Oil	215	365	263	103	–6.9%
Gas	189	410	562	631	0.9%
Other	0	0	0	10	–
Total	*951*	*1 399*	*1 515*	*1 332*	*–1.0%*
World					
Coal	2 631	4 059	4 747	7 074	3.1%
Oil	1 179	1 065	1 056	927	–1.0%
Gas	494	835	1 138	1 945	4.2%
Other	1	5	24	70	8.7%
Total	*4 305*	*5 964*	*6 964*	*10 016*	*2.8%*

* Transition economies include non-OECD Europe and former Soviet Union.
Note: "Other" includes industrial waste and non-renewable municipal waste. CO_2 emissions are from electricity and heat production including public and auto producers.
Source: IEA, 2005a.

Challenges for Electricity Generation Technologies

Energy technologies that can significantly limit the growth in CO_2 emissions in the power generation sector are at varying stages of development and deployment.

The *demonstration stage* refers to plants that have been built for the purpose of demonstrating technology feasibility. Usually, government funds a significant share of these projects. After a successful and completed demonstration phase, a given technology is then ready to move to the *deployment stage*. This stage refers to when plants can be operated to provide electricity to the grid, implying successful technical operations under market conditions, without necessarily being economically successful. A *commercial technology* is one that is available in the market but that may still need financial support, while a competitive technology can compete without a subsidy.

Efficient fossil-fuel power plants, such as combined-cycle and supercritical steam-cycle plants, are commercially available today, as are biomass-based combined heat and power units, onshore wind power, geothermal and hydropower technologies. Some technologies, such as offshore wind power, need deployment support to accelerate technology learning. Others, such as grid-connected solar photovoltaic systems, need cost reductions and improved performance to be widely deployed. Still other technologies would benefit from further RD&D, including concentrating solar power, integrated gasification combined-cycle systems and CO_2 capture and storage.

Technology innovation in the power generation sector can play a key role in order to achieve significant CO_2 emission reductions. Innovation in energy technology involves many complex processes. Scientific research can lead to findings that spawn new technological advances. Dissemination of new technologies can lead to efficiency improvements and reductions in manufacturing costs (technology learning), which can in turn spur more technology use. Demonstration and deployment also provide opportunities for learning as feedback from market experience may suggest ways to improve the technology reduce costs and better match technology features with consumer needs.

New technologies face a number of barriers that consist of technical issues, costs, resource availability, environmental issues, institutional barriers and public acceptance, including local opposition to large-scale electricity infrastructure projects. However, the relevance of these barriers differs by technology and by country. The following sections address relevant barriers for the main technology categories.

Fossil Fuel-fired Power Plants: Status and Prospects

Overview

Reducing CO_2 emissions from fossil-fuel fired plants can be achieved by improving conversion efficiency, co-firing coal with biomass, adding synthetic biogas to natural gas, employing CO_2 capture and storage (CCS) and by switching from coal to natural gas.[2] The choice of mitigation strategy depends on

2. The potential for CCS to contribute to an emissions mitigation strategy and the potential for biomass technologies are discussed later in this chapter.

the existing power generation stock, the price of competing fuels and the cost of alternative technologies. The current mix of natural gas and coal in electricity generation varies by country and region according to resource availability and domestic fuel prices. This section examines the current shares of natural gas and coal-fired plants worldwide and their efficiency in electricity generation. It also provides the status and prospects for five advanced technologies: natural gas combined-cycle (NGCC); advanced steam cycles for coal-fired generation; fluidised-bed combustion; integrated gasification combined-cycle (IGCC); and fuel cells.

All efficiency figures are based on Lower Heating Value (LHV). The difference between the LHV and the higher heating value (HHV) of a fuel is the energy needed to transform the water product of the combustion reaction into steam. European and IEA statistics are reported on an LHV basis, while US statistics are reported on an HHV basis. The difference is about 5% for coal and 10% for natural gas, corresponding to about two percentage points lower efficiency for a coal-fired power plant when HHV is used instead of LHV, and a five percentage points drop for a gas-fired combined-cycle plant.

Status of Natural Gas and Coal-fired Electricity Generation

Table 4.3 shows the shares of coal and natural gas in total electricity generation by country and region. In China, the share of coal in power generation is nearly 80%. Australia also uses coal for more than three-quarters of its electricity generating needs. In India, coal accounts for more than two-thirds. Coal-fired generation also accounts for more than half of electricity generation in the United States. The share of natural gas is greatest in the Middle East, but it is also quite high in the countries of the former Soviet Union, where the share of natural gas in electricity generation is 43%. Natural gas accounts for a large share of electricity generation in Mexico and in many Asian countries, including Bangladesh and Thailand.

Table 4.3 also shows a given country or region's contribution to the global use of natural gas and coal for electricity generation. China, India and the OECD countries account for 88% of global coal-fired electricity production. Electricity production from natural gas is more evenly distributed, with the OECD countries and Russia accounting for 66% of global gas-fired power production.

Table 4.4 shows the capacity of natural gas and coal-fired plants by technology in 2003. Worldwide, 97% of all coal-fired capacity uses pulverised coal. Some 85% of coal-fired capacity is based on subcritical pulverised coal, while 11% is supercritical and 2% ultra-supercritical. Another 2% is based on subcritical fluidised bed combustion (FBC) and less than 0.1% uses integrated-gasification combined-cycle. Natural gas-fired combined-cycle plants account for 38% of global gas-fired capacity, while 25% is open-cycle gas turbine. Gas boilers make up 36% of global gas-fired capacity, while internal-combustion engines account for less than 1%.

Table 4.3 ▶ **Shares of coal and natural gas in power generation, 2003**

	Coal share in domestic electricity generation	Gas share in domestic electricity generation	Share in global coal use for electricity generation	Share in global gas use for electricity generation
OECD				
United States	*51%*	*17%*	*31%*	*21%*
Canada	*19%*	*5.8%*	*1.7%*	*1.1%*
Mexico	*14%*	*35%*	*0.5%*	*2.4%*
OECD Europe	*30%*	*18%*	*15%*	*19%*
Japan	*28%*	*24%*	*4.4%*	*7.8%*
Korea	*39%*	*12%*	*2.0%*	*1.3%*
Australia	*77%*	*14%*	*2.6%*	*1.0%*
Transition economies				
Former Soviet Union	*19%*	*42%*	*3.9%*	*17%*
Non-OECD Europe	*46%*	*7.7%*	*1.3%*	*0.5%*
Developing countries				
Africa	*46%*	*25%*	*3.5%*	*4.0%*
China	*79%*	*0.3%*	*23%*	*0.2%*
India	*68%*	*11%*	*6.5%*	*2.3%*
Other Asia	*29%*	*37%*	*3.8%*	*10%*
Latin America	*3.0%*	*13%*	*0.4%*	*3.4%*
Middle East	*6.5%*	*52%*	*0.5%*	*9.0%*
World	**40%**	**19%**	**100%**	**100%**

Table 4.4 ▶ **Current capacity of natural gas and coal-fired power plants world wide, 2003**

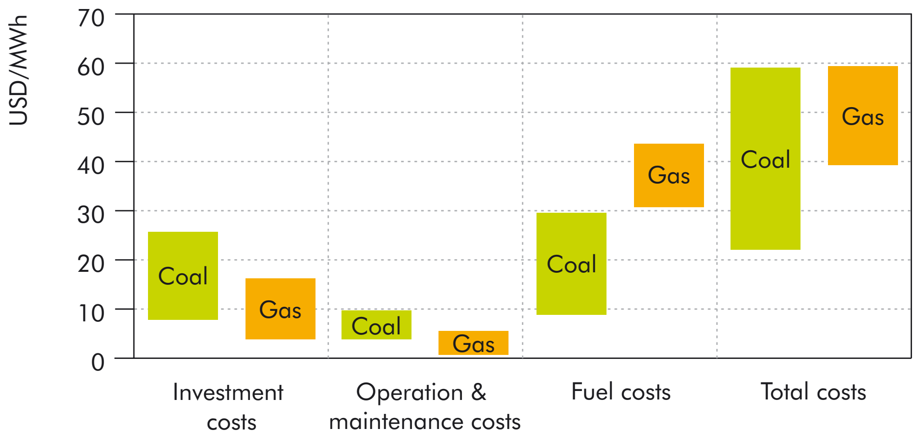
Natural gas	GW	Coal	GW
Combined-cycle	351	PCC subcritical	970
Natural gas turbine	225	PCC supercritical	138
Steam cycle	332	PCC ultra-supercritical	17
Internal combustion engine	7	Fluidised bed combustion subcritical	17
		Integrated gasification combined-cycle	1

Note: PCC – pulverised coal combustion. Supercritical plants are defined as those operating with steam temperatures above 540 °C. Ultra-supercritical plants are supercritical pressure units operating with temperatures above 580 °C.

Source: Natural gas-fired capacity from IEA, 2004b; coal-fired capacity from IEA Clean Coal Centre.

Power generation using natural gas is competitive given today's prices for natural gas in many regions of the world (typically USD 4 to USD 6 per GJ). However, total generation costs are more sensitive to increases in fuel prices in natural gas combined-cycle (NGCC) plants than in plants using other generation technologies. Fuel costs account for 60 to 75% of total generation costs, whereas in plants powered by renewables, nuclear or coal, the share of fuel costs is between zero and 40% (Figure 4.1). Consequently, comparable increases in different fuel prices for electricity generation, in absolute or relative terms, would have a more serious impact on the economics of NGCC than that of other technologies. Developments in the United States and Europe in recent years have confirmed this, as rising natural gas prices have resulted in a switch to coal-fired generation. The rapid development of natural gas-fired power generation could strain gas production and transmission systems and lead to further natural gas price increases.

Figure 4.1 ▶ **Costs of natural gas and coal-fired power plants**[3]



Key point

Natural gas plants are more sensitive to fuel costs, while coal plants are generally more capital intensive.

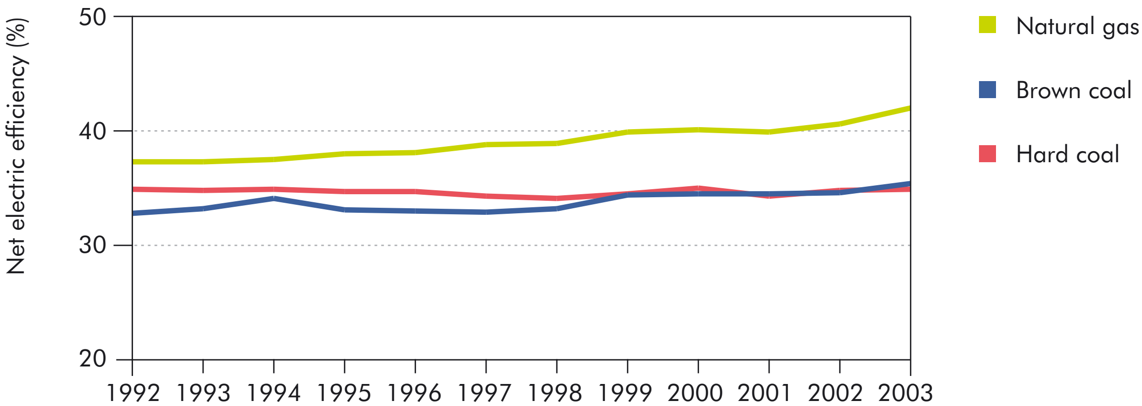
Efficiency of Natural Gas and Coal-fired Plants

The evolution of average efficiency for hard coal, brown coal and natural gas-fired power plants is shown in Figure 4.2.[4] The efficiency of hard coal-fired power plants averaged about 35% from 1992 to 2003, while the efficiency of brown coal-fired power plants increased from 33% in 1992 to 35% in 2003. The average efficiency of brown coal-fired plants is now slightly higher than that of hard coal-fired plants, because lignite plants modernised in Germany in the 1990s have pulled up the average.

The average efficiency of natural gas-fired power plants increased from 35% in 1992 to 42% in 2003. Most of the improvement in efficiency was a result of the introduction of large combined-cycle units, which now account for 38% of global gas-fired capacity.

3. Investment cost ranges cover discount rates from 5% to 10% as reported in NEA/IEA, 2005. In each category, the 5% highest and lowest values have been excluded.
4. The data refer to gross efficiency, so they are not corrected for own-electricity use. The figures refer only to centralised power plants.

Figure 4.2 ▶ **Global average power plant efficiencies, 1992-2003**



Key point

The introduction of large combined-cycle units has significantly improved the average efficiency of natural gas plants.

Regional trends in efficiencies are provided in Table 4.5. In 2003, the efficiency of natural gas-fired power plants ranged from about 33% in Russia to 49% in Western Europe. Average efficiencies in Europe have increased since 1990 with the introduction of natural gas combined-cycles units. The range of efficiencies among regions widened, mainly because of the rapid efficiency gains in Western Europe. If Russian gas-fired plants had the same average efficiency as that of Western Europe, a third less gas would be needed to cover current electricity demand.

Table 4.5 ▶ **Evolution of the gross electric efficiency of natural gas and hard-coal plants (%)**

	Natural gas			Hard coal		
	1974	1990	2003	1974	1990	2003
United States	37	37	43	34	37	37
Western Europe	39	40	49	32	38	39
Japan	40	42	44	25	39	42
China	–	35	44	27	31	33
Russia	36	33	33	–	–	–
World	**36**	**35**	**42**	**30**	**34**	**35**

Note: Russian coal-fired plant efficiency is not included because data available to the IEA indicate that there are virtually no electricity-only plants in operation.

In 2003, the efficiency of hard coal-fired power plants ranged from 33% in China to 42% in Japan. China is the world's largest consumer of coal, and if Chinese plants were as efficient as the average plant in Japan, coal demand would be 21% less in China.

4

The average efficiency of hard coal-fired plants in the United States has not changed significantly over the last 30 years, while the efficiency of plants in Western Europe and China has increased by about 6 percentage points. This difference can be explained by the investment patterns and the technology choice. Coal-fired power plants in the United States tend to have lower efficiencies than those in Europe or Japan. Coal prices are lower in the United States, so there is less of an economic incentive to invest in more efficient technology.

The current efficiency of most coal-fired power plants is well below state-of-the art and there is still potential for significant efficiency improvements in state-of-the-art technologies. Efficiency gains can be realised by improving existing plants or by installing new generation technology. The cost of retrofit or replacement depends on the efficiency and the age of the stock in place. Retrofitting an existing plant is more economical the younger the plant.

The efficiency of power plants also depends on the quality of fuel, especially of coal, on environmental standards and the operation mode. All else being equal, power plants using high-ash, high-moisture coal have a lower efficiency than plants using low-ash, low-moisture coal. This is the main reason for the low efficiency of coal-fired generation in India. Cleaning of flue gases requires energy and therefore reduces the power plant efficiency. Running plants below their rated output, a common practice in market-driven electricity-supply systems, substantially reduces plant efficiency.

Pulverised coal combustion (PCC) accounts for about 97% of the world's coal-fired capacity. Improving the efficiency of PCC plants has been the focus of considerable efforts by the coal industry as it seeks to stay competitive and to become more environmentally acceptable. PCC subcritical steam power plants, with steam pressure of around 180 bar, temperatures of 540°C and combustor-unit sizes up to 1 000 MW, are commercially available and in use worldwide.[5] The overall efficiency of older, small PCC plants that burn low-quality coal can be below 30%. The average net efficiency (after in-plant power consumption) of larger subcritical plants burning higher quality coal is between 35 and 36%. New subcritical units with conventional environmental controls operate closer to 39% efficiency.

Supercritical steam-cycle plants with steam pressures of around 240 to 260 bar and temperatures of around 570°C have become the system of choice for new commercial coal-fired plants in many countries. Early supercritical units developed in Europe and the United States in the 1970s lacked operational flexibility and reliability and experienced maintenance problems. These difficulties have been overcome. In Europe and Japan, plants with supercritical steam operate reliably and economically at net thermal efficiencies in the range of 42 to 45%, and even higher in some favourable locations. Ultra-supercritical plants are supercritical pressure units with steam temperatures of approximately 580°C and above.

Integrated coal gasification combined-cycle (IGCC) plants are a fundamentally different coal technology, and are now commercially available. However, only a small number of plants, which were built initially as demonstrations with public funding, are currently operating, with the best one achieving 42% electric efficiency.

5. Steam cycles are classified according to their steam conditions: subcritical, supercritical and ultra-supercritical.

Future coal-fired steam units and IGCC plants are expected to achieve efficiencies above 50% in demonstrations within ten years.

PCC is not always appropriate for coal with high ash and sulphur content. With these fuel characteristics, fluidised-bed combustion (FBC) in boilers operating at atmospheric pressure are more efficient. FBCs rely on two technologies: bubbling beds (BFBC) and circulating beds (CFBC), the latter being more commonly used for power generation applications. The power generation efficiency of larger CFBC units (200 to 300 MW_e) is generally comparable to that of PCC plants because they use steam turbine cycles employing similar conditions.

Brown coal (lignite) is expected to increase its contribution to coal supply in many countries. It has a higher water content than hard coal, a lower heating value and different boiler requirements. The optimal technology choice for hard coal and lignite may differ, as the availability and price of different coal types affects the power generation technology choice.

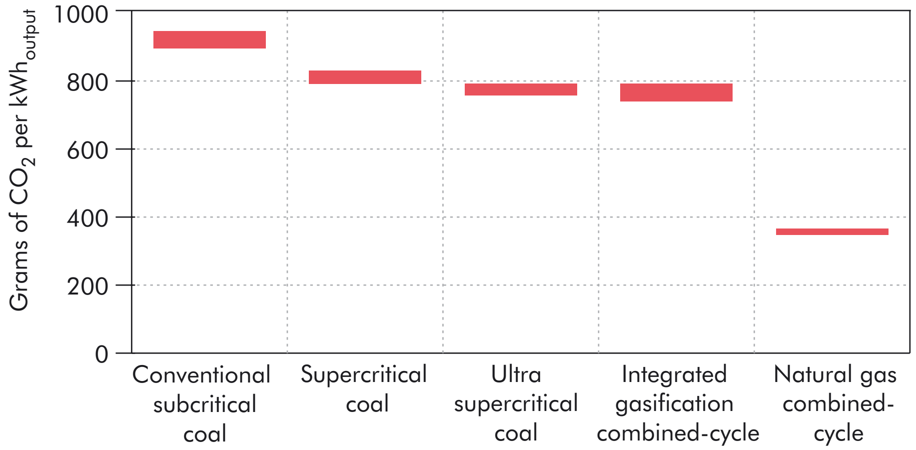
There is considerable opportunity to increase the efficiency of natural gas-fired generation, primarily by replacing gas-fired steam cycles with more efficient combined-cycle plants, which now account for more than one-third of global gas-fired capacity. A combined-cycle natural gas-fired plant consists of a gas turbine and a steam cycle. Efficiency is much higher in combined-cycle plants than in open-cycle (gas-turbine only) plants or gas-fired steam cycle plants. A gas-fired steam cycle has efficiency similar to that of a coal-fired plant. Open-cycle plants are used as peaking plants, so their annual use is low, hence making their low efficiency more acceptable from a cost perspective.

Natural gas-plant efficiency falls considerably when plants are run at widely varying loads. This explains why reported fleet efficiencies fall below quoted design efficiencies. Since the early 1990s, NGCC plants have been the preferred option for new gas-fired generation. Efficiencies of the best available combined-cycle plants are 60%.

Because of the long lifespan of power plants, the average efficiency of currently operating power plants is substantially lower than what could be achieved by the best available technology. Power producers aim primarily to minimise their production costs, not to maximise efficiency – and these two objectives do not always coincide. The best available gas-fired plants achieve about 60% electric efficiency. The best available coal-fired plants achieve 46 to 49%, depending on location and the cooling system. A comparison of the efficiencies in Table 4.5 with the best available power plant efficiency shows that fuel consumption and CO_2 emissions could be reduced considerably if the best available technologies were employed.

Efficiency improvements can be powerful tools for CO_2 and other emissions abatement. For a power plant with efficiency of 30%, a 15 percentage point increase in efficiency brings about a 33% decrease of CO_2 emissions. Efficiency improvements have the potential to reduce emissions of sulphur dioxide and, in certain cases, nitrous oxides (NO_X). Natural gas combined-cycle plants have the lowest CO_2 emissions of all fossil fuel-based technologies, because of the low carbon intensity of natural gas and the high efficiency of the plants (Figure 4.3). The prospects for the technologies in Figure 4.3 are discussed at the end of this section.

Figure 4.3 ▶ **CO_2 emissions by type of plant**[6]



Key point

Natural gas combined-cycle plants have the lowest CO_2 emissions of all fossil fuel-fired options.

Age of Coal-fired Plants

The age of existing coal generation plants has a considerable impact on the potential for CO_2 emission reductions. Some of the main factors influencing the lifespan of a coal-fired power plant are the outage rate, the degree of monitoring of plant operation, the ability to repower existing plants, environmental standards and electricity market liberalisation. Outage rates for coal-fired plants are generally about 5% for plants that are 10 to 20 years old. Unless the plant is refurbished, the rate increases to 20% at age 40. Trade-offs are, therefore, possible between low efficiency and the outages of aging plants on the one hand, and investment in new plants on the other (Armor, 1996). Monitoring of power-plant operations has improved, bringing better control of process conditions and longer power-plant life. In the United States, repowering projects for existing coal plants have significantly extended plant lifetimes and, in certain cases, resulted in substantial efficiency improvements. China is planning to repower existing plants by introducing circulating-fluidised bed steam boilers and by replacing pulverised coal boilers with supercritical plants.

Environmental regulations exert an influence on plant lifespan, as well. Measures to reduce pollutant emissions and to co-fire with other fuels require careful economic assessment, especially in older plants, where changes to operating conditions may be detrimental to boiler life. Electricity market liberalisation has brought more start-and-stop cycles than were contemplated in original plant designs, and this has considerably reduced boiler life (Paterson and Wilson, 2002).

6. The emissions shown in this chart are based on a range of efficiencies.

The age profiles of coal-fired power plants currently operating in the United States, China, Germany, Japan, United Kingdom and India are shown in Figures 4.4 through 4.9. For each country, installed coal-fired capacity in MW is shown on the y-axis, and the plant's commission date is shown on the x-axis.[7] On each bar, the capacity is subdivided according to the size of the units, in the ranges of 50 to 200 MW, 200 to 400 MW and units greater than 400 MW. Plant life extension programmes will be more important in the countries with a larger number of aging coal-fired plants.

In Germany, about a third of the stock is under 15 years old. Given a lifespan of 40 to 60 years, retrofits may be considered for these plants. In the United Kingdom, most plants currently operating are 30 years old. Plant life extension is considered a viable option for these plants. New plants in Europe normally include flue gas desulphurisation and NO_X controls, so at this stage no retrofits are expected for these newer units.

Construction of coal-fired stock in the United States peaked around 1970. Given a lifespan of 40 to 60 years, many plants will have to be replaced between 2010 and 2030. Therefore, retrofitting existing plants will probably not be a favoured option but is still possible for larger units with higher steam parameters. In Japan and China, the bulk of coal-fired power plant stock is under 15 years old, so retrofitting existing stock may be a good option. Indian plants are on average 20 years old, which may offer retrofit opportunities.

Prospects for Fossil Fuel-fired Power Plants

Natural Gas Combined-cycle

Technology Status

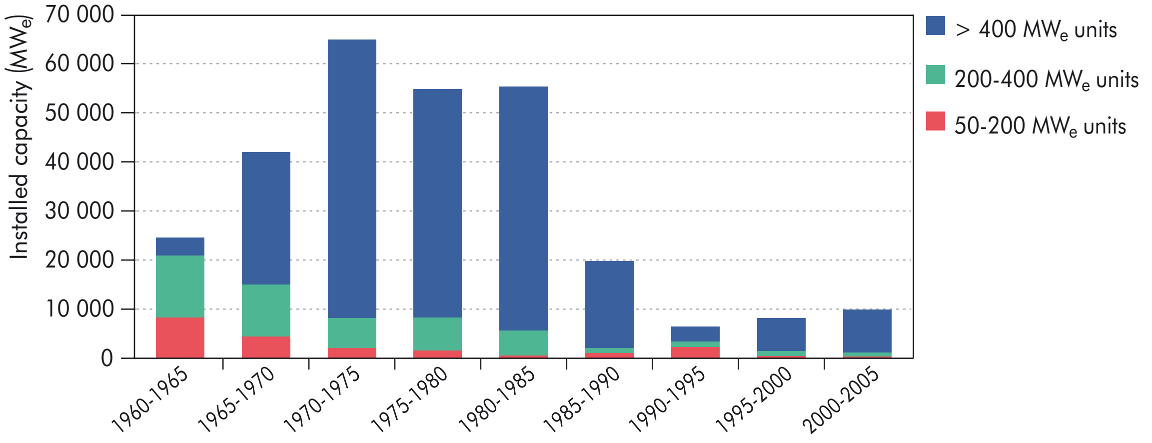
Natural gas burned in a turbine produces energy that can be converted to electricity with a coupled generator; the process also produces hot exhaust gases. Routing these gases through a waste-heat recovery boiler produces steam, which can be turned into electric power with a coupled steam turbine and generator. The gas turbine, waste-heat boiler, steam turbine and generator make up a combined-cycle unit. Steam from the boiler can also be used for heating purposes.

Today, NGCCs are often preferred over conventional coal-fired plants based on the following factors:

- Efficiency achievements topping 60% (LHV).
- Lower capital costs of USD 450 to USD 600 per kW, compared with USD 1 000 to USD 1 200 per kW for a typical coal-fired plant.

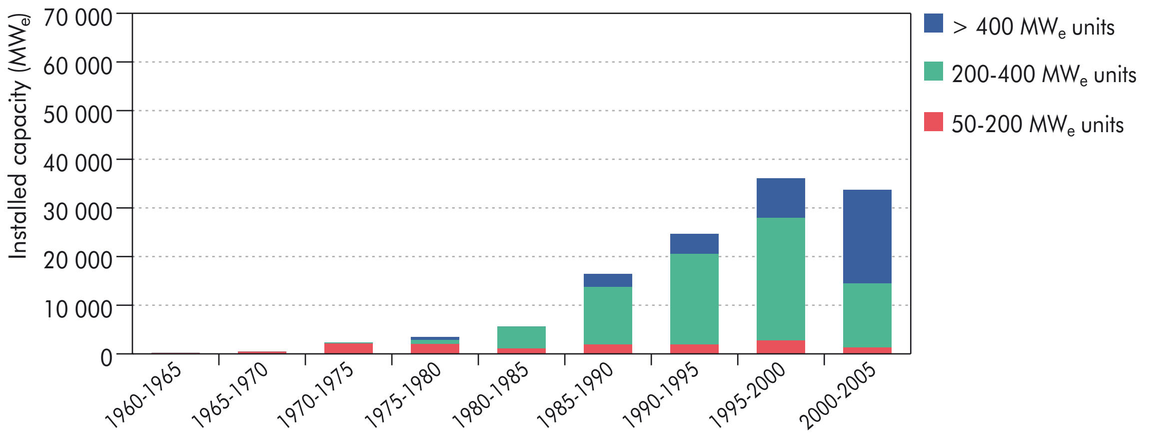
7. Note that the y-axis scale for the Unites States and China differs from the scale used for the other four countries.

Figure 4.4 ▶ **Age distribution of coal-fired capacity by size in the United States**



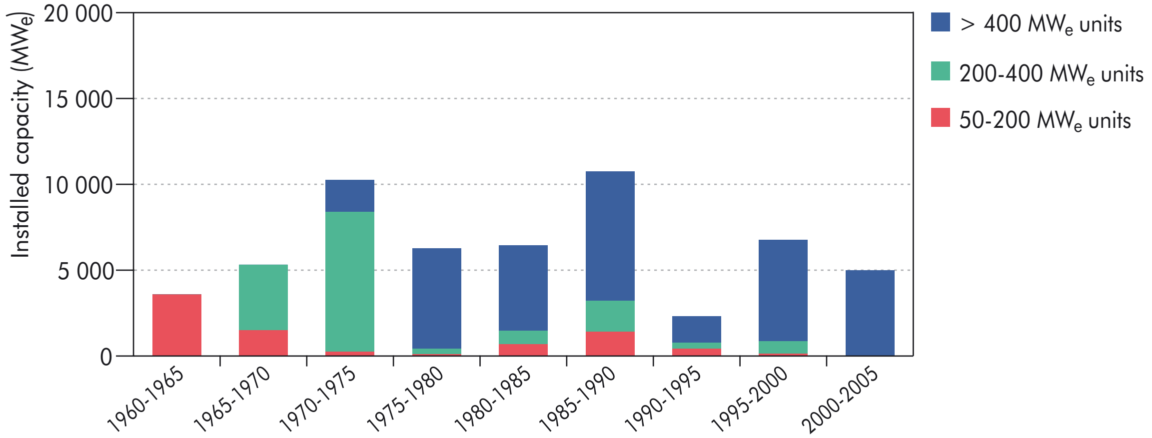
Source: IEA Clean Coal Centre, 2005b.

Figure 4.5 ▶ **Age distribution of coal-fired capacity by size in China**



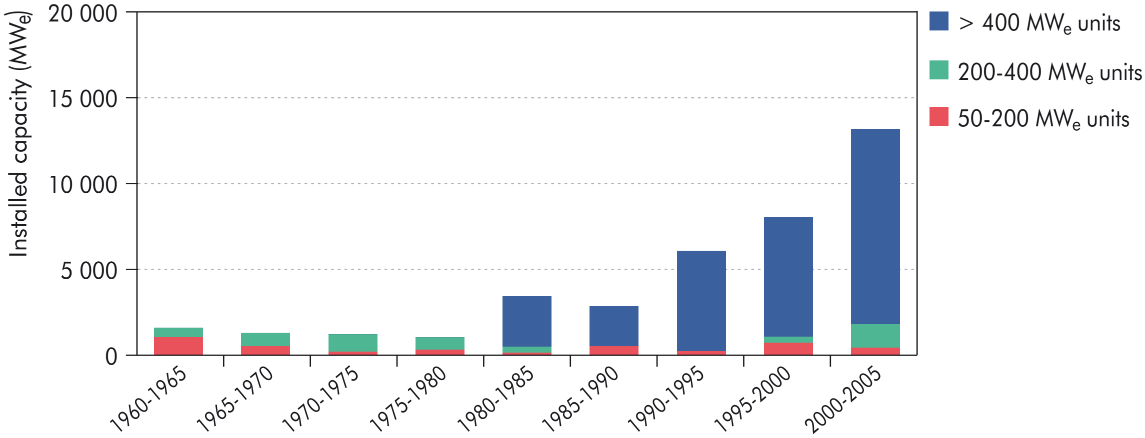
Source: IEA Clean Coal Centre, 2005b.

Figure 4.6 ▶ **Age distribution of coal-fired capacity by size in Germany**



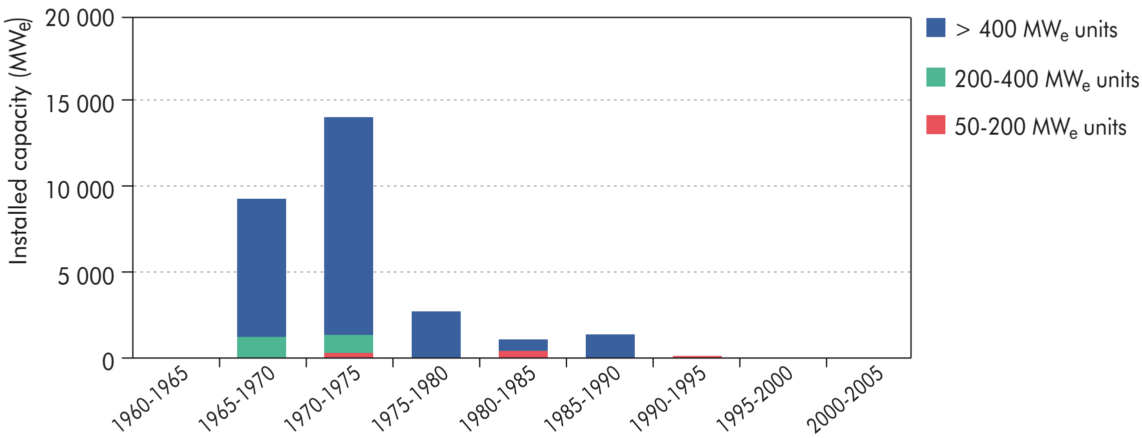
Source: IEA Clean Coal Centre, 2005b.

Figure 4.7 ▶ **Age distribution of coal-fired capacity by size in Japan**



Source: IEA Clean Coal Centre, 2005b.

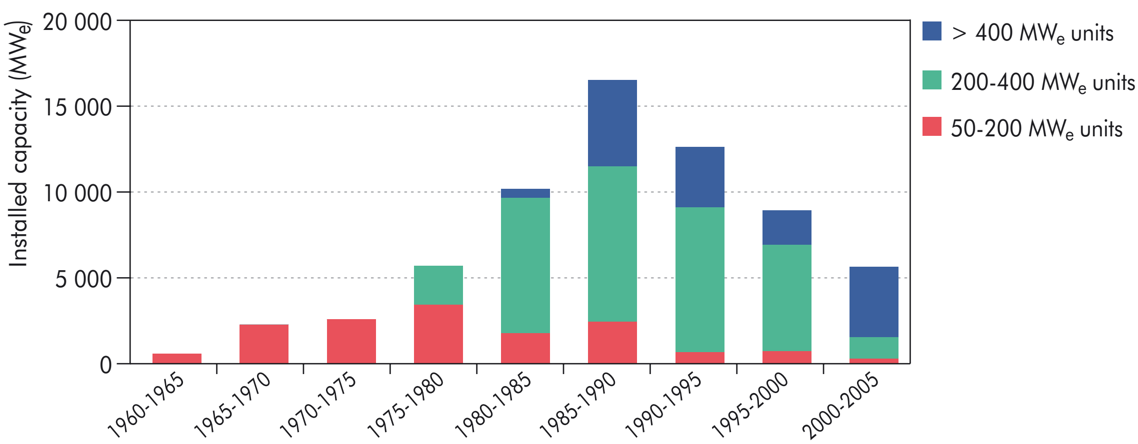
Figure 4.8 ▶ **Age distribution of coal-fired capacity by size in the United Kingdom**



Note: No new plants in the 1995-2005 periods.

Source: IEA Clean Coal Centre, 2005b.

Figure 4.9 ▶ **Age distribution of coal-fired capacity by size in India**



Source: IEA Clean Coal Centre, 2005b.

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- Shorter construction times, as NGCCs are modular and much of the plant can be fabricated at a factory in three years or less from the time of ordering to commissioning.

- Emissions are low (less than half the CO_2 emissions of coal-fired plants).

The efficiency of NGCCs has improved with new gas turbine technology. The F-class combined-cycle gas turbine (in the 200 MW range) was first introduced in the 1990s. Many of its features derive from jet-engine technology. However, the turbines for power generation were not subjected to the same rigorous testing. Although commissioning problems have occurred, combined-cycle gas turbine designs have progressed, with advances in both cooling systems and materials, including higher compression ratios and higher firing temperatures. The efficiency of combined-cycle technology using the latest turbine design (the H-class) is now 60% (LHV). It is estimated that advanced NGCCs, compared to today's technology, will bring a further reduction of 3 to 6% in CO_2 emissions per kWh of electricity generated. Further efficiency gains are possible if fuel cells are integrated into the design, or if a bottoming cycle using waste heat is added.[8] Of course, complex designs will add to the cost.

Natural gas turbines are also employed as peaking plants that generate electricity only during periods of high demand. Such single cycle plants will likely coexist with advanced NGCCs, since low capital costs are more important than high efficiencies when the annual load factor is low.

Future R&D Efforts

Future R&D efforts will likely focus on natural gas turbine design and additional efficiency improvements (see Box 4.1). Gas turbine R&D is aimed at higher firing temperatures and the use of reheat, which gives higher power outputs and efficiencies but which may increase NO_X formation. A number of counter measures are under consideration, including the use of novel gas turbine cycles. Many gas turbine manufacturers are also investigating the possibility of more advanced combustors, including catalytic combustors. Other R&D activities aim to increase the aerodynamic efficiencies of components to reduce the number of compressor and turbine stages, and to improve turbine-stator and blade-cooling mechanisms.

Challenges to Future Deployment

The greatest challenge to the further adoption of NGCCs is uncertainty regarding future natural gas prices. Fuel costs account for 60 to 75% of total generation costs, compared to between zero and 40% for renewables, nuclear and coal. Hence, a given increase in fuel prices would have a more serious impact on the economics of an NGCC plant than on other technologies. A rapid increase in the use of NGCCs could, in itself, lead to higher prices for natural gas, and in some countries, to concerns over energy security and diversification.

8. A bottoming cycle uses a medium with a low boiling temperature, such as an organic solvent.

Box 4.1 ▶ Material design and higher temperature steam

Strategies for increased power plant efficiency are usually aimed at higher temperature and pressure conditions. Because higher temperatures cause more corrosion and higher steam pressures require stronger vessels and tubing, the design of appropriate materials is one of the main challenges to improve the efficiency of NGCC and coal-fired steam cycles. The efficiency of steam cycles is determined by the steam conditions, especially temperature. The steam's maximum temperature is limited by the availability of materials that can withstand very high pressure. Current steel alloys reach their limit at a temperature of about 600°C. Other materials, such as ferritic steel with a limit of 650°C and austenitic steel of 700°C, were the focus of research in the 1990s, but these materials have not yielded satisfactory results. In recent years, research has focused more on nickel alloys, originally developed for use in gas turbines. These alloys can withstand temperatures of between 700°C and 750°C.

Nickel alloys cost ten times as much as ferritic and austenitic steels and a hundred times as much as carbon-manganese steels (Fleming, 2002). The use of nickel for turbine construction on a large scale could increase the price of nickel. So far, there has not been widespread use of these alloys. However, only certain parts of any plant experience the high-temperature conditions that require the use of the nickel alloys. Novel plant designs can reduce the costs of investment in nickel alloys. Such designs have been developed in the framework of the EUs 700°C-power plant project. Their introduction and other measures would enable the construction of power plants with a maximum steam temperature of 700°C. The net electric efficiency of ultra-supercritical coal plants such as these could exceed 50%. There are plans to demonstrate such plants within ten years.

In the United States, the Department of Energy is funding part of the design and construction of ultra-supercritical plants, as well as paying operating costs for the first few years.

Advanced Steam Cycles: Supercritical and Ultra-supercritical Pulverised Coal-fired Plants

Technology Status

Supercritical and ultra-supercritical plants are defined by the steam temperatures. Supercritical plants use steam temperatures of 540°C and above, while ultra-supercritical plants use 580°C and above. Supercritical steam-cycle technology has been used in IEA countries for several decades. The technology is now also applied in developing countries. In China, more than 60 GW of supercritical units were ordered in the past two years. Japan has five ultra-supercritical plants in operation, all with steam temperature of 593°C (Australian Black Coal Utilisation Research Ltd., 2003). There are also ultra-supercritical plants in operation in Denmark and Germany. Ultra-supercritical units operating at temperatures of 700°C and higher are still in the R&D and demonstration phase.

Costs and Potential for Cost Reductions

Total investment cost for ultra-supercritical steam cycles plants can be 12 to 15% higher than the cost of a subcritical steam cycle and still be competitive because of fuel savings. The balance-of-plant cost is 13 to 16% lower in an ultra-supercritical plant, because of reduced coal handling and reduced flue-gas handling. The boiler and steam turbine costs can be as much as 40 to 50% higher for an ultra-supercritical plant. In the near future, higher investment costs will be balanced by the fuel savings; making ultra-supercritical steam cycle plants the most economic choice (Viswanathan, 2003). Studies in the United States of supercritical coal power plants indicate a relatively low learning rate of 5% for the capital cost.

Efficiency Improvements

Improvements in the average efficiency of coal-fired power plants are feasible now. Two-thirds of all coal-fired plants are older than 20 years, have an average net efficiency of 29% or lower, and emit at least 3.9 Gt CO_2 per year. If all of these were replaced by plants with efficiencies of 45%, the new plants would emit 36% less CO_2, for a reduction of 1.4 Gt CO_2 per year.

In power plants based on steam cycles, the introduction of coal drying for lignite may improve efficiency by up to 4 percentage points. This technology is expected to be commercial by 2010. Typically a switch from supercritical to ultra-supercritical steam conditions would raise efficiency by another 4 percentage points. Overall, the efficiency of ultra-supercritical pressure units could be in the range of 50 to 55% by 2020.

Challenges to Future Deployment

The major barriers to advances in supercritical and ultra-supercritical steam cycles are metallurgical and control problems. Developments in new steels for water and steam boiler tubes and in high alloy steels that minimise corrosion are expected to result in a dramatic increase in the number of supercritical plants installed over the next few years. New control equipment and strategies will also allow these plants to be more flexible than in the past.

Subcritical and Supercritical Fluidised-bed Combustion

Technology Description

In fluidised-bed combustion (FBC), coal is combusted in a boiler in which the coal, ash and sometimes inert materials are rendered highly mobile by an upward stream of preheated air. Most of the sulphur dioxide (SO_2) produced by the oxidation of the sulphur in the coal is captured by a sorbent (limestone or dolomite) that is also fed into the combustor. The solid waste that results is made up of sulphated sorbent plus ash. It can be used in agricultural and construction applications, although currently it is used for land reclamation purposes. At fluidised bed temperatures of 760 to 870°C, the mixing of the coal and sorbent enhances both combustion and sulphur capture. The operating temperature in the bed is much lower than for PCC plant burners. The heat is used to generate steam which drives a steam cycle that may be identical to a PCC.

Two parallel paths have been pursued in FBC development – bubbling (BFBC) and circulating (CFBC) beds. Bubbling beds use a dense fluid bed and low fluidisation velocity which mitigates erosion of the in-bed heat exchangers. Circulating beds use a relatively high fluidisation velocity which results in entrained flow. The solid material is separated from the gas in the hot cyclones and recirculated. Another promising option, particularly for CO_2 capture, is a circulating fluidised bed (CFB) power plant working with O_2 instead of air. In this case, solids are cooled down before their return to the bed and, consequently, the control of the temperature is achieved more effectively. This could lead to a significant reduction in flue gas recirculation, thus reducing both investment and operation costs.

Technology Status

There are hundreds of atmospheric circulating fluidised-bed combustion units operating worldwide, including a number of plants as large as 250 to 300 MW_e. Fluidised beds are particularly suited to the combustion of low quality coals, and most of the existing CFBC plants burn such materials. There are various designs on offer from different manufacturers, with some of them using external heat exchangers. The efficiency of large CFBC units is of the same order as that of comparable PCC plants firing similar coals. Moving to supercritical cycles is a logical step for very large CFBC units. A 460-MW_e supercritical unit is under construction at Lagisza, Poland. This plant is due for start-up at the beginning of 2009. This unit is expected to have a thermal efficiency of 43%. Designs for even larger 600 MW_e supercritical CFBC units have also been developed.

Other advantages of CFB systems include fuel flexibility, good emissions performance, boiler island cost savings as compared to pulverised fuel (PF) and Stoker firing, and the ability to scale up from a few MW_e to over 500 MW_e. CFB technology is a near-term solution, because it uses commercially available technologies including oxygen production and CO_2 stream gas processing.

There is ongoing work in the United States, funded by the US Department of Energy, to carry out tests under oxyfuel conditions in CFB (Marion, *et al.*, 2003). Such a design would reduce the plant size and facilitate CO_2 capture. Considerable R&D is needed to commercialise this technology. Preliminary observations from the DOE work are the following:

- **Bed dynamics.** Firing the base case CFB coal in O_2/ CO_2 mixtures, containing up to 40% volume O_2 in the primary combustor zone, *i.e.* upstream of the lowest overfire air port presented no bed agglomeration related problems.
- **SO_2 emissions.** In order to get efficient limestone calcination, the bed temperature was operated at about 900°C. For most fuels this temperature is above the optimum for sulphur capture, so emissions would be higher. Compared to air firing at the same temperature, the emissions may be comparable if calcination were complete. In the test the SO_2 emissions were lower with air firing at the same high temperatures as the 21% and 30% O_2 (in CO_2 balance), but the solids inventories were different. Quantitative analysis of these data will be completed in conjunction with the solids analysis and other operating parameters.
- **NO_X emissions:** NO_X emissions were lower with the O_2 firing, but the staging scenarios have not yet been fully analysed. The quantitative analysis of this data is in progress.

- **CO emissions:** CO emissions may be higher with O_2-firing due to higher CO_2 partial pressure in the flue gas. At comparable bed temperatures, for example, CO emissions were 1.2 to 1.8 times greater for 21% and 30% O_2-firing (in CO_2 balance), respectively compared with air firing.

Efficiency Improvements

Fluidised-bed combustion can also be employed at high pressure, in which case the boiler exhaust gases can be expanded through a turbine of moderate inlet temperature (around 850°C) to generate additional power. Heat is also recovered from the exhaust of the turbine. This approach has been applied in demonstrations at a small number of locations. The result is a form of combined gas and steam cycle that gives efficiencies of up to around 44%. However, conventional pressurised fluidised-bed combustion (PFBC) is currently without a champion. The first PFBC demonstration units had capacity of about 80 MW, but two larger units operate in at Karita and Osaki, Japan. The Karita unit uses supercritical steam.

Second-generation PFBC cycles, which are hybrid systems incorporating higher-temperature turbines with supplementary firing of coal-derived gas after the combustor, are under development in some locations, including Japan. These systems combine features of PFBC and IGCC. They have not yet reached demonstration scale.

Further R&D Efforts

Further work is required to understand the oxyfuel combustion conditions, to clarify further the mechanisms involved in pollutant formation and carbonation due to high CO_2 concentrations. Design considerations, particularly for supercritical boilers, are also important areas of research. It is also important to determine the extent of fuel flexibility and options for CO_2 sequestration in a cost effective manner, as well as issues concerning the oxygen supply for oxyfuel operations, such as the need for a liquid O_2 supply tank to deliver and maintain constant pressure.

Integrated Gasification Combined-cycle

Technology Description

Integrated gasification combined-cycle (IGCC) technology consists of four basic steps – (1) fuel gas is generated from a solid fuel such as coal that reacts with high-temperature steam and with an oxidant in a reducing environment; (2) the fuel gas either is passed directly to a cleanup system to remove particulates, sulphur and nitrogen compounds, or is cooled to produce steam and then cleaned conventionally; (3) the clean fuel gas is combusted in a gas turbine generator to produce electricity; and (4) the residual heat in the hot exhaust gas from the gas turbine is recovered in a heat-recovery steam generator. The steam is used to produce additional electricity in a steam turbine generator.

IGCC systems are among the cleanest and most efficient of the clean-coal technologies. Gasification technology can process all carbonaceous feedstocks, including coal, petroleum coke, residual oil, biomass and municipal solid waste.[9]

9. Petroleum coke is a black solid by-product, obtained mainly by cracking and carbonising petroleum-derived feedstock, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking.

Some three-quarters of IGCC plants in operation today run on a combination of these feedstocks.

Technology Status

Because of its high cost and availability problems, coal-based IGCC is not yet competitive. However, the technology is widely used in combination with heavy refinery residues. A small number of coal-fired IGCC demonstration plants are now operating in Europe and the United States, and one is being constructed in Japan. A 235 MW unit at Buggenum in the Netherlands has operated since 1993 and is currently being tested to incorporate up to 30% biomass. The plant's efficiency is about 42%. The 335 MW unit at Puertollano, Spain, fires a mixture of high-sulphur petroleum coke and high-ash coal. In the United States, the Wabash River unit in Indiana has a capacity of 260 MW and runs on petroleum coke. The 250 MW Polk Power unit near Tampa, Florida, operates on a combination of coal and petroleum coke. A 225 MW IGCC in Delaware is currently running on oil, but a new coal-based plant is expected to become operational in 2008. The efficiency of US plants is lower than that of European plants, mainly due to less efficient gasification technology in the United States.

Germany has one IGCC in operation, a 75 MW unit at SVZ Schwarze Pumpe, operating on oil. Several commercial IGCC plants based on petroleum residues have been built in recent years, and the main focus of commercial IGCC plants is currently on petroleum residues.

Further R&D Efforts

Major R&D efforts are ongoing in the field of gas turbines, gasification systems and oxygen production. Research is also being carried out to reduce capital and operating costs and to improve efficiency. System optimisation, integration of fuel cells, slagging in gasifiers, coal characterisation and the blending and re-use of waste material are also the focus of R&D. Cogeneration of electricity and other products, such as hydrogen or other transportation fuels, is also being considered.

Costs and Potential for Cost Reductions

Capital costs of IGCC plants today are about 20% higher than for PCC plants. General Electric, together with Bechtel, and Siemens with ConocoPhillips are preparing to launch reference plant designs within a year or so which are expected to yield higher efficiencies and to reduce costs to about the same level as those for PCC plants.

Studies have shown that second-generation IGCC plants will need to have an investment cost of less than USD 1 400 per kW and a net efficiency of more than 48% to be competitive with other clean coal technologies. Second-generation IGCC plants are expected to have lower kWh costs than PFBC and supercritical plants. Their competitiveness relative to NGCC plants depends on the evolution in natural gas prices. IGCC will benefit from advances in combined-cycle gas turbine technology. Current demonstration IGCC plants have efficiencies of 45%, but efficiencies of about 50% are expected to be achieved by 2020.

Challenges to Future Deployment

The greatest challenges to widespread adoption of IGCC plants include unresolved technical issues, low availability, high capital costs and competition from other clean-coal technologies. The technical challenges are related to gasifier capacity needs and maintenance requirements, heat transfer after the gasifier, gas clean-up, gas composition and combustion, waste-water treatment and the degree of process integration. Because gasifiers are pressure vessels, they cannot be fabricated on site in the same way that PCC boilers can. Large gasifiers are hard to transport, because of their weight and size. But this challenge has been overcome in principle, since two or more trains of smaller gasifiers and gas turbines can be combined to yield any desired size of plant.

Fuel Cells

Technology Description

Fuel cells use hydrogen or a hydrogen-rich fuel such as natural gas and oxygen to produce electricity through an electrochemical process. A fuel cell consists of two electrodes – a positive anode and a negative cathode – sandwiched around an electrolyte. They operate by feeding hydrogen to the anode and oxygen to the cathode. Activated by a catalyst, the hydrogen atoms separate into protons and electrons, which take different paths to the cathode. The electrons go through an external circuit – creating electricity – while protons migrate through the electrolyte to the cathode, where they reunite with oxygen and electrons to produce water and heat.

Stationary fuel cells can be used for the distributed and centralised production of electricity, but their use for decentralised power generation is much closer to commercialisation. If the waste heat generated is used in a combined heat and power system, the electric efficiency of decentralised systems can exceed 45% and overall system efficiency can exceed 90%. The clear advantage of using hydrogen in stationary fuel cells is that the high efficiency of fuel cells can be combined with zero CO_2 emissions from the generation plant.

Molten carbonate fuel cells (MCFCs) are being developed for use at natural gas and coal-fired power plants. They cannot be fuelled by pure hydrogen. MCFCs use a molten-carbonate-salt electrolyte suspended in a porous, inert ceramic matrix. They do not need an external reformer, because they operate at high temperatures (> 650°C). In addition, they do not use precious metal catalysts, further reducing their cost. Current designs achieve less than 50% electric efficiency (IEA, 2005d). Future MCFCs are projected to achieve stack efficiency of 60% and overall efficiencies of up to 90% if used for cogeneration. Their resistance to poisoning is also being improved, and efforts are underway to extend their economic life, which is limited by their high operating temperature and electrolyte-induced corrosion.

Solid oxide fuel cells (SOFCs) use a non-porous ceramic electrolyte and appear to be the most promising fuel cell technology for centralised electricity generation. The high temperature of these fuel cells would allow integration with gas turbines. In such configurations, SOFCs are expected to achieve an electrical efficiency up to 70% and up to 80 to 85% efficiency in cogeneration. However, today's stand-alone SOFC systems achieve at most 53% electric efficiency (IEA, 2005d). High operating temperatures of 800°C to 1 000°C mean precious-metal catalysts and external reformers are unnecessary, helping to reduce the cost of SOFCs. These advantages, though, are offset by cell design problems and a slow start-up capability due to the high operating temperature. SOFCs also have the advantage of being able to use carbon monoxide as fuel. The RD&D goal for SOFCs is to enhance their sulphur tolerance so that they can be fuelled by gas derived from coal. The development of materials with a high durability is also a critical technical challenge for this technology.

Proton exchange membrane fuel cells (PEMFC) are primarily aimed at the transport market. Due to their relatively low efficiency and hydrogen fuel needs, they are less suited for power generation. However, there may be opportunities to use this technology for combined heat and power generation for space heating.

Costs and Potential for Cost Reductions

The current investment costs for stationary fuel cells are high, between USD 13 000 and USD 15 000 per kW, compared to USD 500 to USD 700 per kW for a conventional large-scale gas-fired combined-cycle power plant. With mass production, the cost of molten carbonate fuel cell systems should be able to reach a target level of about USD 1 650 per kW. The stack cost represents half of the current investment cost. The incremental cost of fuel cells, however, should be weighed against the increased energy efficiency relative to other options. If the size of the molten carbonate fuel cell can be increased from 200 kW to 2 MW, the cost should decline by about 26% (Blesl, *et al.*, 2004).

Future Deployment

Because they are efficient on a small scale, fuel cells are well suited for decentralised power generation and could be used for cogeneration of electricity and heat. IEA analysis indicates that fuel cells could potentially account for about 3% of global power production capacity by 2050, which would correspond to between 180 GW and 300 GW (IEA, 2005d). Natural gas-fuelled systems appear to have greater potential than hydrogen-fuelled systems. If used for cogeneration, fuel cells can bring about a 20 to 50% efficiency gain. Fuel costs for decentralised residential systems, however, are much higher than for centralised power plants, although the transmission and distribution costs are lower.

In the future, fuel cells could be integrated into large centralised gas or coal-fired IGCCs. The electric efficiency would be five to ten percentage points higher. Large, high-temperature fuel cells suitable for large scale power generation are currently in the R&D stage. Demonstration is foreseen around 2020 and deployment about a decade later.

Cost Overview

In the long term, the electricity production cost of natural gas and coal-fired power generation technologies may converge, but this is dependent on future fuel prices (Table 4.6). Natural gas prices in particular vary widely across regions, and fuel availability is also very country specific. Consequently, the fuel and technology mix in 2050 will differ among regions.

Table 4.6 ▶ **Technology prospects for fossil-fuel power plants for baseload capacity**

	Net electric efficiency, 2015-2030 (% LHV)	Investment cost, 2015-2030 (USD/kW)	2015 Electricity generation costs (USD/kWh)	2030 Electricity generation costs (USD/kWh)	2050 Electricity generation costs (USD/kWh)
Gas NGCC	>60	400-500	0.032 - 0.036	0.035 - 0.045	0.045 - 0.05
Coal PCC	>50	1 000-1 150	0.041	0.035 - 0.04	0.035 - 0.04
Coal FBC	>45	1 000	0.035 - 0.04	0.035 - 0.04	0.035 - 0.04
Coal IGCC	>50	1 250	0.04 - 0.05	0.035 - 0.04	0.035 - 0.04
Gas fuel cells	>50	1 250	0.15	0.10	0.05 - 0.08

Note: Using 10% discount rate. The natural gas price increases to USD 5/GJ in 2030 and USD 6.5/GJ by 2050, USD 2/GJ higher for decentralised fuel cells. The coal price is USD 2/GJ over the whole period. Because fuel cells are a decentralised technology, transmission costs are reduced by up to USD 0.05/kWh compared to technologies for centralised power plants. This has not been taken into account in this table. The actual global range is wider as discount rates, investment cost and fuel prices vary.

CO_2 Capture and Storage: Status and Prospects

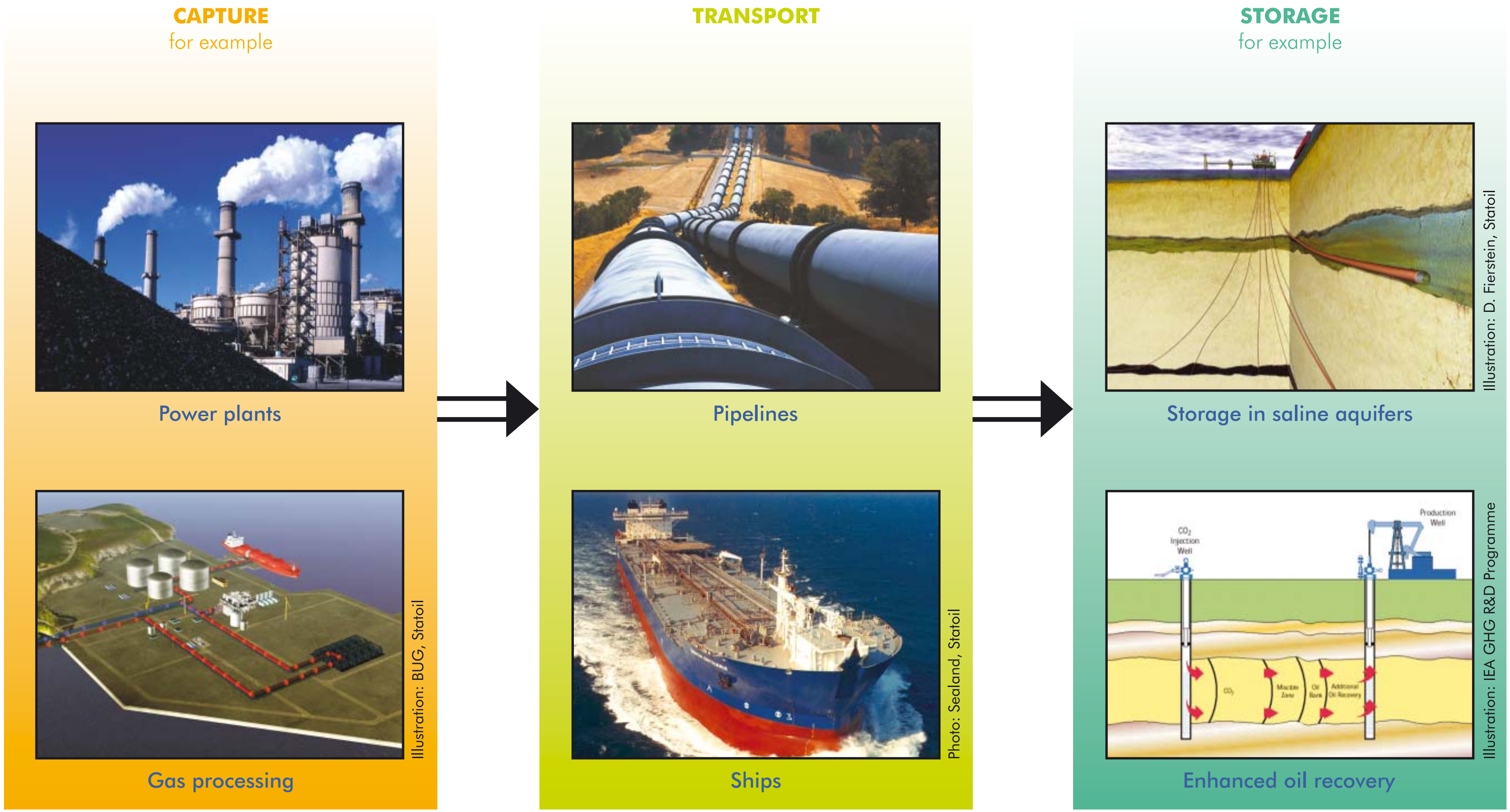
Status of CO_2 Capture and Storage

CO_2 capture and storage involves three distinct stages (Figure 4.10): (1) capturing CO_2 from power plants, industrial processes or fuel processing; (2) transporting the captured CO_2 by pipeline or in tankers; (3) storing CO_2 underground in deep saline aquifers, depleted oil and gas reservoirs or un-mineable coal seams. The technologies that are needed have been in use for decades, albeit not in combination with the purpose of reducing CO_2 emissions. Further technology development is needed, and the bulk of the costs will be on the capture side. The retention aspects of underground storage need to be proven and the economics and energy efficiency of capture need to be improved.

CO_2 separation has been widely applied in industrial processes and for natural gas processing, but there is limited experience with its use for power plants. While a number of capture technologies could be applied today, their use for commercial-scale power plants needs to be demonstrated. A number of such demonstration projects for coal and for gas-fired power plants are in various stages of development in Australia, Canada, Europe and the United States.

CO_2 can be stored in natural geological formations at a depth of more than 600 metres. There is little experience in the long-term effectiveness of CO_2 storage. Storage in deep saline aquifers has been demonstrated in one commercial-scale project in Norway (the Sleipner sub-sea storage project). About 1 Mt of CO_2 per year has been stored since 1996. This project is important as it proves that storage in aquifers can work in practice. CO_2 storage in combination with enhanced oil

Figure 4.10 ▶ *CO_2 capture, transport and storage concept*



recovery has been demonstrated at the Weyburn project in Canada. About 2 Mt of CO_2 per year has been stored since 2001. In both projects the behaviour of the CO_2 underground has corresponded to what models had predicted, and important progress was achieved in the understanding and monitoring of CO_2 behaviour underground. So far, no leakage has been detected.

Pilot projects suggest that CO_2-enhanced coal-bed methane and enhanced gas recovery may be viable, but the experience so far is not sufficient to consider these two as proven options. All options that enhance fossil fuel production can create revenues that may off-set part of the capture cost. Encouraged by the promising results so far, many more underground storage demonstration projects have been started or are planned.

Underground storage seems the only realistic option. The prospects for ocean storage (in the water column) are hampered by environmental risks. Above-ground storage would be costly and the technology is immature.

In principle, CO_2 can be captured from all installations that combust fossil fuels and biomass, provided that the scale of the emission source is large enough. When CO_2 capture is applied to processes that use biomass, the final result will be a net reduction of CO_2 from the atmosphere. CO_2 capture is generally limited to large sources since the per-tonne costs of capturing CO_2 increase as the amount of CO_2 emissions decrease.

CO_2 can be captured either before or after combustion using a range of existing and emerging technologies. In conventional processes, CO_2 is captured from the flue gases produced during combustion (post-combustion capture). It is also possible to convert the hydrocarbon fuel into CO_2 and hydrogen, remove the CO_2 from the gas stream and combust the remaining hydrogen-rich gas (pre-combustion capture). In pre-combustion capture, physical absorption of CO_2 is the most promising option. In post-combustion capture, options include processes based on chemical absorption or oxygen-fuelling. If oxygen is used for the combustion process, a nearly pure CO_2 flue gas is generated without further separation. In the long term, gas separation membranes and other new technologies may be used for both pre- and post-combustion capture. Captured CO_2 must be pressurised to 100 bar or more for the transportation and storage. This pressurisation adds to the energy-intensity of CCS.

In electricity generation, CO_2 capture only makes economic sense in combination with large-scale, high-efficiency power plants. For coal-fired plants, integrated gasification combined-cycle fitted with physical absorption technology to capture CO_2 at the pre-combustion stage is considered to be promising. Coal-fired ultra-supercritical steam cycles fitted with post-combustion capture technologies or various types of oxygen-fuelling (oxy-fuelling) technology (including chemical looping, where the oxygen is supplied through a chemical reaction instead of air separation), may emerge as alternatives. For natural gas-fired plants, oxyfuelling (including chemical looping), pre-combustion gas shifting and physical absorption in combination with hydrogen turbines, or post-combustion chemical absorption are promising options. At a later stage, fuel cells may be integrated into high-efficiency gas and coal-fired power plants fitted with CCS. Capturing CO_2 from plants which cogenerate electricity and synthetic fuels could reduce cost (IPCC, 2005).

Given the range of ongoing R&D efforts, it is not yet possible to pick a "winner" among the CCS options. It is likely that several technologies can co-exist, but all options require further improvements to cut costs and improve energy efficiency before they can be applied on a commercial scale, a process which is likely to take years. R&D is needed for certain emerging options such as chemical looping, while demonstration projects are needed for other pre- and post-combustion processes. The development must be accelerated if CCS is to play a substantial role in the coming decades and have a significant impact on emissions.

Prospects for CO_2 Capture Technologies

Cost and Potential for Cost Reductions

Today, the cost of CCS is estimated at between USD 40 and USD 90 per tonne of CO_2 captured and stored depending on the power plant fuel and the technology used. For the most cost-effective technologies, capture costs are USD 20 to USD 40 per tonne, with transport about USD 10 per tonne. In certain cases the benefits from enhanced oil recovery can off-set part of these costs. By 2030, costs could fall to below USD 25 per tonne of CO_2 captured for coal-fired plants provided sufficient R&D and demonstration efforts are put in place. The bulk of the cost is on the capture side.

Using CCS with new natural gas and coal-fired power plants would increase electricity production costs by USD 0.02 to USD 0.03 per kWh. By 2030, CCS cost could fall to USD 0.01 to USD 0.02 per kWh (including capture, transportation and storage). The per-tonne capture costs are lower for coal-fired power plants than for gas-fired plants, but more CO_2 would need to be captured per kWh.

The costs of pipelines for CO_2 transportation depend strongly on the volumes being transported and, to a lesser extent, on the distances involved. Large-scale pipeline transportation costs range from USD 1 to USD 5 per tonne of CO_2 per 100 kilometres.

The cost of CO_2 storage depends on the site, its location and method of injection chosen. In general, at around USD 1 to USD 2 per tonne of CO_2, storage costs are marginal compared to capture and transportation costs of which longer-term costs for monitoring and verification of storage sites are of secondary importance. Revenues from using CO_2 to enhance oil production could be substantial. The level of enhanced oil recovery (EOR) can range from 0.1 to 0.5 tonne oil per tonne of CO_2. At an oil price of USD 45/bbl, this translates into USD 30 to USD 160 per tonne of CO_2. This would offset all or a significant share of the capture cost. However, CO_2-EOR must be compared with other competing EOR options, which may yield similar improved yields.

The future cost of capturing, transporting and storing CO_2 depends on which technologies are used, how they are applied, how far costs fall as a result of RD&D and market uptake (learning-by-doing), and fuel prices. Since capture requires more energy use and thus leads to production of more CO_2, the cost per tonne of CO_2 emission reduction is higher than the per tonne cost of capturing and storing CO_2. The gap between the two narrows as capture energy efficiency increases.

Efficiency and Retrofitting

CO_2 capture from electricity plants with low efficiency is not economically viable. The higher the efficiency of electricity generation, the lower the cost increases per kWh of electricity for applying CCS. Therefore, investing in high-efficiency power plants is a first step in a CCS strategy. It may be possible to retrofit capture installations to high efficiency power plants. Such capture-ready plants constitute a new concept that is currently being developed.

In a case study of a new gas-fired power plant in Karstø, Norway, two capture systems were compared. The first was an integrated system, where steam was extracted from the power plant, and the second a back-end capture system with its own steam supply designed for retrofit after the power plant had been built. The analysis suggested an efficiency penalty of 3.3 percentage points for the retrofit option but similar investment costs. This efficiency penalty is modest and therefore investments in capture-ready plants may make economic sense if natural gas prices are sufficiently low and the need for CO_2 capture is uncertain (Elvestad, 2003).

Since most coal-fired plants have a long life span, rapid expansion of CO_2 capture in the power sector would mean retrofitting. New capacity would still be needed to offset the capacity de-rating caused by CO_2 capture. In the case of new coal fired IGCCs, the initial design could allow for retrofit at a later stage. This would require space for a shift reactor, physical absorption units, a larger air separation unit, expanded coal handling facilities and larger vessels. Also, CO_2 capture would involve changes in the gas turbine, as the gas composition would change. Pulverised coal-fired plants could also be retrofitted, with oxy-fuelling seeming the best option. Oxy-fuelling retrofit is being proposed for two pilot projects in Germany and Australia.

In general, the issue of retrofit and capture-ready plants deserves more attention. It is one of the topics that will be elaborated by the IEA in the framework of the G8 Programme on Climate Change, Clean Energy and Sustainable Development, the results of which are scheduled for 2007 and 2008.

Challenges to Future Deployment

The main challenges for the future adoption of CCS are high costs, public acceptance and legal issues of storage (see Box 4.2). A price will have to be established for CO_2 if CCS is to be deployed widely. The technology will not be deployed in the absence of such an incentive, except for cases with substantial benefits from enhanced oil recovery. However, the same reasoning applies to other CO_2-free electricity production options with higher costs. CCS seems a relatively low cost option to mitigate CO_2 emissions, especially in countries that rely on cheap coal for power generation.

The key challenge for geological storage is the issue of retention of CO_2 underground. Measurement systems which validate CO_2 storage activities and sites must be developed. Sufficient proof of a high degree of CO_2 retention is essential for any credible CO_2 capture and storage strategy. Suitable storage sites need to be identified. Legal and regulatory issues need to be resolved.

Box 4.2 ▶ What will it take to bring CO_2 capture & storage to market?

CCS technology can be expected to be deployed from 2015 onward if R&D and demonstration efforts succeed and if economic incentives for reducing CO_2 are in place. CCS could in this case be considered an important "transition technology" to a sustainable energy system for the next 50 to 100 years.

Public acceptance of storing CO_2 underground may become an important issue. Unless it can be proven that CO_2 can be safely stored over the long term, the option will be untenable, whatever its additional benefits.

Accelerating investment in R&D and demonstration projects will be needed if CCS is to make a significant contribution. The potential for 2030 is two to three orders of magnitude greater than the projected megatonne-scale demonstration projects for 2015. Taken together, all the planned CCS projects in the coming decade will barely reach a scale of 10 Mt CO_2 per year.

Succeeding with CCS will require increasing the number of commercial-scale storage pilot projects over the next 10 years. R&D and demonstration activities should initially focus on storage projects which enhance fossil-fuel production and those which advance knowledge on sub-sea underground storage and aquifer storage in locations with low population density. Processes which consult, review, comment on and address stakeholder concerns should be built into all pilot projects. Procedures for independently verifying and monitoring storage and related activities should also be established. A regulatory and legal framework for CO_2 storage projects also must be developed to address issues of liability, licensing, leakage, landowner, royalty and citizens rights.

Governments must address the present shortage of sizeable R&D and demonstration projects in order to advance technological understanding, increase efficiency and drive costs down. This will require additional R&D of capture options, investment in CCS demonstration projects and power-plant efficiency improvements. Given the range of technologies that are under development at least ten major power plants fitted with capture technology need to be operating by 2015. These plants would cost between USD 500 million and USD 1 billion each, half of which would be additional cost for CCS. The current global government CCS budget is more than USD 100 million per year; the needed RD&D would represent a five-fold increase. While the amount required is challenging, it is not insurmountable given the scale of past energy R&D budgets. It would represent a 30% increase of the current total R&D budget for fossil fuels and power & storage technologies. Leveraging the funds in private/public partnerships is essential.

Creation of an enabling environment to ensure technology development must be accompanied by the simultaneous development of legal and regulatory frameworks. In the interest of time, and given the diversity of institutional arrangements and policy processes between countries, working at the national level using existing frameworks may be the best short-term option.

Countries should create a level-playing field for CCS alongside other climate change mitigation technologies. This includes ensuring that various climate change mitigation instruments, including market-oriented trading schemes, are adapted to include CCS. The future role of CCS depends critically on sufficiently ambitious CO_2 policies in non-OECD countries. Therefore, outreach programmes to developing countries and transition economies, plus international commitment to reduce CO_2 emissions, are prerequisites. The maturation of a global emissions trading scheme, a meaningful price for CO_2 and a predictable return on investment are important factors that could stimulate the timely deployment of CCS.

All three storage options – deep saline aquifers, depleted oil and gas reserves, and un-mineable coal seams – need more proof on a large scale. Small leakages of CO_2 over a long period of time would reduce the effectiveness of CCS as an emission mitigation option. This retention problem is currently addressed in field tests and through modelling studies. Depleted oil and gas fields have contained hydrocarbons for millions of years. This suggests they should be able to contain CO_2 for long periods as well. The main questions for such reservoirs are whether extraction activity has created leakage pathways, and whether abandoned boreholes can be plugged properly so the CO_2 cannot escape.

Many projects for natural gas storage and acid gas storage, which have similar characteristics as CO_2 storage projects, have worked well. The Sleipner aquifer storage demonstration project has reconfirmed the expectation that storage is feasible as no leakage has been detected since its start eight years ago. Progress in modelling allows increasingly accurate forecasts of the long-term fate of the CO_2, which cannot be tested in practice. Several natural phenomena, such as CO_2 dissolution in the aquifer water, will reduce the long-term risk of leakage. The understanding of these phenomena is improving gradually.

While the RD&D results are encouraging, more pilot projects are needed to better understand and validate the retention of underground storage in various geological formations and develop criteria to rank appropriate sites.

Several CO_2 capture options exist and are discussed in more detail in the following section. They include:

- Coal-fired supercritical PCC with CO_2 separation from the flue-gas.
- Coal-fired supercritical PCC with oxy-coal combustion.
- Coal-fired integrated-gasification combined-cycle with CO_2 capture.
- Natural gas combined-cycle with CO_2 capture.

Supercritical PCC with Flue-gas Separation and CO_2 Capture

An established means of CO_2 capture from flue gases is scrubbing by chemical absorbents that are regenerated by heat to release carbon dioxide. Amines are the most widely applied type of chemical absorbents, but mostly in combination with natural gas-fired power plants. The CO_2 concentrations in the flue gases of coal-fired power plants are higher, about 13% vs. 3 to 4% in gas-fired power plants. Also the level of impurities is higher with coal use, which affects solvent degradation. This means that amine capture is not necessarily the best option. A major issue is the large energy requirement for regeneration and also needed for CO_2 compression. Recent performance estimates show that the loss of efficiency due to carbon capture could be held to 9 percentage points for PCC with a certain type of amine scrubbing. Net efficiencies of 35 to 36% (LHV) look possible in optimised cycles. New absorbents, many with a degree of sulphur tolerance, are expected to improve on this figure.

Work is being done in Europe, the United States and Japan to develop membrane contactors. In these processes, chemical solvents absorb the CO_2 after it passes through a membrane which separates the gas stream and solvent. Inorganic reagents have been considered for CO_2 capture, because their need for regeneration heat is lower. However, their absorption rates are also lower, so additives are needed. Many other techniques are also in the early stages of research.

Better solvents may help to minimise corrosion and reagent loss, and to reduce the detrimental effects of CO_2 capture on efficiency and generation costs. Membrane contactors and other absorption systems also require further development.

Supercritical PCC with Oxy-coal Combustion and CO_2 Capture

Oxy-coal combustion involves burning coal in a mixture of oxygen and recycled flue gas. The CO_2-rich gases from the boiler are cooled, the condensate removed, the recycle stream returned to the boiler, and the balance of CO_2 taken away for storage. While this approach would avoid the need for costly CO_2 gas separation, the additional cost for air separation would be high. The oxy-fuelling boiler efficiency needs to be improved. A cycle for a supercritical plant has recently been evaluated for the IEA Greenhouse Gas R&D Programme in which the net efficiency was 35% (LHV). This is similar to a PCC unit with post-combustion capture.

Oxy-coal combustion needs further pilot tests and demonstration to confirm its operability, performance, burner design, process integration and the extent of slagging, fouling and corrosion. In the case without CO_2 capture, its efficiency is lower than PCCs because the production of oxygen consumes considerable power. However, the avoidance of CO_2 separation can make oxy-fuelling a viable option in the case with CCS.

Ion-transport membrane technology and other systems for oxygen production, which are expected to be available in five to ten years, will allow some power and cost savings. Oxy-fuelling has an advantage over post-combustion capture in that it would reduce NO_X emissions dramatically. Oxy-coal is potentially the best system for the co-disposal of SO_2 and NO_X, dust and mercury, as well as CO_2, to achieve zero emissions. The efficiencies of oxy-fuelling are similar to those of post-combustion in coal-fired power plants.

Tests are planned with various coal types and various gas recycle systems. One critical issue to be studied is that sulphur concentrates in the off-gas when recycled. This requires careful control of the off-gas and recycle-gas temperature in order to avoid SO_X condensation, which would result in corrosion. Compression of the enriched CO_2 off-gas may pose technical challenges as the gas contains 11% nitrogen and 0.2% SO_X.

Oxy-fuel combustion for power generation has so far been demonstrated only in test units. Two projects are in an advanced stage of development in Germany and Australia.

The Vattenfall Company has announced plans to build a pilot plant at its Schwarze Pumpe facility in Germany. The plant will use residues from lignite briquette production. This facility will have a 30 MW thermal capacity (equivalent to about 10 MW net electric capacity). It will consist of a separate burner unit from which the heat will be integrated into the existing steam system through a set of heat exchangers. This will not be a retrofit, but a separate oxy-fuelling unit. It is scheduled to come on-line in 2008.

The Callide A unit in Queensland, Australia, planned by CS Energy, is a retrofit of an existing coal-fired plant (Spero, 2005). It will focus on oxy-fuelling, with a plan to add CO_2 storage at a later stage. The existing plant has a 30 MW net electric capacity; the new plant will have a 25 MW net electric capacity. The existing boiler will be used, while new elements will include the air separation unit, the gas treatment unit and gas recycling units (including heat exchangers). The project cost is AUD 115 million (USD 80 million), including investment and operating costs over five years. The retrofit would result in capture of 90% of the CO_2 in the flue gas. Provided the project gets funded, it is scheduled to come on-line in 2009, with storage demonstration from 2010.

Integrated Gasification Combined-cycle with CO_2 Capture

Conventional IGCC systems use oxygen for coal gasification to produce a synthesis gas (syngas). This syngas is cleaned and fired in a gas turbine. The heat in the exhaust gas is used to power a steam cycle. The efficiency of the combined-cycle is much higher than the efficiency of a single steam cycle. Extensive gas cleaning is needed to protect the gas turbines, and this cleaning has the added benefit of keeping emissions low. For IGCC with CO_2 capture, the cleaned syngas would be sent to a shift reactor to convert carbon monoxide to carbon dioxide and additional hydrogen. CO_2 would be separated and the hydrogen burnt in the gas turbine. The feasibility of combusting high H_2 fuel in a gas turbine has been demonstrated by General Electric in a full-scale combustor, but the turbine design needs further development.

Because the shifted fuel gas is at elevated pressure and the CO_2 concentration is high, the CO_2 is readily removable by means of physical absorbents, keeping the cost and efficiency penalties for CO_2 separation low. The separation of CO_2 based on physical absorption is a proven technology.

Instead of pre-combustion capture, post-combustion capture can be applied. If oxygen is used for the combustion in the gas turbine, then the resulting flue gas consists largely of CO_2 and steam, from which CO_2 can be separated easily. It is expected that this would be cheaper than pre-combustion CO_2 removal and hydrogen turbines.

The costs and loss of efficiency due to CO_2 capture are also expected to be less, in many circumstances, than those of PCC based on scrubbing. The fact that adding

CCS to IGCC plants is the cheapest capture option makes a strong argument for IGCC use. However, IGCC is today more expensive than power generation based on steam cycles, and the future cost of IGCC are not clear. As a consequence, there is no consensus about which option – IGCC plants or steam cycles with CO_2 capture – will be cheaper in the future. In all likelihood, both technologies will be employed.

The United States and others are focusing on bringing IGCC to the market place, with proposals for demonstrating this technology for CO_2 capture and geological storage. Especially the FutureGen project can play an important role in the United States. In Europe, there is also a considerable focus on advanced steam cycles with CO_2 capture.

Natural Gas Combined-cycle with CO_2 Capture

Chemical absorption of CO_2 from NGCC flue gases is based on established technology. Current efforts are primarily directed at developing better solvents and at modifying the design of power plants to optimise the use of waste heat. In Norway, there are plans to build gas-fired power plants with CCS, based on chemical absorption. An alternative approach is being developed by British Petroleum in Scotland. The gas is shifted, the CO_2 removed, and the remaining hydrogen gas is used for power generation. In both cases the project is driven by EOR revenues for CO_2 use.

Post combustion CO_2 capture from gas-fired power plants is more difficult than for coal-fired plants due to the lower CO_2 density of the flue gases, and therefore more costly per tonne of CO_2 captured. Mitigation costs based on existing technology are more than USD 50 per tonne of CO_2 captured, even at low gas prices. The scope for significant cost reductions is limited. It is unlikely that the total cost for capture, transport and storage from gas-fired plants will fall below USD 25 per tonne of CO_2 by 2050.

The optimal CO_2 capture system for gas-fired power plants is not yet clear. New solvents are being developed that reduce the energy needs for chemical absorption technology. Oxygen-fuelled systems with CO_2 recycle are also being examined. Finally, steam reforming of natural gas with fuel gas CO_2 capture, in combination with new hydrogen gas turbines, is being investigated. New concepts such as chemical looping reactors are being developed (a metal oxide is used to supply oxygen and subsequently regenerated), but they are still far from demonstration. Overall, it seems likely that novel power generation approaches will be needed if substantial reductions in the cost of capture are to be achieved.

Cost Overview

Table 4.7 provides an overview of the characteristics of power plants with CO_2 capture. All cases have been assessed based on a product CO_2 flow at 100 bar, meaning that CO_2 compression is included in the efficiency losses. The efficiency loss due to CO_2 capture ranges from 12 percentage points for existing coal-fired power plants to 4 percentage points for future designs with fuel cells.

With natural gas prices at USD 4 to USD 5 per GJ, gas plants are in many cases the cheapest electricity supply option. Even if CO_2 capture would be added, the gas-based systems with CO_2 capture are often cheapest in terms of cost of generated electricity, although this depends on local fuel prices and discount rates. Moreover, differences between coal- and gas-fired systems are relatively small. The figures suggest an electricity cost price increase of USD 0.01 to USD 0.02 per kWh when CCS is applied. Electricity consumer prices are considerably higher than producer costs. The average electricity price was USD 0.11 per kWh for households in OECD Member countries in 2000. The use of CCS increases consumer prices by 10 to 20%. Table 4.7 shows that the option with the lowest CO_2 capture cost is not necessarily the option with the lowest power generation cost. Ultimately it is the power generation cost that will drive decision making in this sector. But the differences in power generation costs are so small that various technologies may co-exist.

CO_2 capture is energy intensive and results in increased coal and gas use for electricity production. The increase ranges from 39% for current designs to 6% for more speculative designs, and between 11 and 29% for likely future technologies (Table 4.7). This is a substantial increase, with impact on global coal and natural gas markets, especially if CCS is widely applied.

Biomass-fired power plants with CO_2 capture constitute a special option. Because renewable biomass is a CO_2 neutral energy carrier, combining biomass-fired power plants with CO_2 capture results in a net removal of CO_2 from the atmosphere (Möllersten, *et al.*, 2003; Möllersten, *et al.*, 2004). However, generally the scale of operation for biomass-fired power plants is much smaller than for fossil-fuelled power plants. A typical biomass IGCC would have a capacity of 25 to 50 MW, compared to a coal-fired IGCC with capacity of 500 to 1 000 MW. As a consequence, investment costs per kilowatt are twice as high for biomass. Biomass feedstock costs vary and must be assessed on a regional level. Waste and residues are often available at low cost or may even come with a treatment fee, while the costs of biomass from plantations and forestry residues vary widely and are often uneconomic compared to *e.g.* coal.

In a CO_2 constrained world, the value of removing CO_2 from the atmosphere may offset these disadvantages. Moreover, certain industrial biomass conversion processes, such as black liquor gasifiers in pulp production, generate CO_2 in quantities of a similar order of magnitude as power plants. Such CO_2 could be captured at very low additional cost (Table 4.7), but the potential is limited. A certain amount of biomass can be co-combusted in coal-fired plants (see Box 4.3 in the next section)

Energy efficiency losses due to CO_2 capture and pressurisation determine to a large extent the cost of CO_2 capture. R&D aims to introduce new technologies with higher efficiencies. Such developments are deemed critical for successful large-scale introduction of CCS (Klara, 2003). However, as the complexity of the design increases, so does efficiency and capital costs. Systems integration problems also tend to increase. A number of new conceptual designs seem attractive, but their successful development is far from certain. The development of conceptual designs to full-scale power plants is generally a slow process that can take decades. CCS could be applied in the short term, but the cost and efficiency penalties would be higher than those listed in Table 4.7.

Table 4.7 ▶ **Characteristics of power plants with CO_2 capture**

Fuel & Technology	Starting year	Investment cost (USD/kW)	Efficiency (%)	Efficiency loss (%)	Additional fuel (%)	Capture efficiency (%)	Capture cost (USD/t CO_2)	Electricity cost (UScents/kWh)	Electricity cost reference plant (UScents/kWh)	Additional electricity cost (UScents/kWh)
Likely technologies										
Coal, steam cycle, CA	2010	1 850	31	-12	39	85	33	**6.79**	3.75	3.04
Coal, steam cycle, membranes + CA	2020	1 720	36	-8	22	85	29	**6.10**	3.75	2.35
Coal, USC steam cycle, membranes +CA	2030	1 675	42	-8	19	95	25	**5.70**	3.75	1.95
Coal, IGCC, Selexol	2010	2 100	38	-8	21	85	39	**6.73**	3.75	2.98
Coal, IGCC, Selexol	2020	1 635	40	-6	15	85	26	**5.71**	3.75	1.96
Gas, CC, CA	2010	800	47	-9	19	85	54	**5.73**	3.75	1.98
Gas, CC, Oxyfueling	2020	800	51	-8	16	85	49	**5.41**	3.75	1.66
Black liquor, IGCC	2020	1 620	25	-3	12	85	15	**3.35**	2.35	1.00
Biomass, IGCC	2025	3 000	33	-7	21	85	32	**10.06**	7.46	2.60
Technologies under development										
Coal, CFB, chemical looping	2020	1 400	39	-5	13	85	20	**5.26**	3.75	1.51
Gas, CC, chemical looping	2025	900	56	-4	7	85	54	**5.39**	3.75	1.64
Coal, IGCC & SOFC	2035	2 100	56	-4	7	100	37	**6.00**	3.75	2.25
Gas, CC & SOFC	2030	1 200	66	-4	6	100	54	**5.39**	3.75	1.64

Note: The above comparison is based on a 10% discount rate and a 30-year process lifespan. The investment costs exclude interest during the construction period and other owner costs, which could add 5-40% to overnight construction cost. This approach has been applied to all technologies that are compared in the study. Coal price = USD 1.5/GJ; Natural gas price = USD 3/GJ. CO_2 product in a supercritical state at 100 bar. CO_2 transportation and storage is not included. Capture costs are compared to the same power plant without capture. CA = Chemical Absorption. CC = Combined-cycle; CFB = Circulating Fluidised Bed; IGCC = Integrated Gasification Combined-cycle; SOFC = Solid Oxide Fuel Cell; USC = Ultra Supercritical. The IGCC data for 2010 refers to a European highly-integrated plant based on a Shell gasifier, while the 2020 data refers to a less integrated US design based on an E-gas gasifier. The efficiency remains at the same level because new gas turbines will become available in the 2010 to 2020 period (the so-called 'H-class') and result in an increase in efficiency. The gasifier substitution reduces capture efficiency losses and reduces investment cost penalties. Assuming 4% fixed operation and maintenance cost, the electricity cost can be calculated by the formula: Electricity cost = (Investment cost × (0.11+0.04)/31.54/Availability Factor + Fuel price/Efficiency) × 0.036.

Renewable Energy: Status and Prospects

Status of Electricity Generation from Renewable Energy

In 2003, renewable energy supplied some 18% of global electricity production. Renewable electricity capacity worldwide is estimated at 880 GW (or 160 GW, excluding large hydro). Hydropower supplies the vast majority of renewable energy, generating 16% of world electricity. Biomass supplies an additional 1%. Power generation from geothermal, solar and wind energy combined accounts for 0.7%.

The share of renewable energy in electricity generation is highest in Canada and Latin America, because of the predominant use of hydropower (Table 4.8). The use of geothermal electricity generation explains the rather high non-hydro renewable share in Mexico and other Asia. This share is also relatively high in OECD Europe, at nearly 4%. At the global level, Latin America, China and the OECD countries account for nearly 80% of global hydropower production. The United States and OECD Europe account for nearly 70% of global non-hydro generation.

Table 4.8 ▶ ***Share of renewable energy in electricity generation, 2003***

	Renewable energy share in domestic electricity generation	Non-hydro renewable energy share in domestic electricity generation	Share in global use of hydro for electricity generation	Share in global use of non-hydro renewable energy for electricity generation
OECD				
United States	9.3%	2.4%	10.5%	30.2%
Canada	59.2%	1.7%	12.8%	3.1%
Mexico	13.1%	4.0%	0.8%	2.7%
OECD Europe	17.5%	3.6%	17.6%	37.0%
Japan	11.2%	2.1%	3.6%	6.8%
Korea	2.0%	0.6%	0.2%	0.6%
Australia	8.0%	0.9%	0.6%	0.7%
Transition economies				
Former Soviet Union	16.7%	0.2%	8.4%	0.8%
Non-OECD Europe	24.4%	0.1%	1.7%	0.0%
Developing countries				
Africa	17.1%	0.3%	3.2%	0.5%
China	15.0%	0.1%	10.7%	0.8%
India	12.8%	0.9%	2.8%	1.7%
Other Asia	18.3%	3.2%	5.0%	8.6%
Latin America	70.9%	2.6%	21.4%	6.6%
Middle East	2.9%	0.0%	0.6%	0.0%
World	**17.8%**	**1.9%**	**100.0%**	**100.0%**

Growth in hydropower and geothermal electricity production slowed considerably in the 1980s and 1990s (Table 4.9). These more mature renewable technologies did not receive the strong government support that targeted new renewables in the

1990s. Albeit from a low base, the use of solar, wind and biomass energy for electricity generation has grown considerably over the past two decades. Energy production from solar and wind grew by about 22% per year from 1989 to 2000, and the pace has accelerated in the last few years. Hydropower is still the primary source of renewable energy-based generation, supplying 2 645 TWh of generation in 2003. This compares with some 200 TWh for bioenergy, 54 TWh for geothermal and 69 TWh for solar and wind combined.

Table 4.9 ▶ ***Global electricity generation from renewables (average annual growth rates)***

	1971-1988	1989*-2000	2000-2003
Renewables	**3.4%**	**2.4%**	**1.0%**
Hydro	*3.3%*	*2.2%*	*0.3%*
*Geothermal***	*11.4%*	*3.9%*	*1.2%*
Biomass	*4.0%*	*3.5%*	*5.9%*
*Wind/Solar****	*4.9%*	*21.8%*	*24.8%*

* There is a break in IEA data for biomass in 1988, necessitating the period breakdown.
** The IEA Geothermal Implementing Agreement reports growth of 6.1% per year from 1995 to 2000 and 3.2% per year from 2000 to 2004.
*** Wind and solar are not shown separately in IEA statistics.

Source: IEA, 2005b; IEA 2005c.

The largest hydropower producers are Canada, China, Brazil, the United States and Russia. More than half the world's small hydropower (categorised as from 10 to 30 MW) capacity is in China, where nearly 4 GW were added in 2004. At least 24 countries have geothermal electric capacity, and more than 1 GW of geothermal power was added between 2000 and 2004, mostly in France, Iceland, Indonesia, Kenya, Mexico, the Philippines and Russia. Most of the current capacity is in Italy, Japan, Mexico, New Zealand, the United States, the Philippines and Indonesia. The use of renewables other than hydropower and geothermal for power generation has considerable potential but will require public support and private investment to accelerate commercial use.

Electricity production from biomass is steadily expanding in Europe, mainly in Austria, Finland, Germany and the United Kingdom. Cogeneration of wood residues in the pulp and paper industry accounts for the majority of bioelectricity in OECD Europe, followed by generation from the biodegradable portion of municipal solid waste (MSW). The use of sugar cane residues for power production is significant in countries with a large sugar industry, including Brazil, Colombia, Cuba, India, the Philippines and Thailand. Increasing numbers of small-scale biomass gasifiers are finding applications in rural areas and there are projects demonstrating the use of biomass gasification in high-efficiency combined-cycle power plants in several IEA countries.

Spain, Portugal, Germany, India, the United States and Italy have led recent growth in wind power. In Denmark, wind turbines supply about 20% of electricity, a portion expected to increase to 25% by 2009. Global wind power capacity was 47 GW at the end of 2004, up from 39 GW in 2003. Wind power from offshore turbines is being developed or is under consideration in the United Kingdom, Denmark, Germany, the Netherlands and the United States.

Grid-connected solar photovoltaic (PV) installations are concentrated largely in three countries: Japan, Germany and the United States. The solar thermal power market has remained relatively stagnant since the early 1990s, when 350 MW was constructed in California. Recently, commercial plans in Spain and the United States have led to a resurgence of technology and investment. Projects are also underway in Algeria, Egypt, Israel, Italy, Mexico and Morocco. Ocean technologies are still in the demonstration stage, with a few projects mainly in Europe and Canada.

The greater use of renewable energy is a key component of government strategies to enhance energy diversity and security, as well as to reduce greenhouse gas emissions. Because biomass absorbs CO_2 as it grows, the full biopower cycle (growing biomass, converting it to electricity and then regrowing it) can result in very low CO_2 emissions.

By using residues, biopower systems can even represent a net sink for GHG emissions by avoiding the methane emissions that would result from the land filling of unused biomass. A typical geothermal power plant emits 1% of the sulphur dioxide, less than 1% of the NO_x and 5% of the CO_2 emitted by a coal-fired plant of equal size. A 1-MW hydro plant, producing 6 000 MWh in a typical year, is estimated to avoid the emission of 4 000 tonnes of CO_2 and 275 tonnes of SO_2, compared with a coal-fired power plant.

Prospects for Electricity Generation from Renewable Energy

First-generation renewable technologies are mostly confined to locations where a particular resource is available. Hydropower, high-temperature geothermal resources and onshore wind power are site specific, but are competitive in places where the basic resource is plentiful and of good quality. Their future use depends on exploiting the remaining resource potential, which is significant in many countries, and on overcoming challenges related to the environment and public acceptance.

The second-generation of renewables has been commercially deployed, usually with incentives in place intended to ensure further cost reductions through increased scale and market learning. Offshore wind power, advanced biomass, solar PV and concentrating solar power technologies are being deployed now. All have benefited from R&D investments by IEA countries, mainly the 1980s. Markets for these technologies are strong and growing, but only in a few countries. Some of the technologies are already fully competitive in favourable circumstances, but for others, and for more general deployment, further cost reductions are needed. The challenge is to continue to reduce costs and broaden the market base to ensure continued rapid market growth worldwide.

Third-generation renewables, such as advanced biomass gasification, hot dry-rock geothermal power and ocean energy, are not yet widely demonstrated or commercialised. They are on the horizon and may have estimated high potential comparable to other renewable energy technologies. However, they still depend on attracting sufficient attention and RD&D funding.

Recent IEA analysis suggests that RD&D activities have played a major role in the successful development and commercialisation of a range of new renewable energy technologies in recent years (IEA, 2005e). Successful RD&D programmes need to be well focused and should be co-ordinated both with industry efforts to promote commercialisation and competitiveness in the market and with international programmes. In addition, they must reflect national energy resources, needs and policies. They also need to have roots in basic science research. Issues related to public acceptability, grid connection and adaptation, and managing intermittency are common to a range of renewable energy technologies and need to be addressed in government RD&D programmes.

Each country has its own RD&D priorities based on its own particular resource endowments, technology expertise, industrial strengths and energy markets. Because of the diverse nature of renewable energy sources, it is important that each country or region promote technologies and options that are well suited to its specific resource availability. RD&D in renewable energy must be strengthened, but priorities must be well selected, in order to address priority policy objectives, especially as they relate to cost-effectiveness. Industry can be expected to play a major role in the development of all technologies, whether or not yet commercially available. But it is important to recognise that some renewable technologies will continue to depend to a considerable extent on government RD&D.

A high global share of renewable energy can only be achieved if new renewable technologies are adopted by both developing and developed countries. Governments should consider including, in their renewable technology RD&D programmes, an element that specifically concerns the adaptation of renewable technologies to meet the needs of developing countries.

This section looks at prospects for electricity generation using the following renewable energy technologies:

- Bioenergy.
- Large and small hydropower.
- Geothermal.
- Onshore and offshore wind.
- Solar photovoltaics.
- Concentrating solar power.
- Ocean (marine).

Bioenergy

Technology Description and Status

Biomass encompasses a wide variety of feedstocks, including solid biomass, *i.e.* forest product wastes, agricultural residues and wastes, and energy crops, biogas, liquid biofuels, and the biodegradable component of industrial waste and municipal solid waste. Feedstock quality affects the technology choice, while feedstock costs, including transportation costs, determine the process economics. Bio-electric plants are an order of magnitude smaller than coal-fired plants based on similar technology. This roughly doubles investment costs and reduces efficiency relative to coal. Biomass-based electricity generation is a base load technology and, provided that adequate supplies are available, is considered one of the most reliable sources of renewable-based power.

Methods for converting biomass to electricity fall into four main groups:

Combustion. The burning of biomass can produce steam for electricity generation via a steam-driven turbine. Current plant efficiencies are in the 30% range at capacities of around 20 to 50 MW. Using uncontaminated wood chips, efficiencies of 33 to 34% (LHV) can be achieved at 540°C steam temperature in combined heat and power (CHP) plants. Operated in an electricity-only mode this technology would generate at least 40% electricity output. With municipal solid waste, high-temperature corrosion limits the steam temperature that can be generated, thereby holding electric efficiency to around 22% (LHV). Plants with electric efficiencies of 30% (LHV) are in the demonstration phase. Supplying energy for district heating systems from municipal solid waste is expected to generate 28% electricity in CHP mode. Many parts of the world still have large untapped supplies of residues which could be converted into competitively priced electricity using steam turbine power plants. For example, sugar cane residues (bagasse) are often burned in inefficient boilers or left to decay in fields.

Stirling engines have received attention for CHP applications, but such systems are not yet competitive.[10] Small-scale steam cycles also need to see cost reductions.

Co-firing. Fossil fuels can be replaced by biomass in coal power plants, achieving efficiencies on the order of 35 to 45% in modern plants. Because co-firing with biomass requires no major modifications, this option is economic and plays an important role in several countries' emission reduction strategies (Box 4.3). To raise biomass shares above 10% (in energy terms), technical modifications and investments are necessary. Co-firing systems that use low-cost, locally available biomass can have payback periods as short as two years.

Box 4.3 ▶ Biomass co-firing: potential for CO_2 reduction and economic development

Biomass co-firing has been demonstrated successfully for most combinations of fuels and boiler types in more than 150 installations worldwide. About a hundred of these have been demonstrated in Europe, mainly in Scandinavian countries, the Netherlands and Germany. There are about 40 plants in the United States and some 10 in Australia. A combination of fuels, such as residues, energy crops, herbaceous and woody biomass, have been co-fired. The proportion of biomass has ranged from 0.5 to 10% in energy terms, with 5% as a typical value.

Co-firing biomass residues with coal in traditional coal-fired boilers for electricity production generally represents the most cost effective and efficient renewable energy and climate change technology, with additional capital costs commonly ranging from USD 100 to USD 300 per kW.

10. A Stirling engine is a highly efficient, combustion-less, quiet engine that harnesses the energy produced when a gas expands and contracts as its temperature changes. Invented by Robert Stirling in 1816, the Stirling engine uses simple gases and natural heat sources, such as sunlight, to regeneratively power the pistons of an engine.

The main reasons for such low capital costs and high efficiencies are (1) optimal use of existing coal infrastructure associated with large coal-based power plants, and (2) high power generation efficiencies generally not achievable in smaller-scale, dedicated biomass facilities. For most regions that have access to both power facililties and biomass, this results in electricity generation costs that are lower than any other available renewable energy option, in addition to a biomass conversion efficiency that is higher than any proven dedicated biomass facility.

Co-firing of woody biomass can result in a modest decrease of boiler efficiency. A typical reduction is 1 percentage point boiler efficiency loss for 10% biomass co-firing, implying a combustion efficiency for biomass that is 10 percentage points lower than for the coal that is fired in the same installation. A coal-fired power plant with 40% efficiency would have an efficiency of 30% with co-firing, which is higher than for dedicated biomass-fuelled power plants. Biomass is either injected separately or it is mixed with coal. The challenges for wood co-firing are not so much in the boiler but in wood-grinding mills. Co-firing of herbaceous biomass is technically possible, but results in a higher chance of slagging and fouling, and its grinding costs and energy use are higher than for other types of biomass.

Worldwide, 40% of electricity is produced using coal. Each percentage point that could be substituted with biomass in all coal-fired power plants results in a biomass capacity of 8 GW, and a reduction of about 60 Mt of CO_2. If 5% of coal energy were displaced by biomass in all coal-fired power plants, this would result in an emission reduction of around 300 Mt CO_2 per year. Furthermore, the biomass used in this process would be approximately twice as effective in reducing CO_2 emissions as it would be in any other process, including dedicated biomass power plants. In the absence of advanced but sensitive flue gas cleaning systems commonly used in industrialised countries, co-firing biomass in traditional coal-based power stations will typically result in lower emissions of dust, NO_x and SO_2 due to the lower concentrations of fuel components (ash, sulphur and nitrogen) that cause these emissions. The lower ash content also results in lower quantities of solid residue from the plant.

Biomass co-firing has additional benefits of particular interest to many developing countries. Co-firing forest product and agricultural residues adds economic values to these industries, which are commonly the backbone of rural economies in developing countries. This economic stimulus addresses a host of societal issues using markets rather than government intervention and involves rural societies with large-scale businesses such as utilities and chemical processing. Co-firing also provides significant environmental relief from field/forest burning of residues that represent the most common processing for residues. All of these benefits exist for both developed and developing countries, but the agriculture and forest product industries commonly represent larger fractions of developing countries' economies, and the incremental value added to the residues from such industries generally represents a more significant marginal increase in income for people in developing countries. Most developing countries are located in climatic regions where biomass yields are high and/or large amounts of residues are available. In countries that primarily import coal, increased use of biomass residues also represents a favourable shift in the trade balance.

Co-firing of biomass and waste is now being actively considered. Blending biomass with non-toxic waste materials could regularise fuel supply and could enhance the prospects for co-firing. Certain combinations of biomass and waste have specific advantages for combustor performance, flue gas cleaning or ash behaviour.

Source: *IEA Bioenergy Implementing Agreement and IEA Clean Coal Centre (2005a).*

Gasification. At high temperatures, biomass can be gasified. The gas can be used to drive engines, steam or gas turbines. Some of these technologies offer very high conversion efficiencies even at low capacity. The biomass integrated gasifier/gas turbine (BIG/GT) is not commercially employed today, though the overall economics of power generation are expected to be considerably better with an optimised BIG/GT system than with a steam-turbine system. However, the costs are much higher than for co-combustion in coal-fired or fossil-fuelled power plants. Black liquor gasification, (discussed in Chapter 7), is economic for electricity and steam cogeneration. Other technologies being developed include integrated gasification/fuel cell and bio-refinery concepts.

Anaerobic Digestion. Using a biological process, organic waste can be partly converted into a gas containing primarily methane as an energy carrier. This biogas can be used to generate electricity by means of various engines at capacities of up to 10 MW.[11] While liquid state technologies are currently the most common, recently developed solid-state fermentation technologies are also widely used. Anaerobic digestion technologies are very reliable, but they are site-specific and their capacity for scaling-up is limited; thus, the market attractiveness of this approach is somewhat restricted. The increasing costs of waste disposal, however, are improving the economics of anaerobic digestion processes.

Costs and Potential for Cost Reductions

The additional cost of biomass co-firing with coal is between USD 50 and USD 250 per kW of biomass capacity, depending largely on the cost of biomass feedstock. It is the most attractive near-term option for the large-scale use of biomass for power-only electricity generation. Very low generation costs (slightly above USD 0.02 per kWh) can be achieved with co-firing in situations where little additional investment is needed and biomass residues are available for free.

The cost of producing electricity from solid biomass depends on the technology, fuel cost and fuel quality. Solid biomass plants tend to be small, typically 20 MW or less, although there are some CHP plants in Finland and Sweden that are much larger. In Canada, the capital cost is about USD 2 000 to USD 3 000 per kW installed for biomass-based capacity. Plants such as these are connected to district heating systems and are economic in cold climates.

Generation costs are expected to range from USD 0.10 to USD 0.15 per kWh in innovative gasification plants (Table 4.10). Biomass integrated gasifier/gas turbine plants have long-term potential in terms of both efficiency and cost reduction. Larger plants require that biomass is transported greater distances to the generating station, and long transport routes make biomass less attractive in both economic and environmental terms. For even lower capacities, gasification will probably be combined with gas engines or turbines in combined heat and power units, replacing current steam processes.

Table 4.10 provides an overview of European biomass plant efficiencies and cost characteristics. Co-combustion in coal-fired power plants is the least-cost option in the near term – USD 0.054 per kWh. All other systems need to see further cost

11. After purification, the gas can be used for production of transport fuels. See the Chapter 5,"Road Transport Technologies and Fuels" for details.

reductions to be competitive. Costs are typically higher than USD 0.10 per kWh, or more than twice the cost for comparable fossil-fuel power plants. The use of waste biomass will lower costs, but the potential is limited.

Table 4.10 ▶ ***Efficiencies and costs of European biomass plants (in operation and proposed)***

	Efficiency (% LHV)	Investment (USD/kW)	Size (MW_e)	Typical electricity cost (USD/kWh)
Co-firing	35	1 100-1 300	10-50	0.054
IGCC	30-40	3 000-5 500	10-30	0.112
Gasification + turbine	20-31	2 500-3 000	5-25	0.096
Large steam cycle	30	3 000-5 000	5-25	0.110
Gasification + engine (CHP)	24-31	3 000-4 000	0.25-2	0.107
Small steam cycle (CHP)	10	3 000-5 000	0.5-1	0.130
Stirling Engine (CHP)	11-19	5 000-7 000	<0.1	0.132

Note: Based on a biomass price of USD3/GJ. Heat by-product valued at USD5/GJ. Based on a 10% discount rate.

Source: Novak-Zdravkovic and de Ruyck, 2005; IEA data.

Future R&D Efforts

Short-term priorities for bioenergy focus on two primary areas – widening the availability of large quantities of relatively cheap feedstocks and further increasing conversion efficiency of basic processes while reducing their costs (IEA, 2005e). Standards and norms on fuel quality are needed so that a dedicated market emerges to support trade – locally, nationally and internationally. R&D will also be focused on innovative materials design to reduce cost.

Gasification technologies still need to demonstrate reliable commercial operation. The main barriers are efficient tar removal and economics. The success of the Varnamo plant in Sweden, the first and only plant to demonstrate an integrated gasification combined-cycle based on biomass, and recent advances on tar elimination indicate that the technical problems could be overcome in the short to medium term. Economics, however, may still pose a challenge.

Major R&D efforts are directed at multi-fuel co-firing with biomass and waste, to avoid any negative impact on combustion efficiency, flue gas cleaning requirements or ash behaviour. The EU is providing financial incentives for the development of technological environmental sound solutions, both for short and long-term. As an example, the COPOWER European project integrates 10 organisations from 6 countries (United Kingdom, Turkey, Sweden, Portugal, Italy and Germany) with the aim of developing a comprehensive understanding of process synergy during co-firing of coal with biomass and wastes, in circulating fluidised bed systems. Research is also being carried out on fouling and slagging, and dioxin formation and destruction. Given public sensitivity to waste combustion, this option requires careful consideration.

Challenges to Future Deployment

One of the most significant barriers to accelerated penetration of all biomass conversion technologies is that of adequate resource supply. In the long term, the potential for the sustainable use of biomass in the energy sector will be limited by factors such as competition with food production, the need for biodiversity, and competition between the use of feedstocks as fuels and using them for generating power.[12] The negative effects of intensive farming and long transport distances can reduce the economic and environmental benefits of biopower. In this context, it will be attractive to convert biomass into an energy carrier with higher energy density. This can be achieved with flash-pyrolysis technologies that convert solid biomass into bio-oil, a liquid biofuel that can be transported economically over long distances.

Other challenges to increased market penetration of biomass-fired generation are the high initial cost of replacing boilers with biomass technologies and the higher capital costs for biomass systems compared with conventional technologies. While biomass combustion plants are commercially available at various sizes, their efficiency could still be improved and their costs further reduced. Technology improvements are also needed in areas such as gasification, the development of plants that can use a variety of biomass feedstocks, polygeneration and co-firing using a range of feedstocks.

A significant challenge in developing countries is upgrading the efficiency of cogeneration units run on bagasse.[13] While a handful of countries, including Mauritius and Brazil, use modern generating units, the technology in most countries could be improved considerably. Another issue is storage. For example, power plants in Mauritius only run on bagasse during the harvest season. Techniques for bagasse storage are needed so the plants can operate on biomass year-round.

Market barriers include the limited public awareness of the benefits of biomass technologies, and some unresolved environmental issues, such as emissions from boilers used in urban environments. Because the market for biomass conversion plants is at an early stage of development, there is a perception of high business risk for both suppliers and utilities. Obtaining development and project financing for plants can be lengthy and difficult. Standardisation of feedstocks and technologies could help to overcome these barriers to some extent.

Large and Small Hydropower

Technology Description and Status

Hydropower is an extremely flexible technology from the perspective of power system operation. Its fast response time enables hydropower to meet sudden fluctuations in demand or to help compensate for the loss of power supply from other sources. Hydro reservoirs provide built-in energy storage, which helps optimise electricity production across a power grid. The dividing line for categorisation of small-scale and large-scale hydro differs from country to country, but generally it ranges from 10 to 30 MW.

12. Uncertainty regarding biomass supply potential is discussed in Chapter 5, "Road Transport Technologies and Fuels".
13. Bagasse is the fibrous residue remaining after the extraction of juice from crushed stalks of sugar cane.

Small-scale hydropower is normally run-of-the-river design and is one of the most environmentally benign energy conversion options available, because it does not interfere significantly with river flows. Small hydro is often used in autonomous applications to replace diesel generators or other small-scale power plants or to provide electricity to rural populations.

Large-scale hydropower projects can be controversial because they affect water availability downstream, inundate valuable ecosystems and may require relocation of populations. New less-intrusive low-head turbines are being developed to mitigate these effects. As hydropower usually depends on rainfall in the upstream catchment area, its availability is affected by weather variations. Therefore backup capacity can be needed to ensure power availability, which adds to hydropower costs.

The IEAs Hydropower Implementing Agreement estimates the world's technically feasible hydro potential at 14 000 TWh per year, of which about 8 000 TWh per year is considered economically feasible for current development. About 808 GW are in operation or under construction worldwide. Most of the remaining potential for development is in Africa, Asia and Latin America. The technical potential of small hydropower worldwide is estimated at 150 to 200 GW. Only 5% of global hydropower potential has been exploited through small-scale sites.

At present, OECD countries and the rest of the world produce roughly equal amounts of hydroelectricity. The share in non-OECD countries will likely increase, however, as most large hydro potential that is economically attractive and socially acceptable has already been developed in OECD countries, while untapped potential and pending projects remain in non-OECD countries. China will add some 18.2 GW of capacity by 2009 with the completion of the Three Gorges Dam.

Costs and Potential for Cost Reductions

Existing hydropower is one of the cheapest options on today's energy market, because most plants were built many years ago and their initial costs have been fully amortised. For new large plants in OECD countries, capital costs are about USD 2 400 per kW and generating costs are in the USD 0.03 to USD 0.04 per kWh range. Small hydropower costs are in the range of USD 0.02 to USD 0.06 per kWh. Such systems commonly operate without major replacement costs for 50 years or more.

Future R&D Efforts

The technology challenges facing hydropower include improving efficiency; reducing equipment costs; reducing operating and maintenance costs; improving dependability; integrating with other renewables; developing hybrid systems, including hydrogen; developing innovative technologies to minimise environmental impact; and facilitating education and training of hydropower professionals. Table 4.11 lays out the R&D priorities for large and small hydropower.

Although small-hydro technology is mature and well-established in the market, there is a need for further R&D to improve equipment designs, investigate different materials, improve control systems and optimise generation as part of integrated water management systems. One priority area is increasing the range of head and flow at acceptable costs, particularly in small-capacity and low-head equipment.

Low-head equipment must accommodate considerably more water flow than high-head equipment of equivalent capacity. Hence, low-head installations are physically larger and require more extensive engineering.[14] Since output shaft speed is lower as head decreases, low-head schemes generally need speed increasers to drive high-speed generators.

Table 4.11 ▶ Technology needs for hydropower

Large hydro	Small hydro
Equipment ■ Low-head technologies, including in-stream flow ■ Communicate advances in equipment, devices and materials	**Equipment** ■ Turbines with less impact on fish populations ■ Low-head technologies ■ In-stream flow technologies
O&M practices ■ Increasing use of maintenance-free and remote limited operation technologies	**O&M practices** ■ Develop package plants requiring only O&M
	Hybrid systems ■ Wind-hydro systems

Source: IEA, 2005e.

Challenges to Future Deployment

Concerns over undesirable environmental and social effects have been the principal barriers to hydro worldwide. Because most hydroelectric projects depend on dams, a river habitat is often replaced by a reservoir. Conditions for wildlife and aquatic creatures can be radically altered. Proper siting, design and operation can mitigate many of these problems, but more difficult challenges arise when human populations are forced to relocate. In some developing countries, the economic well-being and health of affected populations have declined after relocation.

Protection of fisheries is often one of the most contentious environmental issues with hydropower development. Most countries require that a minimum flow be maintained in the river to ensure the life and reproduction of indigenous fish and the free passage of migratory fish. The determination of an acceptable minimum flow is a key issue in the economic viability of any hydro scheme. To date, there is no universally accepted method of determining this flow to the satisfaction of both developers and regulators.

The construction of hydropower systems can have temporary effects on the local environment, particularly on water quality, such as muddying the water downstream from the development. Temporary access for construction vehicles can also cause disturbance, though once established, run-of-river hydro schemes have minimal visual impact. The principal permanent impacts are on the depleted stretch of the watercourse, where mitigating measures need to be taken to sustain river ecology

14. The head is the height through which the water falls. The flow rate is the amount of water flowing per unit of time.

and fisheries. Some types of turbines provide increased oxygenation of the tailrace water, thus improving water quality.

In the last few years, more emphasis has been put on the environmental integration of small hydro plants into river systems in order to minimise environmental damage. The requisite technology can be considered commercially and technically mature, although improvements are possible to make it suitable for export to rapidly expanding non-OECD markets. Innovations in civil engineering design, electro-mechanical equipment and control are possible, as well as in instrumentation and systems which mitigate environmental effects.

Other challenges for small hydro include regulatory delays for siting and permitting, as well as the burden of lengthy environmental impact reviews and assessments, which are often as rigorous as for large hydropower projects.

Geothermal[15]

Technology Description and Status

Geothermal power plants can provide an extremely reliable base-load capacity 24 hours a day. There are three types of commercial geothermal power plants: dry steam, flash steam and binary cycle. Dry steam sites are rare, with only five fields discovered in the world to date. Reservoirs that contain hot, pressurised water are more common. Flash steam power plants use resources that are hotter than 175°C. Before fluids enter the plant, their pressure is reduced until they begin to boil, or flash. The steam is used to drive the turbine and the water is injected back into the reservoir.

Binary-cycle plants use geothermal resources with temperatures as low as 85°C. The plants use heat exchangers to transfer the heat of the water to another working fluid that vapourises at lower temperatures. This vapour drives a turbine to generate power. This type of geothermal plant has superior environmental characteristics compared to others because the hot water from the reservoir, which tends to contain dissolved salts and minerals, is contained within an entirely closed system before it is injected back into the reservoir. Hence, it has practically no emissions. Binary power plants are the fastest growing geothermal generating technology.

Large-scale geothermal power development is currently limited to regions near tectonic plate boundaries, such as the western United States, Central America, Italy, the Philippines-Indonesia-Japan Pacific area and East Africa. These areas are likely to be the most promising for large development in the near term. If current R&D efforts are successful, however, geothermal potential will expand to other regions.

Costs and Potential for Cost Reductions

Up-front investments for resource exploration and plant construction make up a large share of overall costs. Drilling costs alone can account for as much as one-

15. High temperature geothermal resources can be used in electricity generation, while lower temperature geothermal resources can be tapped for a multitude of direct-uses, *e.g.* district heating and industrial processing. This section only deals with geothermal for electricity generation.

third to one-half of the total cost of a geothermal project. IEAs Geothermal Energy Implementing Agreement, which provides a framework for international collaboration on geothermal issues, is pursuing research into advanced geothermal drilling techniques and investigating aspects of well construction with the aim of reducing costs.

The resource type (steam or hot water) and temperature, as well as reservoir productivity, all influence the number of wells that must be drilled for a given plant capacity. Power-plant size and type (flash or binary), as well as environmental regulations, determine the capital cost of the energy conversion system. Because costs are closely related to the characteristics of the local resource system and reservoir, costs cannot be easily assessed for an average geothermal plant. Capital costs for geothermal plants vary from USD 1 150 per kW installed capacity for large, high-quality resources to USD 5 500 for small, low-quality ones.

Generation costs depend on a number of factors, but particularly on the temperature of the geothermal fluid, which influences the size of the turbine, heat exchangers and cooling system. US sources report current costs of producing power from as low as USD 0.015 to USD 0.025 per kWh at The Geysers field in California, to USD 0.02 to USD 0.04 for single-flash and USD 0.03 to USD 0.05 for binary systems. New construction can deliver power at USD 0.05 to USD 0.08 per kWh, depending on the source. The latter figures are similar to those reported in Europe, where generation costs per kWh are USD 0.06 to USD 0.11 for traditional power plants (liquid-steam water resources). Projected generation costs per kWh for hot dry rock geothermal systems in Europe are in the USD 0.24 to USD 0.36 range.

New approaches are helping to exploit resources that would have been uneconomic in the past. This is the case for both power generation plant and field development. Drawing an experience curve for the geothermal power sector is difficult, not only because of the many site-specific features that affect the technology system, but also because of a lack of good data.

The costs of geothermal energy have dropped substantially from those of systems built in the 1970s and 1980s. Overall costs fell by almost 50% from the mid-1980s to 2000. Large cost reductions, however, were achieved by solving initial problems of science and technology development. Future cost reductions may be more difficult to attain.

Future R&D Efforts

R&D efforts are focused on ways to enhance the productivity of geothermal reservoirs and to use more marginal areas, such as those that have ample heat but are only slightly permeable to water. More complex geothermal systems, including hot dry rock, are in the research phase. To extract energy from hot dry rock, water is injected from the surface through bore holes into hot granite rock underground. The water heats as it flows through cracks in the granite and, when it returns to the surface, the super-heated steam is used to generate electricity. R&D for new approaches, for improving conventional approaches and for producing smaller modular units will allow economies of scale in plant manufacturing.

Several technical issues need further government-funded research and close government collaboration with industry if the exploitation of geothermal resources is to become more attractive to investors. These issues are mainly related to the exploration and enhancement of reservoirs, drilling and power-generation technology, in particular for the exploitation of low-temperature geothermal resources.

Challenges to Future Deployment

Challenges to expanding geothermal energy include long project development times, the risk and cost of exploratory drilling and undesirable environmental effects. Geothermal energy entails higher risks than most other renewable forms of energy because of the geological uncertainties of developing reservoirs which can sustain long-term fluid and heat flow. It is difficult to fully characterise a geothermal reservoir prior to making a major financial commitment. Another potential challenge for hot dry rock is the large quantity of water required in the process. A small 5-MW plant could use 8.5 megalitres of water per day, while a full-scale commercial plant could use ten times that amount.

Various countries with geothermal resources have devised policies to underwrite risks at both the reservoir assessment and drilling stages. For these countries, it would be impossible to attract private investment without these measures. Some aquifers can produce moderately to highly saline fluids that are corrosive and present a potential pollution hazard, particularly to fresh water drainage systems and groundwater. Re-injection and corrosion management are therefore important.

Onshore and Offshore Wind

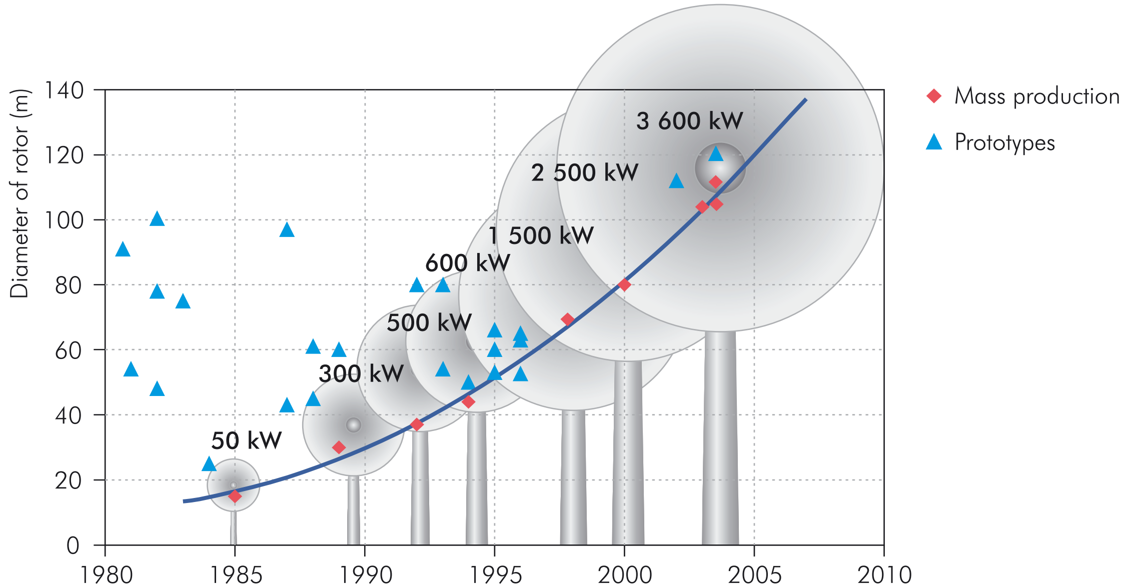
Technology Description and Status

The commercial and technological development of wind energy has been closely related to turbine size. From 10 metres in the mid-1970s, wind turbines have grown to diameters of 126 metres, with multi-MW installed power (Figure 4.11). Increasing the rotor diameter is an important prerequisite in developing turbines for offshore applications. All new offshore wind farms are expected to have turbines exceeding 1.5 MW.

Modern wind turbines are designed to have a lifetime of twenty years. Other technological developments include variable-pitch (as opposed to fixed-blade) rotors, direct drives, variable-speed conversion systems, power electronics, better materials and improved ratios between the weight of materials and generating capacity.

There are important economies of scale to be achieved in wind turbines. Larger machines can usually deliver electricity at a lower average cost than smaller ones. The reason is that the cost of foundations, road building, maintenance, electrical grid connections and a number of components in the turbine are largely independent of the size of the machine. Large turbines with tall towers use wind resources more efficiently. There is less fluctuation in the electricity output if a number of widely-spaced wind parks feed energy into the grid in order to take advantage of the variations in wind regimes at specific sites to offset intermittency.

Figure 4.11 ▶ Development of wind turbine size



Source: German Wind Energy Institute (DEWI), 2004.

Key point

Up-scaling wind turbine rotor diameter has allowed for multi-megawatt turbine output.

In 2004, installed global wind capacity exceeded 47 GW, including 578 MW of offshore capacity. Germany has the largest amount of installed capacity, followed by Spain, the United States and Denmark. India has nearly 3 GW of installed capacity. Offshore wind is currently employed by Denmark, the United Kingdom, Italy and Sweden.

Costs and Potential for Cost Reductions

From a pre-market level of about USD 0.80 per kWh in 1980, wind power costs have declined steadily. Wind power crossed the USD 0.10 per kWh threshold in about 1991, and dropped to about USD 0.05 per kWh in 1998. Since then, costs at the very best sites have dropped to about USD 0.03 to USD 0.04 per kWh.[16]

Costs of wind power installations depend on system components and size, as well as on the site. Generating capacity is primarily determined by the rotor-swept area and local wind patterns. Typical turnkey installation costs of onshore wind turbines are USD 850 to USD 1 150 per kW. Investment costs differ considerably between onshore and offshore applications. For offshore installations, the foundation accounts for one-third or more of the cost. Turnkey installation costs are now in the range of USD 1 100 to USD 2 000 per kW for offshore wind turbines, which is 35 to 100% higher than for onshore installations.

16. These costs are not directly comparable with fossil-fuel-based power generation due to the variable nature of wind electricity and the grid integration costs.

Operating costs for turbines include servicing, repairs, site rental, insurance and administration. A study, conducted in Denmark, tracked operating costs for turbines in the size range of 150 kW to 600 kW. It shows nearly contemporary turbines (500 to 600 kW) having annual operating costs steadily increasing from 1% of the investment cost in the first year to 4.5% after 15 years. These figures are consistent with estimates of 2 to 4% in Portugal and estimates of 3.4% in the Netherlands for smaller projects. Maintenance and repair costs account for roughly one-third of total operating costs.

Future R&D Efforts

R&D priorities include increasing the accuracy of forecasting power performance, reducing uncertainties related to engineering integrity, improvement and validation of standards, reducing the cost of new storage options, expanding the cost effective use of existing storage such as hydropower dams, enabling large-scale use and minimising environmental effects (see Box 4.4). R&D is also focused on new design features, such as tall towers made of lightweight materials and advanced aerofoils and on further advances in power electronics. The feasibility of floating wind turbines, individually and in multi-unit formations, has also been the focus of several studies.

Offshore wind development and the role of wind energy within hydrogen-based energy systems are R&D priority areas for the long term. Technology and environmental issues raised by offshore wind energy development are the subject of much research and are likely to form an important part of future activities. In addition to using wind energy for electricity production, the technology could be applied to other energy applications in the long term, particularly hydrogen generation.

Box 4.4 ▶ Priority research and development areas for wind energy

Reducing cost

Improved site assessment and identifying new locations, especially offshore.
Better models for aerodynamics and aeroelasticity.
New intelligent structures/materials and recycling.
More efficient generators and converters.

Increasing value and reducing uncertainties

Forecasting power performance.
Engineering integrity, improvement of standards.
Storage techniques.

Enabling large-scale use

Electric load flow control and adaptive loads.
Better power quality.

Minimising environmental impacts

Finding suitable locations in terms of wind potential.
Compatible use of land and aesthetic integration.
Noise studies.
Careful consideration of interaction between wind turbines and wildlife.

Challenges to Future Deployment

The current challenges to increased penetration of wind power are grid integration, forecasting of wind availability, public attitudes and visual impact. For offshore wind energy, a major challenge is cutting costs. The variable nature of wind electricity makes it difficult for wind to fully displace other electricity sources. When wind turbines constitute only a small fraction of generation capacity, their intermittency is hardly noticed by system operators, who are used to adjusting output to sudden changes in demand. At high penetrations, however, the marginal value of wind energy is equal only to the cost of the fuel and other marginal operating costs of power plants that are displaced. But if wind energy could be efficiently stored, wind power could compete economically with other types of electricity generation.

There is a wide range of technologies now available for storing wind energy, but choosing the appropriate one depends critically on the duration of storage required. For small turbines and at durations of only a few seconds to minutes, battery storage is a cheap option, along with flywheels and ultra capacitors. For longer durations, large-scale storage technologies such as pumped hydroelectric storage and compressed air energy storage are available at much lower costs per kWh of stored energy.

Another storage option is to combine back-up generation or integration with existing facilities such as gas turbines or hydro power. The back-up would be used when wind power generation is low. In extreme cases, wind turbines would simply be turned off when wind generation exceeds demand. More typically, the generator would try to maximise wind turbine output and shut off back-up sources of power. At least in the near term, this may be a more cost-effective strategy than large-scale energy storage.

Improved site assessment and identifying new locations, especially offshore, are important challenges. A 10% increase in wind speed will result in an energy gain of 33%. Improved assessment and siting require better models and measurements. Better measures are also needed to predict extreme wind, wave and ice situations. This may eventually make it possible to design site-specific systems that can utilise cheaper, lighter and more reliable turbines.

Several tools have been developed to overcome the aesthetic impacts of wind farms. Mapping of the zone of visual influence is used to show how many turbines will be visible from various locations. Photo-montage and animation techniques are employed to view potential wind parks from various angles. There has also been a great deal of research into the effect of wind turbines on the routes of migratory birds and on sites of special significance to bird populations. Sensitive siting has been found to avoid most of the problems.

Expensive undersea cabling and foundations have until recently limited the attractiveness of offshore wind energy. But new approaches in foundation technology, together with multi-megawatt-sized wind turbines, are at the point of making offshore wind energy competitive with onshore wind, at least at shallow water depths up to 15 metres. Offshore wind turbines generally yield 50% higher output than turbines on nearby onshore sites because of more favourable and stable wind conditions.

Offshore wind turbines in deep water will become more economic with advances in floating platforms and continuing reductions in undersea cable costs. Recent studies have examined the technical feasibility of using floating platforms that are tethered to the ocean floor at depths of 180 metres. Today, these installations are more expensive (USD 0.08 per kWh) relative to shallow installations (USD 0.05 to USD 0.06 per kWh). Deep-water wind costs are projected to decrease to nearly the same level as shallow-water costs by 2015 and to reach USD 0.04 per kWh by 2025 (Greenblatt, 2005).

Although wind power is already competitive at many locations based on electricity production costs, the additional costs related to grid integration and back-up capacity must be considered as well. With government support for its development, wind power may become generally competitive with conventional technologies between 2015 and 2020. The deep-water offshore share in total wind power will increase, particularly if shallow sites in the United States and in Europe are exploited fairly quickly.

Solar Photovoltaics

Technology Description and Status

Photovoltaic (PV) cells are based on semiconductors and convert light directly into electricity. They are usually encapsulated within modules with a power up to several hundred watts that can be combined into larger power arrays. These systems are connected to consumers or to the grid via electronics. Solar-photovoltaic technologies include off-grid and on-grid applications. PV systems are made either from crystalline semiconductor modules or from thin films, and PV technologies are characterised by their modularity.

The overall efficiency of systems available on the market varies between 6 and 15%, depending on the type of cell. Crystalline silicon has been the most important PV technology so far. Because of their extremely high cost, other crystalline technologies, such as gallium arsenide (GaAs), are used only in space exploration. The first thin-film PV device, an amorphous silicon (a-Si) module, was developed in the 1980s. More recently, other semiconductors, including cadmium telluride (CdTe) and copper indium diselenide (CIS/CIGS), have been used in industrial module production. The potential for thin-film modules is considered very high, but so far their diffusion has been limited by their high cost.

Installed grid-connected capacity is mostly in Japan, Germany and the United States. These three countries account for about 85% of global PV capacity. PV is often perceived as economic only in niche applications, such as traffic lights, weather stations and stand-alone systems for isolated buildings. Stand-alone or off-grid PV systems are particularly well suited for remote areas.

Costs and Potential for Cost Reductions

Costs for PV systems vary widely and depend on the system's size and location, the type of customer, the grid connection and technical specifications. In a standard building-integrated PV system, about two-thirds of the installation cost is for the module. The remainder reflects the cost of components, such as inverters and module support structures. The PV cells account for slightly more than half the total cost of the module itself. Cheaper cells would lower the system cost, but only so long as they deliver good efficiencies. Otherwise, higher balance-of-system costs might outweigh the lower cost of the cells.

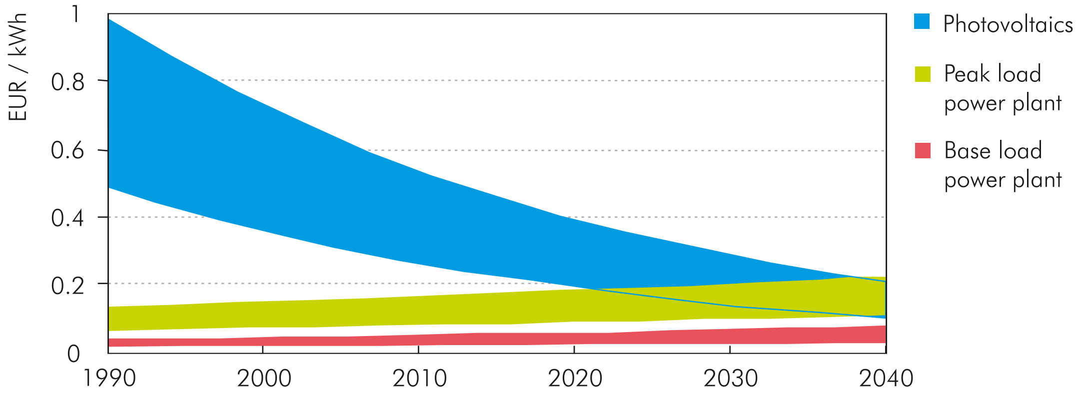
Average installation costs are about USD 5 to USD 9/W for building-integrated, grid-connected PV systems. Costs vary according to the maturity of the local market and specific conditions. For off-grid systems, investment costs depend on the type of application and the climate. System prices in the off-grid sector up to 1 kW vary considerably from USD 10 to USD 18/W. Off-grid systems greater than 1 kW show slightly less variation and lower prices. This wide range is probably due to country and project-specific factors, especially the required storage capacity.

Stand-alone systems cost more, but can be competitive with other autonomous small-scale electricity-supply systems, particularly in remote areas. Solar cells and modules are expensive components of PV systems, so reducing the cost of the cells is vital. A variety of reliable components is available, but the efficiency, lifetime and operation of some components can be further improved, especially those of inverters and batteries.

Investment costs are the most important factor determining the cost of the electricity generated from PV installations. Operation and maintenance costs are relatively low, typically between 1 and 3% of investment costs. The expected lifespan of PV systems is between 20 to 30 years. However, inverters and batteries must be replaced every five to ten years, and more frequently in hot climates.

Figure 4.12 illustrate electricity generating costs for PV and bulk and peak utility power. In liberalised electricity markets, utilities are likely to charge higher rates in periods of peak demand. As a consequence, PV systems will be more competitive with standard peak power utility supply.

Figure 4.12 ▶ Projected cost reductions for solar PV[17]



Source: Hoffmann, 2001.

Key point

Solar PV will become more and more competitive with peak power utility supply.

17. The upper and lower boundaries of the PV costs reflect the meteorological situations of Germany and Southern Europe, respectively. The cost increase for conventional electricity is assumed to be 2% per year. External costs are not considered and could lead to a much earlier break-even for PV electricity. It may be estimated that PV electricity can be competitive with peak-load electricity within two decades and to base-load electricity within four decades, depending on the meteorological conditions of the installation site.

About half of potential future cost decreases for PV is expected to result from RD&D directed towards improving materials, processes, conversion efficiency and design. Substantial cost reductions can also be gained through increased manufacturing volume and economies of scale.

Future R&D Efforts

The following are key drivers for future reductions in PV electricity costs: decreasing cell costs while maintaining or increasing efficiency (based on lower specific material consumption, more efficient production schemes and new cell concepts); increasing module lifespan; reducing specific module costs through higher cell efficiencies and more advanced encapsulation techniques; and reducing specific balance-of-system costs through higher module efficiencies and improved electronics.

RD&D focused on the long term is of high importance for PV. In order to bring new cells and modules to production, new manufacturing techniques and large investments are needed. Such developments typically require five to ten years to move from laboratory research to industrial production. Over the next decade, thin-film technologies are expected to display their potential for cost reduction and improved performance. RD&D allows new cell technologies to evolve, but is also necessary to the process of acquiring the manufacturing experience to make the technologies commercial. Since PV cell manufacturing requires large investments, market and manufacturing volume is very important.

Challenges to Future Deployment

Cost reduction is a key issue for PV, as costs are still relatively high compared to those for other electricity generation technologies. RD&D efforts, together with market deployment policies, have been effective in helping reduce PV costs. Both grid-connected and stand-alone applications need better ancillary components. A variety of reliable components are available, but the efficiency, lifetime and operation of some components can be further improved, especially for inverters and batteries.

Standardisation and quality assurance are crucial, for components as well as for the entire system. Standards exist for testing PV modules, and work has been done on standards for PV systems. To give users and investors more confidence, however, there is a need for standards to be developed for all the main system components, as well as certification or qualifications for designers and installers.

As solar energy is intermittent, storage systems are needed for stand-alone solar systems. However, solar power generation may work well as part of a diversified power supply system. The system compatibility depends on the shape of the electricity load curve. In sunny regions with an electricity demand peak during summer days (often caused by air conditioning), the peak contribution of solar can be high. Such conditions can be found in California and Japan. However, at higher latitudes with a winter morning peak, solar contribution to peak demand is negligible. This difference affects the need for backup capacity.

Until recent years, supplies of crystalline silicon were abundant. However, as production levels increase, demand from the PV industry versus world market supply of crystalline silicon is becoming a serious issue. In order to resolve this bottleneck, new feedstock production must be developed quickly. This will require significant investment by industry, which previously relied on silicon from the semi-conductor industry. Manufacturing approaches for solar cell technologies are diversifying and many varieties of materials are being investigated.

A number of technologies are in the commercial stage; many others are still in the pilot manufacturing or even laboratory phase. It is likely that different technologies will continue to co-exist for different applications for some time. It would be valuable to undertake an early assessment of production processes, industrial compatibility and costs, including an assessment of generic issues faced by thin-film manufacturing processes.

Concentrating Solar Power

Technology Description and Status

There are three types of concentrating solar power (CSP) technology: trough, parabolic-dish and power tower.[18] Trough and power tower technologies apply primarily to large, central power generation systems, although trough technology can also be used in smaller systems for heating and cooling and for power generation. The systems use either thermal storage or back-up fuels to offset solar intermittency and thus to increase the commercial value of the energy produced.

The conversion path of concentrating solar power technologies relies on four basic elements: concentrator, receiver, transport-storage and power conversion. The concentrator captures and concentrates solar radiation, which is then delivered to the receiver. The receiver absorbs the concentrated sunlight, transferring its heat to a working fluid. The transport-storage system passes the fluid from the receiver to the power-conversion system; in some solar-thermal plants a portion of the thermal energy is stored for later use.

The inherent advantage of CSP technologies is their unique capacity for integration into conventional thermal plants. Each technology can be integrated in parallel as "a solar burner" to a fossil burner into conventional thermal cycles. This makes it possible to provide thermal storage or fossil fuel backup firm capacity without the need of separate back-up power plants and without disturbances to the grid. With a small amount of supplementary energy from natural gas or any other fossil fuel, solar thermal plants can supply electric power on a steady and reliable basis. Thus, solar thermal concepts have the unique capability to internally complement fluctuating solar burner output with thermal storage or a fossil back-up heater.

The efficiency and cost of such combined schemes, however, can be significant. Current costs are about USD 0.10 per kWh and are expected to fall to about USD 0.72 per kWh by 2050. This technology relies on small-scale gas-fired power plants with low efficiency (40 to 45%), compared to 500-MW centralised plants with efficiencies of 60%. If the efficiency loss is allocated to the hybrid scheme, the economics would be less encouraging.

18. CSP is used interchangeably with solar thermal power.

Fresh impetus was given to solar thermal-power generation by a Spanish law passed in 2004 and revised in 2005. The revised law provides for a feed-in-tariff of approximately EUR 0.22 (USD 0.27) per kWh for 500 MW of solar thermal electricity. In several states in the United States and in other countries, the regulatory framework for such plants is improving. At present, solar plant projects are being developed in Spain (50 MW), in Nevada in the United States (68 MW) and elsewhere. Two US plants will also be constructed in southern California under the state's Renewable Portfolio Standard. A 500 MW solar thermal plant, expected to produce 1 047 GWh, is due for completion in 2012.

There is a current trend toward combining a steam-producing solar collector and a conventional natural gas combined-cycle plant. Projects in Algeria and Egypt, currently at the tendering stage, will combine a solar field with a combined-cycle plant. There are also plans to add a solar field to an existing coal plant in Australia. On a long-term basis, the direct solar production of energy in transportable chemical fuels, such as hydrogen, also holds great promise.

Cost and Potential for Cost Reductions

Since concentrating solar power uses direct sunlight, the best conditions for this technology are in arid or semi-arid climates, including Southern Europe, North and Southern Africa, the Middle East, Western India, Western Australia, the Andean Plateau, North-eastern Brazil, Northern Mexico and the Southwest United States. The cost of concentrating solar power generated with up-to-date technology at superior locations is between USD 0.10 and USD 0.15 per kWh. CSP technology is still too expensive to compete in domestic markets without subsidies. The goal of ongoing RD&D is to reduce the cost of CSP systems to USD 0.05 to USD 0.08 per kWh within ten years and to below USD 0.05 in the long term. Improved manufacturing technologies are needed to reduce the cost of key components, especially for first-plant applications where economies of scale are not yet available. Field demonstration of the performance and reliability of Stirling engines is critical.

The European Commission (EC) has undertaken a co-ordination activity, the European Concentrated Solar Thermal Road-mapping (ECOSTAR), to harmonise the fragmented research methodology previously in place in Europe, which previously led to competing approaches on how to develop and implement CSP technology. Cost-targeted innovation approaches, as well as continuous implementation of this technology, are needed to realise cost-competitiveness in a timely manner.

Future R&D Efforts

Improvements in the concentrator performance and cost will have the most dramatic impact on the penetration of CSP. Because the concentrator is a modular component, it is possible to adopt a straightforward strategy that couples development of prototypes and benchmarks of these innovations in parallel with state-of-the-art technology in real solar-power plant operation conditions. Modular design also makes it possible to focus on specific characteristics of individual components, including reflector materials and supporting structures, both of which would benefit from additional innovation.

Research and development is aimed at producing reflector materials with the following traits (IEA, 2005e):

- Good outdoor durability.
- High solar reflectivity (>92%) for wave lengths within the range of 300 nanometres (nm) to 2 500 nm.
- Good mechanical resistance to withstand periodical washing.
- Low soiling co-efficient (<0.15%, similar to that of the back-silvered glass mirrors).

Scaling up to larger power cycles is an essential step for all solar thermal technologies (except for parabolic trough systems using thermal oil, which have already gone through the scaling in the nine solar electric generation stations installations in California, which range from 14 MW to 80 MW). Scaling up reduces unit investment cost, unit operation and maintenance costs and increases performance. The integration into larger cycles, specifically for power tower systems, creates a significant challenge due to their less-modular design. Here the development of low-risk scale-up concepts is still lacking.

Storage systems are another key factor for cost reduction of solar power plants. Development needs are very much linked to the specific system requirements in terms of the heat-transfer medium utilised and the necessary temperature. In general, storage development requires several scale-up steps linked to an extended development time before market acceptance can be achieved. Research and development for storage systems is focused on improving efficiency in terms of energy and energy losses; reducing costs; increasing service life; and lowering parasitic power requirements.

Challenges to Future Deployment

The widespread application of CSP plants is hindered by the heavy investment required for large centralised power plants - the economically viable plant size being on the order of several MW - and by the high ratio of risk to return for investors if long-term power purchase agreements are not in place.

Building a sustainable market for CSP will require taking the lessons learned in the countries where CSP deployment is successful and transferring them to others. This would promote faster market growth, attract larger global companies and lead to costs that are increasingly competitive with conventional sources.[19]

Most of the technological components of solar thermal-power plant systems still need improvement. For example, higher operating temperatures and efficiencies will become possible in parabolic trough systems by using steam as a heat transfer medium and improved selective absorbers. Advanced storage systems will allow extended daily operation hours and improved plant utilisations. Technical components are already operational in principle, thereby making the development of appropriate support policies the crucial issue for the future of solar thermal power plants.

19. See: CSP Global Market Initiative (GMI; www.solarpaces.org/gmi.htm).

Ocean

Technology Description and Status

Ocean (marine) energy technologies for electricity generation are at a relatively early stage of development. Approaches to using ocean energy fall into several categories (Table 4.12): converting potential and kinetic energy associated with ocean waves into electricity; harnessing kinetic energy associated with marine (tidal) currents; converting potential energy associated with tides to electricity by building tidal barrage plants and by using mature hydro-electric turbine/generator technologies; extracting power from temperature differences between the surface and the seabed in deep oceans (ocean thermal energy conversion) ; using salinity gradients such as the latent heat of dilution at river mouths; and making use of marine biomass.

Wave energy and tidal current energy are the two main areas under development. The IEA Ocean Energy Systems Implementing Agreement is developing programmes expected to be operational in 2007.

The technology required to convert tidal energy into electricity is very similar to that used in hydroelectric power plants. Gates and turbines are installed along a dam or "barrage" that goes across a tidal bay or estuary. Electricity can be generated by water flowing into and out of a bay (a difference of at least five metres between high and low tides is required). As there are two high and two low tides each day, electrical generation from tidal power plants is characterised by periods of maximum generation every six hours. Alternatively, the turbines can be used to pump extra water into the basin behind the barrage during periods of low electricity demand. This water can then be released when demand on the system increases. This allows the tidal plant to function with some of the characteristics of a pumped-storage hydroelectric facility.

Table 4.12 ▶ Status of ocean renewable energy technologies

Sub-sector	Status
Wave	Several demonstration projects up to a capacity of 1 MW and a few large-scale projects are under development. The industry aims to have the first commercial technology by about 2007.
Tidal and marine currents	Three demonstration projects up to a capacity of 300 kW and a few large-scale projects are under development. Industry is aiming for 2007 for the first commercial technology.
Tidal barrage (rise and fall of the tides)	Plants in operation include the 240 MW unit at La Rance in France (built in the 1960s), the 20 MW unit at Annapolis Royal in Canada (built in the 1980s) and a unit in Russia. Tidal barrage projects can be more intrusive to the area surrounding the catch basins than wave or marine current projects.
Ocean thermal energy conversion (OTEC)	There are a few demonstration plants, up to 1 MW, but there is still uncertainty surrounding the commercial viability of OTEC.
Salinity gradient / osmotic energy	A few preliminary laboratory-scale experiments, but limited R&D support.
Marine biomass	Negligible developmental activity or interest.

Note: In addition to the grid-connected electricity generation opportunities, there are potential synergies from the use of ocean renewable energy resources, for example: off-grid electrification in remote coastal areas; aqua-culture; production of compressed air for industrial applications; desalination; integration with other renewables, such as offshore wind and solar PV, for hybrid offshore renewable energy plants; and hydrogen production.

Ocean thermal-energy conversion (OTEC) may become important in the long term, after 2030, for certain countries, but it is considered uneconomic in the short or medium term. Salinity gradient and marine biomass systems are currently the object of very limited research activities. Neither seems likely to play a significant role in the short or medium term.

Costs and Potential for Cost Reductions

Opportunities for cost reductions depend on the distance from shore; the choice of maintenance location (onshore or *in situ*); the frequency and duration of maintenance visits and the balance of predicted and unplanned maintenance; and the type and availability of the required vessels and their availability.[20]

Future R&D Efforts

R&D efforts are aimed at overcoming technical barriers related to wave and tidal technologies and to salinity gradient. The main focus is on wave behaviour and hydrodynamics of wave absorption; structure and hull design methods; mooring; power take-off systems; and deployment methods. Typical research on tidal stream current systems can be divided into basic research that focuses on areas such as water stream flow pattern and cavitations and into applied science, which would examine supporting structure design, turbines, foundations and deployment methods.

Research efforts on turbines and rotors will need to focus on cost-efficiency, reliability and ease of maintenance. Both components should be manufactured using materials designed to resist marine environments. Special attention should be given to bearings to ensure that they function safely and reliably in the marine environment. Control systems for turbine speed and rotor pitch will also be important to maximise power output. The main challenge for salinity gradient systems is to develop functioning and efficient membranes that can generate sufficient energy to make an energy system competitive.

Challenges to Future Deployment

A factor common to all marine technologies is that pilot projects need to be relatively large-scale if they are to withstand offshore conditions. These are costly and carry high perceived risks. These considerations have inhibited early development of these technologies. It is only in recent years that adequate funds have been made available to permit sizeable pilot projects, due largely to government policies to encourage ocean renewables. Once successful pilot projects are completed and confidence in the concepts grows, financing for even larger projects may become easier to obtain. Any major failures would, however, set progress back.

Although the prospects for tidal barrages are good in certain locations, their site-specific environmental effects need careful assessment. The technology reduces the range of the tides inside the barrage. This may affect the mud flats and silt levels in rivers, which would cause changes in the wildlife living in and around the estuary. It could also change the quality of the water retained by the barrage.

20. See http://www.thecarbontrust.co.uk/ctmarine3/Page1.htm

Non-technical challenges include the need for resource assessment, the development of energy-production forecasting and design tools, test and measurement standards, environmental effects, arrays of farms of ocean energy systems and dual-purpose plants that combine energy and other structures.

Cost Overview

Table 4.13 provides an overview of cost estimates for renewable electricity generation technologies. There is a wide range of costs for each renewable technology due mainly to varying resource quality and to the large number of technologies within each category. Investment includes all installation costs, including those of some demonstration plants in certain categories. Discount rates vary across regions. Because of the wide range in costs, there is no specific year or CO_2 price level for which a renewable energy technology can be expected to become competitive. A gradual increase in the penetration of renewable energy over time is more likely. Energy policies can speed up this process by providing the right market conditions and to accelerate deployment so that costs can be reduced through technology learning.

Technology learning in bioenergy systems has been studied using experiences in Denmark, Finland and Sweden (Junginger, *et al.*, 2005a, 2005b). In the supply chain, learning rates for wood fuel-chips are 12 to 15%. For energy conversion in biogas or fluidised bed boiler plants, available data are much more difficult to interpret. An average learning rate of 5% for energy-producing plants appears to be a reasonable average estimate.

Technology learning is a key phenomenon that will determine the future cost of renewable power generation technologies. Unfortunately, the present state-of-the-art does not allow reliable extrapolations. National data indicate learning rates between 4 and 8% for wind turbines in Denmark and Germany. Learning rates for installation costs are one or two percentage points higher (Neij, 1999; Durstewitz and Hoppe-Kilpper, 1999; Neij, *et al.*, 2004). From 1980 to 1995, the cost of electricity from wind energy in the European Union decreased at a considerably higher rate of 18%. Wind energy is a global technology and experience curves based on deployment in major manufacturing countries like Germany and Denmark may be much lower than learning rates elsewhere analysed the installation cost of wind farms from a global learning perspective and found learning rates between 15 and 19% (Junginger, *et al.* 2004). Other recent studies quote learning rates of 5% for recent years.

Technology learning rates are better documented for photovoltaics than for other renewable energy sources. PV modules have shown a steady decrease in price over more than three decades, with a learning rate of about 20% (Harmon, 2000; PHOTEX, 2004). In 1968, the price of one peak watt of PV module was about USD 100 000 per kW. Today the price is about USD 3 000 per kW. Learning for PV modules is a global phenomenon, but prices for balance-of-system components reflect national or regional conditions. The EU-PHOTEX project found learning rates for balance-of-system in Germany, Italy and the Netherlands to be from 15 to 18%.

Table 4.13 ▶ Key cost and investment assumptions for renewables

	Learning rate (%)	Investment cost 2005 (USD/kW)	2030 (USD/kW)	2050 (USD/kW)	Production cost 2005 (USD/MWh)	2030 (USD/MWh)	2050 (USD/MWh)
Biomass	5	1 000-2 500	950-1 900	900-1 800	31-103	30-96	29-94
Geothermal	5	1 700-5 700	1 500-5 000	1 400-4 900	33-97	30-87	29-84
Large hydro	5	1 500-5 500	1 500-5 500	1 500-5 300	34-117	34-115	33-113
Small hydro	5	2 500	2 200	2 000	56	52	49
Solar PV	18	3 750-3 850	1 400-1 500	1 000-1 100	178-542	70-325	<60-290
Solar thermal	5	2 000-2 300	1 700-1 900	1 600-1 800	105-230	87-190	<60-175
Tidal	5	2 900	2 200	2 100	122	94	90
Wind onshore	5	900-1 100	800-900	750-900	42-221	36-208	35-205
Wind offshore	5	1 500-2 500	1 500-1 900	1 400-1 800	66-217	62-184	60-180

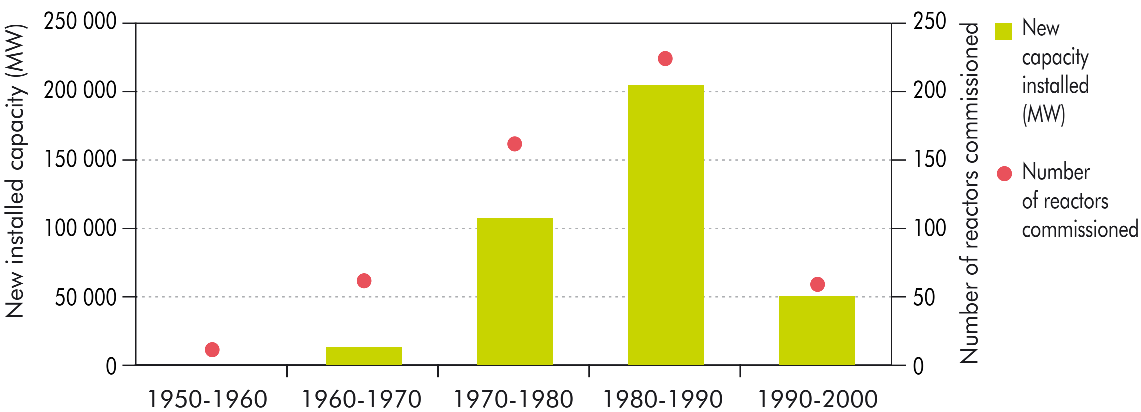
Note: Using 10% discount rate. The actual global range is wider as discount rates, investment cost and fuel prices vary. Wind and solar include grid connection cost. Learning rate implies percentage cost reduction for each doubling of installed capacity.

Nuclear Electricity Generation: Status and Prospects

Status of Nuclear Power

In early 2006, there were 443 nuclear power plants in operation in 30 countries, with a total capacity of 370 GW (Figure 4.13). Most of the plants were built in the 1970s and 1980s. In addition, there were 24 reactor units under construction.[21] Nuclear power supplies 16% of the world's electricity and 25% of the electricity in OECD countries. Nuclear electricity has grown in line with total global electricity generation since 1986, despite a limited increase in the number of reactors. This trend can be attributed partly to an increase in the global average availability factor for nuclear plants in operation, from 76% in 1994 to 83% in 2004, and partly to uprating of existing reactor units.[22] Global nuclear power production increased swiftly in the 1970s and 1980s, with an average annual growth rate of nearly 17% from 1971 to 1990, tapering off to 2.1% from 1990 to 2003.

Figure 4.13 ▶ Nuclear reactor development by decade, 1950 to 2000



Source: Nuclear Energy Agency.

Key point

Strong growth in nuclear power capacity in the 1970s and 1980s, but limited construction since then.

About 60% of global nuclear capacity is in the United States, France and Japan. The United States has 104 reactors, the largest number of any country. Lithuania had the highest share of nuclear in its power generation mix in 2003 at 80%, with France as

21. Reactors under construction: India (8), Russia (4), China (2), Ukraine (2) and one each in Argentina, Finland, Iran, Japan, Pakistan and Romania.
22. A power uprate is the process of increasing the maximum power level at which a commercial nuclear power plant may operate.

a close second at 78% (Figure 4.14). However, Lithuania has only one nuclear reactor in operation (Ignalina, which is scheduled for closure between 2005 and 2009), while France has 59. Another quarter of global nuclear capacity is in Russia, the United Kingdom, Korea and India. Nuclear power accounts for more than half of total electricity generation in Lithuania, Slovakia, Belgium, Sweden and Ukraine. India has 15 nuclear plants in operation, and its government plans to increase nuclear capacity from 3 040 MW today to 20 000 MW by 2020. China plans to increase its nuclear capacity from some 6 600 MW today to 40 000 MW over the same period (World Nuclear Association, 2005a).

Nuclear reactors are first classified by neutron energy level into thermal reactors and fast breeder reactors. They are also classified by their coolant material (water, gas, or liquid metals) and by their moderator type (light water, heavy water or graphite). Fast breeder reactors do not require a moderator.

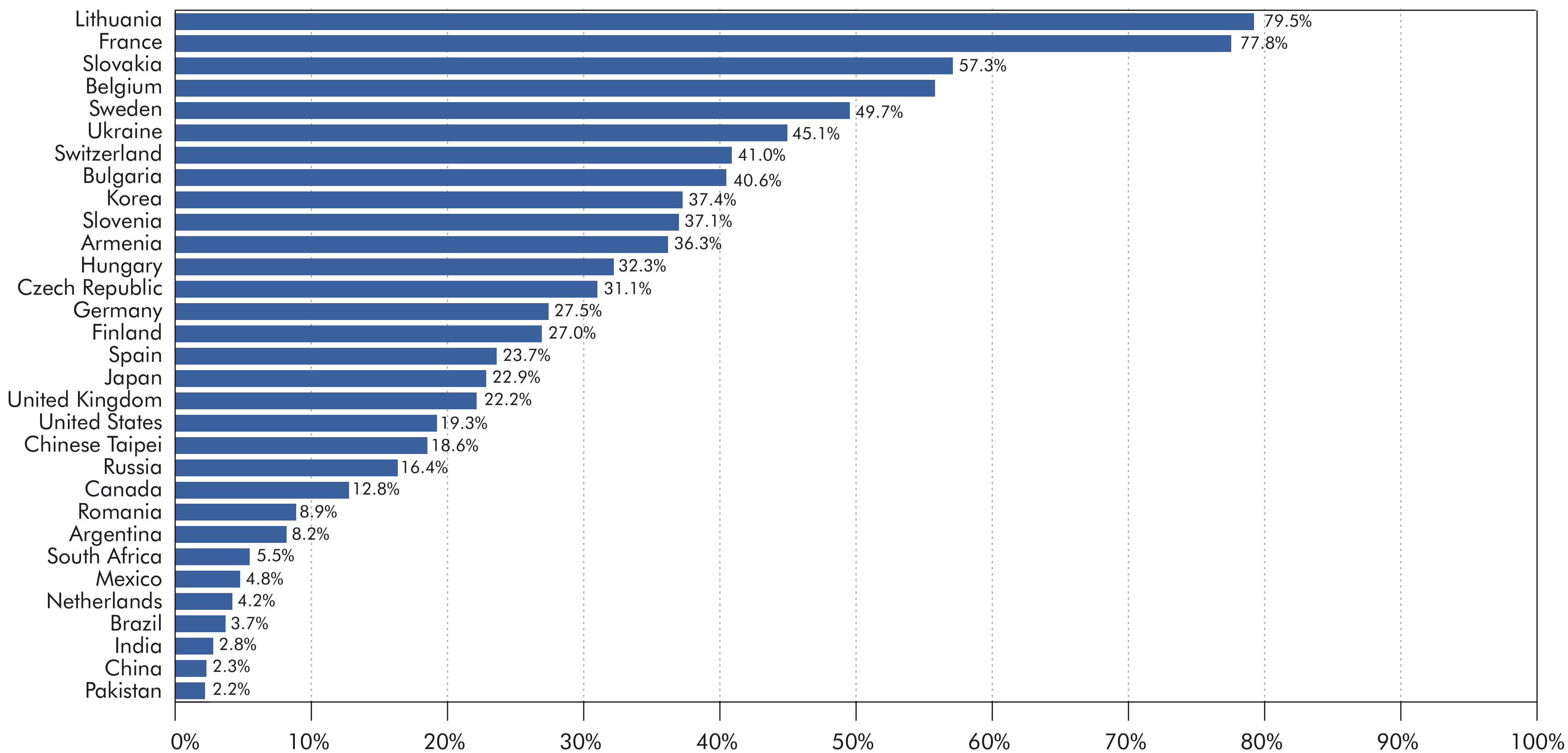
Another classification is by reactor "generation". Four generations are discerned. Generation I was used in the 1950s and 1960s in prototype reactors. Generation II appeared in the 1970s in the large commercial power plants that are still operating today. Generation III reactors were developed in the 1990s with a number of evolutionary designs that offered advances in safety and economics. Several of these have been built, mainly in East Asia. Some sources differentiate proven Generation III reactors from those that are expected to become available in the next few years (Generation III+). Generation III reactors differ from their predecessors in that they include "passive safety" features: in the event of malfunction, the first phase of accidents can be avoided without active intervention. Generation III reactors are standardised or modular to facilitate licensing, reduce capital cost and reduce construction time. They also have a simpler, more rugged design that offers several benefits. They are easier to operate and less vulnerable to operational upsets, they possess a longer operating life (typically 60 years compared with 30 to 40 for Generation II), they have less possibility of reactor core-melt accidents and they have fewer environmental effects and better burn-up characteristics to reduce fuel use and waste.

The vast majority of nuclear power plants use water as a coolant; the heat energy generated from uranium fuel in the reactor is transferred to this water. Light water reactors (LWRs) use ordinary water as the coolant, which takes the form of steam (in boiling water reactors) or pressurised water (in pressurised-water reactors). In a pressurised-water reactor, the pressurised water in the primary cooling loop is used to transfer heat energy to a secondary loop to create steam. The two-circuit design reduces the risk of radioactive water losses. In either a boiling-water or pressurised-water installation, steam drives a turbine that generates electricity. There are other reactor designs, in which the heat energy is transferred not by ordinary water, but rather by pressurised heavy water, gas, liquid metal or another cooling substance.

Ninety percent of nuclear power plants in operation are water-cooled. Most of these are LWRs and the rest are pressurised heavy-water reactors (PHWR). The remaining 10% are gas-cooled reactors (GCR), graphite-moderated water cooled reactors (GWCR) or fast breeder reactors (FBR).

PHWRs are in use primarily in Canada and India, but others operate commercially in Korea, China, Romania, Pakistan and Argentina. Canadian-designed PHWRs are

Figure 4.14 ▶ **Nuclear share in electricity production, 2003**



Key point

The role of nuclear in the electricity generation mix varies greatly among countries.

Table 4.14 ▶ Nuclear reactors by type

	Type	In operation		Under construction	
		units	MW	units	MW
Pressurised water	LWR	214	205 368	3	2 766
Pressurised water (Russian-variant, WWER)	LWR	53	35 870	10	9 499
Boiling-water	LWR	90	79 161	0	0
Pressurised heavy-water	PHWR	41	20 963	7	2 645
Light water-cooled graphite	LWR	16	11 404	1	925
Advanced gas-cooled		14	8 380	0	0
Advanced boiling-water	LWR	4	5 259	2	2 600
Fast breeder		3	1 039	1	470
Gas-cooled		8	2 284	0	0
Total		**443**	**369 728**	**24**	**18 905**

Source: IAEA database, http://www.iaea.org, as of 25 January 2006.

known as "CANDU" (for Canada Deuterium Uranium) reactors. Siemens, ABB (now part of Westinghouse) and Indian firms have also built commercial PHWR reactors. Commercial heavy-water reactors now in operation use heavy water as moderator and coolant.

Gas-cooled reactors include Magnox reactors, which have been designed and built in the United Kingdom since the 1950s. Their derivative, advanced gas-cooled reactors (AGR), are operated in the United Kingdom. Similar reactors to Magnox were built and operated in France, Italy and Japan but they have since closed. Commercial GCRs in the United Kingdom have operated longer than any other category of commercial reactors. Like the PHWRs, the original GCRs use natural uranium fuels, but the newer designs (AGR) use slightly enriched fuels.

High-temperature gas-cooled reactors (HTGR), a subset of GCRs, have been developed in China, France, Germany, the Netherlands, South Africa and the United States. There is some interest in building commercial HTGRs in several other countries. Small research prototypes already exist in Japan and China. HTGRs use helium as a coolant. In some cases, the turbine is run directly by the gas. In South Africa, the gas is used to generate steam or hot gases in a second loop that drive the turbine. The very high temperatures attained within HTGRs, in combination with their comparatively small unit size, might permit them to be used as sources of industrial process heat. HTGRs are also thought to adapt better to changing load requirements than light-water reactors.

Fast-breeder reactors have received much research funding, but only limited market support since uranium has remained cheap. Their merit is their efficiency in the use of uranium (U). They extract some 30 to 60 times more energy per kilogram of uranium than other reactor type.[23] A breeder reactor can convert more U-238 to usable fuels

23. The advantage of "breeder" or "fast" reactors lies in their ability to convert uranium-238 into fuel. Uranium-235 is the only naturally occurring uranium isotope that is directly suitable for commercial energy production. U-235 makes up only 0.7% of natural uranium. Most of the naturally occurring uranium is the U-238 isotope, which is not directly usable as a reactor fuel.

Box 4.5 ▶ Uranium resources and a nuclear expansion

The prospect of an expansion of nuclear power raises questions about uranium supply. From 1975 to 1993, nuclear power increased fivefold, but, due to advances in fuel use and plant efficiency, uranium demand increased only threefold (World Nuclear Association, 2005b). At the current rate of demand for uranium (65 000 tonnes per year), known conventional supplies (4.6 million tonnes) are sufficient to fuel nuclear power for 85 years. While nuclear power is expected to grow only marginally to 2010, expansion after that date could cut the resource-to-production ratio to less than 50 years (Table 4.15).

Reprocessing of spent fuel from conventional light water reactors would use existing supplies more efficiently (World Nuclear Association, 2005b). Another option would be to expand the use of fast-breeder reactors. Table 4.16 indicates potential gains from these changes.

Table 4.15 ▶ World uranium and thorium resources

Category	Type	Status 2003	Quantity (Mt)
1	Uranium	Produced until 2001	2.1
2 Known conventional	Uranium < USD40 per kg	Reserves	1.73
3 Known conventional	Uranium < USD40 per kg	Estimated additional resources I	0.79
4 Known conventional	Uranium < USD40 to USD130 per kg	Reserves + estimated additional resources I	2.07
5	Secondary uranium (from recycling)		0.40
6	Uranium < USD130 per kg	Estimated additional resources II	2.25
7	Uranium	Other speculative resources	13.44-14.74
8	Thorium	Reserves	2.16
9	Thorium	Resources	2.35

Source: BGR, 2002; NEA, 2004.

Table 4.16 ▶ Years of resource availability for various nuclear reactors

Reactor/fuel cycle	Years of current nuclear electricity generation with known conventional resources	Years of current nuclear electricity generation with total estimated conventional resources
Current fuel cycle (Light-water reactor, once-through)	85	270
Recycling fuel cycle (Plutonium only, one recycle)	100	300
Light water and fast reactors (with recycling)	130	410
Pure fast reactor fuel cycle with recycling	2 550	8 500

Source: NEA, 2004.

(in this case plutonium) than the reactor consumes. The fuel has to be "reprocessed" before the plutonium and the remaining U-235 can be re-used as a reactor fuel. The plutonium in the spent and reprocessed fuel needs to be securely guarded, as it could be used to make a nuclear weapon.

Fast-breeder units operate in Russia, Japan and France. Prototypes have also been built in India, the United States and the United Kingdom. China intends to build a prototype FBR. India and Russia are building FBRs that might be described as commercial. As of 2006, all large-scale FBR power stations have been liquid metal fast breeder reactors cooled by liquid sodium.

The production costs of electricity from an FBR fuel cycle are at least twice those of a regular nuclear cycle although the impact on total costs is not large. However, the higher fuel efficiency may make sense in a case with significant expansion of nuclear power production (see Box 4.5).

Apart from Uranium, thorium can be used as nuclear fuel. India has ambitious nuclear expansion plans and significant indigenous thorium reserves (a quarter of total identified world reserves). However, the use of thorium as a nuclear fuel will require further technology development. The Indian programme is initially aiming for demonstration of thorium fuel use in an advanced heavy-water reactor (AHWR).

The use of thorium could expand the resource base for nuclear power production. Neutron-efficient reactors, such as CANDU and high temperature gas-cooled reactors, are capable of operating on a thorium fuel cycle, once they are started with a fissile material such as U-235 or Pu-239. Then the thorium (Th-232) atom captures a neutron in the reactor to become fissile uranium (U-233), which continues the reaction. Some advanced reactor designs may be able to make use of thorium on a substantial scale.

Prospects for Nuclear Power Plants

Technology Description and Status

Water-cooled reactors will continue to be deployed through 2050. Gas-cooled reactors have useful safety characteristics and higher thermal efficiencies than LWRs. Between 2010 and 2020, nuclear power could increase its presence in the world generating market through the adoption of Generation III advanced light-water reactors (ALWRs). Several third-generation thermal reactors are already being marketed, most of them with evolutionary designs using pressurised-water technology. The French company AREVA has developed a large (more than 1 600 MWe) European pressurised water reactor (EPR), which was confirmed in mid-1995 as the new standard design for France. EPRs have an evolutionary design and the highest thermal efficiency of any light water reactor, at 36%. They are expected to provide electricity at lower cost than existing LWRs. Availability is expected to be 92% over a 60-year service life. The first unit will be built at Olkiluoto in Finland and is expected to be operating by 2009. A second unit will be built at Flamanville in France.

There are two concepts under development for the commercial use of gas-cooled reactors. The AP1000 design is commercially available and currently under consideration for use in China. It is an up-scaled version of the proven AP600 design. Third-generation gas-cooled reactors, such as the pebble bed modular reactor (PBMR) and the gas-turbine modular helium reactor (GT-MHR), offer enhanced operational and safety features and may become available beyond 2015 (with Generation III+ designs). A PBMR demonstration is planned in South Africa for 2011, with commercialisation from 2015. China is also working on this technology. PBMRs and GT-MHRs stand out for their modular approach to construction, which may make them more appealing in liberalised electricity markets and in developing countries. Generation IV systems may be available for international deployment from 2025.

So many reactor designs are currently under development that a detailed discussion is beyond the scope of this analysis. A brief overview is provided in Table 4.17. The fact that many different designs are under development points to the need for better international co-ordination and co-operation in order to maximise the outcome of scarce RD&D funding.

Table 4.17 ▶ Examples of innovative reactor designs under development

Generation	Reactor type	Design types
III	Light-water reactors (LWR)	• EPR (France) • AP-1000 (US) • IRIS (US) • KLT-40C, ABV-6M, B-500 SKDI (Russia) • SMART (Korea) • MRX, RMWR, SCLWR, SPWR (Japan) • NHR-200 (China) • NP-300, SLP-PWR (France) • SWR 1000 (France) • CAREM-25 (Argentina)
III	Heavy-water reactors (HWR)	• Advanced CANDU reactor (Canada) • APHWR (India)
III+	High-temperature gas-cooled reactors (HTGCR)	• GT-MHR (US/Russia) • PBMR (South Africa/China) • HTGR-MHD (Japan) • HTR-Module (Germany)
IV	Molten-salt reactors (MSR)	• FUJI (Japan/Russia/US) • MSR-NC (Russia) • USR (US)
IV	Supercritical water reactor (SCWR)	
IV	Very High Temperature Reactor (VHTR)	
IV	Liquid-metal-cooled fast breeder reactors (LMCFR)	• BREST 300, BN-800 (Russia) • ENHS, PRISM, SAFR (US) • Rapid-A, Rapid-L, 4S, DFBR (Japan)
IV	Gas-cooled fast reactor	

Source: University of Chicago (2004), IAEA data.

International Collaboration on Nuclear Reactors

Eleven countries and organisations – Argentina, Brazil, Canada, Euratom, France, Japan, Korea, South Africa, Switzerland, the United Kingdom and the United States – have joined together to form the Generation IV International Forum, the Technical Secretariat of which is provided by the NEA. The Forum aims to develop a future generation of nuclear energy systems that will provide competitively priced and reliable energy products while satisfactorily addressing the issues of improved nuclear safety, public acceptance, waste and proliferation.

In addition to the Generation IV International Forum, the International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO) is a major initiative to develop designs supporting the safe, sustainable, economic and proliferation-resistant use of nuclear technology. The INPRO initiative was undertaken under the auspices of the International Atomic Energy Agency (IAEA) with participants drawn from Argentina, Brazil, Bulgaria, Canada, China, Germany, India, Indonesia, Korea, Pakistan, Russia, Spain, Switzerland, the Netherlands, South Africa, Turkey and the European Commission. INPRO is assessing the nuclear fuel cycle with the aim of developing innovative and proliferation-resistant nuclear technology.

In February 2006, the United States launched the Global Nuclear Energy Partnership and allocated USD 250 million to the Department of Energy's 2007 budget for this initiative. The programme aims to expand the development of nuclear technologies. Other objectives are to minimise nuclear waste, demonstrate recycle technology, demonstrate advanced burner reactors, establish reliable fuel services, demonstrate small, exportable reactors and enhance nuclear safeguard technology.

Costs and Potential for Cost Reductions

The nuclear fuel cycle includes several steps, from uranium mining to the disposal of spent fuel and radioactive waste from reprocessing. Investment costs include design and construction, the reactor, major refurbishing and an allowance for decommissioning. Decommissioning includes all costs from the shutdown of the plant until the site is released in accordance with national policy. It can take many decades. Operation and maintenance costs include operating and support staff, training, security and costs of periodic maintenance. Because these costs are variable, they represent a major opportunity for cost-reduction. Fuel costs are related to the fuel cycle and include the purchasing, converting and enriching of uranium, fuel fabrication, spent fuel conditioning, reprocessing and disposal of the spent fuel from reprocessing and transport.

A joint NEA/IEA study has estimated the levelised nuclear fuel cycle costs (NEA/IEA, 2005). At a 5% discount rate, the costs of nuclear generated electricity are in the range of USD 0.021 to USD 0.031 per kWh; investment accounts for about 50% of generation costs, operation and maintenance costs account for 30% and fuel-cycle costs for some 20%. At a 10% discount rate, the costs of nuclear generated electricity in most countries are in the range of USD 0.030 to USD 0.050 per kWh; the share of investment is about 70%, while the operation and maintenance costs account for 20% and fuel-cycle costs (including uranium fuel preparation and waste fuel storage) for 10%. Typical overnight investment costs (not including the costs of capital during construction phase) for new nuclear reactors are USD 1 200/kW for mature designs and USD 1 500 to USD 1 800 for new designs (University of Chicago, 2004). Capital costs during the construction period matter, given construction times of 4 to 5 years or more. On the other hand, technology learning-by-doing and series production can lower the unit cost.

Improving Operational Safety

Existing safety agreements under the auspices of the IAEA include conventions on nuclear safety, the safety of spent-fuel management and radioactive waste, and the physical protection of nuclear material, as well as rules for the early notification of a nuclear accident. The IAEA has enumerated the elements required to ensure the safety of nuclear power plants (IAEA, 2004). They are:

- A design life of 60 years; reliable and flexible operation with high overall plant availability, low levels of unplanned outages, short refuelling outages, good controllability and operating cycles extended up to 24 months.
- Increased margins to reduce sensitivity to disturbances and to diminish the number of safety hazards.
- Improved automation and operator-to-machine interface.
- More time for the operator to act in accident situations to reduce the probability of operator errors.
- Core damage less frequent than 10^{-5} per reactor-year and large releases following core damage less frequent than 10^{-6} per reactor-year.
- Design measures to cope with severe accidents.

The advanced light-water reactors in Table 4.17 are designed to enhance safety by reducing the core-power density and increasing the use of passive systems. These advanced reactors also enhance safety by reducing the number of pressure components and support components below the numbers found in current light-water reactors, thus eliminating large amounts of reactor-coolant system piping. Heavy-water reactors, such as the advanced CANDU reactor, retain the two passive shutdown systems found in the CANDU reactor and, in addition, incorporate passive-decay heat removal capabilities. The enhanced safety features of other innovative reactor designs are discussed in the following sections.

Challenges to Future Deployment

Nuclear power generation is suitable for large-scale centralised power stations that lie at the heart of most of today's electricity grids. Nuclear power is a CO_2-free supply option based on proven technology that could be applied in the short and medium term. Interest in nuclear power recently has increased in some countries, although others remain committed not to build nuclear stations and to phase-out existing plants.

This study is primarily concerned with economic potential. The safety, proliferation and waste management affects of nuclear power are therefore beyond its scope. It is clear, however, that the public will need to be reassured on these issues if nuclear power is to achieve its full potential in the coming decades.

Nuclear power technology is still evolving. Although each generation of nuclear reactors represents an improvement on its predecessor, nuclear fission technologies continue to face a number of technology challenges, namely:

- Investment costs based on current technology (including working capital during construction period, waste treatment and decommissioning) are high. Therefore cost reduction should be a priority.
- New reactor types with potentially lower unit capacity cost need to be proven on a commercial scale, a process that takes decades. Larger reactors reduce investment cost per unit of capacity, but the project investment costs increase. Certain new reactor designs are of a smaller unit size.
- Massive expansion (more than a doubling of capacity over more than 50 years) will put pressure on uranium reserves and may encourge the use of thorium or fast breeder reactors in the long term, which will create new technology challenges (See Box 4.5).

Capital cost reduction can be achieved through improved construction methods, reduced construction time, design improvement, standardisation, building multiple units on the same site and improving project management.

In many circumstances, new nuclear plants appear to be more expensive than natural gas and coal-fired plants when capital, fuel and operating costs are taken into account. However, if a price were placed on CO_2 emissions, the relative economics would become much more favourable to nuclear power (MIT, 2003). If nuclear generation is to become truly attractive to the market, the perceived uncertainty surrounding the cost of new nuclear plants must be resolved.

A 1 000 MW nuclear reactor generates typically 1 000 tonnes of spent fuel over a 40-year life time. Reprocessing can reduce this amount to 36 tonnes of high-level waste, but this waste must be stored for a period of 10 000 years. Partitioning and transmutation (P&T) has the potential to change the nature of the wastes requiring geological disposal. This process involves the transmutation of long-lived radionuclides into shorter-lived ones through neutron capture or fission, thereby eliminating those parts of high-level waste that contribute most to its heat generation and radioactivity. Partitioning and transmutation can reduce the time that waste needs to be kept isolated to several hundred years. Sufficient conversion of the longer-lived isotopes to achieve these aims would require many stages of P&T and a fully developed reprocessing fuel cycle. Solutions are not expected over the next two decades. The main lines of research are advanced separation technologies to better remove the fission products and transuranic elements from spent fuel and the use of accelerator-driven and reactor systems for transmutation.

There are six design concepts in the Generation IV collaborative programme. Three are fast reactors: the liquid metal fast reactor (LFR), which includes the sodium fast reactor (SFR), and the gas-cooled fast reactor (GFR). Also there are three thermal reactors: the very-high-temperature thermal reactor (VHTR), the molten-salt reactor (MSR) and the supercritical water reactor (SCWR) which can also be a fast reactor.

These designs feature improved economics and enhanced safety, minimisation of waste and proliferation-resistant fuel cycles. Each of the six design concepts are discussed in more detail below.

Liquid-metal-cooled Fast Reactors

Liquid-metal-cooled fast reactors allow for the indefinite recycling of spent fuel. Designs include: the 300 MW BREST fast-neutron reactor being developed by Russia; the 20 MW ENHS being developed by the University of California; the 50 MW 4S or Rapid-A system being developed by Japan; the Japanese Atomic Energy Research Institute-funded 200 kW Rapid-L design; Japan's 53 MWe LSPR design for use in developing countries; the 150 MWe PRISM designed by General Electric in the United States; and the Energy Amplifier being developed by the European Organisation for Nuclear Research.

Like gas-cooled fast reactors, liquid-metal-cooled fast reactors use a fast-neutron spectrum and closed fuel cycle. They use a lead or lead/bismuth liquid-metal coolant for efficient heat-transfer and high temperature operating capability. Configuration options include a range of plant ratings, including a 50 to 150 MWe factory-fabricated "battery" with a ten-to-thirty year refuelling interval, a modular system rated at 300 to 400 MW and a monolithic plant option rated at 1 200 MW.

The high-temperature capability of lead-based coolants may allow for operations at coolant-outlet temperatures of above 1 000°C, depending on the outcome of current research on high-temperature materials.

Liquid-metal-cooled fast reactors enhance safety through the use of passive decay heat removal and the simplification of safety systems. The use of lead coolant avoids the potential for fires and for water-coolant reactions associated with sodium. These reactors offer temperatures substantially above those available from current water-cooled reactors, increasing thermodynamic efficiency. They operate as breeders or near-breeders to increase resource utilisation and can ease the management of radioactive waste by consuming plutonium and transmuting minor actinides into stable isotopes.

Liquid-metal-cooled fast reactors are primarily intended for electricity production and actinide burning and waste management, although they may be used for hydrogen production at the upper temperature range.

Up to now, technology development has focussed on sodium-cooled fast reactors using liquid sodium metal coolant for efficient heat transfer. The outlet temperature is approximately 550°C. These reactors are primarily intended for electricity production, actinide burning and waste management. Their development is supported by considerable R&D and by demonstrations in the United States, France, Japan and Russia.

Gas-cooled Fast Reactors

Gas-cooled fast reactors use a fast-neutron spectrum and closed fuel cycle for efficient uranium conversion. Effective management and thorough burning of plutonium and other actinides enhances the efficiency of the process. GCFRs are helium-cooled systems, operating at an outlet temperature of 850°C and using the outlet gas directly in a turbine for high thermal efficiency.

Several alternative fuels are being considered for GCFRs because of their ability to operate at very high temperatures and to ensure complete retention of fission products. These include composite ceramic fuel, advanced coated fuel particles and ceramic-clad actinide fuels. Core configuration options include pin- or plate-based fuel assemblies or prismatic blocks.

Advanced gas-cooled fast reactors enhance safety by including low power density and negative temperature-reactivity coefficients sufficiently strong to moderate the reactors output. Safety is also improved because of the capability of the fuel to retain fission products at high temperatures.

These reactors are intended for electricity production and actinide burning and waste management, although they may also support efficient hydrogen production.[24]

Very-high-temperature Reactors

Very-high-temperature reactors use a thermal-neutron spectrum and a once-through open fuel cycle. A design has a 600 MW thermal helium-cooled core based on prismatic block fuel similar to that envisioned for the gas turbine modular helium reactor (GT-MHR) or the pebble fuel used in South Africa's pebble bed modular reactor (PBMR). The primary circuit can be connected to a steam reformer or steam generator to deliver high-quality process heat. The coolant outlet is designed to operate above 1 000°C.

These reactors will no doubt benefit from the development of particle fuel for the GT-MHR or PBMR, but may require higher-temperature alloy materials, fibre-reinforced ceramics, composite materials or zirconium-carbide fuel coatings.

Very-high-temperature reactors are primarily intended for high-efficiency/high-temperature process heat applications such as thermo-chemical or thermo-electrical hydrogen production. They could incorporate electricity generation to meet the needs of thermo-electrical hydrogen or cogeneration.

Molten-salt Reactors

Molten-salt reactors were first explored in the United States for use in breeder technology in the 1960s. There is renewed interest in these reactors in the United States, Japan and Russia. Latest innovative designs include the 100 MW FUJI reactor being developed by a Japanese, Russian and US consortium. It would operate as a near-breeder. Attractive features of FUJI's fuel cycle include the fact that high-level waste is made up of fission products only, so that it has shorter-lived radioactivity. It

24. Actinide burn-up is disposal of fissile nuclei and waste management and refers to the transmutation of long-lived nuclei, thereby facilitating waste storage.

also has only a small inventory of weapons-grade fissile material, low fuel use and passive safety features.

Molten-salt reactors enhance safety by ensuring that no materials with moderating capability are located in the vicinity of the reactor vessel, so that the molten salt/fuel fluid cannot achieve criticality outside the core in the event of an accident involving leakage of molten salt from the vessel. The design offers a substantial increase in temperature capability for heat applications as compared with current water-cooled reactors.

These reactors use an epithermal neutron spectrum and a closed fuel cycle designed for the efficient use of plutonium and minor actinides as a fuel. The fuel is a circulating liquid mixture of sodium, zirconium and uranium-plus-actinides fluorides. The molten-salt fuel mixture flows through graphite core channels, producing a relatively thermal neutron-energy spectrum. Heat generated in molten salt is transferred to a secondary coolant system through an intermediate heat exchanger, and then another heat exchanger is used to isolate the molten salt fuel from the power conversion system. There is no solid fuel fabrication since liquid fuel salt allows for the withdrawal of the fission products with varying composition to meet criticality and power-generation needs. The reactors typically have a power level of 1 000 MW and operate at low pressure (0.5 MPa or less) with a coolant outlet temperature of 700°C, thus affording high thermal efficiency.

Molten-salt reactors are primarily intended for electricity production, actinide burning and waste management.

Supercritical-water-cooled Reactors

Supercritical-water-cooled reactors have two fuel-cycle options: an open, once-through cycle with a thermal neutron spectrum reactor derived from today's water-cooled reactors and a closed fuel cycle with a fast-neutron spectrum and full actinide recycling. Both options use a high-temperature, high-pressure water-cooled reactor system operating above the thermodynamic critical point of water to achieve high thermal efficiency (about 44%). The fast-spectrum option uses advanced aqueous reprocessing for actinide recycling. These reactors typically are 1 700 MW systems, operating at a pressure of 25 MPa and a reactor outlet temperature of 550°C.

Supercritical-water-cooled reactors have passive safety features similar to those of the simplified boiling-water reactor. The balance-of-plant in the SCWR is considerably simplified because the coolant does not change phase in the reactor, unlike in boiling-water reactors. These reactors are primarily intended for electricity production with an actinide management option in the fast-neutron version.

Prospects for Nuclear Fusion

Fusion is a nuclear process that releases energy by joining together light elements, the direct opposite of fission. 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 enabled considerable advances in this technology. Production of fusion energy has been established in existing experimental devices at levels up to 16 MW, though only for short times (seconds). Extensive studies have shown that fusion has inherent safety and environmental features. Fusion reactors have limited stocks of energy capable of causing accidents. The fusion process burns a mix of deuterium (the non-radioactive isotope of hydrogen) and tritium (the radioactive isotope of hydrogen, generated in-situ by the irradiation of lithium compounds). Although a fusion reactor contains significant amounts of tritium, an in-plant accident would be expected to result in limited hazard to the public. The fusion reaction produces no greenhouse gases and no radioactive fission reaction products. Inner components of the fusion reactor are activated by neutrons emerging from the fusion reaction. However, materials under development for these components are such that almost all the activated materials can be disposed of as inert waste, recycled, or given shallow-land disposal a few decades after the end of operation.

The cost of fusion electricity will depend upon the extent to which fusion physics, technologies and materials are further optimised in the next few decades. Scientific and technological knowledge, as well as an agreed design, are now available for the construction of the first experimental reactor close to a commercial-scale, the International Thermonuclear Experimental Reactor (ITER), in order to demonstrate that harvesting power from fusion is scientifically and technically feasible. ITER will produce up to 500 MW net thermal power output for long-standing pulses of hundreds of seconds, up to steady-state operation. Prototypes of most of the key components of the reactor have been produced and successfully tested individually at close to the necessary conditions.

Fusion is being developed in the context of a long-standing international co-operation programme. The ITER project is an international joint venture including China, the European Union, India, Japan, Korea, Russia and the United States. According to the fusion programme roadmap, construction of ITER will take some 10 years, and the facility will operate for about 20 years. ITER would be complemented by the construction and operation of the International Fusion Material Test Facility (IFMIF) and followed by a demonstration power plant (DEMO) for electricity generation. The material test programme should be run in parallel with ITER to ensure material characterisation for the demonstration power plant. The timely implementation of this roadmap could considerably accelerate the achievement of fusion power.

Fusion power generation on a commercial scale remains a long-term challenge and requires research and development efforts including material and system optimisation through technological engineering and scientific advances. The *in-situ* tritium generation and structural materials for the fusion power plants remain to be tested. These efforts will require continued strong domestic programmes of supporting research. Because of the potential benefits of fusion, very high shares of IEA countries' energy R&D budgets are allocated to researching its feasibility and potential. It is not likely to be deployed until at least 2050.

Electricity Networks and Distributed Generation: Status and Prospects

Advanced Electricity Networks

Technology Description and Status

Advanced electricity networks and associated technologies will form the backbone of the 21st century energy system. Numerous technologies that could dramatically reduce emissions depend on the electricity delivery system, including integrated distributed and small-scale generation sources, grid-connected intermittent renewable energy sources and energy-storage technologies.

Many factors, such as aging equipment, increasing levels of electricity trading and network congestion, already pose challenges to the capacity and reliability of electricity transmission and distribution systems. Most of today's systems are based on technology from the 1950s and require substantial upgrading. At the same time, electricity system reliability is coming to be seen as an important element of energy security. In many countries, the shape of the electricity load curve is changing with more extremes in base load and peak load demand. Also, the integration of more distributed and intermittent generation sources will pose still further challenges.

Tomorrow's electricity infrastructure and control systems will have to be equipped to handle higher and more complex loads, and to recognise and dispatch small-scale components. Yet the performance of power systems decreases with the increasing size and complexity of networks, because of problems related to load flow, power oscillations and voltage quality.

Costs and Potential for Cost Reductions

Transmission and distribution costs are as important as electricity production costs. Moreover, in many developing countries the losses during transmission and distribution are quite high. While some of these losses may be attributed to theft, outdated technology plays a role as well. Solving these problems will largely be a matter of investment, rather than technology development.

Future R&D Efforts

Modernising and improving the reliability and security of electricity networks and providing the network architecture for a low-emissions energy system, will call for new technologies, new information and control systems, and new approaches to systems management. Some of these will have to be integrated into today's systems, while others will be part of rapidly expanding electricity supply networks in developing countries.

New large-scale electricity storage technologies, such as underground compressed air storage systems, will be needed to cope with massive amounts of electricity from intermittent sources.

Many promising systems management technologies are emerging. They include large-scale devices for routing power flows on the grid, advanced information systems for observing and assessing grid behaviour, and real-time controls and operating tools. There are also new systems planning methods to handle the many uncertainties that are already present or are emerging in the power system. These elements of a 21st century electricity system are in view, but not yet in place.

Challenges for Future Deployment

Key issues in building a modern electricity system involve both technology and policy. This discussion focuses on technology. Technology needs to be developed on myriad fronts – advanced sensors, superconducting cables, advanced visualisation technologies, power-flow and control technologies with rapid-response capabilities, and many others. Existing technologies require cost reductions if they are to be widely deployed. The fact that electricity is widely regarded as a "public good", coupled with the rapid growth of interconnections, points to the need for more international collaboration in R&D, testing and demonstration. Putting these technologies into place will require long-term investments in both transmission and distribution. Investments in, and upgrades to, transmission and distribution systems are expensive and may not be made unless they are promptly and directly beneficial to the entities expected to make them. Today, priority for current and planned investments is being given to low-cost solutions that may not, in fact, solve system problems over the long term.

Demand-side technologies are those that reduce electrical consumption at the point of use. These technologies have several requirements: control hardware and a consumption profile, which can allow for load control; frequent electricity price information or, alternatively, an automatic control signal from the electricity supplier when prices reach a pre-determined level; and special metering that allows users to keep track of electricity consumption at different price levels. "Real-time pricing" systems allow large commercial and industrial customers to modify their electrical loads in response to changes in electricity prices. Two-way communications between electricity users and suppliers and specialised control systems can automatically reduce loads and shift use of electrical equipment in response to real-time prices. Such systems are most useful for large-scale users of lighting, heating and ventilation, such as hotels, large office buildings, shopping centres and business centres. Industrial facilities of all types can benefit from this type of system. Metering technologies are critical for the use of demand-side controls, particularly for smaller loads where metering costs are high in relation to the total electricity bill.

Building an up-to-date power-delivery network that can support a low emissions energy system will require that technology development go hand-in-hand with the provision of policy, economic and regulatory frameworks that provide incentives for investment. Public acceptance of overhead power transmission lines is in certain cases an issue that needs to be tackled as well. Underground transmission is technologically feasible, but its costs are much higher unless new technologies can help reduce them.

Distributed Generation Systems[25]

Distributed power generators are small, modular electricity generators sited close to customer loads. Distributed power generation systems have received considerable market and policy attention in recent years. They are commercial options in markets with varying characteristics, from densely populated urban areas, where supply reliability and energy efficiency are key advantages, to sparsely populated regions with abundant renewable resources and high grid-connection costs. During the past decade, in addition to focus on conventional technologies for decentralised power production such as oil and gas engines, a lot of attention has focused on micro-turbines, Stirling engines and renewable technologies. Decentralised power supply systems using renewable energy have been introduced in areas where the transmission and distribution system is absent or inadequate.

They offer advantages that large-scale, capital-intensive, central-station power plants cannot provide. For example, distributed generation does not rely on a costly transmission and distribution system. This can be an advantage in regions where such a system does not yet exist, where population densities are very low, transmission and distribution costs are very high, or where costly line upgrades would be needed. By siting smaller, more fuel-flexible systems near energy consumers, distributed generation avoids transmission and distribution power losses and provides a choice of energy systems. Many distributed power systems produce little noise and low emissions and can be located inside, or immediately adjacent to, the buildings where the power is needed. This greatly simplifies the problems of bringing power to expanding commercial, residential and industrial areas.

Distributed power generation technologies use a variety of fuels, including natural gas, diesel, biomass-derived fuels, fuel oil, propane, hydrogen, sunlight and wind. This makes a generic discussion difficult, as characteristics vary widely.

Combined heat and power (CHP) production is the largest segment of the existing decentralised generation market. (CHP in industry is discussed in Chapter 7.) Large-scale CHP systems, based on natural gas turbines or boilers represent 96% of the CHP market worldwide. Such systems have reached maturity at a scale of 1 MW or more. More recently, attention has switched to the use of fuel cells in small-scale CHP systems because of the large potential market for their use in the residential and commercial sectors. Their electric conversion efficiency is high compared to other small-scale decentralised electricity supply options, but the comparison is less favourable if they are compared to large-scale centralised electricity supply options with grid delivery, even if the 5 to 7% losses in electricity transportation and distribution are subtracted in the case of centralised production.

In CHP mode, decentralised systems can have an overall efficiency advantage due to their use of the residual heat, which is generally not utilised at centralised power plants. In particular, if a continuous heat demand is required, rather than just seasonal space heating or cooling, the use of significant additional quantities of heat can significantly raise the overall efficiency and may favour fuel cell systems. However, moving from centralised power production to distributed power generation

25. Micro generation technologies are discussed in Chapter 6 "Buildings and Appliances".

systems that use fossil fuels will also be hampered by the fact that CO_2 capture and storage will not be economical for distributed systems. Therefore, if decentralised fuel cell systems are not to add to CO_2 emissions, they will need to run on hydrogen that has been produced without emissions.

Numerous technologies, such as Stirling engines, ICEs, Rankine cycle engines and fuel cells, compete in the small-scale CHP market (Wilcox, 2004). The Rankine cycles seem far from market introduction and are not discussed in more detail. An overview of the status of the other two systems in Europe is shown in Table 4.18. These systems are at the demonstration stage or in an early stage of market introduction. The Stirling engine and fuel cell systems under development are smaller than the ICE systems (1 to 4 kW vs. 10 to 20 kW). The reason is that the ICE system costs rise exponentially as the electric capacity decreases. Therefore, the competition for single-family dwellings seems to be limited to Stirling engines, fuel cells, boilers, heat pumps and district heating in combination with electricity supply from the grid. For larger installations in multi-dwelling and apartment buildings, ICEs and micro-turbines can play an important role. An important characteristic of fuel cells, compared to the other CHP systems, is their high electricity-to-heat ratio. This can be an important advantage as the insulation level of buildings improves and the ratio of electricity-to-heat demand increases.

Transmission and distribution costs are high in remote areas with low population densities. In these areas fuel cells may have a competitive advantage over other centralised electricity supply options. An electricity supply system based on decentralised fuel cells may offer superior efficiency, reliability and availability performance in comparison with other systems, for example renewable systems. Depending on the circumstances, a decentralised fuel cell system may also offer superior reliability and supply security than the grid supply from centralised production.

Distributed energy systems offer reliability for businesses and consumers who need dependable, high-quality power to run sensitive digital equipment. However, this is a niche market. More important, distributed systems can provide alternative,

Table 4.18 ▶ *Characteristics of Stirling engines and ICE CHP systems*

	Electric (kW_e)	**Thermal** (kW_{th})	**Status**
Stirling engines			
DISENCO (SIGMA)	3	9	25 field units planned
Whisper Tech Mk. 4	0.85-1.2	6-8	400 units sold. Agreement with EON to buy 80 000 units
BG Microgen	1	5-36	Announced for 2007
ENATEC	1	6-26	Field trials 2005-2006
ICE CHP systems			
BAXI/Senertec	5-5.5	12.5	18 800 EUR 10 000 units installed
VAILLANT/Ecopower	4.7	12	Demonstration units

Source: Wilcox, 2004.

less-expensive power sources during peak price periods. In the United States, the potential market for providing power during peak price periods is as high as 460 GW, according to a US Department of Energy study.[26]

Buildings offer large areas from which to capture solar radiation for producing electricity, either for use in the building or to be fed into the electrical grid. Studies have shown that significant shares of the electricity demand can be met by solar PV systems on buildings.[27]

Costs and Potential for Cost Reductions

The costs of emerging small-scale gas fuelled CHP systems are currently more than USD 5 000/kW, but they are expected to drop quickly by a factor of two or three, once mass production starts. The potential for net metering, grid access and feed-in tariffs determines the economics to a large extent in case of grid connections. (See the renewables section of this chapter for cost and cost reduction potentials for renewables power generation.)

Future R&D Efforts

Reciprocating-engine technology is commercially available. Micro-combined heat and power using the Stirling engine is considered near to the market, but they still need more development to get costs down. Fuel cells are further away from market readiness.

Fuel cell technology is still under development, although some versions have been deployed commercially or in demonstration projects. Several types of fuel cells that are appropriate for buildings are under development. Proton exchange membrane fuel cells can be used for buildings and they are considered a promising technology. Micro-CHP systems using fuel cells still require more R&D and pilot studies. Fuel cells will be competitive for both commercial and residential applications when capital costs are reduced to USD 1 350/kW (Jones, 2005).

Challenges to Future Deployment

Initial costs and the length of the payback period are crucial issues for distributed generation technologies. So is the availability of equipment and know-how. There can be concerns about quality and standardisation because manufacturers and installers may be small and have been in the business for only a short time. Local officials' lack of experience with distributed generation systems can hinder or prevent approval processes. Historical or architectural preservation rules can prohibit modifications to buildings that PV systems would require. It may also be difficult to sell to the grid the excess electricity produced by distributed generators.

As a new technology, micro-CHP faces many of the same barriers that confront other energy-efficient technologies. CHP needs to be incorporated into existing legislation, accreditation and rating frameworks, and CHPs initial cost is still a major barrier.

26. http://www.eere.energy.gov/de/power_generation.html
27. Potential for building integrated photovoltaics, IEA PVPS Task 7-4, 2002.

Chapter 5 ROAD TRANSPORT TECHNOLOGIES AND FUELS

Key Findings

- *Energy demand for transport, which is almost entirely fuelled by oil, will continue to experience high growth in the decades ahead. To meet transport service needs in an affordable, secure and sustainable manner, fuel economy improvements, diverse fuel sources and modified infrastructure are essential.*

- *Technology has often been used to improve performance and offer new features on vehicles, rather than to increase fuel savings. High oil prices and the introduction of fuel standards have been the most effective drivers for the development and use of vehicle technologies that achieve actual fuel economy improvements and for the education of consumers.*

- *Internal combustion engine technologies, such as variable valve control, direct fuel-injection and advanced combustion in downsized engines, offer significant opportunities to reduce fuel consumption. Light-weight materials, efficient tyres and energy efficient on-board appliances provide additional fuel savings. If all technical means of engine, transmission and vehicle technologies are implemented, a 40% improvement in the fuel economy of gasoline vehicles could be achieved at low costs by 2050.*

- *Hybrid vehicles can provide impressive fuel savings and emission reductions. Today, hybrids are significantly more expensive than conventional gasoline and diesel vehicles. The prospect for overcoming the cost barrier is improved by the availability of various "degrees" of hybridisation (full, mild and light) that are suitable for different vehicle classes. This gives latitude in the design that can help contain costs.*

- *Batteries are responsible for a large fraction of the cost penalty of hybrid vehicles. Improved battery technology can help reduce the cost of hybrid vehicles and boost the diffusion of plug-in hybrids, a possible key to the electrification of transport systems.*

- *The prospects for hydrogen and fuel cell vehicles are less certain. They depend on significant cost reductions and simultaneous development of a fuel cell vehicle market and a hydrogen infrastructure.*

- *The development of large quantities of non-conventional oil and Fischer-Tropsch synthetic fuels would enhance fuel options in the transport sector, but it would require significant energy inputs, implying substantial CO_2 emissions.*

- *Biofuels may become a key transport fuel option. Through fuel blending and increased use of flexible fuel vehicles, biofuels can use the existing fuel distribution infrastructure with only minor adjustments required. Biofuels offer energy security* *and CO_2 emissions reduction opportunities. Full development of the biofuel option requires a thorough analysis of any possible unintended consequences of a major shift in land use.*

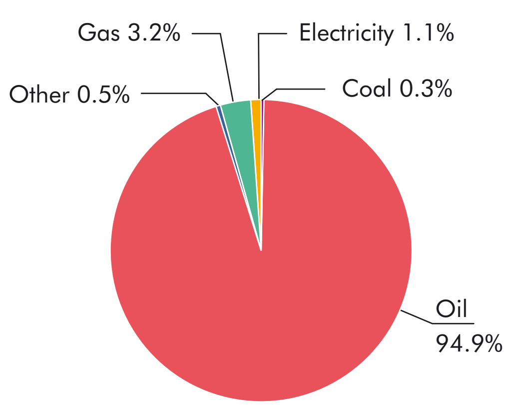
- *Widespread use of biofuels will require expanding the range of feedstocks and the introduction of advanced conversion technologies such as Fischer-Tropsch synthesis and ethanol production from cellulosic feedstocks.*

Overview

This chapter first looks at trends in energy use and CO_2 emissions in the global transport sector. Then it discusses transport fuel options and presents the status of and prospects for road vehicle technologies, with a special focus on cars and light trucks. Technologies for air, water and rail transport modes are not addressed in this study.

Almost all the energy used for transport purposes today is in the form of oil products. Transport is the dominant oil-consuming sector in most countries. In 2003, transport generated nearly 60% of the final demand for oil worldwide and nearly two-thirds of the demand in OECD countries. Petroleum fuels fulfilled 93% of total transport energy demand in 1971 and nearly 95% in 2003 (Figure 5.1). The remaining 5% was provided by electricity and coal (mainly for rail transport), biomass (in the form of liquid fuels) and natural gas (mainly in road applications, but also for pipeline transport). Over the past thirty years, oil use in the transport sector nearly doubled in OECD countries and nearly tripled in non-OECD countries. Practically all the global increase in oil consumption was from transport demand.

Figure 5.1 ▶ Total final consumption in transport, 2003



Key point

Transport is an extremely oil-intensive sector.

The CO_2 emissions from transport increased more than 30% between 1990 and 2003, second only to electricity and heat production (44% in the same period). Global CO_2 emissions from transport exceeded 6 700 Mt in 2003.

The OECD countries are responsible for nearly 60% of CO_2 emissions from the transport sector (about 4 000 Mt in 2003). The OECD *share* is slowly declining, however, because of the rapid growth in transport in non-OECD countries. Between 1990 and 2003, CO_2 emissions from transport in OECD countries increased by 26%, or 820 Mt, more than from any other sector. Road transport was responsible for more than 85% of this increase. Air transport has also shown significant growth (more than 50% since 1990), but its overall share of OECD transport emissions is only about 10%, compared to nearly two-thirds for road transport.

In non-OECD countries, CO_2 emissions from transport exceeded 2 000 Mt in 2003. Transport is the second fastest growing sector in non-OECD countries, after electricity and heat production, with more than a 41% increase from 1990 to 2003. Road transport contributed about 80% of the total. Emissions from road transport in China more than doubled over the same time period.

Road transport accounts for 73% of total transport energy demand, air transport for 11%, water transport for 9% and rail for 3%. Escalating energy demand for road transportation is driven by dramatic growth in developing economies, a trend that is projected to continue. In the Reference Scenario presented in the IEA's *World Energy Outlook*, CO_2 emissions from the transport sector are projected to increase by 80% from 2002 to 2030. Road transport represents the bulk of the increase. Demand from air transport is also expected to grow strongly, but from a lower base.

Energy use in the transport sector depends primarily on the following factors:

- Transport activity (the level of demand for personal mobility and for the transport of goods).[1]
- Modal mix (the chosen mix of transport modes like cars, buses, planes, ships, aircraft, etc.).
- Fuel mix (the types and the mix of fuel used in each transport mode).
- Energy intensity (including the fuel efficiency of the different modes).

Transport Activity

All OECD countries have experienced sustained increases in passenger travel over the past three decades, sustained by economic growth and increased personal expenditure. Currently there is a wide spread in average travel per capita. The United States, Canada and Australia are well above the European countries, and probably well above many non-OECD countries, for which a precise estimate is difficult due to a lack of detailed data.

1. The main activity indicators are the passenger-kilometre, the measure of how far people move; and the tonne-kilometre for freight haulage, which accounts for both the weight of the freight and the distance moved.

Similarities in "travel time budgets" and cost budgets are seen in several countries and world regions. For example, the average time spent travelling per person is about one hour per day. These time budgets suggest that as personal income grows, people gain access to faster modes of travel. Cars are a key element in this pattern and they play a major role in increased travel activity. The United States has the highest levels of travel per capita in the world (more than 25 000 kilometres per person per year).

In Europe, the overall distance travelled by road passenger vehicles has tripled in three decades. The number of cars in Europe has increased substantially and car ownership is expected to continue to rise, especially in the new European Union (EU) member states. Yet the picture varies widely from country to country, as passenger-kilometres per capita increased at various rates in different countries; the regions with relatively low levels of travel in 1970 have played "catch-up" to those with higher levels. Some regions in the world are now getting closer to the personal income levels that characterised many European countries a few decades ago, and they are likely to experience a similarly impressive growth in car ownership and travel demand in the next few decades.

The global picture can be represented by these considerations: in regions where the average personal income is less than USD 5 000 per year, car ownership growth is very slow, as other transport modes (walking, bicycles, two- and three-wheelers) are widespread. As the income per capita grows, vehicle ownership generally increases until it reaches 300 to 400 cars per thousand inhabitants. Once this level is reached (as is the case in OECD countries), the growth of car ownership tends to slow, reflecting a saturation level, which is dependent on the nature of the transportation infrastructure.

The levels of freight haulage vary among countries and can be driven by several important factors. Low population densities tend to result in higher per-capita tonne-kilometre rates. Natural resource endowment, along with the geographical location of production facilities and the structure of the economy, also drive freight haulage levels. Total freight haulage roughly follows GDP in most countries, and although freight transport per capita has increased substantially in the last three decades, on a per-unit of GDP basis, it has been flat or has declined in many OECD countries. On average, OECD economies have become slightly less freight-intensive, reflecting a faster growth in the service sector than in goods sectors like manufacturing. Moreover, OECD countries have seen an increasing average value per unit-weight of the goods moved, as when less coal and more computers are shipped in the economy.

Modal Mix

In the transportation sector, the modal mix is affected not only by consumer choices, but also by the *availability* of various modes, prices of competing fuels and vehicles, and by the legislative and fiscal policies in effect.

Research shows that people are unlikely to pay more than a certain percentage of their income on travel (studies estimate that the average expenditure per person for travel is about 10% of personal income). As incomes increase, people are likely to switch to faster modes. Air travel now has the highest growth rate among all modes in the OECD and can be expected to be the fastest growing mode for some time. Passenger cars, on the other hand, will have the largest role in the growth of the travel activity of non-OECD countries.

Increased economic growth does not necessarily make it inevitable that the entire world will own cars if they can afford them, as long as other modes can provide similar speeds and travel times. European and Japanese cities have often succeeded in creating transit and intercity rail systems that allow people to get where they want to go as fast, or faster, as by car. This may help explain lower car ownership rates in these regions compared to North America.

Targeted policies can promote efficient transit systems and other solutions to encourage a shift from cars to public transportation. Particular care should be paid when these systems are conceived and built, as the actual impact of measures favouring modal shifts is not always effective in terms of fuel savings or quantity of CO_2 abated. Modal shift policies are often conceived for other transport policy goals, or even objectives beyond the transport sector, such as providing access to low cost public transport (ECMT, 2006).[2]

If modal shift policies were able to transfer 10% of the total passenger-kilometres in 2003 from light-duty vehicles to buses (with unchanged load factors), the net energy savings on a global basis would amount to 3.6 Mtoe.[3] This represents about 5% of total transport energy demand and would reduce CO_2 emissions (on a well-to-wheel basis) by 0.3 Gt of CO_2 equivalent. On the other hand, a 10% displacement of passenger-kilometres seems a large estimate, if projected to the future. A recent OECD study highlights that modal shift policies do not constitute the cornerstone of an effective CO_2 abatement policy in the transport sector, since such policies tend to achieve much lower abatement levels than measures focusing on fuel efficiency.

Differences among transport modes also exist for freight haulage. Freight transport by truck, per unit of GDP, has increased in most OECD countries over the past three decades, while there were decreases in the GDP intensity of rail and shipping. This underscores the fact that trucking gained market share, even if total rail and shipping freight haulage did not decline. Although precise estimates are difficult because of a lack of data, trucking is likely to count even more in developing countries in the next decades, given the lack of surface transport infrastructure for non-road modes, especially rail.

Fuel Mix

Gasoline and diesel fuel use for road transport accounts for about three-quarters of global transport energy demand. In OECD countries, cars and passenger light trucks account for more than 50% of the energy demand for surface transport. Freight trucks use a consistent part of the remaining share (about 30%), and rail, bus, and water-borne passenger and freight travel for less than 15%. Air modes consume about 10% of global transport energy.

2. Savings depend on the load factors achieved in buses (or other mass transit vehicles). In many cases, when bus services are enhanced, half of the additional ridership transfers are from walking and cycling. This results in a lower (or even negative) reduction of energy demand and CO_2 emissions.

3. Light-duty vehicles are defined as cars, minivans, sport-utility vehicles and personal use pickup trucks.

Fuel prices and the compatibility between a given fuel and a given mode have a primary influence on the choice of fuel used. The current situation, where petroleum-based fuels such as gasoline, diesel and jet fuel dominate the markets, has remained nearly unchanged over the past thirty years. However, some significant changes of the final energy mix have taken place. Three notable examples are the shift to diesel in Europe, the growth of bioethanol in Brazil and the electrification of the railways in many OECD countries.

- The share of diesel cars and light trucks in OECD countries at the beginning of the 1970s was around 1%. It grew above 10% in the 1990s, pushed by very strong growth rates of diesel car sales in Europe, where the percentage of diesel cars nearly doubled, reaching 32% in 2000 (IFP, 2005).
- The fuel alcohol programme (Proalcool) in Brazil, launched in the 1970s, is the largest commercial application of biomass for energy production and use in the world. By December 1984, 17% of the country's car fleet was running on hydrated alcohol. The share of hydrous ethanol vehicles sold on the market rose to almost 100% in 1988, but it fell to less than 1% by the mid-1990s, as the sharp decrease in oil prices in the mid-1980s led to the revocation of the Proalcool plan in 1991. High oil prices in 2000 led alcohol cars to regain the favour of consumers, especially after the introduction of the flex-fuel technology. Such technology allows vehicles to run on any gasoline-ethanol blend and guarantees the flexibility that was not granted by dedicated alcohol vehicles. In 2002, the Brazilian Government began reviving the Proalcool programme: the industrial production tax was reduced for manufacturers of ethanol-powered cars and subsidies were introduced for the purchase of new ethanol cars. The Government also introduced credits for the sugar industry to cover storage costs in order to guarantee ethanol supplies. In November 2005, flex-fuel sales accounted for 71% of all cars sold in Brazil.
- In the early 1970s, about two-thirds of OECD energy demand for passenger rail transport was supplied by diesel-fired locomotives, while the remaining third was served by electric trains. In recent years, this ratio has more than inverted.

Energy Intensity

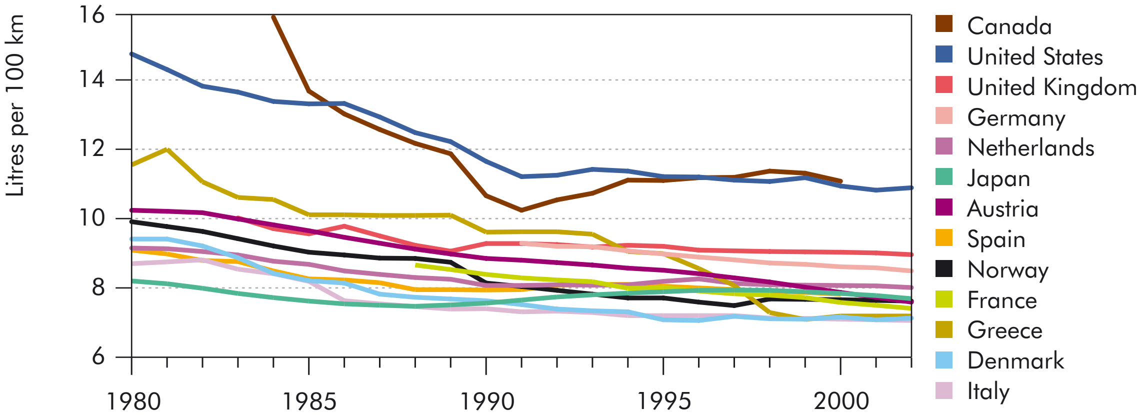
Energy intensity is expressed as final energy per unit of transportation activity, e.g. the energy needed to cover a given distance by a passenger or tonne of freight. Energy intensity is closely linked to income growth and changes in fuel prices.

Income growth can shape the demand of goods, affecting the energy needs for transportation through modal choice and vehicle characteristics. Vehicle ownership, closely coupled with personal income, has a primary effect on the modal distribution of passenger travel, ultimately influencing the energy intensity of transportation. Income level also affects access to technology and can result in less-efficient transportation modes in developing countries. Many older, less-fuel-efficient vehicles are exported to developing regions since such vehicles are cheaper to buy.

Countries with relatively high fuel prices tend to have transport vehicles with lower energy intensity in each vehicle class. This effect is particularly evident when regional price differences exist, such as in the light-duty vehicle market in Europe and the

United States. Figure 5.2 shows how in Europe, where fuel prices are higher because of fuel taxes, the average vehicle currently on the market typically consumes between 7 and 9 litres of fuel per 100 km (corresponding roughly to CO_2 emissions between 170 and 220 g per kilometre). The situation is very different in North America, where fuel taxes are much lower than in Europe. In the United States, the average light-duty vehicle uses about 35% more fuel per kilometre than the average European car.

Figure 5.2 ▶ *Average fuel intensity of the light-duty vehicle stock*



Source: IEA and Odyssee.

Key point

Fuel intensity has tended to improve, but it remains very different among OECD regions.

This comparison also offers an opportunity to analyse how, even if trends observed in several regions might suggest that the availability of technologies differs from one place to another, much of the difference in actual efficiencies can be explained by the fact that new technology has been used differently in the regions. In Europe, high fuel prices represented a strong incentive for vehicle manufacturers to improve fuel economy and led to the rapid adoption and widespread use of energy-efficient technologies. In the United States, lower fuel prices resulted in a greater interest for manufacturers to offer increased power availability rather than better fuel economy, which resulted in larger and heavier vehicles that require more power to offer the same performance.

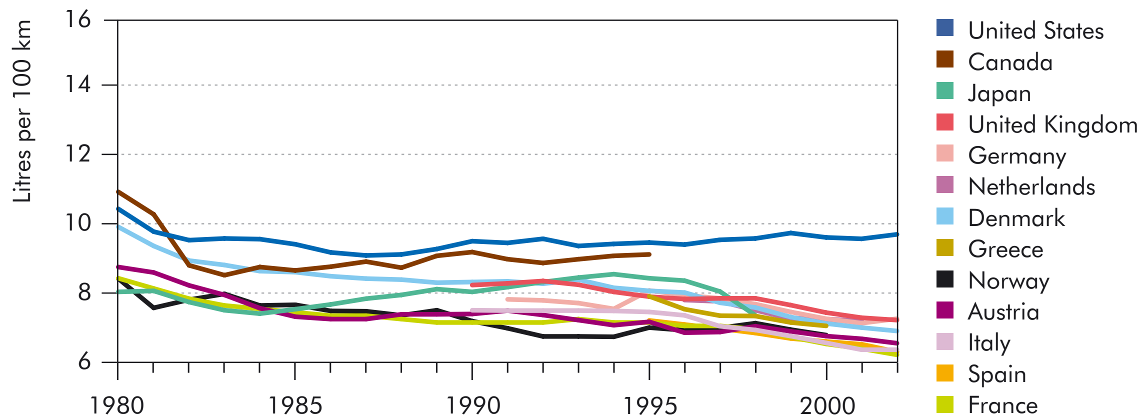
Other factors, such as public incentives, investment choices, road conditions, congestion and fuel economy improvement programmes can significantly influence final energy intensity of road transport. Some of these factors have played an important role in the historical evolution of vehicle fuel economies. Policies addressing fuel economy are particularly relevant in this context. The evolution of the fuel economy of light-duty vehicles helps to highlight the influence of such policies.

In the United States and Canada, strong fuel economy improvement programmes resulted in decreased fuel use per vehicle-kilometre during the 1970s and the 1980s. Fuel economies of new vehicles were close to 10 litres per 100 km in the

United States (less than 9 litres per 100 km in Canada) by the early 1990s. Since then, fuel intensity of new vehicles has been stable. This effect can be explained by the fall of oil prices in the second half of the 1980s and the little change in the US Corporate Average Fuel Economy (CAFE) standards since 1985.[4]

The effect of policies in Europe is particularly interesting due to recent developments. In 1995, a voluntary agreement was signed between several car manufacturers and the European Commission. It set a test-based emission target of 140 g of CO_2/km for average new vehicles sold in 2008-2009.[5] Even if it will be very hard to meet these targets, significant improvements have been achieved in recent years: CO_2 emissions from new cars in the EU-15 decreased by almost 12% between 1995 and 2005. (Figure 5.3).[6] The current discussion focuses on a combination of biofuels and vehicle efficiency measures (European Commission, 2005).

Figure 5.3 ▶ Average fuel intensity of light-duty vehicle sales



Source: IEA and Odyssee (test fuel economy).

Key point

Different trends in fuel economy characterise the new light-duty vehicle market.

Other policy-related evolutions can be expected in the future, and they assume a particular relevance in developing countries, where the vehicle stock is expected to increase significantly. In 2004, for instance, China approved new fuel-economy standards to reduce its dependence on imported oil and encourage foreign

4. US CAFE standards require each manufacturer to meet specified fuel-economy levels for cars and light trucks. The standards for passenger cars have remained unchanged since 1985 at 27.5 miles per gallon. The standard for light trucks was increased from the existing standard of 20.7 mpg in 2004 to 21.0 for 2005, 21.6 for 2006, and 22.2 mpg for 2007. Canadian standards have matched US standards each year.

5. The average difference between tested and on-road fuel economy (the on-road fuel-economy "gap factor") is estimated to be about 18% in Europe.

6. The auto industry has committed to the target as a whole, but it is not publicly known how individual manufacturers plan to reduce their CO_2 emissions to bring the industry to its fleet-wide target, nor if there is any agreement among manufacturers about exactly how to meet the target. Some European models have already met the 140 g CO_2/km target. According to a study by the World Resources Institute, this is the case for more than 20% of the models sold by four manufacturers, but none of the models of another manufacturer has met the target.

automakers to introduce more fuel-efficient vehicles to the Chinese market (An and Sauer, 2004). The effects of this decision are not yet visible, but they are likely to impact the Chinese market in the coming years, favouring an increased penetration of technologies for fuel economy improvements.

As activity projections are closely related to income levels and modal shifts tend to achieve relatively low fuel savings with respect to measures focusing on fuel efficiency, technology is a key element for an effective reduction of the energy intensity of the transport sector.

Greenhouse Gas Characteristics of Transport Fuels

Greenhouse gases (GHGs), such as CO_2, are one of the main products of fuel combustion. The GHG impact of road transport depends on the propulsion system, the type of fuel used, and the production and distribution of the fuel itself.

The well-to-wheel analysis (WTW) of GHG emissions from transport vehicles helps to detect how vehicle use or fuel production and distribution contribute to the final GHG emissions. WTW analysis is broken down into two sub-categories:

- Tank-to-wheel (TTW) analysis. It accounts for the GHGs emitted through the combustion of the fuel in the propulsion system and is associated with the vehicle use.
- Well-to-tank (WTT) analysis. It accounts for the emissions derived from the fuel production processes and those associated to the fuel distribution.

In a conventional light-duty vehicle running on gasoline produced from refined oil, WTT emissions account for 10 to 15% of the total WTW emissions.

Another component completes the life cycle analysis of the GHG emissions associated to the transport service: the GHGs emitted for the vehicle manufacture. For conventional cars and light trucks, this component makes up between 5 and 10% of the total GHG emissions.

Pollutant Emissions

Transport vehicles release pollutants through fuel combustion and evaporation. Transportation contributes significantly to the emission of air pollutants such as carbon monoxide (CO), volatile organic compounds (VOCs), nitrogen oxides (NO_X) and particulate matter (PM). The sector also emits lead and sulphur oxides.

Programmes to limit the emissions of these pollutants from light-duty vehicles have been put in place in all OECD countries and are increasingly implemented elsewhere. Such programmes have resulted in important improvements in vehicle equipment and promoted the use of cleaner fuels. They have also contributed to the reduction of pollutant emissions from the existing car stock (for this reason, tightening fuel standards can have more rapid effects on pollutant emissions than tightening vehicle emissions standards). The standards introduced in the past decades have led to steadily lower emissions of several pollutants. For example, lead has been virtually eliminated with the near universal use of unleaded fuel.

In some cases, the introduction of pollutant emission standards was associated with improvements that led to better fuel economy, as in the case of electronic injection for three-way catalysts. Depending on which technologies are used to reduce pollutant emissions, future standards may or may not continue to be beneficial for fuel economy. The third section of this chapter focuses on vehicle technologies and addresses this issue on a case-by-case basis.

Besides light duty vehicles, other transport modes are also responsible for pollutant emissions and have been targeted by regulators, but not always with the same intensity.

Road Transport Fuel Options

Petroleum gasoline, diesel fuel, jet fuel, bunker oil and electricity are the main fuels used in transportation. Minor quantities of liquefied petroleum gas, natural gas, ethanol and biodiesel are also used. Except for electricity, all these fuels are refined products derived from conventional crude oil.

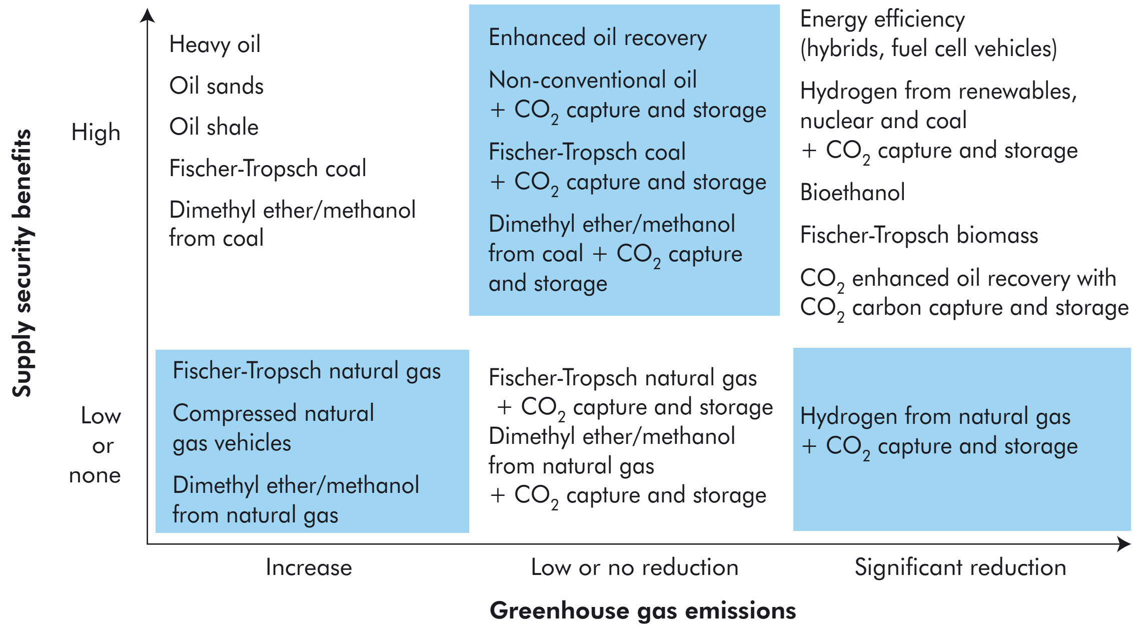
The *World Energy Outlook 2004* states that sufficient conventional oil reserves exist to meet growing demand over the next three decades. It adds, however, that exploiting these reserves will require significant new investments, along with an implied increased dependence on the Middle East. In 2005, oil prices peaked well above USD 50/bbl and prices have remained high ever since. This price increase may to some extent be explained by an increased "risk premium" on oil from the Middle East and by short-term supply constraints derived from the combination of high economic growth in some developing countries and under investment in oil exploration due to low oil prices in the 1990s. Nonetheless, higher prices and increased price fluctuations have spurred renewed interest in potential substitutes for conventional oil.

Some substitutes for oil do exist and this fact has a moderating effect on oil markets. While alternative energy may be costly when it is first introduced, its cost will decline over time. But the development of energy technology is often a slow process. It can take decades.

Along with concerns about supply security, environmental concerns have become increasingly important. Policies to mitigate climate change seek to reduce CO_2 emissions in the transportation sector and in the production of transportation fuels. This may increase demand for carbon neutral fuels, such as electricity, biofuels and hydrogen.

Figure 5.4 categorises alternative fuels by their potential benefits in terms of supply security and CO_2 emission reductions. Certain fuels could enhance supply security, but would also increase emissions. Very few options would contribute both to supply security and to CO_2 emissions reduction. They include enhanced oil recovery using the injection of CO_2 derived from fossil fuel combustion processes, improved energy efficiency and the use of biofuels.

Figure 5.4 ▶ Alternative fuel options and their contribution to supply security and CO_2 reduction



Key point

Not all fuel supply options that contribute to increased energy security also offer low CO_2 emissions.

This section gives a brief description of the refining process and the important aspects of alternative-fuel technologies. Alternative-fuel technologies include:

- Non-conventional oil resources.
- Fischer-Tropsch production of diesel and gasoline from coal, natural gas or biomass.
- Methanol and dimethyl ether (DME).
- Bioethanol.
- Biodiesel and other biofuels.
- Hydrogen.

The IEA Implementing Agreement on Advanced Fuels for Transportation is helping to co-ordinate research and pre-standardisation work in these areas.

Conventional Oil Refining

Description

Oil refineries convert crude oil into oil products through a wide range of processes. The most important of these is the distillation of crude oil, followed by other conversion processes based on hydrogen addition, catalytic or thermal conversion and coking.

Refineries either purchase hydrogen or invest in a hydrogen facility. Hydrogen plants process natural gas or light refinery streams as feedstock and they consume energy. Heat and electricity are also needed to run a refinery. Heat is either produced directly by heaters or indirectly by steam recovery or other means. Electricity can be generated at the refinery, *e.g.* through combined heat and power processes, gas or steam turbines, or integrated gasification combined cycle units, or it can be purchased from the grid. Both electricity and steam produced in refineries can be sold. The fuel used to produce steam and to power the furnaces can be obtained from refining by-products. Otherwise, natural gas may be used. Between 5% and 15% of the crude throughput is used for the refining process. The percentage is higher for complex refineries that produce a large share of transportation fuels.

Over time, the crude oil reaching refineries has become increasingly heavy and sour (*i.e.* rich in sulphur). The production of unconventional oil is also growing. This trend presents a major challenge to the refining industry because about 60% of the product generated by heavy crude oils consists of low-value heavy products, such as fuel oil, and because of the additional treatment required by sulphur-rich crudes.

Development Status

Oil refineries rely on well-established technologies, but some important new developments are taking place. The product mix of refineries is changing toward lighter products (with a higher carbon-to-hydrogen ratio). These products are largely used in transportation, where demand is growing fastest.

In most OECD countries unleaded gasoline has replaced leaded gasoline. The trend toward low-sulphur gasoline and diesel continues and will develop further in the next decade. The use of low-sulphur fuels is strongly promoted in OECD countries by government policies that set limits on pollutant emissions. Low-sulphur content in the fuel is very important for the proper functioning of such after-treatment systems as particulate filters and nitrous-oxide traps. Low-sulphur fuels will be the norm in the developed world after 2010 and in most developing countries by 2030, despite the fact that refinery-based desulphurisation processes are energy-intensive, consume a lot of hydrogen (mainly in hydrocracking units and hydrodesulphurisation processes) and increase well-to-wheel CO_2 emissions.[7]

Barriers to Greater Market Penetration

European and US regulators continue to push for cleaner gasoline and diesel fuel. Europe is moving toward sulphur contents of less than 10 parts per million, and the United States is expected to introduce similar standards before 2010. Most countries in Asia, Africa and South America are also beginning to adopt emissions standards and fuel requirements, albeit with more lenient specifications.

Complex refineries converting heavier products or crude oils may face the most difficult technical and economic challenges in meeting new sulphur specifications.

7. Hydrocracking units, in particular, are best suited for high-quality products with low sulphur contents, but they require very heavy investments.

More challenges will grow out of the development of advanced combustion technologies (especially controlled auto-ignition), which may require the development of appropriate additives.

Prospects for Overcoming Barriers

Stricter sulphur regulations are likely to be enforced progressively in all regions. Phasing-in the regulations over time would make their fulfilment more affordable. The cost of installing desulphurisation units will depend on the complexity of the refinery, CO_2 policies in place, the available range of crude oils, fuel prices and ongoing technological developments in the refinery process. The desulphurisation of fuels will, in any case, require significant amounts of capital investment.

Non-Conventional Oil: Extraction and Upgrading

Description

There are three major types of non-conventional oil reserves: heavy oil, tar sands bitumen and oil shale.

- Medium-heavy oil and extra-heavy oil have densities ranging from 25° API (American Petroleum Institute) gravity to 7° API, and have a viscosity ranging from 10 to 10 000 centipoise (cP). These oils are mobile in reservoir conditions. Resources of extra-heavy oils are concentrated in Venezuela, where some 1 200 gigabarrels (Gbbl) exist. The recoverable fraction (which can vary if the technology used for the extraction improves) of the Venezuelan reserves is 270 Gbbl.
- Tar sands and bitumen have a density ranging from 12° API to 7° API, and have a viscosity above 10 000 cP. They are not mobile in reservoir conditions. Tar sands and bitumen are concentrated in Canada (1 630 Gbbl). This represents about 80% of worldwide reserves of heavy oil and tar sands. Currently, the recoverable fraction of the Canadian reserves of tar sands amounts to 310 Gbbl.
- Oil shale is an inorganic rock that contains kerogen, a sort of immature oil that has never been exposed to high temperatures. There is 4% kerogen in lean shale, and 40% in rich shale. When the rock is heated to between 350°C and 400°C, it yields 20-200 litres of shale oil per tonne of shale. The bulk of the world's oil shale resources are located in the United States, where there are more than 500 Gbbl of oil shale of medium quality, capable of yielding 95 litres of fuel per tonne of shale. There are about 1 000 Gbbl of lower-quality oil shale in the United States, as well.

Development Status

Open-cast mining is the main production technology for tar sands in Canada, where it accounts for about 80% of total production. In open-cast mining, the mined sand is transported to a processing plant where the bitumen is removed using mixing and cleaning processes that involve water, caustic soda and some form of agitation. Following cleaning, the bitumen is diluted with naphthalene and sent to an upgrader to be refined.

Currently, Canadian underground production of tar sands is less common, but it has a large potential for expansion. A number of underground production techniques can be employed to extract extra heavy oils and tar sands. Current technology uses cyclical steam injection, a process that reduces the viscosity of bitumen by heating it to about 80°C to allow extraction. A new process, steam-assisted gravity drainage (SAGD), uses two horizontal wells one on top of the other and can significantly improve the recoverable fraction of the hydrocarbons contained in underground tar sands (from less than 10% to 40%). Such an improvement would bring the world reserves of oil sand and heavy oil up to the level of global conventional oil reserves. In underground extraction, steam is injected into the upper well and the liquefied hydrocarbons are recovered from the well beneath. This production pathway requires steam-to-oil ratios between 2:1 and 4:1, as opposed to a ratio of 5:1 for the cyclical extraction processes.

Similar techniques could be used for the extraction of extra heavy oils. In the case of the extra heavy oil in Venezuela's Orinoco region, the temperature of the reservoirs 1 000 metres below ground is 55°C. This temperature is high enough to reduce the oil's viscosity, allowing recovery with very limited or no thermal stimulation.

The exploitation of oil shale for shale-oil is currently limited to some small-scale activities, mainly in Estonia, Brazil and China.

Costs

The total cost of producing and upgrading tar sands with SAGD technologies is about USD 15/bbl. The cost would be USD 20/bbl if CO_2 capture were added. Open-cast mining is cheaper, but underground mining appears to have a larger potential over the next decades as 90% of the Canadian resources are located too deep underground for open-cast mining. With either approach, production costs are now well below the price of conventional oil. This is also the case for the mining and upgrading of oil shale to syncrude, which costs about USD 11/bbl. For these reasons, production of oil from tar sands is rapidly increasing. However, issues such as the remote location of the resources, limitations in oil product transportation and limited natural gas availability for the production of steam explain why Canada is not moving faster to extract these resources to benefit from high oil prices. Canada produced 829 million barrels of bitumen in 2002. By 2011, Alberta's oil sands are expected to generate nearly 2 million barrels per day of crude oil, more than half of Canada's projected total crude oil production.

In Venezuela, there are plans to apply deep-conversion technology to tar sands to produce high-value transportation fuels. Delayed coking is the primary conversion technology. There are plans to produce 622 000 barrels of syncrude per day by 2009.

Barriers to Greater Market Penetration and Prospects for Overcoming Barriers

Once extracted, tar sands need energy-intensive processes for upgrading. Heating the bitumen to 500°C yields about 70% of a marketable hydrocarbon product called syncrude, which in turn yields good quantities of kerosene and other middle distillates. The remaining fraction either cracks thermally to form gaseous products or is converted into petroleum coke, which is mainly burned for energy recovery. The energy efficiency of the upgrading process is about 75%, and net CO_2 emissions amount to between 22 and 34 kg of CO_2/GJ syncrude, more than double the 10 kg CO_2/GJ for conventional oil refining).

Emissions are even higher for the production of shale-oil. If large-scale production was undertaken, oil-shale processing would generate about five times the CO_2 emissions produced by conventional oil refining. Given these characteristics, public opposition may represent a significant barrier to the extensive exploitation of all these resources.[8]

Environmental and CO_2 policies are decisive elements in the development of tar sands and shale-oil. The industry has the potential to diversify the energy mix thereby adding to energy security, but it comes with high environmental impacts. Clear and stable messages from governments are needed, as is a regulatory framework to address environmental issues, among others. Such an approach could help determine a cost range for exploitation of the non-conventional resources, and could boost the interest in technology advances such as the application of CO_2 capture and storage in the upstream sector. Other supply options, like carbon-neutral solutions, could also be favoured by such a regulatory environment.

Timeline for Greater Contribution

In total, Canadian and Venezuelan production could amount to roughly 3 million barrels per day of crude-oil equivalent in 2010, or 3% of world oil production. The IEAs *World Energy Outlook* projects that syncrude production from both countries will total 6 million barrels per day by 2030. Several multi-billion dollar projects, requiring significant planning time and a stable development environment, would be needed to reach this level of production.

Other potential obstacles exist, as well. These projects are likely to conflict with CO_2-related policies, and, in the case of Venezuela, political instability can be a major investment barrier. However, technology developments could reduce the CO_2 emissions from extracting and processing these non-conventional oil resources and offer opportunities for their wider use.

The future of extra heavy oils, tar sands and shale-oil will also depend largely on how governments will act to favour carbon-neutral energy resources in the national, regional and international contexts, as well as on the degree of exploitation of competing alternative energy sources like coal and natural gas.

Fischer-Tropsch Synthesis from Natural Gas: Gas-to-liquids

Description

Gas-to-liquids (GTL) is a process that allows the conversion of natural gas to liquid fuels. It is composed of two main steps:

- Conversion of natural gas into synthesis-gas ("syngas"), composed of CO and H_2, through partial oxidation, steam reforming, catalytic autothermal reforming or a combination of these processes.
- Fischer-Tropsch (FT) exothermic catalytic conversion of the syngas into synthetic fuels.

8. The largest oil shale project so far was the Stuart project in Australia. Widespread opposition to this project led to its closure.

Depending on the FT catalyst used and the temperature reached in the reactor, the process can lead to the production of different products. High-temperature FT synthesis leads to the production of synthetic gasoline and chemicals. Low-temperature FT synthesis leads to the production of waxy products that can be cracked to produce synthetic naphtha, kerosene or diesel fuel. The diesel produced in GTL plants is a high-quality product with an energy density similar to conventional petroleum diesel, a high cetane number and low sulphur content. The conversion efficiency of the GTL process described above is about 55%, with a theoretical maximum of about 78%. Using other reactors and units other than the FT reactor in the second step, numerous products, including dimethyl ether (DME) and methanol, can be derived from the two fundamental building blocks (CO and H_2) that compose the syngas.

Development Status

Gas-to-liquids technology based on FT synthesis is well-established, but margins for improvement exist. One of the biggest technical challenges faced by GTL processes is the optimisation of energy integration between the syngas generation and the subsequent syngas conversion. The thermal efficiency of GTL plants can also be increased by making better use of the heat generated in the exothermic processes of FT synthesis; co-production of steam or electricity could be one option to improve the economics of GTL production, for example. The GTL process also allows the production of various chemicals. Finding markets for these co-products is essential to the economics of the FT process.

Not many GTL facilities are currently in operation, and only a few others are being built or planned.

Costs

Costs for gas-based FT production are about USD 30/bbl (USD 5-6 per GJ), assuming a gas price of USD 0.50/GJ. However, gas prices today are above USD 8/GJ, as oil prices are well above USD 50/bbl. Given this context, GTL projects are best suited for gas reserves that do not have access to markets (stranded gas) and are not large enough to justify the investment of a LNG terminal. A viable GTL project today also needs at least 1.5 EJ (about 35 Mtoe) of gas nearby, and the large scale of a GTL plant is a key element for making it viable.

Barriers to Greater Market Penetration and Prospects for Overcoming Barriers

The high capital costs are among the main barriers for a wide market introduction of GTL fuels. Recent developments show that, as the cost of transporting LNG declines and gas demand increases, interest in marketing large gas reserves with GTL processes is declining. Development of GTL projects in the Middle East and elsewhere will depend on LNG expansion. If the investment costs for GTL can be contained, smaller-scale GTL projects could become popular in the forthcoming decades, but much will depend on the cost of alternative solutions to market the natural gas.

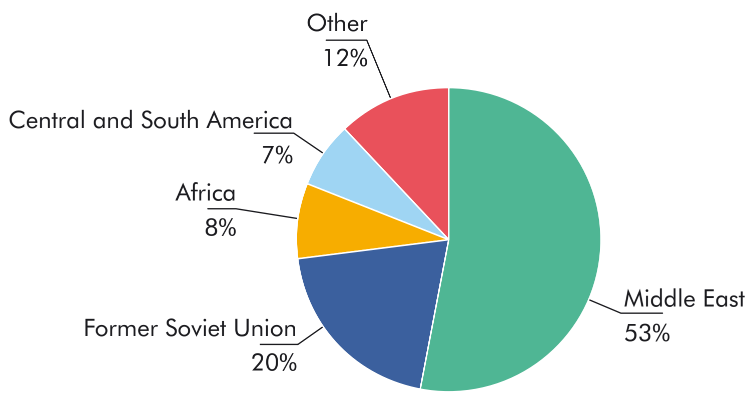
GTL processes also lead to higher well-to-tank CO_2 emissions than conventional refining processes (about three times higher in the best cases). The use of CO_2 capture and storage is possible for the GTL process, but it would lead to additional capital costs.

Timeline for Greater Contribution

GTL fuels are competitive if oil prices are above USD 30/bbl, if CO_2 capture and storage is not included and if the process relies on cheap stranded gas.

The total amount of stranded gas reserves is 6 000 EJ (about 140 000 Mtoe, *i.e.* half of global gas reserves), equal to 60 years of current gas use. A large fraction of these reserves is situated in the Middle East (Figure 5.5)

Figure 5.5 ▶ Stranded natural gas resources by region



Key point

The bulk of the stranded gas reserves are in the Middle East and the Former Soviet Union.

The supply security benefit of FT synthesis based on Middle Eastern gas is unclear. Outside the Middle East, the long-term availability of sufficient stranded gas to fuel a significant share of the world transportation fleet is not as evident, and a diffusion of GTL projects seems possible only if costs of smaller plants can be contained. The *WEO 2005* projects that 2.3 million barrels per day of GTL fuels will be produced by 2030, mainly from large-scale projects in the Middle East.

Fischer-Tropsch Synthesis from Coal: Coal-to-liquids

Description

Coal liquefaction, also known as coal-to-liquid (CTL) synthesis, is the conversion of coal into synthetic liquid fuels. The process is based on two main steps:

- Production of syngas from coal and water, followed by adjustment of the carbon monoxide/hydrogen ratio in appropriate reactors and sulphur removal.
- Fischer-Tropsch catalytic conversion of the cleaned syngas into synthetic liquid fuel products ("synfuels").

Fischer-Tropsch synthesis was first developed in coal-rich Germany in the early decades of the twentieth century. Liquid fuels were synthesised from coal and used during the Second World War. South Africa, which, like Germany, has no oil reserves, developed and improved the process during the apartheid boycotts. Sasol, the South African oil company, operates two coal-to-liquid plants with a capacity of 150 000 barrels of crude oil equivalent per day. The product mix consists of 80% synthetic diesel fuel and 20% of synthetic naphtha.

Development Status

Process technologies for the production of synthesis gas from coal are well established, as well as the FT synthesis of syngas to liquid fuels. Similarly to the GTL process, the thermal efficiency of CTL plants can be increased by making better use of the heat generated during FT synthesis. In recent years, increased attention has been given to the co-production of electricity and heat from coal. Other improvements can make the CTL process more economical, such as the combined production of methanol and DME, but this opportunity is available only if there is sufficient market demand for these products. Co-production of electricity, heat and other chemicals would allow a high average load factor and therefore reduce the capital cost per unit of product. A study by Sasol points out that the co-production of FT transportation fuels and electricity from coal raises the energy conversion efficiency of the process by 40 to 50%. Cogeneration plants would produce fuels and electricity in a ratio of eight-to-one, and synfuel production costs might be reduced by 10% if a co-production strategy were applied.

Costs

With a coal price of USD 1/GJ (*i.e.* USD 20/tonne, less than a third of the steam coal market prices in the late 2005), the production costs of synfuels from coal would be between USD 8 to 10/GJ (roughly equivalent to a liquid fuel price of USD 50/bbl and to a crude-oil price of USD 35 to 40/bbl). The CTL process is less sensitive to feedstock prices than is the GTL process, but the capital costs of the coal-based process are substantial: the construction of a CTL installation producing 80 000 barrels per day of liquid fuels would cost about USD 5 billion, versus USD 1.6 to 1.9 billion for a GTL installation. Moreover, a CTL process can only be economic in a location close to a seaport facility or in an area with at least 2 to 4 Gt of coal reserves nearby. As is the case of GTL, the transportation of CTL products to market will also require the construction of new infrastructure.

Barriers to Greater Market Penetration and Prospects for Overcoming Barriers

High capital cost is the major barrier to the further development of FT synthesis from coal, as CTL plants can only be competitive if they are extremely large facilities. CTL processes are also very energy intensive and lead to 10 times higher CO_2 emissions per unit of energy delivered than in a conventional refining process. In coal-to-liquid conversion, two-thirds of the carbon in the coal is released as CO_2 in the fuel production process. Well-to-wheel emissions are more than doubled by CTL processes.

Climate change concerns and CO_2 mitigation policies may disfavour CTL processes, but the use of CO_2 capture and storage (CCS) can improve the GHG balance of CTL processes. However, CCS would add additional investment costs to an already capital-intensive operation.

Timeline for Greater Contribution

Synfuels from coal are competitive with oil at prices above USD 35 to 40/bbl, if CO_2 capture and storage is not included and if coal is available at a low price. CTL projects can be appealing for coal-rich oil importing countries like South Africa, China, India, Australia, the United States and Poland. Inevitably, these are the countries where initial investments will be concentrated due to existing technological know-how. China has expressed interest for an advanced version of the Sasol CTL process, and Poland is considering the construction of a 4 to 5 Mt/yr CTL facility with CO_2 capture and storage.

Unlike stranded gas reserves, coal reserves are abundant in various regions, and hence CTL will benefit from this resource availability. However, environmental impacts are a concern as the high level of GHG emissions resulting from these processes needs to be addressed before CTL can be widely adopted. The growth of CTL investments will depend not only on the availability of other energy sources, but also on whether and how governments will act to favour competing carbon-neutral energy resources in the national, regional and international contexts.

Box 5.1 ▶ Fuels for commercial aircraft

Aviation energy demand will grow very rapidly during the next decades, even if more efficient airplanes are introduced. Therefore, CO_2-free aviation fuels are needed.

FT fuels are currently the only alternative fuels that can be used on large commercial aircraft as a potential substitute for petroleum-based jet kerosene. FT fuels are not only suitable as a replacement, but they also have superior quality. FT fuels for commercial aviation are estimated to be capable of reducing CO emissions by an order of magnitude. Other advantages include the virtual elimination of PM emissions and the absence of sulphur. The higher quality of FT fuels can also reduce tank-to-wheel CO_2 emissions by 2 to 3%.

The certification of a 50/50 mix of petroleum products and FT fuels is already a reality, and it has been driven by the supply situation in South Africa, where such mixes were the only fuel type available. A 100% FT jet fuel is expected to be certified by the end of 2006.

FT fuels can be made from a range of feedstocks, including biomass. If biomass feedstock is used, the CO_2 balance of the fuel is much better than that of fossil fuels. So an FT biofuel (biomass-to-liquids) could be used today to fuel aircraft, without any adjustments in fuel supply or engine design.

Methanol and Dimethyl Ether

Description

Methanol is liquid at ambient conditions. The bulk of methanol is currently produced from natural gas and is used for the production of chemicals, including methyl tertiary butyl ether (MTBE), a gasoline additive. MTBE is almost exclusively used in motor gasoline. Methanol can also be used directly as a fuel for spark-ignition internal combustion engines and has characteristics that are similar to ethanol. Methanol, in particular, has a very high octane number. However, unlike ethanol, methanol is not miscible (*i.e.* it cannot be mixed) with hydrocarbons, and therefore it is not suitable for blending with gasoline.

Methanol can also be converted into dimethyl ether (DME). DME is physically similar to liquefied petroleum gas (LPG); it can be stored in low-pressure tanks as a refrigerated liquid at -25°C, or in pressurised tanks. Methanol and DME can also be produced from a wide range of feedstocks, including natural gas, biomass, agricultural and urban waste and coal. Current global production of DME is less than 0.5 Mt per year. Its main use is as an aerosol propellant.

DME has excellent combustion properties and good energy density. DME is also well-suited for compression ignition engines, *e.g.* diesel engines, even though some modifications are needed (one problem with DME is its lack of lubricity). In experimental tests, DME combustion produces very little nitrous oxides or particulate matter.

Development Status

Methanol synthesis is an established process based on the catalytic reaction of hydrogen and carbon monoxide (the components of synthesis gas). These building blocks can be obtained from several primary energy sources, such as coal (from the first step of CTL processes), natural gas (from the first step of GTL processes), oil (using a similar approach to the one described for natural gas) and biomass (through biomass gasification, a process similar to coal gasification).

MTBE is mainly derived from the chemical reaction of methanol and isobutylene (a hydrocarbon either produced as a by-product of the refining process or chemically derived from butane), but it can also be obtained as a by-product of the propylene oxide production process.

DME can be produced from methanol, but recently there have been developments in the direct synthesis of DME from syngas, and much interest has been aroused by the recent construction of DME synthesis plants in China using coal as a feedstock for the syngas production. Various process designs have been proposed for co-producing methanol and DME, and for the cogeneration of DME and electricity. Such designs circumvent the problem of incomplete conversion of feedstock into DME and could lower production costs.

Barriers to Greater Market Penetration

Methanol has fallen out of favour as a transportation fuel mainly because of its immiscibility with hydrocarbons, which poses a transition barrier as a dedicated methanol distribution system would be needed and make it unsuitable for solutions such as flex-fuel vehicles. Other reasons that do not favour the use of methanol as a fuel for spark-ignition engines are its relatively low energy content and high toxicity.

MTBE, on the other hand, has been widely used in response to the increased demand for oxygenates and octane enhancers resulting from the phase-out of lead from gasoline and later from the rising demand of premium gasoline (characterised by a higher octane number). In recent years, though, the use of MTBE as an additive for gasoline has been questioned because MTBE is characterised by a high solubility and low biodegradability in groundwater. Increased concentrations of MTBE in drinking water have resulted in a ban on MTBE use in parts of the world, as even low levels of MTBE can make drinking water supplies undrinkable due to its offensive taste and odour.[9]

Unlike methanol, DME is non-toxic. The most significant barrier for DME use as a transport fuel is the absence of a distribution infrastructure. Inevitably, this limits investment in the development of DME as a transport fuel. Moreover, large-scale production units, which require heavy capital investment, seem today to be the only way to produce DME at costs that can compete with conventional diesel fuel. Additional issues include the lack of commercial bi-fuel vehicles running on diesel or DME, or flex-fuel vehicles running on diesel and DME.

Prospects for Overcoming Barriers and Timeline for Greater Contribution

There is currently little interest in methanol use as fuel, as ethanol proved to be a better alternative because of its miscibility with hydrocarbons, which makes it suitable for the flex-fuel technology.

MTBE is still widely used today, but the use of MTBE is not likely to increase in the future. Given the potential effects on drinking water supplies and possible additional concerns, legislation banning or restricting the use of MTBE in gasoline has already been passed in several US states and restrictions are under consideration elsewhere. Ethyl tertiary butyl ether (ETBE), in particular, could be used as a replacement of MTBE. ETBE could be produced by converting the existing MTBE production capacity, which would ease transition to ETBE and reduce some of the social impacts of the MTBE phase-out. However, ETBE also bears similar properties to MTBE for raising concerns about the impact on water resources, as well as similar odour and taste detection thresholds. This is one of the reasons why ethanol, rather than ETBE, may be a preferred replacement for MTBE.

Two coal-based DME plants are in operation in China, with a total capacity of 40 kt/yr. A rapid expansion of Chinese DME production is planned, to more than 1 Mt/yr (0.03 EJ/yr, or 0.7 Mtoe/yr) in 2009. Further gas-based projects are planned

9. Independent expert review groups have not concluded that the use of MTBE-oxygenated gasoline poses an imminent threat to public health. However, there are limited data on the health effects of drinking MTBE. Recent work by the US EPA and other researchers is expected to help determine more precisely the potential for health effects from MTBE in drinking water.

or have been proposed in the Middle East, and recent developments in the production of DME make it appear as a more realistic alternative to conventional diesel fuel.

However, the wide implementation of DME as an alternative fuel for transport seems unlikely over the short term, as it would require extensive development of a distribution infrastructure. Research is also needed to develop vehicles with more fuel choice flexibility, such as diesel-DME bi-fuel vehicles, as they are better suited to stimulate the demand needed in a transition process. Extensive development of DME in the short term could only be justified if the existing set of technological difficulties were overcome, making DME better than diesel. In the long term, DME could become a viable option because it can be derived from multiple primary energy sources.

Ethanol

Description

Ethanol is available in a liquid state at ambient temperature and it can be used in blends in existing vehicles due to its solubility in hydrocarbons. Efforts to introduce ethanol into the fuel market used in spark-ignition engines have focused on low-percentage blends, such as ethanol E10, a 10% ethanol and 90% gasoline blend, known as gasohol.

Ethanol has several properties that make it a good fuel choice for spark-ignition engines:

- Its miscibility with gasoline, which makes it suitable for blends.
- A high octane number, and therefore a low tendency to induce knocking.
- An energy density that is two-thirds that of gasoline.
- The presence of oxygen in its molecule, which can provide a more homogeneous distribution of the oxygen in combustion (appreciably reducing CO emissions) and reduces the combustion temperature. A lower combustion temperature in turn reduces heat loss in the engine coolant and results in much lower NO_X emissions.
- A high latent heat of vaporisation, which cools air on contact (a good characteristic to reduce knock).

However, there are also some disadvantages associated with ethanol:

- The high latent heat of vaporisation also creates running difficulties on a cold start.
- Its miscibility with water may cause problems in mixtures with hydrocarbons, which are not miscible with water.
- Its tendency to oxidise into acetic acid makes it incompatible with some types of plastics, rubber and elastomers. This also can cause corrosion of metal alloys of aluminium, brass, zinc and lead.
- It induces the emission of aldehydes, which are harmful to the human respiratory system.

It is also possible to use ethanol in diesel vehicles, but important problems would need to be solved:

- Ethanol has a low cetane number, which makes it very difficult to burn by compression ignition, a key technology used in diesel engines.
- Ethanol is not miscible with diesel fuel.

Recently developed additives, however, can improve ethanol's solubility in diesel and its ignition properties.

Conventional Ethanol Production Technologies

Conventional ethanol production from biomass may be based on the fermentation of sugars or on the conversion of starch into sugar, which is then fermented into ethanol. In both processes, ethanol is then distilled to fuel grade. In OECD countries, most ethanol fuel is produced from starchy crops like maize (corn), wheat and barley, but ethanol can also be derived from potatoes, sorghum and cassava. The world's largest ethanol producer is Brazil, where ethanol is derived entirely from sugar cane.

The bulk of ethanol production using starch crops is based on cereal grains. The process starts with the separating, cleaning and milling of the starchy feedstock. The grains are soaked and broken down either before the starch is converted to sugar (dry milling) or during the conversion process (wet milling). The starch is converted into sugar in a high-temperature enzyme process. After this point, the process is similar to that of sugar crops, where the sugars are fermented into alcohol using yeasts and other microbes. The grain-to-ethanol process yields several co-products, including protein-rich animal feed. Co-products reduce the costs of ethanol production, as well as its GHG emissions.

There has been considerable discussion about the net energy achieved by producing ethanol from grains. Some research suggests that it may take more fossil energy to produce a litre of ethanol from grain than the energy contained in that litre, leading to an energy balance lower than 1. Calculations are very sensitive to assumptions about key parameters and co-product credits. The key factors and assumptions that affect the energy balance of ethanol production from grain include issues related to agricultural practices, the maize yield per hectare, the efficiency and energy requirements of ethanol conversion, the energy embedded in the fertiliser used to grow maize, the use of irrigation and the value, or "energy credit", allowed for the co-products produced along with ethanol (mainly animal feed). A recent study compares several reports published on maize ethanol production in the United States by using consistent parameters (Farrel, *et al.*, 2006). According to this study, the results would still differ, but the "best point estimate" indicates that the current production of ethanol from maize reduces petroleum use by about 95% on an energy basis and reduces GHG emission only moderately, by 13%.[10] The ratio among primary energy inputs per unit energy output, for the best point estimate, is very close to 0.8.[11]

10. Maize ethanol substantially displaces petroleum because 5 to 26% of the energy used is renewable. The rest is primarily natural gas, or coal in lignite-fired plants.
11. In the case of CO_2-intensive production of ethanol, the primary energy (excluding the primary biomass) is higher than that of petroleum gasoline production (the ratio input/output is very close to 1).

Box 5.2 ▶ Crops for conventional ethanol production

Ethanol from Starch

Cereals are currently the main feedstock for the production of fuel ethanol from starchy feedstocks. The main cereals used today are maize and wheat, but others are also suitable.

Maize (corn) represents 21% of total grain production and is the world's largest cereal crop. It is the most efficient plant for capturing the energy of the sun and converting it into food. The main producers of maize are the United States, China and Brazil, but it is widely cultivated in all regions with temperate climates. Currently the main producer of ethanol from maize is the United States. Wheat is the second-largest cereal crop, and it is cultivated in temperate climates. The largest producers of wheat are China, India, Russia and the United States. Wheat is used for ethanol production mainly in Europe. The typical yields for ethanol derived from starchy crops range between 2 000 and 3 000 litres per hectare (or 1 300 to 2 000 litres of gasoline equivalent per hectare), depending on the crop, the amount of fertilisers used and water availability.

Sorghum is a smaller cereal than maize, but with a similar appearance. It is grown extensively in the United States, Pakistan, India, Africa and China. Sorghum is used chiefly as feed for livestock and poultry in Europe and North America, but it is widely used as food in other world regions. No significant production of ethanol from sorghum exists today, but sorghum is a rapid growing feedstock that can be harvested several times a year and requires one-third less water than sugarcane. Because of these characteristics, sorghum can be as attractive as ethanol feedstock in parts of Sub-Saharan Africa, even if the ethanol yields from sorghum in many developing countries are likely to be in the low end of the range for maize and wheat yields.

Other starchy crops do not contribute significantly to current ethanol production, but some have the potential of being further developed. Cassava (or manioc) is extensively cultivated in tropical and subtropical regions for its edible, starchy root. Cassava can grow on infertile land with minimal inputs and offers reasonable yields. For effective ethanol production, dried cassava chips are convenient because they can be easily stored and transported to an ethanol plant. The successful use of cassava in Thailand could set an example for other countries.

Ethanol from Sugar

Sugar cane and sugar beets are the most significant feedstocks for sugar-to-ethanol production.

Sugar cane is a tall grass grown for sugar and alcohol production in tropical countries. The largest producers are Brazil, India and China, followed by Thailand, Pakistan, Mexico, Colombia, Australia, the United States (the state of Florida in particular), the Philippines and Indonesia. Sugar cane is an ideal feedstock for ethanol in terms of efficiency and flexibility. Cane-derived ethanol can be produced either from sugar cane or from molasses. About 70 litres of ethanol can be produced per tonne of cane, although an average of 80 litres per tonne of cane has been reported in Brazil. These figures translate to ethanol yields that range between 3 000 and 4 000 litres of gasoline equivalent per hectare. If sugar is produced from the cane and ethanol is produced only from the molasses by-product, then 1 tonne of cane yields as little as 9 litres of ethanol (and about 100 kg of sugar). Intermediate approaches are also possible, as distilleries can be designed to switch back and forth from sugar to ethanol production depending on demand.

Sugar beets can be grown in temperate or cold climates. The European Union, United States and Russia are the world's largest sugar beet producers, but ethanol production from sugar beets is more expensive than from sugar cane. European sugar beets offers ethanol yields close to 3 300 litres of gasoline equivalent per hectare.

The transformation of sugar to ethanol is the least complicated way to produce ethanol. Sugar cane (in Brazil, India and other tropical countries) and sugar beets (in Europe) can be used as feedstock for ethanol production. When sugar cane is used, the crushed stalk of the plant, the "bagasse", can be burnt for process energy in the manufacture of ethanol. This is one reason why the fossil energy requirements of ethanol produced from sugar cane are very low; for each unit of ethanol produced, only about one-eighth of a unit of fossil energy is required. This is far better than the eight-tenths of a unit required to produce a unit of ethanol from grain.

Given the very high rate of energy output per unit of fossil fuel input, it is not surprising that well-to-wheels CO_2 emissions from ethanol produced from sugar cane are very low. GHG emissions are estimated to be, on average, about 200 to 300 g of CO_2 equivalent per litre of fuel used, versus GHG emissions of 2.8 kg of CO_2 equivalent per litre for gasoline – a reduction of 90%.

Studies also indicate that the conversion of sugar beets into ethanol can yield reductions in well-to-wheels GHG emissions of up to 50 to 60%, compared to gasoline.

Advanced Ethanol Production Technologies

In the conventional grain-to-ethanol processes outlined above, only the starchy part of the plant is used for the production of fuel. These starchy parts, however, represent a fairly small percentage of total plant mass, leaving considerable fibrous remains (seed husks and stalks). Much current research is focused on innovative processes to also use these lignocellulosic materials to create fermentable sugars. This could lead to impressive improvements in production. In the case of maize, a much larger fraction of the plant could be used to produce fuel, thereby substantially increasing its ethanol yields.

Lignocellulosic feedstocks typically contain 20 to 45% (weight) of cellulose, 20 to 25% of hemicellulose and other components (notably lignin). The production of ethanol from lignocellulosic feedstocks is a process that requires five steps:

- The pre-treatment, which is the cleaning and breaking down of the feedstock by a combination of physical and chemical processes at high temperatures. It increases the susceptibility of cellulose and hemicellulose to further conversions.
- The hydrolysis, where cellulose, hemicellulose and lignin are separated, and cellulose and hemicellulose are converted respectively to six- and five-carbon sugars (lignin cannot be further converted, but it can be used as a fuel).[12] Acid hydrolysis can be used for this conversion, but it is expensive and is reaching its limits in terms of yields. Enzymatic hydrolysis is seen as a promising solution. Enzymatic hydrolysis is based on the use of biological enzymes to obtain sugars from cellulose and hemicellulose.[13] This field is being investigated and important advances have been made in recent years.
- The fermentation, which allows the conversion of the sugars into ethanol. In some enzymatic hydrolysis units, the combined action of enzymes and fermenting microbes allows the simultaneous saccharification and fermentation of cellulose and

12. Hydrolysis is a chemical process in which a molecule is split in the presence of water.
13. Hemicellulose leads to the production of five-carbon sugars (C5), which are difficult to convert to ethanol.

hemicellulose (depending on the pre-treatment): as the sugars are produced, micro-organisms convert them to ethanol.

- The product separation, where the solid residue is separated from the liquid solution containing ethanol (the fermented broth). The solid residue consists mainly of lignin, which is used as a fuel and satisfies a consistent part of the energy requirement of the process, and non-hydrolysed cellulose.
- The distillation and rectification of ethanol to fuel grade.

The production of ethanol from cellulose would open the door to a much wider array of potential feedstocks, including waste cellulosic materials and dedicated cellulosic crops such as grasses and trees. Ethanol production could then soar. Fast-growing crops rich in cellulosic components, such as poplar trees and switchgrass, are well suited to produce ethanol. In North America, much attention is being given to maize stover and other grain straw. In Europe, attention is focused on food-processing waste, grass and wood crops. In Brazil, sugar cane stalks (bagasse) are already used to provide process energy for ethanol conversion, once the sugar is removed, but cellulosic material is not actually converted into ethanol itself. Much of the sugar cane crop is still left in the field and burned. Advanced conversion processes would also allow the full use of the biomass available in the sugar cane plant.

The energy requirements for enzymatic hydrolysis are high: including the energy carried in the primary biomass inputs, the energy requirements are 30% to 90% higher than the energy delivered by the fuel produced, though most of this energy is provided by biomass sources. Estimates of net GHG emissions reductions from the production and use of lignocellulosic ethanol are close to 70% with respect to conventional gasoline. In some cases, the savings could approach and even exceed 100% with, for example, the cogeneration of electricity that displaces coal-fired electricity from the grid.

Significant technological challenges exist for the production of ethanol from woody feedstocks because all the steps of the production process need to be optimised. Researchers are now aiming at the achievement of a fermented broth with a higher concentration of ethanol, in order to reduce the energy needs of the distillation to fuel grade.

Problems in producing ethanol from lignocellulosic crops need to address:

- Pre-treatment of the substrate (the type of pre-treatment has consequences in the following conversions).
- Enzymatic hydrolysis of the substrate into fermentable sugars (depending on the pre-treatment dedicated enzymatic saccharification of hemicellulose may be needed).
- Fermentation of the sugars to ethanol, and in particular the development of organisms that can tolerate the inhibitory compounds generated during pre-treatment.
- Product separation, as the residue tends to be difficult to separate into a solid and a liquid fraction.

Other research is directed towards the possibility of producing all required enzymes within the reactor vessel, thus using the same "microbial community" to produce both the enzymes that break down cellulose into sugars and those that ferment the sugars to ethanol. This "consolidated bioprocessing" is seen by many as the logical end-point in the evolution of biomass-conversion technology.

Costs

The cost of producing biofuels depends on the type of feedstock and the conversion technology. Moreover, costs vary by region, depending on biomass yields, land costs, labour costs and availability of capital. In regions such as Europe, agricultural subsidies affect production costs significantly.

No single cost figure can be cited for producing biofuels, but some indications are possible. Ethanol produced in Brazil from cane sugar costs about USD 0.30 per litre of gasoline equivalent free-on-board (FOB). Costs for sugar cane ethanol production are not well established outside of Brazil. Other developing countries can achieve the yields and production scale of Brazil and should be able to contain ethanol production costs, although ethanol produced in other world regions is likely to cost more (about USD 0.40 to 0.50 per litre of gasoline equivalent FOB), because in Brazil many existing installations were built with subsidies in the 1980s and are today completely depreciated. India is currently producing sugar cane ethanol at higher costs, but the scale of the facilities is not the same.

Maize-based ethanol produced in the United States is sold at about USD 0.80 per litre of gasoline equivalent. Its production cost is estimated to be close to USD 0.60 per litre. In Europe, production costs for ethanol derived from sugar beets are similar, while producing ethanol from wheat costs about USD 0.10 to 0.15 more per litre. In any circumstance, costs of grain ethanol are alleviated by the possibility to produce animal fodder as a by-product and potential economies of scale. However, yields are not expected to change radically in the near future, as conversion technology is already mature.

Estimates for the cost of lignocellulosic ethanol production are USD 28/GJ, slightly less than USD 1.00 per litre of gasoline equivalent (Hamelinck, *et al.*, 2005).[14] Cost are expected to decrease to USD 0.50 per litre of gasoline equivalent FOB in the long term, due to the achievement of better ethanol concentrations before the distillation, lower costs for enhanced enzymes (resulting from biotechnological research) and improved separation techniques. Cost reductions are also expected from the upscaling of production facilities and lower feedstock cost for ethanol production units using biomass residues (corn stovers or bagasse) as feedstock. Additional cost reductions could be derived from lower labour costs in developing countries.

Barriers and Prospects for Ethanol as a Transport Fuel

Ethanol has the potential to leapfrog a number of traditional barriers faced by alternative fuels and can become widespread in the next decades. Ethanol is available in a liquid state at ambient temperature and can be blended with gasoline. Gasoline-ethanol blends containing less than 10% ethanol can be used in the

14. These estimates refer to a feedstock price of USD 3.6/GJ, which reflects the cost of solid biomass in compressed form, *e.g.* pellets, delivered to Western Europe from Latin America.

majority of existing vehicles without problems. Richer blends are becoming common in some world regions, and flex-fuel engines – a key enabling technology available at low cost – are gaining market share in Brazil, United States and in parts of Europe.

Ethanol can also replace MTBE, either as a direct blending component or, combined with isobutylene, in the form of ETBE. However, since ETBE raises questions similar to those surrounding MTBE regarding impact on water resources and odour and taste detection, straight ethanol may be a preferred replacement for MTBE.

However, many of the conventional feedstocks needed for ethanol production require large amounts of water and pesticides, calling into question their long-term sustainability. Increased production of conventional biofuels would also imply higher fertiliser production. Preliminary estimates suggest that synthetic nitrogen fertiliser demand may increase by about 40% in a scenario where 25% of all transportation fuels are derived from biomass. Moreover, conventional biofuel crops would compete with food crops for land availability, thereby risking an increase in food prices that is already visible in the sugar market. For these reasons, the expansion of the range of feedstocks and the introduction of advanced conversion technologies such as enzymatic hydrolysis of lignocellulosic feedstocks are necessary for a full development of the biofuel option.

Producing biofuels will also require large land areas close to the production plants, and would require land reforms in some world regions. A large expansion of biofuel production would also require increased biofuel trade, given that the production costs differ substantially from region to region. But this would depend on the reduction of trade barriers for agricultural products.

A substantial development of the biofuel option also needs to be based on increased productivity of the land in developing regions. Bioenergy crops can be a key element for the transfer of advanced agricultural practices to the developing world. The use of advanced agricultural practices for bioenergy crops would also benefit the cultivation of other crops, *e.g.* food crops, and has the potential to result in a generalised improvement of yields, which would translate to an increased potential for food and bioenergy production.

Ethanol Supply Curves

The IEA has conducted a preliminary analysis of potential supply curves for ethanol. It is based on the build-up of a scenario of "maximum biofuel production" and takes into account four key factors for the three major feedstock groups used in ethanol production: sugar cane; grains and sugar beets; and lignocellulosic crops. The key factors considered are:

- Degree of allocation of land to the feedstock production.
- Evolution of feedstock yields over time (agricultural productivity).
- Evolution of the ethanol yield per tonne of feedstock (conversion efficiency).
- Maximum rate of increase for ethanol production from world areas where the crops are cultivated or available.

For sugar cane ethanol, future increases in sugar demand are also taken into consideration. The results of this analysis show there is enough cane to meet a 2% annual increase in sugar demand, while the rest is used for ethanol. The supply curve analysis is based on these additional considerations and assumptions:

- Sugar cane ethanol is the fastest growing low-cost source of biofuels at this time, and it is likely to be the lowest cost source of biofuels for the next 10 to 20 years. Further, it has considerable growth potential in Brazil and in a number of developing countries. Ethanol production from sugar cane has been assumed to increase sharply in those countries where current production is small. In such countries (labelled "countries starting from a tiny base" in Table 5.1), only a low fraction of land is used to grow cane and rapid percentage increases do not require much additional land allocation. High growth rates in ethanol production (maximum 7.5% per year) have also been assumed in those countries that currently devote significant shares of land to sugar cane (labelled "fast growth" in Table 5.1). These countries are not expected to be particularly land-stressed or food-stressed over the coming decades. Finally, lower growth rates in ethanol production have been considered for countries (labelled "food-stressed" in Table 5.1) that are expected to be land- or food-stressed, such as South Asia and China.

- Grains and sugar beets are seen as key feedstocks to satisfy a possible growth of the ethanol demand in large consuming areas as the United States and European Union, until lignocellulosic conversion technology is sufficiently mature to offer a significant contribution to the market. In this analysis, the production of ethanol from grains and sugar beets (mainly in Europe and North America) is assumed to increase by at least 10% per year (more, if existing OECD policies justify a larger increase) through 2010. Grain and sugar beet ethanol production is assumed to grow much less in the following decade, flattening out after 2020 because of the increased availability of ethanol derived from lignocellulosic feedstocks.

- The production of lignocellulosic ethanol is assumed to grow rapidly from 2010 to 2020 due to the increasing number and size of plants built over the decade. The growth of lignocellulosic ethanol production is then assumed to shift over to the standard percentage increase after 2020. Whether such a ramp-up is feasible depends on the amount of investment dedicated to lignocellulosic ethanol and other factors that were not addressed in this analysis.

5

Table 5.1 ► ***Growth rates in ethanol production from sugar cane (annual growth rate)***

	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Countries starting from tiny base	5.0%	25.0%	15.0%	10.0%	5.0%	5.0%	5.0%	4.0%	4.0%
Fast growth	4.0%	7.5%	7.5%	5.0%	5.0%	4.0%	4.0%	3.0%	3.0%
Food-stressed regions	3.0%	5.0%	5.0%	4.0%	4.0%	3.0%	3.0%	2.0%	2.0%

Regarding land availability, the analysis assumes for all cane-producing countries (except Brazil) that a maximum of 10% of total available cropland could be dedicated to sugar cane. This assumption thus allocates 60 million hectares (ha) to sugar cane production, compared to the 13 million ha currently allocated in these countries (FAO, 2006). Brazil is treated differently because it has a very large area of pasture land in the centre-south region that can grow high-yield cane. Extending sugar cane production to this land would add 90 million ha of growing area, which is 18 times the current amount.[15] In the present analysis, the potential cane-producing area in Brazil is therefore capped at 45 million ha.

For cereals and sugar beets, a maximum share of 10% of the cropland (7% for wheat and 3% for sugar beets) is assumed for Europe, the United States and Canada. The share of cropland available for cereals and sugar beet in the rest of the world is limited to 5%.

Up to 5% of the total world pasture land is considered to be available for growing crops for the production of lignocellulosic ethanol. All lignocellulosic ethanol production plants are assumed to draw on crops such as grasses and trees that are cultivated on low-quality land, while better-quality land is assumed to be used for food crops and conventional biofuel crops. Other feedstocks are also suitable for lignocellulosic production (notably agricultural waste, because of its low cost), but they have not been considered in this analysis. Deforestation has not been considered here either, since it is not a viable option for the production of lignocellulosic ethanol.

These assumptions on land availability are preliminary estimates; more research is needed to better map the available land that is suitable for growing cane. It is also important to note that the land assumed available for ethanol production in nearly all cases exceeds the land requirements to satisfy conditions for a quick ramp-up of production. (The only exception is the 10% of cropland considered for cane ethanol.) This indicates good potential for ramping up ethanol production, however, it should be noted that these estimates are preliminary and need further analyses.

This analysis is also based on several assumptions regarding expected increases in agricultural productivity and ongoing improvements in the conversion efficiencies of the feedstock into ethanol:

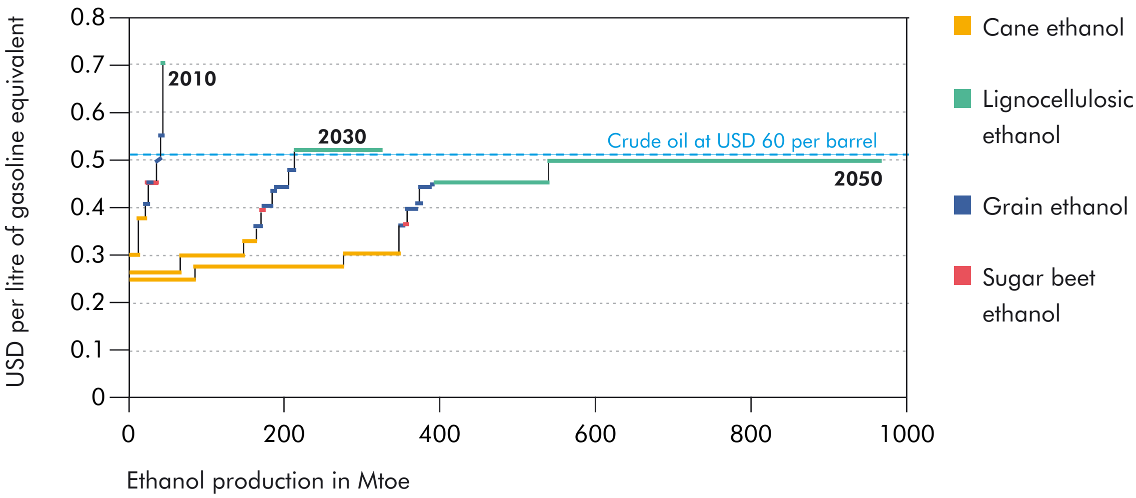
- Agricultural productivity of sugar cane and the process efficiency in Brazil are assumed to be "mature" and to experience slow growth. Thus, annual ethanol yields are assumed to grow 1.0% each year (from 6 000 litres per hectare in 2005 to 9 000 litres/ha in 2050).
- Faster growth is assumed for the agricultural productivity and conversion efficiency in other regions. Ethanol yields here are assumed to grow 1.5% each year, thus raising current annual yields from 4 500 litres/ha to 8 500 litres/ha by 2050 and closing the gap with Brazil.
- Grains and sugar beets are assumed to have initial yields similar to today's averages (2 500 litres/ha for European wheat, 3 000 litres/ha for North American maize and 5 000 litres/ha for European sugar beets), and to grow at 0.8% per year.

15. Other countries may also have pasture land available for growing sugar cane, but it is not considered in this analysis.

- Lignocellulosic ethanol production is assumed (with facilities working at 50% conversion efficiency) to yield 2 300 litres/ha of gasoline equivalent in 2005 and grow to 4 000 litres/ha by 2050.

On the basis of these considerations, it is possible to evaluate supply curves for ethanol production at different points in time. The results are shown in Figure 5.6. The data indicate that over time, assuming a quick ramp-up, ethanol production expands significantly, reaching nearly 45 EJ (*i.e.*, about 1 000 Mtoe) by 2050.

Figure 5.6 ▶ Ethanol supply curves



Key point

Rapid development of ethanol can displace a significant portion of transport oil demand by 2050.

Figure 5.6 also shows that the cost of production drops substantially over time, reflecting an increase in ethanol yields and the idea that the production of ethanol would start in most countries with fairly small add-on facilities and then move to dedicated large-scale facilities. These costs, however, should only be interpreted as reasonable first approximations. These cost estimates may underestimate certain cost components, since costs for some technologies are assumed to be the same in all world regions. Moreover, the decreasing costs over time in Figure 5.6 depend on the assumptions of quick development and rapid ramp-up; they may not be appropriate for a different growth pattern, e.g. where biofuel production ramps up much more slowly or begins in later years.

Biodiesel and Other Biofuels

Biodiesel is a fuel that can replace or complement petroleum diesel. In the most mature technology for its production, biodiesel is derived from vegetable oils based on oilseed crops (soy, sunflower or rapeseed) or other crops (palm and coconut). It can also be produced from used frying oil (e.g. supplied by restaurants), or from animal fats (beef tallow, poultry fat or pork lard). Biodiesel obtained from vegetable oils can be used easily in existing engines in its pure form or in virtually any blended ratio with conventional diesel fuel.

The most common issues concerning this type of biodiesel are its incompatibility with some elastomers and rubber (a marginal issue, eliminated for recent vehicles), and its tendency to gel at low temperatures, though this can be mitigated by mixing it with petroleum diesel. Additional issues are associated with its miscibility with water, which can reduce its heat of combustion, corrosion of fuel system components and the formation ice crystals that accelerate the gelling of the fuel.

Conventional Biodiesel Production Technologies

The most mature technology for biodiesel production is the transesterification of vegetable oil, frying oil or animal fats. With this technology, the oily feedstock is first filtered and pre-processed to remove water and contaminants. The recuperated oils and fats are then mixed with an alcohol (usually methanol) and a catalyst (usually sodium hydroxide or potassium hydroxide). The oil molecules (triglycerides) are broken apart and reformed into esters and glycerol, which are then separated from each other and purified. The resulting esters are the biodiesel product. Glycerol is used in many types of cosmetics, medicines and foods. Its co-production improves the economics of making biodiesel, but markets for it are limited and it could end up being used largely as an additional process fuel in the making of biodiesel, a relatively low-value application.

The value of biodiesel co-products affects the final cost of biodiesel itself. A vast expansion of biodiesel production could drive down the price of glycerol, thereby indirectly increasing the cost of biodiesel. The cost of biodiesel made from waste feedstock is lower and can compete with petroleum diesel, though feedstock limitations allow only for relatively small volumes.

Estimates for the net reduction in GHG emissions that could be delivered by rapeseed-based biodiesel range from about 40% to 60% compared to petroleum diesel fuel. As in the case of ethanol, however, these results may be influenced by several factors, including the use of the by-products. Production costs for biodiesel can vary widely by feedstock, conversion process, scale of production and region.

The biodiesel obtained from fatty-acid methyl esters (FAME) is very suitable for use in standard diesel engines. It can be used in its pure form (B100) or in a blend with conventional diesel fuels. FAME biodiesel is sulphur free. When blended with conventional petroleum diesel, it reduces the sulphur content in the fuel. Pure FAME biodiesel also acts as a mild solvent, so B100 is not compatible with certain types of elastomers and natural rubber compounds and can degrade them over time. On the other hand, the solvent properties of biodiesel can help keep engines clean and well running. Biodiesel blends also improve lubricity: even a 1% blend can improve lubricity by up to 30%, helping engine components to last longer. Biodiesel contains only about 90% as much energy as diesel fuel, but its high cetane number and lubricity lead to efficiencies just a few percentage points below that of diesel.

Box 5.3 ▶ Conventional biodiesel crops

Typical crops for conventional biodiesel production include soy, sunflower, rapeseed, palm and other oil-seed bearing crops such as jathropa.

Soybeans are grown as a commercial crop in more than 35 countries. The major producers are the United States, China, the Democratic People's Republic of Korea, the Republic of Korea, Argentina and Brazil. Soybean is grown primarily for the production of seed. It has a multitude of uses in the food and industrial sectors (including biodiesel production) and represents one of the major sources of edible vegetable oil and proteins for livestock feed use. Soybeans are often rotated with such crops as maize, winter wheat, spring cereals and dry beans.

The many diverse species of sunflowers produce two types of seeds: oil-bearing and edible. Oil seeds have an oil content greater than 40% and are best suited for biodiesel production. The main producers of sunflower seeds are Russia, Ukraine and Argentina, but sunflowers are also widely cultivated in China, India, the United States and Europe. Yields vary widely according to the growing environment. Water availability is the main cause of the variations.

Rapeseed (colza) is a member of the mustard family. Two types of rape are commonly cultivated to produce either tuber-bearing or oil-bearing rapeseed. Rapeseed is used for the production of edible oil in Asia, and elsewhere for the production of animal feed, vegetable oil and biodiesel. China, India, Europe and Canada are now the top producers, although rapeseed can be successfully grown in the United States, South America and Australia. The spring-type oleiferous rapeseed performs well under a wide range of soil conditions but is not very drought tolerant. Oilseed rape cannot be grown on the same field more than once every three years to prevent the build up of diseases, insects and weeds.

Crops for biodiesel demand more than three times as much land as sugar cane used for ethanol to deliver the same amount of biofuel energy. Sunflower and rape seed lead to much lower biofuel yields per hectare than those for ethanol. The typical yield of soybeans cultivated in Brazil is 600 to 700 litres of diesel equivalent per hectare, while European rapeseed yields are around 1 100 litres of diesel equivalent per hectare.

Palm oil offers an opportunity for expanding the energy supply in developing countries by using it as a biomass resource. Care should be paid to analyse which areas of land are used to supply the palm fruits, as palm oil plantations grown in tropical areas are a major cause of deforestation in countries like Malaysia and Indonesia. Malaysia is the world's largest producer and exporter of palm oil. As with other oily crops, current estimates of fuel yield from palm oil are low: about 900 litres of diesel equivalent per hectare.

Oil-importing countries are considering the production of biodiesel from physic nut or jatropha grown on degraded land. The idea is not to compete with land where profitable food production would be possible. The jatropha tree is indigenous to South America, but it is widely planted in Central America, Africa and Asia. It is adapted to high temperatures and it can tolerate drought. The tree is well adapted to marginal soils with low nutrient content. Its cultivation is technologically simple and requires comparatively low capital investment. The oil of the physic nut can be used after detoxification to make edible oil, or it can be converted into biodiesel. Nicaragua is a leading producer of biological diesel substitute based on the oil of the physic nut.

Advanced Production Technologies for Biodiesel and Other Biofuels

Producing FAME biodiesel through chemical transesterification faces several challenges related to its high energy-intensity, the difficulty of recovering glycerol and the need to remove the water and the catalyst from the product. Some progress has been made, for example, with enzymatic catalysts, recently developed to catalyse the transesterification of triglycerides and thus make it easier to remove the glycerol. But such production of FAME biodiesel is very costly, since enzymatic catalysts are far more expensive than conventional catalysts.

Diesel fuel can also be produced through the hydrocracking of vegetable oil and animal fats. This technology has reached the demonstration stage. However, it needs to be integrated with an oil refinery to be cost competitive, in order to avoid building a dedicated hydrogen production unit and to maintain a high level of fuel quality. Therefore, its production potential is currently limited.

Other advanced technologies also exist for converting biomass into liquid or gaseous biofuels. One approach is to use biomass gasification combined with Fischer-Tropsch synthesis. In this method, biomass must first be converted into a syngas through a two-step process:

- Thermal degradation of the biomass that converts it into the syngas components H_2 and CO, as well as into methane, large hydrocarbons and tars.
- Cleaning of the gas derived from the thermal degradation. Tar cleaning is particularly difficult and extremely important to obtain a syngas that can meet the FT feed-gas specifications.

Then, FT synthesis is used to convert the syngas into fuel in the same manner as in gas-to-liquid and coal-to-liquid fuel production. The diesel product obtained from FT synthesis is high quality.

Besides gasification and FT synthesis, there are other ways to produce transportation fuels from biomass. One of these is the production of diesel through hydrothermal upgrading (HTU). In this method, cellulosic materials are first dissolved in water under high pressure and at relatively low temperatures to be converted into a "biocrude" liquid. This biocrude can then be upgraded to diesel fuel in a hydrothermal upgrading unit.

Another approach is fast pyrolysis, in which biomass is quickly heated to high temperatures in the absence of air and then cooled down, forming a liquid ("bio-oil") plus various solids and vapours. This liquid can be used for the production of chemicals or further refined into products such as diesel fuel, but its treatment has proven to be difficult. The approach is also used to convert solid biomass residues such as bagasse into a fuel that is easier to burn for process heat during the production of ethanol. At present, however, fast pyrolysis is associated with unacceptable energy and financial costs.

Costs

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. In regions such as Europe, agricultural subsidies affect production costs significantly.

Costs of conventional biodiesel production from rapeseed in Europe range between USD 27.5 and USD 30/GJ, which corresponds to about USD 1.2 per litre of diesel equivalent. Some estimates put the figure as low as USD 0.7 per litre of diesel equivalent, as the economics of biodiesel production depend on several factors, including the sale of co-products.

Converting biomass into liquid fuels via Fischer-Tropsch processes gives higher yields per hectare than biodiesel based on oil-seed crops. Production cost estimates for large-scale plants are around USD 19/GJ (USD 0.9 per litre of diesel equivalent) for a biomass feedstock price of USD 3.6/GJ. Costs could decline in the medium term to USD 14 to 16/GJ, delivering FT biodiesel for USD 0.7 to 0.8 per litre of diesel equivalent. Small demonstration units exist, and other larger plants are planned, but there are currently no plans to initiate large-scale production. Moreover, logistical problems related to the biomass harvesting still need to be overcome.

Barriers and Prospects for Biodiesel as a Transport Fuel

The cost of conventional biodiesel from oleiferous crops is currently much higher than the costs of commercial bioethanol and requires a much larger portion of cropland to deliver the same amount of energy. Inevitably, this is an important barrier for widespread adoption of biodiesel. However, biodiesel cannot be ruled out in Europe because of the high share of diesel cars that cannot use ethanol, unless new ethanol-to-diesel additives are used. Biodiesel could also be important in all world regions, where a large fraction of heavy-duty vehicles run on diesel.

Although the cost of conventional biodiesel can decline when large-scale plants are built, there appear to be few opportunities for technical breakthroughs that would lead to substantial cost reductions in the future. The most interesting opportunities, therefore, will be offered by innovative production technologies and particularly by biomass-to-liquid (BTL) synthesis, even if this option is believed to remain more expensive than other biofuel production technologies.

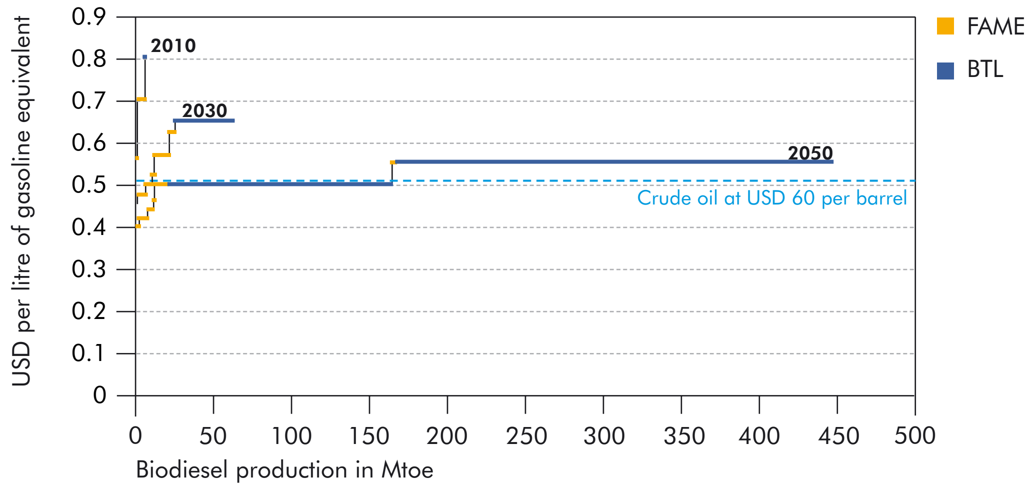
Production of biodiesel is currently small, at about 3 billion litres (about 0.1 EJ, or 2.5 Mtoe) a year. It is concentrated in Europe, which accounts for some 2 billion litres. For this reason, most of the biodiesel cost estimates available are focused on Europe. The production of biodiesel in other world regions where biomass resources can be available at lower cost could lead to lower cost estimates, but the development of a worldwide biodiesel market does not seem as promising as the development of bioethanol. Biodiesel is likely to need stronger governmental support if it is to gain substantial market share.

Biodiesel Supply Curves

Figure 5.7 shows supply curves for FAME and Fischer-Tropsch/BTL biodiesel in the 2010, 2030 and 2050 derived from the IEA preliminary analysis described in the ethanol section. Similar to those for ethanol, these supply curves evaluate the potential of biodiesel in a fast-growth context.

The figure shows that the Fischer-Tropsch synthesis is favoured over conventional FAME biodiesel production because the per-hectare yields from FAME are considerably lower than the yields from the lignocellulosic crops used in FT synthesis. It also shows that the potential for biodiesel and other biofuels is lower in the long term than the potential for bioethanol, and that biodiesel production costs tend to be higher than the production costs evaluated for ethanol. In 2050, biodiesel reaches about 20 EJ (close to 450 Mtoe) while ethanol reaches nearly 45 EJ (about 1 000 Mtoe).

Figure 5.7 ▶ Biodiesel supply curves



Key point

Advanced biomass-to-liquid technologies are needed for large production of biodiesel.

The results shown in Figure 5.7 are driven by four key factors:

- Amount of land allocated to feedstock production.
- Evolution of feedstock yields over time (agricultural productivity).
- Evolution of the yield per tonne of feedstock (conversion efficiency);
- Maximum rate of increase for biodiesel production from world areas where the crops are cultivated or available.

The curves in Figure 5.7 reflect a development that is based on a production ramp-up rate similar (even faster, in some cases) to that assumed for ethanol. In the United States, Canada and Europe, strong policy drivers are assumed to result in very rapid increases (25% per year) from the small production levels of 2005 to 2010. A slower increase (10% per year) in conventional FAME biodiesel is taken into account in the following decade, when the production volumes are larger. Most other regions are assumed to have a fairly modest ramp-up rate through 2010 (since investment decisions for this time frame have mostly been taken already). Strong growth in the production of FAME biodiesel from oil seeds is limited until 2020, when advanced biofuels as BTL biodiesel begin to enter the market. Advanced BTL fuels are assumed to be fully commercialised by 2020.

The impact on land availability for FAME biodiesel production remains well below a maximum of 20% of cropland dedicated to soy and rape in the European Union, United

States and Canada. Similarly, in Brazil, biodiesel is assumed to be derived from soy from expanded cultivation on what is now pasture land (as for sugar cane). Production of FAME biodiesel in other world regions is assumed to follow similar production patterns, though it would require much less than 5% of total available cropland.

As with lignocellulosic ethanol, the production of BTL feedstocks is assumed to occur on pasture land, though lignocellulosic ethanol is assumed to have a rapid production ramp-up five years before BTL fuel. It is assumed that BTL plants will yield liquid fuels at a rate of 50% of their total input energy. Depending on the type of facility, output of liquid biofuels could actually be higher or lower than assumed, which affects land requirements.

The assumed yields of the feedstocks for FAME biodiesel are in the range of 700 to 1 200 litres per ha in 2005, with European rape at the high-end and Brazilian soy at the low-end. Yields for BTL feedstocks are the same as those assumed for lignocellulosic ethanol in 2005 and in 2050, *i.e.* between 2 300 and 4 000 litres of gasoline equivalent per hectare over the full time period.

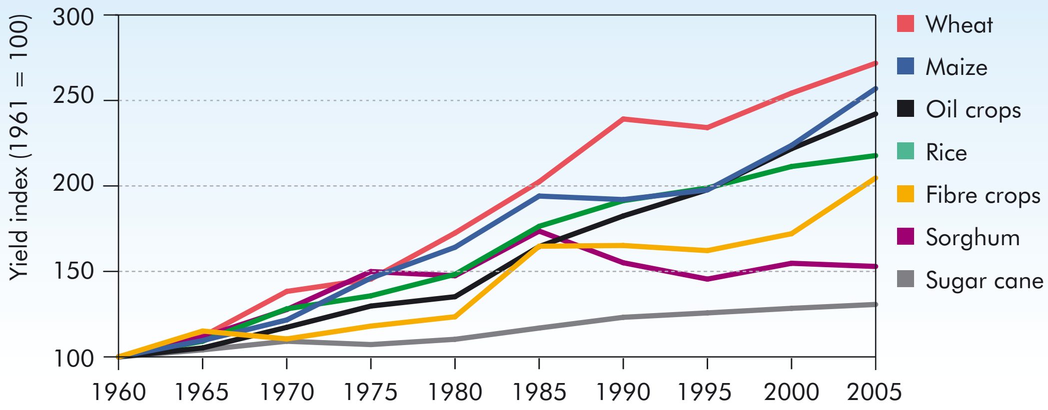
The estimates for production aim to reflect an increase in yields over time, with the idea that the production of biodiesel would start in most countries with fairly small facilities and would move to large-scale facilities at a later stage. Costs for FAME biodiesel (USD 0.40 to 0.70 per litre of gasoline equivalent) are quite optimistic and may underestimate some factors, such as the costs of collecting biomass from a much larger land surface than for ethanol, the price reduction of by-products or the increase in feedstock prices. Costs for BTL diesel are expected to be about USD 0.50 per litre in 2050, which reflects technology improvements, technology learning and increased yields per hectare. As for FAME biodiesel, this figure may underestimate some of the costs of the BTL production process.

Box 5.4 ▶ Biomass availability

About 14 million hectares of land are currently used for the production of biofuels. The biomass feedstocks cultivated for biofuel production are almost entirely used in conventional production processes. Conventional biofuel production requires about 1% of all arable land and yields about 1% of global transportation fuels. If 100% of the fuel requirements for world transport were derived from conventional biofuels, the land requirement would reach 1.4 gigahectares, an amount equivalent to all of the world's arable land. For this reason, even if large existing portions of pasture land could be converted to cropland, competition among conventional biofuel production and food production appears to be inevitable. Two factors could mitigate this competition: improving agricultural productivity (a key factor, especially in the developing world) and increasing the amount of arable land.

Since 1960, agricultural yields of key crops have increased between 25% (for yams) and 150% (for maize). On average, yields have doubled (Figure 5.8) and further yield improvements are possible. The simplest way to achieve this is to introduce better agricultural practices, a time-consuming process. Investments in biofuels in developing countries can be a key element in the transition toward more-efficient land use and can bring additional benefits to the production of non-energy crops. Given the large potential for enhanced agricultural productivity, the development of biofuels, if accompanied by effective transfer of technologies and improved agricultural practices, may not conflict with food production.

Figure 5.8 ▶ Key crops: average yields per hectare, 1961-2004



Source: FAO statistics.

Key point

Crop yields have increased significantly since 1960.

The following factors demonstrate the importance of agricultural productivity for biofuels:

- *World population is expected to grow by 37% by 2050.*
- *Average food intake is expected to grow by 16%.*
- *Transport fuel demand is expected to double by 2050.*

A doubling of the crop yields for food production by 2050, combined with an increase of 30% for bioenergy crops, could allow 20% of all arable land to become available for other purposes. The use of this land, which does not account for pasture land conversion to cropland, could potentially supply 40 EJ (close to 950 Mtoe) of primary biomass, corresponding to 13% of all transportation demand. If average agricultural crop yields were to triple instead of double, almost half of all agricultural land could be used for biomass, offering an additional 100 EJ (about 2 400 Mtoe) of primary biomass potential.

These estimates, however, make no allowance for human habitation needs, water availability, land degradation or declines in crop yields due to climate change. Furthermore, they do not account for increased productivity in animal raising. About 150 EJ (nearly 3 600 Mtoe) of biomass is annually used as animal feed, while grains, vegetables and oilseeds for human consumption account for only 75 EJ (1 800 Mtoe).

If non-conventional biofuel production is considered, agricultural by-products like straw can be used to produce biofuels (by enzymatic hydrolysis of cellulose and distillation). Crops that are now wasted and crop residues could produce 491 billion litres of ethanol annually (equivalent to about 20 EJ or 500 Mtoe of primary biomass). Additional contributions could be offered by the increased recovery of wood from forests, which is not considered in this analysis. Animal manure could represent 9 to 2 5 EJ (200 to 600 Mtoe), and organic waste could account for up to 3 EJ (less than 75 Mtoe). Biomass by-products and waste could provide an additional 30 to 50 EJ (700 to 1 200 Mtoe).

In total, new biomass potential could be between 60 EJ (about 1 400 Mtoe) and 150 EJ (3 600 Mtoe). If added to the current 40 to 50 EJ (950 to 1 200 Mtoe) of existing bioenergy sources, total biomass potential could be 100 to 200 EJ/yr by 2050 (2 400 to 4 800 Mtoe/yr). It is worthwhile to note that with total primary energy use expected to grow to between 800 and 900 EJ (19 to 21.5 thousand Mtoe) by 2050, primary biomass could meet 10 to 25% of this demand.

Hydrogen Production

Description

Hydrogen can be produced from fossil fuels or from nuclear or renewable energy by a number of processes. These include water electrolysis, natural gas reforming, gasification of coal and biomass, water-splitting by high-temperature heat, photo-electrolysis, and biological processes. Of the 5 EJ (about 100 Mtoe) of hydrogen production per year, 40% is used in chemical processes, 40% in refineries and 20% in other areas. In 2003, 48% of all hydrogen was produced from natural gas, 30% from oil and off-gases of refineries and chemical plants, 18% from coal, and 4% from electrolysis. Most of this hydrogen is produced on-site in refineries and chemical plants for captive, non-energy uses.

Decentralised production of hydrogen is currently based on water electrolysis and small natural gas reformers. Decentralised production will be needed in the early phases of hydrogen introduction, as a limited number of vehicles does not warrant centralised production. Electrolysis is a costly process that produces high-purity hydrogen. The cost of electrolysis can be reduced significantly, but electricity remains an expensive feedstock in most parts of the world. Small-scale natural gas reformers are commercially available. Several demonstration projects are testing units in industrial applications. In recent years, suppliers have considerably improved reformers' size (down to 10 × 3 × 3 m) and capacity (up to 500 to 700 normal cubic meters per hour, equivalent to 5.5 to 7.5 GJ per hour).

Once the hydrogen demand will be high enough to justify centralised production structures, hydrogen production from natural gas or coal in centralised units could be introduced. Such processes will need to be combined with CO_2 capture and storage if emissions reduction is a goal. Large-scale natural gas reforming and hydrogen production is an established process and could benefit from further R&D in order to lower costs, increase efficiency and enhance the flexibility of the process. Improved catalysts, adsorption materials, separation membranes and purification systems are also needed to produce hydrogen that is suitable for all types of uses.

Hydrogen production based on coal gasification and the water-gas shift reaction is also an established technology, the cost of which is higher than production from natural gas. Cheaper gasifiers and new oxygen production technologies may reduce the cost of hydrogen from coal in the future. Also, cogeneration of electricity and hydrogen from coal has received attention in recent years, as this could reduce cost.

For centralised hydrogen production from natural gas or coal, CO_2 capture and storage will be an essential part of an emissions reduction strategy that includes hydrogen. Capture technologies are already well developed; the main challenge centres on proving the efficacy of long-term underground CO_2 storage.

Development Status

The cogeneration of hydrogen and electricity from coal in centralised integrated gasification combined-cycle plants with CO_2 capture and storage has the potential to produce cost-effective, CO_2-free hydrogen from coal. The US FutureGen project is a leading activity in this field. Ongoing CCS demonstration projects on an industrial scale are producing promising results, but more R&D and demonstration is needed to prove and commercialise this technology.

Hydrogen production from high-temperature processes based on nuclear or solar energy could avoid the need for CO_2 capture and storage, but they are still a long way from being commercially viable. To be economic, thermo-chemical water splitting using high-temperature heat requires new materials for the process equipment, additional cost reductions and cheap supplies of high-temperature heat.

Further R&D is needed to reduce costs and increase the efficiency of the decentralised production of hydrogen. Distributed production avoids the need for building an expensive hydrogen transportation infrastructure, but this is offset to some extent by the generally higher costs per unit of capacity and the lower efficiency of the smaller plants. In addition, adding CCS to decentralised production sites like small natural-gas reformers is probably too difficult and too costly to be feasible.

The production of hydrogen from photo-electrolysis (photolysis) and from biological production processes are both at a very early stage of development.

Prospects

The currently established technologies for producing hydrogen require significant cost and efficiency improvements if hydrogen is to be commercially produced for energy use. The prospects for such improvements are good.

Vehicle Technologies for Road Transport

In road transportation, power train technology has been dominated for decades by the reciprocating internal combustion engine (ICE). Almost all cars, trucks, buses and motorbikes are equipped with these engines.

ICEs in cars, light trucks, buses and heavy-duty vehicles generally operate on a four-stroke cycle, namely:

- Intake of the air and fuel into the cylinder.
- Compression of the air and fuel mix.
- Combustion and expansion of the fuel.
- Expulsion of the exhaust gases.

ICEs in motorbikes can run on a four-stroke cycle, but also on a two-stroke cycle, where air intake and compression are grouped in one stroke, and combustion and expulsion of the exhaust gases are grouped in the other.

Reciprocating ICEs are generally divided into two main groups: spark-ignition (gasoline) engines and compression-ignition (diesel) engines. Spark-ignition engines can be fuelled not only by gasoline, but also liquefied petroleum gas, ethanol or certain types of natural gas. All these fuels have a high octane number, meaning they are not likely to self-ignite. Compression-ignition engines can be fuelled by diesel, biodiesel or other fuels that ignite by being exposed to high temperature and pressure in the presence of oxygen. These fuels have a high cetane number, meaning that they ignite easily under pressure.

This section describes engine technologies that are common for spark-ignition and compression-ignition vehicles. It also discusses alternative vehicle technologies, including electric, hybrid and vehicles. It further considers non-engine technologies that can contribute to improved fuel economy.

Common Technologies for Spark-ignition and Compression-ignition Engines

Turbochargers

Technology Description

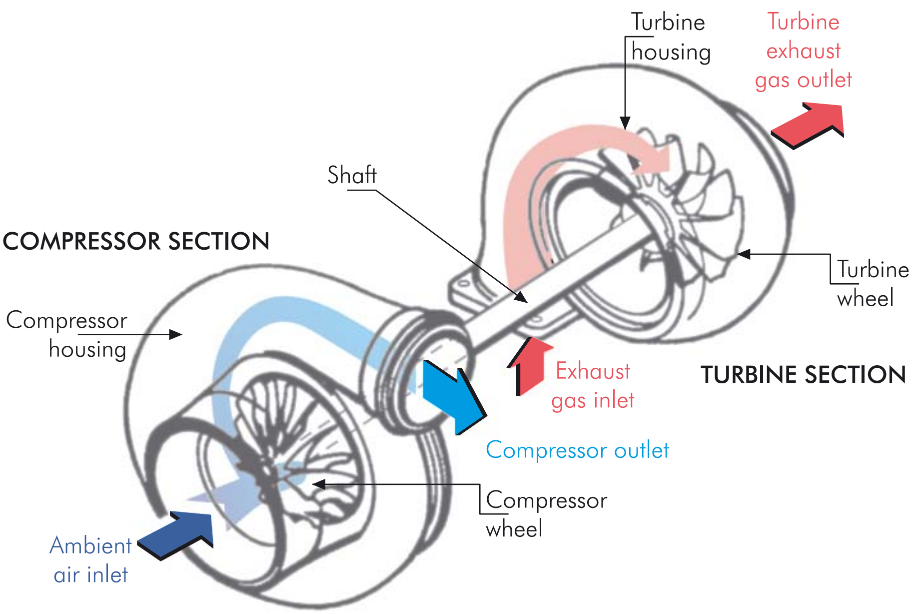
Spark-ignition and compression-ignition engines can intake air at atmospheric pressure (so-called "aspirated engines"), or they can intake pressurised air to deliver more power for a given engine size. The increased pressure of the air entering the cylinders can be achieved with two different technologies: turbochargers and engine-driven superchargers. The ability to use pressurised air has important implications for vehicle downsizing and thus for improving fuel economy.

Superchargers have a compressor geared directly to the engine and are designed to increase the power output of the engine; they are not often used today.

Turbochargers are not geared directly to the engine. Instead, turbochargers recuperate energy from the heated gases leaving the combustion chamber. Combustion gases are routed to a turbine that drives a compressor to increase the pressure of the intake air. Since the energy recovered would otherwise be wasted, turbochargers contribute significantly to improved fuel economy. They suffer, however, from a lack of boost pressure at low engine revolutions that may cause “turbo lag”.

Often used in conjunction with turbochargers and superchargers, an intercooler (technically a heat exchanger) reduces the temperature of the compressed air entering the combustion chamber, thereby decreasing NO_X emissions. Turbochargers are now widely used in diesel-powered vehicles.

Figure 5.9 ▶ Turbocharger



Key point

Turbochargers recuperate energy from exhaust gases to improve engine efficiency.

Technology Status

Turbochargers are commercially available and particularly suited for diesel engines, as these engines can operate unthrottled and with high compression ratios. Some modern diesel engines have turbochargers with variable turbine geometry (VTG), where the angle of the blades changes according to the engine load, improving the efficiency of the system. The turbocharger may also be split into two different-sized turbochargers, which are activated during different engine regimes. Electrically assisted turbochargers are expected to be available by 2020 and will offer a quicker response to the driver inputs, although are not a key element for improved fuel economy.

Barriers to Greater Market Penetration

Turbochargers were first introduced in large vehicles, where the increased cost was easier to absorb. At the start, increasing the pressure of intake air was meant to increase the vehicle's performance, not to improve the fuel economy. This is one reason why the public is generally unaware of this aspect turbochargers.

Turbochargers will remain essential for diesel vehicles in the next decades. They also have the potential to become a key element for spark-ignition engines, once new technologies such as variable valve control and advanced combustion become available.

Electronic Engine and Transmission Control Systems

Technology Description

Electronic engine and transmission control systems have played a key role in the improvement of power trains and in the reduction of pollutant emissions. Most of the automotive improvements achieved in the last two decades would not have been possible without the impressive developments that have occurred in electronic control systems.

Control systems monitor parameters like the temperature and pressure of the intake air, the engine speed, throttle position and quantity of oxygen in the exhaust. The condition of the transmission, temperature and pressure of the cooling fluid, status of the battery charge and activity of other accessories may also be electronically monitored.

Some of the actions performed by the on-board electronic system are of critical importance: one of the most striking examples is the regulation of the mass of fuel injected into the intake air under different driving conditions; other examples include the appropriate use of mixture-enrichment systems at start-up and the management of the transmission-shift points.

Technology Status

Electronic engine and transmission control systems will benefit from further developments in the field of electronics, especially power electronics, related to the availability of electrical power and the introduction of higher voltage systems.

Barriers to Greater Market Penetration

Electronic engine and transmission control systems are widely used on existing vehicles, but not always to the same extent. The main barriers for a larger market penetration of advanced engine and transmission electronic systems are their costs, the cost and the energy density of batteries and the increasing need to use higher voltage systems (42 volts or more), which have not yet been widely introduced. The use of advanced electronic systems is favoured on hybrids, as they are already equipped with large batteries and high voltage systems.

Gradual development of electronic engine and transmission control systems will continue over the next decades. Like many other technologies, improved solutions will be introduced first in the most expensive cars and on heavy-duty vehicles. Then, as costs fall, they will be extended to a larger share of vehicles. Further improvements in electronic engine control systems can be driven by the introduction of new standards on pollutant emissions, as they can favour advanced engine architectures.

Gasoline-fuelled and Related Vehicles

Fuel-injection, Air-intake and Advanced-combustion Technologies for Spark-ignition Engines

Technology Description

Spark-ignition reciprocating ICEs need fuels that have little tendency to self-ignite at high temperature and pressure. In these engines, the spark plug ignites the combustion. Most spark-ignition engines in use today are fuelled by petroleum gasoline, but they can also run on synthetic gasoline from gas-to-liquid processes, on ethanol, on compressed natural gas, on liquefied petroleum gases or on hydrogen.

In the intake system of spark-ignition engines, air is mixed with small amounts of fuel. Traditionally, this process was carried out in the carburettor, where the fuel was drawn into the airflow mechanically. It then entered the cylinders through valves passing through the throttle plates.

In order to meet more stringent emissions requirements, the carburettor has been replaced in nearly all engines by port-injection systems or direct-injection systems. In port-injection systems, fuel injectors spray the fuel close to the intake valves when the engine is in its aspiration phase. Fuel injectors allow much more precise control of the amount of fuel introduced into the cylinder. In direct-injection systems, the injectors introduce the fuel directly into the cylinder. In this configuration, the fuel vaporises and subtracts heat from the gas in the chamber, improving knock resistance and thereby allowing higher compression ratios. Given the need to overcome the compressed-air pressure in the cylinder, however, the fuel must be under higher pressure than in port-injection configurations.

Technology Status

Spark-ignition engines are fully commercial. Work is continuing to introduce several component improvements.

Direct-injection systems are particularly effective in reducing fuel consumption and CO_2 emissions, especially in combination with several combustion technologies that are under development, such as lean-burn technologies. A lean-burn engine is designed to operate with a very low air-to-fuel ratio under light-load conditions. When little power is required, lower amounts of fuel are injected into the combustion chamber, but only in the area around the spark. This reduces the need for throttling and limits nitrogen oxides.

At higher engine speed, a homogeneous fuel-air mixture is produced throughout the combustion chamber by multiple direct injections. This system delivers more power with no additional fuel consumption. Its principal drawback is the production of NO_X emissions higher than those obtained with a nearly stoichiometric airflow and a three-way catalyst. (Stoichiometric airflow refers to the chemically optimal mixture of fuel and air for engine combustion.) For this reason, lean-burn technology in spark-ignition engines requires a sophisticated and fuel-sensitive after-treatment system for NO_X in order to meet strict requirements on pollutant emissions.

Conventional engine architectures use valves to control the gas flow into the combustion chamber and the expulsion of the exhaust gases. In conventional engines, the intake valves (generally larger than the exhaust ones) are activated mechanically by the camshaft. Variable valve control is an advanced system that allows a better management of valve timing and can substantially reduce the need for the throttle plates in gasoline engines. The use of variable valve control systems can result in a 10% improvement of fuel economy. Some mechanical systems for valve timing have already been introduced. Other systems, based on electro-magnetic and electro-hydraulic actuation technologies, are currently being developed and are nearly ready for commercial use. Variable-valve timing can also enable modular use of the engine, completely obviating the need for some of the cylinders when little engine-power is needed. This solution diminishes fuel consumption even further and has already been introduced in some large cars.

Controlled auto ignition (CAI) is another new combustion process actively being explored to improve fuel economy and lower exhaust emissions. CAI engines use a highly diluted mixture of fuel, air and residual gases that can auto-ignite in a four-stroke engine without pre-heating of the intake air or increasing the compression ratio. The main issue in the development of CAI is the range of engine speed and load that will allow correct engine functioning with low NO_X emissions and limited noise.

Table 5.2 ▶ ***Gasoline vehicle technologies, status and prospects***

	2003-2015	2015-2030	2030-2050
Technology stage	Conventional engine, stoichiometric combustion, increased use of variable-valve control.	Turbocharged engine with direct injection and variable-valve control, engine downsizing. Progressive introduction of advanced combustion technologies with NO_X traps.	Downsized turbocharged engine with direct injection and variable-valve control using advanced combustion technologies (CAI) with NO_X traps.
Cost of a mid-size LDV* (USD 000s)	15.3 - 16.9	15.4 - 17	15.5 - 17.1
Fuel economy (litres of gasoline equivalent/100 km)	5.4 - 9.7	5.1 - 9.1	4.7 - 8.4
CO_2 emissions, tailpipe (g/km)	130 - 234	122 - 219	114 - 204
CO_2 emissions, well to wheel (g/km)	151 - 270	141 - 253	131 - 235

* LDV = light-duty vehicle

Note: the tables presented on vehicle technologies give estimates of vehicle costs and vehicle fuel economies that take into account increasing shares of the technology advances described in the relevant section of this chapter. These estimates refer to a mid-size vehicle and consider that roughly half of the potential improvements due to advanced vehicle technologies will be destined to improve vehicle fuel economy. (In the case of hybrids, this share rises to 100%, but hybrid power trains could also be used to increase performance, rather than to improve fuel economy.). These estimates also account for a larger penetration of after-treatment technologies. The cost estimates presented reflect only the introduction of the technologies in an average vehicle. They include retail mark-up and can be thought of as retail price-equivalent. This is not necessarily the same thing as the actual average retail price in different countries, since market forces also determine actual prices and technologies can be introduced to a larger extent and for other purposes than for fuel economy improvement. Vehicle costs presented in these tables do not take into account the total fuel costs over the life of the vehicle and exclude taxes. The estimates presented also assume that considerable learning and optimisation occurs between 2010 and 2050, in addition to large-scale production of the vehicles.

Technologies that reduce or eliminate pumping losses and throttled operations, combined with turbochargers and technologies that help to contain knock, can result in significant reductions in engine size, also allowing substantial fuel economy improvements and CO_2 emission reductions. Many in the automotive industry believe that engine downsizing – including the use of turbochargers – can reduce engine displacement size by up to 30%. Large increases in resistance to engine knock and higher compression ratios can reduce engine displacement by half, entailing efficiency gains and CO_2 emission reductions of 25% or more. Downsizing the engine has also a positive effect on the whole vehicle design, reducing vehicle inertia and therefore engine load, and allowing for better aerodynamics.

Barriers to Greater Market Penetration

Spark-ignition reciprocating ICEs are used in many types of vehicles, including two-and three-wheelers, light-duty vehicles, medium freight trucks and minibuses.[16] Most of the spark-ignition engines sold on the market use port-injection technologies, but direct injection is gaining popularity in some OECD countries, as it can offer lower fuel consumption. On the other hand, the introduction of new fuel-injection technologies increases production costs, and manufacturers tend to include them first in expensive vehicles. In other cases, higher production costs are recovered by offering vehicle equipped with advanced engine solutions at higher prices with respect to conventional solutions that consume more fuel. Even if fuel economy improvements carry a financial burden, many of them can be introduced at a negative life-cycle cost because they reduce fuel consumption over the life of the vehicle.

Improved gasoline engines consuming less fuel due to improved fuel injection and combustion can be increasingly introduced into the market in the next decades. Fuel efficient solutions such as downsized spark-ignition engines using direct injection are expected to take a much greater share of the gasoline-engine market in the medium term. By 2020, they may be more widely-used than conventional port fuel injection engines. They will include progressively advanced combustion technologies (lean burn and, in the longer run, CAI). Variable-valve control will be installed on a large scale even earlier. Often, though, technologies are not introduced to improve fuel economy but rather to include additional features or to maintain the current fuel economies on larger vehicles, or to increase the performance of the engine. Policy measures such as CO_2 emission standards, fuel standards and vehicle taxes based on fuel economy performances would stimulate fuel economy improvements.

Additional challenges arise when the development of advanced technologies is constrained by the need to limit pollutant emissions, notably nitrogen oxides. Limits on emissions from gasoline vehicles are likely to remain very strict and may delay some fuel-economy improvements derived from advanced combustion technologies, unless appropriate after-treatment systems (described later in this

16. Many two- and three-wheelers use two-stroke engines where the fuel is mixed with lubricant oil, but the use of four-stroke engines in two- and three- wheelers is increasing, mostly because of stricter regulations on pollutant emissions. Further details are given in the section that specifically considers two- and three-wheelers.

chapter) are introduced. These systems are not common in current vehicle models because they could make spark-ignition engines 10% to 15% more expensive than conventional versions.

Improved information and public awareness would also improve consumers' attitudes toward fuel efficient solutions.

Heat Recovery

Technology Description and Status

A large percentage of the energy released by the fuel in the operation of internal combustion engines is lost as heat. Efficiency increases of up to 15% may be achieved through steam-based heat recovery systems. BMW recently announced the development of a new technology based on heat recovery, similar to the combined heat-and-power units of electricity plants. The German auto-maker claims that the system recovers more than 80% of the heat energy that is now dissipated in the exhaust gases. The recuperated heat is used together with residual heat absorbed by the cooling circuit of the engine to run an expansion unit (a small steam turbine) linked to the crankshaft.

Barriers to Greater Market Penetration

Heat-recovery technology has never been used in a commercial vehicle and has not yet been demonstrated, but it offers a concrete possibility for improving fuel efficiency. Its coupling with improved exhaust systems, which will be more widely installed as local pollutant emission measures are strengthened, makes it an interesting option for further development. The goal is to move to large volume production within ten years, but diffusion of these systems is still uncertain and seems very unlikely in this time frame.

Ethanol-fuelled Vehicles

Technology Description

Almost all recent-model vehicles equipped with a spark-ignition engine are fully compatible with low-level ethanol fuel blends, such as E5 or E10 (5% and 10% ethanol blends). These blends are widely used in the United States, Canada, Australia and many European countries, where they have delivered more than 1 trillion kilometres of driving without encountering any serious problems in operability or reliability.

In order to use blends of more than 10% ethanol, some engine modifications may be necessary, because of ethanol's low compatibility with some elastomer components and certain metals. Using compatible materials would eliminate these problems, and the use of compatible metals is already common in some countries like the United States and Brazil. The cost of making vehicles fully compatible with E10 is negligible, and costs remain very low for full compatibility to E85 (an 85% ethanol fuel blend).

If engines were designed exclusively for pure ethanol or ethanol-rich blends, their costs would be roughly the same, but their fuel economy (expressed in litres of gasoline equivalent per 100 km) would be better than the fuel economy of engines designed for conventional gasoline with the same performance. Similar effects would be seen in the CO_2 emissions from the tailpipe.[17] These improvements are possible because the high octane number of ethanol-rich blends, plus the cooling effect from ethanol's high latent heat of vaporisation, would allow higher compression ratios in engines designed for ethanol-rich blends, especially in those using the most advanced injection systems available, such as direct-injection systems.

Table 5.3 ► ***Vehicles with ethanol dedicated engines, status and prospects***

Ethanol dedicated engine (E100)	2003-2015	2015-2030	2030-2050
Technology stage	Conventional engine, stoichiometric combustion.	Turbocharged engine combustion with direct injection and variable-valve control. Progressive introduction of advanced combustion technologies needing NO_X traps, progressive downsizing.	Turbocharged downsized engine with direct injection and variable-valve control, using advanced combustion technologies with NO_X traps.
Cost of a mid-size LDV (USD 000s)	15.3 - 16.9	15.5 - 17.1	15.6 - 17.3
Fuel economy (litres of gasoline equivalent/100 km)	4.8 - 8.6	4.5 - 8	4.2 - 7.5
CO_2 emissions, tailpipe (g/km)	120 - 215	112 - 200	103 - 185
CO_2 emissions, well to wheel (g/km)		Depends on the fuel-production technology	

See note in Table 5.2.

The use of dedicated ethanol engines (or engines using exclusively ethanol-rich blends) was common in Brazil during the 1980s, in the successful period of the Proalcohol plan. The problems of the Proalcohol plan of the 1990s, coupled with lower oil prices, displaced nearly entirely the dedicated ethanol engines from the market. The recent increase in oil prices has revived the Proalcohol plan, which has been coupled with the diffusion of flexible-fuel (flex-fuel) engine technology that enables the use of ethanol. Contrary to dedicated ethanol engines, the flex-fuel technology does not offer significant improvements in fuel economy (or reductions in tailpipe CO_2 emissions), but it has the significant advantage of making a spark-ignition engine compatible with any fuel blend containing between 1% and 85% ethanol. The flex-fuel technology is already well proven and commercially successful. In flex-fuel engines, an oxygen sensor evaluates the fraction of alcohol in the fuel mix, enabling all functions of the engine to adapt to it. Some components in the fuel system, like the fuel tank, pump and injectors, are sized differently and made of material that is corrosion-resistant and compatible

17. One recent study estimated that a small turbocharged spark-ignition engine adapted for ethanol use would emit 9% less CO_2 than the original engine running with gasoline (Jeuland, *et al.*, 2004). According to this study, greenhouse gas emissions from the tailpipe could ultimately be cut by 20% in a dedicated ethanol engine, partly because of the higher hydrogen-to-carbon ratio of ethanol and partly because of the improvements in engine efficiency.

with the higher concentration of alcohol in the ethanol. The incremental cost of mass-producing flexible-fuel vehicles is believed to be about USD 100 to 200 per vehicle, a fraction of the incremental cost of producing mono- or bi-fuel vehicles running alternatively on compressed natural gas and conventional gasoline.

Table 5.4 ▶ ***Flexible fuel vehicles, status and prospects***

Flexible fuel vehicle fired with E85	2003-2015	2015-2030	2030-2050
Technology stage	Conventional engine, stoichiometric combustion.	Ethanol-hybrid turbocharged engine with direct injection and variable-valve control, downsizing. Progressive introduction of advanced combustion technologies needing NO_X traps.	Downsized ethanol-hybrid turbocharged engine with direct injection and variable-valve control using advanced combustion technologies with NO_X traps.
Cost of a mid-size LDV (USD 000s)	15.6 - 17.2	15.6 - 17.2	15.6 - 17.2
Fuel economy (litres of gasoline equivalent/100 km)	5.4 - 9.6	5 - 9	4.7 - 8.4
CO_2 emissions, tailpipe (g/km)	133 - 239	125 - 224	116 - 209
CO_2 emissions, well to wheel (g/km)		Depends on the fuel-production technology	

See note in Table 5.2.

Box 5.5 ▶ **Effects of ethanol on emissions of pollutants**

A molecule of ethanol contains oxygen and contributes to more complete combustion of the carbon, thereby reducing the emissions of carbon monoxide. The use of 10% ethanol blends in gasoline has been shown to achieve a 25% or greater reduction in carbon-monoxide emissions.

The use of ethanol as a combustible fuel has a little effect on NO_X *emissions, while the net effect of ethanol use on emissions of volatile organic compounds (VOCs) is less clear, since VOC emissions due to ethanol are difficult to measure accurately with the detector that is usually used to gauge engine pollutant emissions.*[18] *Evaporative VOCs can be higher because of the higher vapour pressure of ethanol and ethanol blends.*

Technology Status

Technologies like direct injection and turbochargers that could lead to downsizing spark-ignition engines also favour the introduction of ethanol as a transportation fuel.

18. Over the full fuel cycle, which takes into account emissions released during feedstock production, ethanol production and fuel preparation, overall NO_X emissions may be significantly higher. This is primarily due to the NO_X released by the fertiliser used to grow bioenergy crops.

A recent evaluation shows that small amounts of ethanol used in an ethanol-boosted engine can increase the efficiency of the engine by approximately 25%, reducing CO_2 emissions by the same fraction (Cohn D.R., *et al.*, 2005). This evaluation considers that the use of direct injection of ethanol would overcome the problem of engine knock in a highly turbocharged engine, half the size and keeping the same performance of a much larger conventional engine. Ethanol can be mixed with conventional gasoline and directly injected into the combustion chamber in fuel mixes containing different fractions, depending on the engine load. The use of directly injected ethanol would be limited only to high load conditions; during most of the drive cycle, when the torque and power are low, the engine would be using gasoline introduced by conventional port fuelling technology. This system would require two separate tanks, one for conventional gasoline and one for ethanol. The increase in the vehicle cost is estimated to be about USD 600, mainly for the turbocharger, the direct fuel-injection system and an ethanol fuel tank.

Barriers to Greater Market Penetration

While vehicles using fully dedicated ethanol engines are not common anywhere in the world, flex-fuel vehicles are already widely available in Brazil and are becoming increasingly common in the United States and in some European countries, like Sweden. Flex-fuel vehicles allow the combined use of ethanol and gasoline at nearly the same cost of gasoline vehicles, while they offer an increased freedom of choice. Flex-fuel vehicles are probably the best solution to solve the "chicken-or-egg" problem affecting all alternative fuel sources for transportation, since flex-fuel vehicles can increase the demand for ethanol at a very low cost and avoid the risk of relying on a single fuel source.

The main problems for wide diffusion of ethanol as a fuel are related to its production costs (ethanol is currently competitive with petroleum gasoline only in Brazil and only when it is produced from sugar cane) and include the need to develop an adequate distribution infrastructure. Currently, small amounts of ethanol are already added to gasoline in many countries, but ethanol distribution at the pump is limited to Brazil, the United States and Sweden. This limited availability of ethanol on the fuel market and the need to adapt the distribution infrastructure are problems that could be solved with limited costs, especially when compared with the costs of building distribution infrastructures for other alternative vehicle fuels, like hydrogen or natural gas. Government support and appropriate policies could also help encourage development of the infrastructure, possibly justified by the quest for increased energy diversification. It is important to note that the life-cycle cost of ethanol as a fuel may well be negative, if the fuel expenditure and the CO_2 emission reduction potential of some of the ethanol production pathways are taken into account.

As a result, further development of the ethanol-distribution infrastructure is likely and the increased availability of improved ethanol-related vehicle technologies is within reach, if not already available. Ethanol is also very well positioned with respect to the fuel economy improvements that can be achieved on spark-ignition engines, as its high octane number and its chemical characteristic favour its use for advanced injection and combustion solutions.

Natural Gas and Liquefied Petroleum Gas Vehicles

Technology Description and Status

Compressed natural gas (CNG) and liquefied petroleum gas (LPG) can deliver good performance and low pollutant emissions in dedicated spark-ignition engines. They contain near-zero sulphur and are characterised by high octane numbers (100 for LPG and 130 for natural gas), which make them suitable for use as fuels for spark-ignition ICEs.[19] Their gaseous state also improves the mixture distribution to the cylinders and allows operating LPG and CNG engines with leaner mixtures, thus improving energy efficiency. Moreover, gaseous fuels reduce deposits on engine surfaces and spark plugs, thereby reducing the wear during cold start and offering better combustion characteristics.

The power generated by a spark-ignition "bi-fuel" engine designed for petroleum gasoline but running on LPG or natural gas is lower over the entire speed range than that of a conventional gasoline ICE because of the lower energy density of LPG and natural gas. (More power is provided during combustion from a given volume of air and petroleum gasoline mixture than from the same volume of air and LPG/natural gas mixture). As a result, natural gas and LPG dedicated engines need higher compression ratios to keep output power and torque comparable to that of a conventional gasoline engine, otherwise higher fuel consumption will result. The high octane number of natural gas, in particular, can lead to better efficiencies in engines exclusively designed for its use as a fuel, but LPG and natural gas are most often used in bi-fuel engine systems, where conditions do not maximise the potential of LPG and CNG. Thus, the use of bi-fuel systems is the result of necessary compromises related to fuel tank size, vehicle range, and the possibility to switch to gasoline as a back-up fuel.[20]

Even if fuel consumption is higher for natural gas and LPG, they can reduce the tailpipe CO_2 emissions because of the higher hydrogen-to-carbon ratios of their molecules, compared with conventional petroleum gasoline. CNG offers increased energy diversification, but well-to-tank emissions vary depending on the methods of production and delivery to the market.

In dedicated engines, LPG and CNG can significantly reduce some pollutant emissions. The lower energy density of LPG and CNG lowers the temperature of combustion and thus reduces NO_X emissions. For CNG, hydrocarbon emissions can be 50% lower than those from a baseline gasoline engine, but hydrocarbon emissions from CNG engines would consist mainly of methane, a powerful greenhouse gas (Tilagone R., S. Venturi, 2004).

Barriers to Greater Market Penetration

LPG is a common alternative fuel for motor vehicles using spark-ignition technologies and has been used widely as a motor fuel for a number of years in the United States, Japan, Europe and more recently in Australia. It is also widely used in some urban transit systems, in Vienna, for example.

19. Natural gas can also be used as a dual-fuel with diesel, notably for heavy-duty applications.
20. Natural gas is not favoured in this context. Its low energy density and the high pressure required for its storage require large, expansive reservoirs to be installed, reducing the room available in the luggage compartment of LDVs and limiting the driving range.

CNG engines make up about 0.5% of the world vehicle stock and are not as common as LPG vehicles. They are currently used in Argentina, Brazil, Pakistan, Italy, India and the United States. CNG engines are often found on fleet vehicles, especially buses, in urban areas, where investment can justified on the basis of local emission reductions.

Safety is a fundamental issue in the design of CNG and LPG vehicles, but CNG and LPG have proved to be at least as safe as petrol, although proper handling is required for CNG and LPG. The main problem regarding LPG and CNG is their gaseous nature, which limits diffusion only to selected national markets where the consumer's acceptance of gaseous fuels is higher. Other important barriers, particularly relevant for natural gas, are costly and cumbersome storage, in addition to the high cost of the distribution and refuelling infrastructure, especially compared with liquid fuels. Moreover, the existing refuelling infrastructure is very spotty, in many countries.

Further development of CNG refuelling infrastructures could occur, but would need government support and would need to be co-ordinated with effective commercialisation of CNG-compatible vehicles, which may also require additional forms of incentives. Such development is first possible in urban areas and can be linked to the deployment of CNG systems in mass transit buses. Unlike CNG refuelling, LPG refuelling can be expanded with inexpensive new refuelling points. Nevertheless, an effective co-ordinated commercialisation of LPG-compatible vehicles would be needed. Contrary to CNG, LPG does not offer supply diversification and remains a niche fuel in most markets.

Hydrogen-fuelled Internal-combustion Engines

Technology Description and Status

Hydrogen can be used as a combustible fuel in ICEs and can deliver good performance. It also limits pollutant emissions when used in dedicated spark-ignition engines.

Hydrogen is particularly sensitive to knocking in conventional combustion conditions because it is highly flammable; but this flammability also means that hydrogen can be used in very lean mixtures (*i.e.* a lower proportion of fuel is mixed with air), thus eliminating the issue of knock completely. Supercharged hydrogen engines designed to run on lean mixtures can run unthrottled and can achieve very significant fuel economy improvements (20 to 30%) with respect to conventional engines using gasoline.

Given the characteristics of hydrogen when it is used as a combustible fuel, the combined use of hydrogen and conventional gasoline (or other liquid fuels) could contribute to a quicker development of lean burn and controlled auto ignition (CAI) technologies.

The main advantage of the use of hydrogen as a fuel is the absence of carbon atoms in its molecule, which results in no hydrocarbon or CO_2 tailpipe emissions. Moreover, even without after-treatment, the NO_X emissions are low due to the opportunity to use lean air-fuel mixtures.

Barriers to Greater Market Penetration

There are currently no vehicles using hydrogen as a combustible fuel on the market and no distribution infrastructure exists for hydrogen as a transport fuel. Even if production costs of hydrogen ICE vehicles were competitive with conventional spark-ignition vehicles, the need for the development of the extremely expensive hydrogen-fuelling infrastructure is an important limitation to widespread adoption of this technology. For vehicles, it is a classic "chicken-egg" dilemma: an expensive hydrogen supply system will not be established without sufficient demand, and the demand for hydrogen ICE vehicles is unlikely to grow without low-cost hydrogen production and extensive refuelling networks.

Hydrogen vehicle costs are currently higher than the cost of conventional spark-ignition vehicles. The main problem is associated with the costs of storage hydrogen on-board the vehicle. Existing on-board storage options do not yet meet the technical and economic requirements to make them competitive.[21] Moreover, the low molecular weight of hydrogen requires large fuel tanks if long distances are to be driven.[22]

Similar to CNG, the development of the hydrogen ICE option could first be possible in urban areas, where the costs of the fuel distribution infrastructure could be supported by demand from fleet vehicles, such as buses. Additional development is possible if pressurised storage tanks (or competitive storage technologies) become available at low cost for ICE or bi-fuel vehicles. However, such storage solutions are not likely in the short term, barring some sudden technological breakthrough. With such a breakthrough, ICE hydrogen vehicles could be an initial stepping stone for hydrogen as a transport fuel, setting the stage for more rapid development of vehicles. In today's situation, development beyond niche markets is probably very difficult.

Technologies to Reduce Pollutants from Gasoline Engines

Gasoline engines are subject to increasingly strict regulation of air pollutants, such as volatile organic compounds (VOCs), carbon monoxide (CO), particulate matter (PM) and nitrogen oxide (NO_X). Gasoline engines emit little particulate matter because they use fast-burning "light" fuels, but other emissions from gasoline engines are high.

Technology Description

In current conditions, pollutant emissions from gasoline engines can be reduced only by treating the exhaust gases in a catalytic converter, which converts residual VOCs, CO and NO_X into non-polluting compounds. Catalytic converters are built of a ceramic or metallic substrate with an active coating incorporating alumina and other oxides with various combinations of the precious metals platinum, palladium and rhodium. Oxidation catalysts convert carbon monoxide and hydrocarbons into CO_2 and water, but they have little effect on NO_X, which must be reduced to nitrogen and oxygen. Three-way catalysts simultaneously oxidise CO and hydrocarbons into CO_2 and water and reduce NO_X to nitrogen and oxygen.

21. More information on the costs and the technologies available for hydrogen storage are reported in the section on fuel cell vehicles.
22. This issue would be less relevant in bi-fuel solutions.

Technology Status

Three-way catalytic converters are fully commercial. They are used nearly universally in modern gasoline engines. Unfortunately, three-way catalytic converters are not compatible with lean-burn technology. Future engines with lean combustion technologies will need other after-treatment systems. They will also need engine-based solutions for the reduction of NO_X. One such approach is exhaust-gas recirculation (EGR), in which cooled exhaust gases are recirculated in the intake air flow to diminish the combustion temperature and reduce the formation of NO_X.

Special materials, such as zeolites, may be used along with or ahead of the catalyst to absorb hydrocarbons when exhaust temperatures are too low for effective catalyst operation. Substantial improvements of the catalyst at cold start can also be achieved by electrical heating.

Advanced combustion technologies, in which the spark-ignition engine runs with lean air-fuel mixtures, do not favour the reduction of NO_X. Research to reduce this effect is ongoing. It follows three main patterns: lean NO_X catalysts (deNO_X), NO_X traps and selective catalytic reduction. Additional details on these technologies are discussed in the diesel vehicle technologies section.

Barriers to Greater Market Penetration

Legal limits on the pollutant emissions from gasoline vehicles have been enforced on the basis of health concerns and are the main driver for the use of after-treatment systems. The regulations are currently widespread in OECD countries and are being increasingly enacted in other regions, but with a certain time lag. Increased policy-related restrictions in OECD countries can accelerate the global reduction of pollutant emissions in the coming decades, as they would keep driving the enforcement of regulation elsewhere.

Past restrictions on pollutant emissions also had beneficial effects on fuel economy, as they promoted the use of electronic engine control systems and three-way catalysers. However, new regulations on pollutant emissions could limit this tendency, given that lean-burn technologies may require NO_X after-treatment units.

Specific Technologies for Two- and Three-wheelers

Technology Description

In some countries in South and East Asia, two- and three-wheelers constitute a majority of road vehicles. They are also common in some Mediterranean countries. These vehicles are relatively inexpensive, and they provide mobility for millions of low-income families. Two- and three-wheelers use much less fuel than automobile or light trucks and generate fewer CO_2 emissions. On the other hand, they contribute disproportionately to conventional pollution because they are not equipped with catalytic converters and because many of them, run by two-stroke spark-ignition engines, also burn lubricant oil with the gasoline.

Technology Status

There are several important initiatives under way to reduce the local pollution from two- and three-wheelers. Most of these plans involve a shift from two-stroke cycles to four-stroke cycles. Some countries have now enacted emissions standards that effectively ban the sale of new two- and three-wheelers powered by two-cycle engines. Additional steps may derive from the introduction of electronically controlled fuel injection system for use in four-stroke, 50 cm^3 engines, which allows the use of three-way catalysts that can bring emissions down to a level comparable with passenger cars (Honda, 2003). As an additional benefit, two- and three-wheelers equipped with a catalytic converter will have to use unleaded fuel and will be able to use synthetic gasoline or ethanol as a substitute. If battery technologies improve further, other solutions, such as plug-in scooters powered by electrical motors, could also gain market share.

Barriers to Greater Market Penetration

Stricter pollution regulations of two- and three-wheelers are likely to be enforced in the near term in many OECD countries. They will result in the increased use of four-stroke engines and catalytic converters. The consequent need for precious metals and for the introduction of electronic injection will increase retail prices and maintenance costs. However, pollutant emissions will be significantly reduced and fuel consumption will decrease. Pollution emission regulations will be increasingly extended in other world regions, but often with a certain time lag compared with OECD countries.

Diesel Vehicle Technologies

Compression-ignition engines (diesel engines) are widely used in passenger cars and light trucks, especially in Europe, but they are most common in heavy-vehicles: medium- and heavy-duty trucks, minibuses and buses. The engines used in heavy- and light-duty vehicles are very similar in design and construction, but they vary considerably in size. Heavy-vehicles often contain more advanced technologies than LDV engines. In the design of heavy-duty engines, more attention is devoted to energy efficiency, since fuel constitutes a major fraction of operating costs (trucks and buses travel close to 60 000 km/year, much more than LDVs).

Diesel engines may also be found in non-road-transport modes, such as agricultural tractors, forestry and construction machines, locomotives and ships. Such engines are based on the same fundamental principle found in a road vehicle, but they are much larger. They also may incorporate less advanced technology, because they are subject to fewer constraints on their pollutant emissions.

Compression-ignition engines are similar to four-stroke spark-ignition engines, with a few essential differences. Most spark-ignition engines work in quasi-stoichiometric conditions. They need a throttle to limit the amount of air entering the combustion chamber in order to avoid having an air-fuel mix with an excess of oxygen, which inhibits the three-way catalyst. Diesel engines do not need to be controlled by a throttle. The power output is controlled by the amount of fuel injected into the cylinder, without airflow limitation. This characteristic reduces the pumping losses that occur in the aspiration phase in spark-ignition engines. Most important, diesel engines do not need spark plugs. The air-fuel mix used in diesel engines self-ignites when the fuel is injected into the combustion chamber. As a result, diesel engines may run lean and reach much higher compression ratios than conventional spark ignition engines. In an evaluation of 24 matched pairs of vehicles sold on the

European market, diesel vehicles demonstrated 24% better fuel economy than gasoline vehicle engines (Schipper L., *et al.*, 2002). Direct-injection diesel vehicles with turbochargers scored much better than gasoline engines. The better performance of diesels was not attributable to vehicle design. Diesel contains 10% more energy by volume than conventional petroleum gasoline, so the efficiency improvement of the two types of diesel engines should be scaled down to 13% and 36%, when calculated on an energy basis.

Fuel-injection, Air-intake and Combustion Technologies for Compression-ignition Engines

Technology Description

Diesel indirect-injection engines (the conventional injection technology used in compression ignition engines until a few years ago) were characterised by fuel delivery in a pre-chamber designed to ensure a proper mixing of the atomised fuel with the compression-heated air. The use of the pre-chamber was mainly finalised through the achievement of a more complete combustion (reducing emissions of VOCs and particulate matter), which could reduce the noise due to slower rates of combustion. It also required very high compression ratios because pressure and temperature in the pre-chamber are lower than in the main chamber. Such high compression ratios resulted in relevant heat losses, which reduce the efficiency of the engine. On the other hand, the lower temperatures reached in the pre-chamber reduced NO_X emissions.

In direct-injection engines, the compression ratio does not need to be as high, as the fuel is injected directly into the main combustion chamber. Older engine architecture used a distributor-type injection pump that forced the fuel into a distribution system, spraying it into the combustion chambers through nozzles. Precise control of fuel delivery was not easy to achieve in these systems and could lead to inefficient combustion.

In recent years, distributor-type injection pumps have been replaced by common-rail systems. These systems still use a pump to store fuel at very high pressure in a reservoir (the rail), which is connected to the combustion chamber by fuel injectors. But rail systems permit the activation of the injectors rather than the pump, eliminating the need to build up pressure before each individual injection. This solution makes it possible to control very precisely the amount of fuel injected and the timing of each injection, thereby maximising performance and optimising fuel use. Similar results can be achieved by unit injectors, which are fitted between the valves of each cylinder head.

Diesel engines can work with higher compression ratios than gasoline engines and without a throttle. The combination of these two characteristics clearly favours the use of intake-air compressors, usually in the form of turbochargers. Such compressors are generally coupled with inter-coolers and after-coolers to increase the density of the air entering the combustion chamber. Turbocharged diesel engines, working with common rail and direct injection are now an established technology. They equip most of the light-duty diesel vehicles sold in Europe and virtually all heavy-duty trucks sold around the world.

Technology Status

Turbocharged direct-injection diesel engines, which are the most efficient ICEs available on the market, and second-generation common-rail systems are already commercial. They use a control unit and multi-jet injectors to deliver a series of very closely spaced injections instead of the single main injection used in the first-generation common-rail engines. They ensure more accurate control of the combustion conditions and further improve fuel efficiency and emission characteristics. The use of these technologies has allowed the downsizing of diesel engines and the reduction of their weight.

Table 5.5 ▶ ***Diesel vehicles, status and prospects***

	2003-2015	2015-2030	2030-2050
Technology stage	Second generation common-rail, progressive downsizing.	Turbocharged downsized engine, variable-valve control, possibly heat recovery, particulate filter and NO_X trap (or selective catalytic reduction systems, especially on large engines).	Turbochargeddownsized engine, variable-valve control, and possibly heat recovery. Particulate filter and NO_X trap (or selective catalytic reduction systems, especially on large engines).
Cost of a mid-size LDV (USD 000s)	16.5 - 18.3	16.6 - 18.4	16.5 - 18.3
Fuel economy (litres of gasoline equivalent/100 km)	4.2 - 7.5	4.1 - 7.3	4 - 7.1
CO_2 emissions, tailpipe (g/km)	108 - 193	105 - 188	102 - 183
CO_2 emissions, well to wheel (g/km)	125 - 223	121 - 218	118 - 212

See note on Table 5.2.

Variable valve control, already described for gasoline engines, also offers improvements in diesel engines, although its ability to reduce fuel consumption is lower for compression-ignition engines than for spark ignition engines because spark-ignition engines suffer from higher pumping losses.

Homogeneous-charge compression ignition (HCCI) is a combustion technology that can be used in direct-injection configurations. It is currently the object of several studies. HCCI could contribute to a reduction of NO_X and PM emissions. It consists of the use of a highly diluted mixture of air, fuel and residual gases (obtained by exhaust-gas recirculation) to achieve simultaneous ignition in all parts of the combustion chamber. The reduction of NO_X and PM emissions is achieved mainly through the thermo-chemistry of the charge, but the system may use 5% more fuel than a direct-injection diesel engine. Among its other drawbacks are high hydrocarbon and CO emissions, and, worst of all, limited control of the combustion at high loads or at limited power. Dual systems, applying HCCI at partial loads and reverting to conventional diesel combustion at full load have already been developed and seem a promising option.

Barriers to Greater Market Penetration

Diesel engines already in use on heavy-duty vehicles have very high efficiency. However, there is further potential for reducing their fuel consumption, mostly by improving the quality of combustion and using heat-recovery systems.

Regulations for low-emissions have sharply increased the cost of light-duty vehicles in the United States and elsewhere. In some cases, such as in California in the United States, the regulations have become a barrier for the sale of diesel vehicles, even if some recent models have shown very promising emission abatement rates. In other parts of the world, cost is the main barrier for diesel LDVs, as they are generally more expensive than their gasoline counterparts. This barrier is greater if the cost differential between diesel fuel and gasoline is low. In these cases, the better fuel economy of diesel vehicles does not appear sufficient to many consumers to justify the higher cost of the vehicle itself.

Sales of light-duty diesels are highest in countries where emission regulations are the least strict, where fuel taxes are high and where the price differential between gasoline fuel and diesel fuel is appreciable. Diesel vehicles suffer from a stodgy image in some regions, where there is little awareness of the most recent improvements.

Renewed enthusiasm for diesel vehicles can be expected in the forthcoming decade, especially in the light-truck segment, as awareness spreads of the strong improvements made in diesel vehicles. Their lower fuel consumption and emissions, plus their increased performance, sometimes beyond that of gasoline engines, will very probably increase their market share. Reduced costs for after-treatment technologies will help diesel vehicles maintain a large share of the market in the medium and long term.

Even if light-duty diesel vehicles are cheaper and use less fuel than gasoline hybrids, they will face very strong competition from hybrids in some regions, especially regions with strict emission controls. Nevertheless, diesel engines can benefit from the introduction of mild-hybrid technologies. Government policies will be important to the diffusion of diesel technologies in the next decades.

Light-duty diesel vehicles are likely to maintain a very high market share in coming years, and even increase, if they continue to offer better fuel economy, especially in regions where the fuel tax differential among gasoline and diesel fuels is high and pollutant emission standards are differentiated. Heavy-duty vehicles will continue to be equipped with diesel engines, and hybrid diesel solutions may soon be widely applied in medium-freight trucks and buses.

Two-way Oxidation Catalysts and Particulate Filters for Diesel Engines

Technology Description and Technology Status

An important disadvantage of diesel engines is their high emissions of particulate matter (PM). These emissions consist of droplets of heavy liquid or particles of carbonated material that result from incomplete fuel combustion. PM may also consist of sulphates, whose formation is enhanced by the presence of sulphur in the fuel. Other emissions, including VOCs and CO, are relatively low because of the lean combustion conditions of diesel engines.

A modern exhaust system for diesel engines includes a two-way oxidation catalyst and, in the most recent versions, a particulate filter. The two-way oxidation catalyst is similar to the catalytic converter used in gasoline cars. It converts unburned hydrocarbons and carbon monoxide into CO_2 and water. These converters are not as effective as those used in gasoline-fuelled vehicles. On the other hand, CO and hydrocarbon emissions from compression-ignition engines are inherently low because of the leaner fuel mixture. Oxidation catalysts reduce particulate mass by as much as 50%. The problem of ultra-fine particulates, one of the most dangerous in terms of health effects, remains unresolved at this stage.

A diesel particulate filter may take the form of a ceramic honeycomb monolith. It may also consist of sintered metal, foamed metal structures, fibre mats or other materials. It removes particulate from the diesel exhaust by physical filtration, capturing the particulate matter on its walls.

Barriers to Greater Market Penetration

Two-way catalysts are a fully commercial technology. Particulate filters are beginning to be widely introduced in OECD countries in the wake of stricter PM emission regulations. Most developing countries are also planning to reach similar standards, though with differing time lags.

Increasingly stringent regulations on emissions from diesel engines will require increasing levels of active surface areas on which the exhaust gases can be treated. More precious metals will be needed on the active surface of the two-way converter. The costs of diesel vehicles would increase, but it would not represent a major barrier to their larger market penetration, especially in Europe.

The introduction of improved after-treatment technologies could have a negative effect on fuel efficiency, but this so-called "fuel penalty" will not be a major hurdle in meeting GHG reduction targets.

Technologies for the After-treatment of Nitrogen Oxide Emissions

Technology Description

Another important disadvantage of diesel engines is the large amount of NO_X emissions. These emissions are due to the high temperatures reached in the combustion chamber. The after-treatment of NO_X emissions in diesel engines presents a tough technical challenge, because of the oxygen-rich condition of the exhaust from engines working in lean conditions. The formation of NO_X may be reduced by using cooled intake-air compression (where an inter-cooler and after-cooler lower the temperature of the air-to-fuel mix in the cylinder) and by exhaust-gas recirculation (EGR).

Technology Status

Research in the field of after-treatment systems continues, including efforts to integrate NO_X reduction with particulate filters. This research follows three main patterns: de-NO_X or lean NO_X catalysts, NO_X traps and selective catalytic reduction.

De-NO_X (or lean-NO_X) catalysts use structural properties of the catalytic coating to create a microclimate rich in hydrocarbons (injected directly into the exhaust), where the nitrogen oxides are reduced to nitrogen. They are a cheap solution and show good resistance to sulphur, but they have low efficiencies, especially at low exhaust temperatures.

NO_X traps are less constrained by operational temperatures than are de-NO_X catalysts and they offer higher conversion efficiencies, about 80%. They operate in two phases, adsorbing and chemically storing NO_X under lean conditions, and releasing the trapped NO_X during one- or two-second returns to stoichiometric or rich operation in order to reduce it to nitrogen in a three-way catalyst mounted downstream. This is a promising technology for light-duty vehicles.

Selective catalytic reduction (SCR), originally introduced in stationary power plants and engines, is now used on heavy-duty diesel engines in areas where NO_X regulations are strict. It maybe extended to light-duty vehicles. SCR systems work by chemically reducing nitrogen oxides (NO and NO_2) to nitrogen through the addition of a reductant (hydrocarbons or ammonia) in the exhaust gas stream. Ammonia SCR systems impose no fuel-economy penalties, but their use may still cause some concern because they entail the release of unreacted ammonia.

Integrated systems, combining a particulate filter and a NO_X reducer, are a promising approach. Some of these systems are already in commercial use. Several different architectures are feasible. SCR systems can be installed after a two-way catalyst and a particulate filter. Low-pressure exhaust gas can be recirculated after the particulate filter with advanced turbocharging, or a platinum catalyst can be coated on the walls of the tiny tubes in a ceramic filter. The diesel particulate–NO_X reduction (DPNR) system developed by Toyota is the first commercial application of a NO_X absorber on a diesel vehicle.

Many of the emissions control technologies discussed here can also be successfully retrofitted. Retrofitting can be an effective and affordable technique on heavy-duty applications such as urban buses. This is the case for PM filters and for selective catalytic reduction systems.

Barriers to Greater Market Penetration

Policies to limit NO_X emissions are increasingly under consideration in the United States, Europe and Japan. Most developing countries are likely to follow the OECD in progressively introducing stricter standards. In this regulatory framework, the use of particulate filters and improved after-treatment technologies for NO_X on diesel vehicles is destined to increase. Both technologies will benefit from the wider use of low-sulphur fuels.

Other Alternative-fuelled Vehicles

Electric Vehicles

Technology Description

An electric vehicle is powered by an electric motor rather than a combustion engine. An array of rechargeable batteries delivers power to a controller, which then directs power to the electric motor. Electric vehicles do not produce any tailpipe emissions, but they may be responsible for some emissions on a well-to-wheel basis, depending on the technology used for power generation. Electric vehicles equipped with regenerative braking can recuperate part of the energy delivered to the vehicle by the drive-train and transform it into electrical energy to recharge the battery.

Technology Status

There are electric vehicles on the market, but they are not widely sold. The weak link in electric car technology is the battery. Current lead-acid batteries are cheap and reliable, but they are also heavy and bulky. Other solutions include nickel-metal-hydride (NiMH) and lithium-ion batteries. NiMH batteries can double a vehicle's driving range and have a much longer lifespan than lead-acid batteries, but they are still too expensive and are very slow to charge. Lithium-ion batteries also offer longer driving ranges and a longer lifespan, as well as quick recharge and high energy and power densities. A detailed description of these batteries and their costs is presented in Box 5.6.

Box 5.6 ▶ Batteries

In the 1990s, there was a lot of interest in electric vehicles with batteries that could be charged from the grid. These vehicles were not commercially successful, because they did not have sufficient driving range and because the weight of the batteries was prohibitive. In theory, the efficiency of such vehicles could be higher than the efficiency of hydrogen vehicles, but the lack of a suitable way to store electricity remains a key obstacle in terms of driving range and storage cost.

Interest in electric vehicles has increased since the emergence of hybrid vehicles, where the batteries are charged using the on-board ICE. Plug-in hybrids are also new concept where batteries can be loaded with electricity either from the grid or through on-board electricity generation using combustion engines or fuel cells.

The battery that is used in the majority of existing electric cars is a lead-acid battery. It is heavy but cheap, at about USD 50/kWh of storage capacity. More advanced nickel-metal hydride (NiMH) and lithium-ion batteries are much lighter, but considerably more expensive. Lithium-ion batteries have about half the weight and volume of NiMH batteries for the same power output and energy storage capacity. The cost of NiMH batteries has risen due to rising nickel prices, but production cost of lithium-ion batteries have come down substantially, to USD 500 to 600/kWh. Further cost reductions could make them attractive for vehicle-drive systems (they are now used mainly in portable appliances).

Lithium-ion batteries hold the promise of further cost reductions. They are being proposed on some vehicle models, but their potential has yet to be fully proven. Currently, repeated deep-cycling could affect their life span and the recharging of these batteries might result in accidental explosions. Even if these problems are solved, there is little prospect of reducing costs below USD 160/kWh, but recent research on lithium-ion batteries that use different materials may offer additional cost reductions.

Barriers to Greater Market Penetration

Cost is a major concern, as is the restricted driving range of electric cars built to date. The current generation of electric vehicles is appropriate only for urban use.

There is increasing research and development being done on batteries and interest in the development of ultracapacitors is growing. In countries like France, where most electricity is derived from nuclear fission, electric vehicles have a large potential.

Consistent financial incentives to help in the purchase of electric cars combined with support for recharging stations would clearly help to spread their use, as would the creation of a network of charging stations.

Improved battery technology would also help increase the use of electric vehicles. One interesting approach is battery switching at recharging stations. This solution treats the battery as a sort of energy tank that can be recharged at appropriate stations and then replaced in the vehicle. Empty batteries would be exchanged against full batteries in a matter of seconds, much as horses were changed at post-houses in days of yore. For the moment, the battery-exchange concept is limited by high battery costs, as well as by the limited battery lifespan and their heavy weight.

It is likely that NiMH and lithium-ion battery packs will become competitive with lead-acid batteries over the next several years and this could boost sales of electric vehicles, but only for urban driving.

Hybrid Vehicles

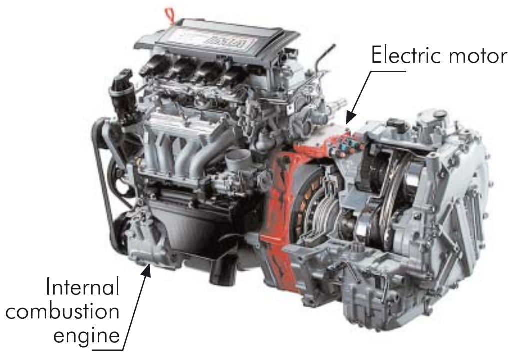
Technology Description

The term hybrid refers to any vehicle that can use different energy sources in combination. In current parlance, it usually refers to hybrid-electric vehicles. Hybrid-electric vehicles are powered by a drive-train that combines a conventional internal combustion engine (powered by gasoline, diesel or an alternative fuel) and an electric motor. Hybrid-electric vehicles can be built in several possible engine architectures with different sizes for the combustion engine and electrical motor. Each presents different trade-offs in terms of cost, efficiency and performance.

Hybrid-electric drive-trains can be differentiated according to how they deliver energy to the transmission. In *series* hybrids, an electric motor drives the wheels and derives its energy from a battery or an engine, generally an internal-combustion engine, used as a power generator. The power generator supplies the average power required to operate the vehicle and the accessories, while a battery stores the excess energy and provides it when needed. This type of engine architecture is close to the one used for electric vehicles. The advantage of series hybrids over full electric vehicles lies in the fact that they are charge-sustaining and can be driven for much longer distances. They do not require charging from the grid but only refuelling. Like electric vehicles, series hybrids may use regenerative braking to recharge the battery. A further efficiency gain is achieved by the fact that the engine is largely uncoupled from the load due to road conditions and can be kept working at a certain range of operating points, where its efficiency is high. This type of engine use offers advantages for the after-treatment of the exhaust gases. Series hybrids are best suited for vehicles whose driving cycle does not vary much, such as urban buses. Buses may also benefit from other characteristics of series hybrids, for example, the floor area may be increased with the use of in-wheel electric engines and an internal combustion engine mounted on the roof. A bus system using this technology was introduced in the Netherlands in 2004.

In *parallel* hybrids, motion is delivered to the wheels by both an ICE and an electric motor. The ICE is no longer used exclusively as a power plant, but works jointly with the electric motor to deliver movement to the vehicle. "Mild" parallel hybrids (Figure 5.10) have an electric motor that acts as a starter and can serve as an alternator

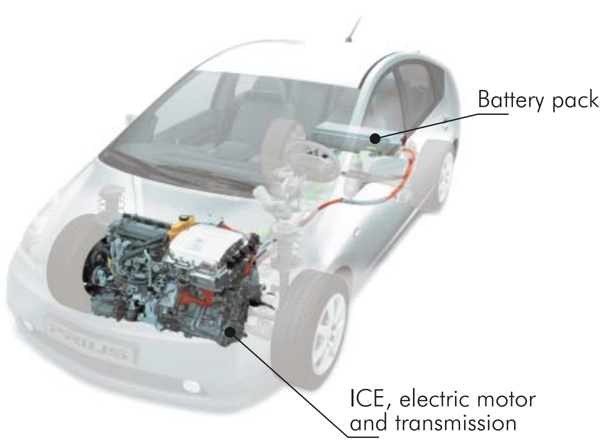
Figure 5.10 ▶ Mild hybrid engine



Source: INRETS, 2005.

during braking (regenerative braking), while an ICE powers the drive-train. In mild hybrid configurations the electric motor may also provide extra torque and additional power when needed. The electric motor used in mild hybrids is generally located between the engine and the transmission or, in "light" designs, in the same position as a standard alternator. Starter-alternator configurations include a regenerative braking function. In urban driving cycles, regenerative brakes can improve fuel economy by up to 10%. There are cars on the market that incorporate the starter-alternator technology, even though they are not advertised as hybrids. One example is the Citroen C3 Stop and Start. Assist hybrids may improve fuel economy by nearly 20%, and even more in urban driving, but they require extensive changes in the design of the drive-train and these changes lead to higher costs. In such arrangements, the electric motor cannot operate independently of the gas engine.

Figure 5.11 ▶ Full hybrid vehicle configuration



Source: INRETS, 2005.

Full hybrids (Figure 5.11) can operate in internal-combustion mode, in hybrid mode or even in all-electric mode, which is mainly used for cold starts and for urban driving with ranges below 50 km. The electric energy is stocked in large batteries during the periods of ICE driving and regenerative braking. In some cases, electricity is stored by charging the battery from the grid (plug-in hybrids). In rural and highway driving, the ICE can work at near-optimal efficiency and the electric motor is used much less than in urban driving. Still, the use of electric motors allows reduction in the size of the ICE and thus the fuel consumption. The combination of the ICE with the electric motor allows the vehicle to turn in "peak" performances, although only for limited periods of time. Hybrid driving is also very sensitive to the operator’s driving style. Fuel economy is reduced by sharp braking and strong acceleration. Smoothly-driven full hybrids can reduce fuel use by 30 to 40% in an urban setting (Badin F., 2005).

Hybrid vehicles will benefit from all the efficiency improvements already mentioned for gasoline and diesel vehicles. Hybrid solutions are not particularly suitable for heavy-duty trucks and intercity buses, because the driving cycle of those vehicles is characterised by long driving periods at steady speeds. Hybrid drive-trains are a promising technology not only for light-duty vehicles, but also for heavy-and medium-duty vehicles that operate locally and for urban buses.

Different degrees of hybridisation have different requirements for electrical power. The current voltage level for light-duty vehicle power-nets is 14 V, but a switch to a 42-volt system is likely to occur soon, with dual-voltage (14/42 V) to be used during the transition period. The 42-volt system will improve the efficiency of regenerative brakes. It could also be extremely useful in mild hybrid configurations, even if some problems still need to be resolved related to more demanding charge/discharge cycles and ultracapacitors for the fast storage of energy during regenerative braking.

Full hybrids currently use 300-volt electrical motors. Although this is the most fuel-efficient parallel configuration, it requires relatively large and heavy batteries, which increase the cost of the vehicles. Mild systems use less powerful electric motors and they will generally benefit from the introduction of a 42-volt system.

Technology Status

ICE hybrids will never be zero-emission vehicles, but their potential for reducing CO_2 emissions per kilometre driven is substantial, especially if electric motors are coupled with ever-smaller clean-gasoline or diesel-powered ICEs.[23] On the other hand, the increased weight of hybrids due to the use of more complex drive-trains and large batteries will have a negative effect on fuel economy, even though that effect will be largely offset by other benefits. Reducing the cost, weight and size of batteries is the greatest technology challenge facing hybrid development. Currently, the batteries which are used in the full hybrid cars are sold for about USD 2 500 and have storage capacity of 1.5 kWh (giving a 20 km driving range). The battery of the Toyota Prius (one of the world's first commercially mass-produced and marketed hybrid cars) is designed to last for the life of the vehicle. New-generation batteries

23. In mild configurations, the ICE plays a bigger role than in full hybrids because the electrical motor provides less power in assist hybrids or is used only for start-and-stop purposes.

are 15% smaller, 25% lighter, have 35% more specific power than in the Prius and cost about 36% less. Continuous evolution is expected in all areas of hybrid components, including electric-motor controllers, batteries and engine-tuning.

Diesel hybrids achieve smaller reductions in fuel consumption than do hybrids that incorporate gasoline engines, but full diesel hybrids may, nevertheless, be the most efficient vehicles in the long run. Future technological advances may well allow full hybrids to exceed the fuel economy of stand-alone internal combustion engines by a greater margin than they do today. Meanwhile, milder hybrid versions do help limit costs and offer very significant reductions in fuel consumption. Many diesel-fuelled LDVs can be expected to be equipped with auxiliary electric motors within the next few years.

Diesel hybrid engines will be best suited to urban buses and medium freight trucks, even though further improvements in battery technology are needed for this type of application. Besides the Phileas bus system in the Netherlands, numerous other demonstration projects are operating in the United States, Europe and Latin America. Hybrid buses are being used in the New York City transit system as well as in the EU-sponsored Sagittaire project and in demonstrations in Mexico, Brazil and Chile. In 2002, hybrid buses scored only 30% below conventional diesel buses for in-service reliability.

Box 5.7 ▶ Plug-in hybrids

Plug-in hybrids are a new concept that combines the advantages of hybrid vehicles and the opportunities offered from the large battery stacks that equip hybrid and electrical vehicles. In plug-in hybrids, batteries can be loaded with electricity either from the grid or through on-board electricity generation using combustion engines or fuel cells. The share of fuel and electricity use will depend on the driving range required and on the battery's storage capacity. As most drivers use their cars mainly for short distances, the share of kilometres driven on electricity could be very high.

Their main advantages would be increased flexibility and long driving ranges, but their cost would be higher. With production volumes of 100 000 cars per year, the cost of a plug-in hybrid electrical vehicle with a battery range of 35 km would be USD 4 000 to 6 100 higher than the cost of a conventional gasoline vehicle. If the battery range were increased to 100 km, then the incremental cost would be USD 7 400 to10 300. In this configuration, the cost of the battery is USD 5 800 (costs are similar for both NiMH and lithium-ion batteries).

Cost reductions to USD 160/kWh would put the minimum cost of a battery with a 100 km range at USD 3 750, which is substantial. On the other hand, the cost of a refuelling infrastructure would be limited, the transition issues would be less daunting than for hydrogen and opportunities for producing carbon-free electricity are improving. In view of all these factors, plug-in hybrids clearly deserve further consideration (Plotkin, 2006).

Barriers to Greater Market Penetration

The main barrier to greater market penetration of hybrid vehicles is their cost, which is still higher than that of competing vehicles, notably diesel. In their most advanced configurations, diesel vehicles offer fuel economies not very far behind those hybrids.

Table 5.6 ▶ *Gasoline hybrids, status and prospects*

	2003-2015	2015-2030	2030-2050
Technology stage	Wide introduction of starter-alternator systems, mild hybrid engines on some modes, full hybrids mainly on large LDVs.	Higher penetration of mild hybrids, even on small vehicles, wide diffusion of full hybrids on large LDVs. Large hybrid shares for minibuses and medium-freight trucks. ICE improved in light hybrids, slightly less for mild and full hybrids.	A large share of ICE vehicles sold on the market equipped with hybrid systems. ICE improved in light hybrids, slightly less for mild and full hybrids.
Full hybrids, mid-size gasoline LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	18.3 - 20.2	17.7 - 19.6	17.3 - 19.1
Fuel economy (litres of gasoline equivalent/100 km)	4.1 - 7.4	3.9 - 7	3.7 - 6.6
CO_2 emissions, tailpipe (g/km)	99 - 178	94 - 169	89 - 160
CO_2 emissions, well to wheel (g/km)	115 - 206	109 - 195	103 - 184
Mild hybrids, mid-size gasoline LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	17 - 18.8	16.8 - 18.6	16.6 - 18.3
Fuel economy (litres of gasoline equivalent/100 km)	4.5 - 8	4.1 - 7.4	3.9 - 7
CO_2 emissions, tailpipe (g/km)	108 - 194	99 - 178	94 - 168
CO_2 emissions, well to wheel (g/km)	125 - 224	115 - 205	108 - 194
Light hybrids, gasoline LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	16.1 - 17.8	16.2 - 17.9	16.2 - 17.9
Fuel economy (litres of gasoline equivalent/100 km)	4.9 - 8.8	4.6 - 8.3	4.3 - 7.7
CO_2 emissions, tailpipe (g/km)	119 - 214	111 - 199	103 - 185
CO_2 emissions, well to wheel (g/km)	138 - 247	128 - 230	119 - 214

See note in Table 5.2.

Table 5.7 ▶ ***Diesel hybrids, status and prospects***

	2003-2015	2015-2030	2030-2050
Technology stage	Introduction of starter-alternator systems, hybrid motorisations on large LDVs, initial diffusion of hybrids in buses, minibuses freight trucks.	Penetration of mild hybrids on small vehicles, wider diffusion of full hybrids on large vehicles. Larger shares of hybrid buses, minibuses freight trucks. ICE improved as for diesel engines in light hybrids, slightly less for mild and full hybrids.	Further cost reductions leading to large shares of new vehicles equipped with hybrid systems. ICE improved as for diesel engines in light hybrids, slightly less for mild and full hybrids.
Full hybrids, diesel LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	19.1 - 21.1	18.4 - 20.4	17.9 - 19.7
Fuel economy (litres of gasoline equivalent/100 km)	3.2 - 5.7	3.1 - 5.5	3 - 5.4
CO_2 emissions, tailpipe (g/km)	83 - 148	80 - 143	77 - 138
CO_2 emissions, well to wheel (g/km)	95 - 171	90 - 165	89 - 159
Mild hybrids, diesel LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	16.8 - 18.6	16.7 - 18.4	16.5 - 18.2
Fuel economy (litres of gasoline equivalent/100 km)	3.4 - 6	3.2 - 5.8	3.1 - 5.5
CO_2 emissions, tailpipe (g/km)	87 - 155	83 - 149	80 - 143
CO_2 emissions, well to wheel (g/km)	100 - 179	96 - 172	92 - 165
Light hybrids, diesel LDV	**2003-2015**	**2015-2030**	**2030-2050**
Cost (USD 000s)	17.6 - 19.5	17.4 - 19.2	17.1 - 18.9
Fuel economy (litres of gasoline equivalent/100 km)	3.7 - 6.7	3.6 - 6.5	3.5 - 6.3
CO_2 emissions, tailpipe (g/km)	96 - 173	94 - 168	91 - 163
CO_2 emissions, well to wheel (g/km)	111 - 199	108 - 193	105 - 188

See note in Table 5.2.

The cost of the battery is the most relevant component of higher costs. Other issues are also associated with the battery's weight and size. Although weight and size do not impact driving range in hybrid vehicles, the weight of lead-acid batteries limits fuel-economy benefits. Lithium-ion batteries, which are lighter and offer better performances than lead-acid and nickel metal hydride batteries, hold the promise of further cost reductions.

The switch to higher voltage systems could also present additional costs. It would require the development of new support infrastructure, including tools, service parts and after-sale services.

Prospects for Overcoming Barriers

The electrical power required for future vehicles is likely to be greater than in the past. Many features designed to provide better fuel economy, improve safety and increase comfort will entail the electrical or electronic control of components that have in the past been hydraulically or pneumatically controlled. The switch to a 42-volt system responds to the increased demand for power electronics, and this switch may contribute substantially to the faster introduction of hybrid configurations. Public procurement of hybrid vehicles could substantially contribute to an accelerated introduction of hybrid technologies.

In the short term, higher-voltage power nets and mild hybrids can substantially improve fuel economy (due to regenerative braking and to the elimination of fuel consumption when vehicles are idle). Mild hybrid configurations are cheaper than full hybrids, and they may sell well in regions like OECD Europe, where full gasoline hybrids face strong competition from diesel. In other regions, such as North America, hybrid systems are increasingly being offered on light trucks and luxury vehicles. More recently, the hybrid systems have begun to be offered on mid-price personal cars like the Toyota Camry.

Large rebound effects are possible, depending on how hybrid vehicles are put onto the market. Some vehicle manufacturers are already offering hybrid vehicles with performances superior to those of their non-hybrid products. Hybrids are being advertised with "no compromise" or "guilt free" slogans. This strategy will certainly help to move hybrids into mainstream markets, but keeping the promises implied by the slogans could limit their benefits in terms of overall energy consumption.

Timeline for Greater Contribution

A rapid increase in the diffusion of 42-volt and starter-alternator systems can be expected very soon. Mild hybrid engines are also expected to be seen soon, mainly with gasoline engines. Full hybrids are expected on large LDVs, especially in North America. In the medium term, lower costs and higher customer acceptance could lead to a higher penetration of stronger hybrids, even on small vehicles. Full gasoline hybrids and mild diesel hybrids could become common. Full hybrids could gain market share on smaller vehicles by 2030, by which time costs will be substantially reduced and improved batteries are likely to be available.

Plug-in hybrids have the potential to reduce the fossil fuel consumption of road vehicles by 75%. If the electricity they use is produced in without CO_2 emissions, they would significantly reduce GHG emissions. Plug-ins would be fully hybridised, and they would refuel their batteries from the grid for all short-distance trips. Plug-in hybrids are probably the key to further electrification of transport systems.

Hybrid vehicles would constitute an excellent niche market for photovoltaic components to be installed on vehicle roofs. They would provide further emission reductions and fossil energy savings.

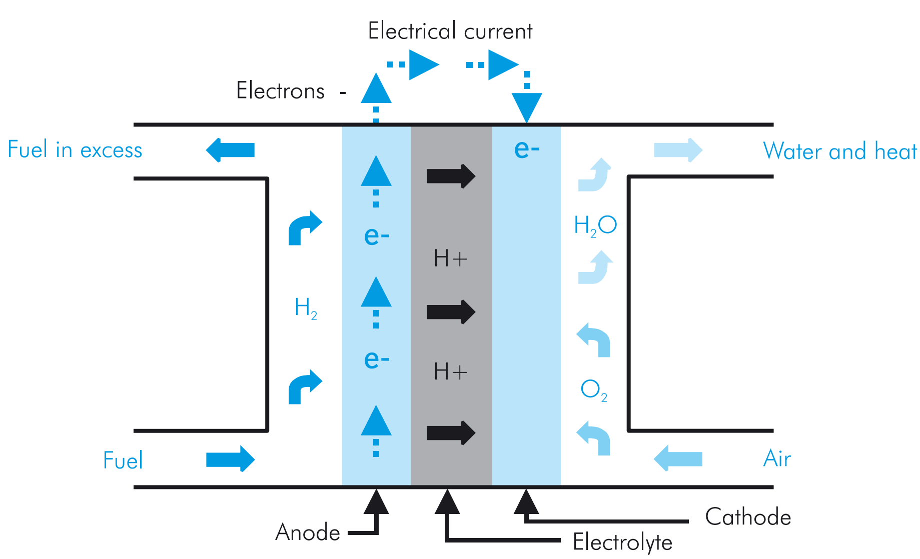
Fuel Cell Vehicles

Technology Description and Technology Status

A fuel cell is an electrochemical device that converts hydrogen and oxygen into water and produces electricity in the process. Fuel cell vehicles (FCVs) are propelled by electric motors with electricity produced within the vehicle.

Proton-exchange-membrane (PEM) fuel cells are particularly suited to powering passenger cars and buses, based on their fast start-up time, favourable power density and large power-to-weight ratio. Fuelled with pure hydrogen from storage tanks or on-board reformers, PEM fuel cells use a solid polymer as an electrolyte and porous carbon electrodes with a platinum catalyst (Figure 5.12). They operate at relatively low temperatures of around 80°C. This has the advantage of allowing s to start quickly, but it requires cooling of the cell in order to prevent overheating. The platinum catalyst is costly and extremely sensitive to carbon-monoxide poisoning. New platinum/ruthenium catalysts seem to be more resistant to CO. Research efforts are focusing on high-temperature membranes that allow the use of lower cost and more robust catalyst systems.

Figure 5.12 ▶ Proton exchange membrane fuel cell concept



The current cost of PEM fuel cells exceeds USD 2 000/kW, but costs could be cut to USD 100/kW through mass-production and technology learning, but it might not be enough. The cost of fuel cell vehicles must fall to below USD 50/kW to make them competitive. This would require fundamental advances in materials technology and the attainment of higher power densities for fuel cells. Developments in PEM fuel cell technology are ongoing, and it would probably be premature to make any prediction about hydrogen infrastructures at this stage, as hydrogen purity requirements and storage systems are not yet clear.

The lifetime of a fuel cell is critical to its overall operating cost. The life span of PEM fuel cells depends crucially on the operating conditions, such as the frequency of low-temperature start-up, excessive or insufficient humidity and fuel purity. The average life span of PEM fuel cells is presently about 2 200 hours (equivalent to a range of 100 000 km), but cell-life varies from 1 000 hours to more than 10 000 hours.

Barriers to Greater Market Penetration

The major car producers currently build and test some 200 fuel cell vehicles each year for demonstration projects, but significant technology and economic hurdles will need to be overcome before fuel cell vehicles are a viable proposition for mass-production. Current fuel cell vehicles are already competitive in terms of efficiency, emissions, silent driving and acceleration. But further R&D is needed to reduce their cost and improve their durability.

A major barrier for fuel cell vehicle deployment is the need to develop a costly production, distribution and refuelling infrastructure for hydrogen. This is a classic "chicken-egg" dilemma: an expensive hydrogen supply system will not be established without sufficient demand, while the demand for fuel cell vehicles is unlikely to grow without low-cost hydrogen production and an extensive refuelling network. Some car manufacturers have tried to get fuel cell cars on the road without the need for elaborate hydrogen infrastructure, by reforming hydrogen on-board from hydrocarbons. So far, however, the on-board production of hydrogen has proven to be very difficult. The current focus is on vehicles that can store hydrogen on-board.

Existing on-board storage options do not yet meet the technical and economic requirements to make them competitive. Gaseous storage at 350-700 bar and liquid storage at –253°C are commercially available, but they are very costly. In the absence of further breakthroughs, gaseous storage at 700 bar seems, at present, to be the technology of choice for passenger cars, but the cost of the tank is between USD 600 to 800/kg of H_2, and 5 kg of storage capacity is needed. Moreover, significant electrical energy is required for compression and liquefaction. Solid storage offers potentially decisive advantages, but it is still under development with a number of materials being investigated. The promising storage characteristics of carbon nano-structures have not yet been confirmed by recent studies (IEA, 2005a).

International quality and safety standards must be established for hydrogen and for on-board storage technologies before full-scale development of the hydrogen infrastructure begins. The on-board storage system that is chosen will have a particular impact on the choice of the hydrogen infrastructure. The identification of a suitable and cost-effective storage technology is, therefore, an urgent issue.

Prospects for Overcoming Barriers

While drive systems for fuel cell passenger cars could be competitive at costs between USD 50 and USD 100/kW, fuel cell engines can be competitive with ICEs in the bus market at USD 200/kW and in the delivery van market at USD 135/kW. Buses may be the most promising market. Although current production volumes are very low (10 buses a year), market developments could increase production volumes and help drive down the costs of fuel cell technology. If such cost reductions did occur, PEM fuel cells could be more widely used in passenger cars as well.

Timeline for Greater Contribution

The efficiency of hydrogen fuel cell vehicles is at least twice that of standard internal-combustion engine cars, but fuel cell cars are not yet ready for commercialisation. They need cost reductions and improvements in their durability and reliability. In addition to the cost of the fuel cell stack, the final price of a fuel cell vehicle depends on the cost of other components such as the electric engine and the hydrogen storage system. All these items need to be less expensive.

Depending on the pace of technology development, the stack cost of a PEM fuel cell could decline to between USD 35/kW and USD 70/kW by 2030. If that were so, the cost of a fuel cell vehicle would exceed that of a conventional ICE vehicle by USD 2 200 to 7 600. On that assumption, the added investment of replacing 30% of the worldwide vehicle fleet with fuel cell vehicles by 2050 (some 700 million fuel cell cars) would range from USD 1 trillion to 2.3 trillion.

Non-engine Technologies

Reducing Vehicle Weight

Technology Description

The lighter a vehicle, the less fuel it consumes. Vehicle mass may be reduced either by decreasing the size of the vehicle or changing the materials it is made of. Lightweighting initiates a benign cycle. Lighter cars can be propelled by lighter engines. A light power-train, in turn, requires less structural support and allows further reductions in the volume of the vehicle frame, suspension and brakes.

Lightweighting technologies are already widely applied in current vehicle manufacturing, and they are definitely cost-effective. When the fuel savings from downsizing are taken into account, the increased costs of vehicle production are lower than the fuel and CO_2 savings they generate.

Steel is currently the main automotive material. Over the past decade, steel made up an average of 55% of the weight of a fully fuelled car without cargo or passengers. Most of the remaining weight is accounted for by iron (10%), aluminium (6 to 10%) and plastics. Design research needs to focus on the materials that account for most of a car's weight: steel, iron and aluminium.

Technology Status

High-strength steel may replace milder grades of steel and iron used in all parts of the vehicle. High-strength steel can be used in the frame, the side impact beams and some engine components (valves, valve springs, camshafts, crankshafts and connecting rods). It may also be used in the wheels, where it faces strong competition from aluminium. Steel-based lightweighting is already being used in some existing vehicles. One example is the Mercedes A-Class, whose body structure includes 67% high-strength steel.

The use of aluminium in automotive applications is expected to increase. So far, aluminium has been used mainly in components obtained from casting processes, such as wheels, certain elements of the suspension, the transmission housing and engine parts (pistons, cylinder heads, manifolds, heat exchanger and, in some cases, the entire engine block). Other wrought forms of aluminium (extrusions and stampings) account for less than 25% of the total aluminium used in vehicles in the United States (Hadley, Das and Miller, 2000). Aluminium extrusions are used as bumper beams or frame components and are better suited for low production volumes than stamping. Although they carry lower capital costs, they generally require longer process times for the additional manufacturing steps (bending or hydroforming).

Stamping may be used for closures or as frame components, but they carry high capital costs. Aluminium closures cost more than steel closures because they require tooling. The unibody design that is currently used for most vehicles makes extensive use of stamping, but it is not very suitable for aluminium-intensive vehicles. The space-frame design is potentially more aluminium-friendly. Space-frame bodies make extensive use of castings and extrusions and less of stamping. The use of space-frame designs could help decrease costs. Recent developments in space-frame joining technologies suggest that the technology could deliver significant cost reduction when it matures. The second-generation Audi A2, which has a space-frame design, is cheaper to assemble than the mainly-steel Volkswagen Lupo at all except very small production volumes.

Recycling can help make aluminium more competitive for automotive use. However, the changing types of aluminium alloys used in different vehicle components may reduce the potential for recycling. It is important to point out that cast aluminium is less sensitive to impurities.

Other solutions, such as the use of composite materials, are extremely interesting. Composite materials could produce impressive improvements in fuel economy, due to the fact that the weight-to-resistance ratio of composite metals is much lower than that of other metals. However, customer resistance could be relevant because damages to composite materials are hard to repair.

Barriers to Greater Market Penetration

Cost and the eventual need for large investments to modify the vehicle production process are the main barriers to the use of lightweight materials. High-strength steel can cost as much as 50% more than traditional steels, but a lower amount of material is needed to achieve the same performance. Replacing steel with aluminium also means higher costs. Other barriers to the use of aluminium derive from the high energy intensity of its production.

Net energy savings and GHG reduction take into account the energy consumed in producing the materials. The analysis is complicated. The production of primary aluminium requires a large amount of electricity. Using primary aluminium alone to reduce the weight of cars would cancel out the potential energy savings. When recycled aluminium is used, only a fraction of the energy needed for primary aluminium is required and GHG emissions are reduced over the whole life cycle.

Lighter materials such as aluminium and magnesium cost more than conventional mild steel, but their larger introduction may lead to improved manufacturing processes, thereby reducing the manufacturing cost. Lightweighting technologies are being progressively introduced and will continue to be part of on-going developments. Few manufacturers are likely to switch to composites in the short or medium term.

Tyres

Technology Description

Rolling resistance is the energy dissipated by a tyre per unit of distance covered. The energy dissipated by the wheels when a vehicle is moving is provided by the power-train unit. Rolling resistance, thus, affects the vehicle's fuel consumption. Overall, the amount of energy needed depends on the speed and acceleration at each moment of the driving cycle, as well as on the vehicle mass and its aerodynamic design.

Manufacturers have already achieved significant reductions in rolling resistance. Tyres with low rolling resistance may cost more to produce, but the consumer quickly recovers the price differential through reduced fuel costs. Moreover, recent studies indicate that fuel efficient tyres do not necessarily sacrifice safety or other performance characteristics (such as durability, wet-grip and noise), but further research is needed in this field.

Technology Status

The energy requirements of the power-train can be reduced through the use of energy efficient tyres. For a light-duty vehicle, fuel consumption can be reduced by between 3% and 4% through the use of currently available low-rolling-resistance tyres. An additional reduction of 1% to 2% in fuel consumption could be achieved by accurately monitoring the tyre pressure, which vehicle owners often keep lower than the value recommended by manufacturers (Penant, 2005; Stock, 2005). Currently available cost effective technologies can automatically sense low pressure and inform the driver. This issue can be addressed with consumer programmes.

Barriers to Greater Market Penetration

Tyres with low rolling resistance are an established technology and are already commercial. Any extra cost is usually justified by the fuel savings they deliver. There is, however, a general lack of awareness of the benefit that better and correctly inflated tyres bring.

Several methods are used for measuring rolling resistance. Some measurements are used for predicting actual on-road performance and others serve as inputs to complex simulations. An internationally harmonised test method suitable for compliance purposes does not yet exist, but is within reach. Fuel economy testing procedures do not always require manufacturers to equip the vehicles they sell with the tyres used in the tests. This can result in a discrepancy of up to 5% between reported and actual fuel economy.[24]

Prospects for Overcoming Barriers

Because of the relatively low potential for power-train improvement in long-haul vehicles, energy-efficient tyres and pressure-monitoring systems are a major option for intercity buses and heavy-duty trucks. Improved awareness and information campaigns are important. Several labelling schemes can be applied to tyres, as well as mandatory standards. Individual efforts by manufacturers to label rolling resistance have been ineffective, as consumers may prefer a third-party labelling system or perhaps they consider fuel efficiency a low priority.

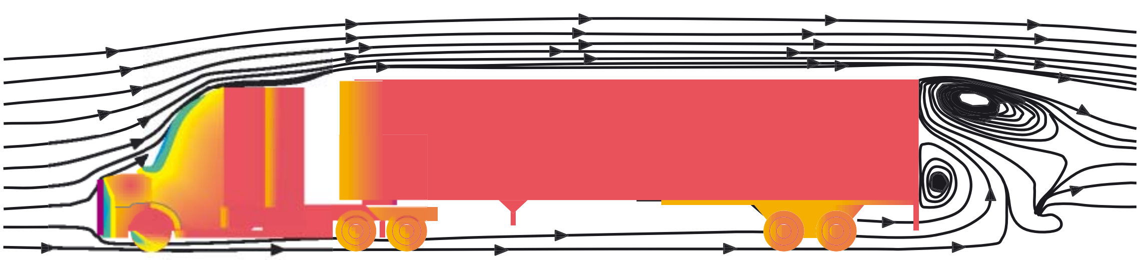
Savings from tyres with low rolling resistance may justify government agencies specifying such tyres on the vehicles they procure.

Vehicle Aerodynamics

Technology Description

Aerodynamic drag, which is proportional to the square of a vehicle's speed, is the main factor determining a vehicle's need for power at high speeds. Aerodynamic issues most acutely affect long-haulage heavy-duty trucks and intercity buses (Figure 5.13), and significant improvements are possible for such vehicles. Air resistance depends on the size of a vehicle and on the aerodynamic-drag coefficient, which is affected by the inclination of the windscreen, the parts protruding from the vehicle and aerodynamic losses resulting from the vehicle's internal airflows.

Figure 5.13 ▶ Vehicle aerodynamics



Key point

Long-haul heavy-duty trucks and intercity buses are particularly affected by aerodynamics.

24. European regulations require only that tyres used in CO_2 emission tests should be one of the types specified by the auto manufacturer as original equipment.

Differences in air pressure between a vehicle’s top and bottom can result in “lift”, which increases the vehicle drag. Such differences can interact with the turbulence of the wake, worsening the drag effect and increasing the vehicle’s instability. One measure that is being widely introduced is a sharpening of the angles of the vehicle's body at the rear. This measure reduces the instability of the wake and its turbulence and so also reduces the drag. Other solutions, such as smoothing the under-body and streamlining the mirrors can improve the vehicle's aerodynamics.

Technology Status

Numerous possibilities for reducing aerodynamic drag exist and are already used in many vehicles. They are particularly beneficial for long-haul trucks (especially when they run without cargo), for intercity buses and for highway traffic. Reducing the vehicle’s frontal area can be achieved by reducing the overall vehicle size, a solution that may conflict with the customers' requirements. Lowering the engine hood to achieve a better drag coefficient may be inconsistent with the size requirements of the engine compartment. This approach may also conflict with the need to provide sufficient airflow into the engine area and around the exhaust system for removal of waste heat. It may also conflict with other requirements such as the need for the driver to easily see the front end of the vehicle.

Barriers to Greater Market Penetration

Passenger and cargo space are important vehicle characteristics. These and the need for comfort may limit aerodynamic improvements because they influence the frontal and lateral size of the vehicle. For most LDV owners, the vehicle’s utilitarian and functional aspects are more important than achieving additional reductions in aerodynamic drag.

Prospects for Overcoming Barriers and Timeline for Greater Contribution

Only minor improvements can be expected in this field for light-duty vehicles because the aerodynamic drag factor is already much lower than in the past. Only new engine designs, such as those that could characterise fuel cell vehicles, may allow radically different solutions that could reduce the aerodynamic drag significantly.

Technologies to Reduce the Energy Requirements of On-board Equipment

Technology Description

The energy consumption of air conditioners and other on-board appliances is not negligible in light-duty vehicles. It can account for half of a vehicle’s fuel consumption. Fewer than 15% of light-duty vehicles sold in France in 1995 were equipped with air conditioning. By 2000, the rate had risen to 60%, and it is expected to reach 100% by 2010, as is already the case in the United States and in Japan. Much the same pattern is discernable in other European countries, especially those surrounding the Mediterranean. The effect on the overall vehicle stock will be gradual because vehicles are only replaced progressively, but the trend is undoubtedly growing. The energy performance of air conditioning systems depends critically on the type of compressor used in the cooling system. Test results indicate that the most inefficient system can consume twice as much power as the most efficient.

Technology Status

Air conditioning systems using supercritical CO_2 are, in effect, reversible heat pumps. They can provide interior heat in winter as well as cooling in summer. They offer advantages for engines that give off little or no surplus heat for heating the passenger compartment.

Buses consume very large amounts of fuel to run their air-conditioning systems. Fuel can also be economised by reducing truck idling through the use of auxiliary power units that would contribute to reduced engine loads.

Barriers to Greater Market Penetration

The main barrier to greater market penetration of efficient on-board components is the fact that the energy consumption of these appliances is not always captured in current vehicle tests. As a result, manufacturers have little incentive to use them. The public is largely unaware of the fuel use of on-board appliances and the costs it entails. One kWh of electricity generated on-board costs just slightly less than the price of 1 litre of gasoline. It exceeds by far the cost of electricity generated in centralised power plants. Improved information is needed urgently.

Prospects for Overcoming Barriers

Even though components such as air conditioning have become lighter and their energy use has been reduced over the past decade, there remains a large potential for efficiency improvements. That potential can be achieved at negative costs, if the associated fuel savings are taken into account. Public awareness can be increased through labelling schemes, but the most substantial incentive for the use of efficient systems would be the inclusion of their consumption in fuel consumption tests.

Other solutions, such as the installation of solar panels on vehicles, could meet some of the vehicle's electricity demand but would also entail new energy-using features. In view of the high cost of generating electricity in mobile vehicles, a solution based on solar panels could be cost competitive.

Chapter 6 BUILDINGS AND APPLIANCES

Key Findings

- *Improvements in existing technologies can make buildings much more energy efficient and give them a much smaller carbon footprint. Although some exciting new developments are not yet at the commercial stage, most of the key technologies are already available and are economically attractive on a life-cycle cost basis. The fact that consumers often do not make purchase decisions on the basis of minimising energy costs is a major barrier that slows uptake of many of these technologies. Better integration of the full range of technologies used in buildings to optimise their effectiveness is key to significant overall improvements.*

- *The availability of more efficient technologies for the building envelope can enhance the energy performance compared with previous generations of buildings. For example, the best windows on the market insulate three times as well as their double-glazed predecessors. Building insulation performance has improved dramatically over the past 25 years. Super-insulation, which is also three times more effective, will soon be on the market.*

- *Natural gas and oil furnaces have achieved efficiencies more than 95% with condensing technology and further improvements are possible with new control systems. District heating has great potential in many countries, and advances are being made in boiler efficiency and controls. Heat pumps also show increasing promise. Solar space heating has long been commercially available. Wood heating, common worldwide, can benefit from advanced combustion technologies.*

- *Energy efficient air conditioners now use 30 to 40% less energy than models sold ten years ago. Ventilation systems have improved and new systems can lead to energy reductions of 10 to 15%.*

- *The efficiency of lighting technologies has improved in recent years. Some estimates show that cost-effective efficiency gains of 30 to 60% remain.*

- *There have been major energy efficiency improvements in refrigerators, freezers, washing machines, dryers and dishwashers and there is potential for further improvements. However, the market uptake of efficient appliances is limited by the fact that energy consumption does not play a major role in purchase decisions of this type of equipment.*

- *Cooking devices range from modern appliances to wood. More energy efficient wood stoves need to be more widely deployed in developing countries.*

- *Hot water heating has also seen major improvements. Solar hot water has been commercially available for more than 30 years. It shows great promise, but further advances are needed to reduce costs.*

- *Television sets vary widely in their energy consumption. The energy efficiency of a computer is not given much consideration by consumers. But efficiency improvements are being made for laptop computers because of the need to re-charge batteries.*

- *"Smart" metering, which displays and records real-time data on energy consumption, is becoming more popular. Energy savings of 5 to 15% are possible because of the feedback of information to the consumer.*
- *Building energy management systems have proven ability to reduce energy consumption by 10 to 20% at very little extra cost. While deployment is improving, the potential is still very significant, especially in small and medium-sized enterprises.*

Overview

Residential, commercial and public buildings are composed of and include a wide array of technologies: the building envelope; heating and cooling; hot water production; lighting; appliances and consumer products; and business equipment. Energy consumption in buildings is highly affected by the individual users of all of these technologies. Other technologies help "manage" the energy load within the building, *i.e.* help manage user behaviour. Advanced buildings, which may use micro-generation technologies to produce electricity that can be used in the building or sold to the grid, have attracted interest in recent years.

Buildings are quite different from other sectors, in that its characteristics can be more dependent on local climate and culture. Furthermore, unlike most consumer goods, buildings can last for decades, even centuries, and more than half of existing buildings will still be standing by 2050 – in some countries, it will be three-quarters of the building stock. Even with rapid technological change, the buildings sector generally can respond only slowly.

Buildings are much more frequently renewed than replaced. A considerable portion of a building's energy use is affected by parts that are changed or modified over a much shorter time. Lighting, appliances and HVAC (heating, ventilation and air-conditioning) systems are often changed after 15 to 20 years. Even facades and windows need renovation. Office equipment, which can affect cooling demand, is often changed after three to five years. Choosing the best available technology at the time of renovation or purchase is important to reduce energy demand in buildings.

Policies to improve energy efficiency in new and existing buildings need to be designed to ensure that new structures are built to the highest standards of efficiency. Policies should foster new technologies to meet the requirements of new generations of buildings and the energy-using equipment inside of them.

Governments play a key role in encouraging the development of new building technologies. Since the building technology sector is a highly fragmented industry, there are few companies large enough to engage in expensive technology development. The exception is in appliances, where the manufacturing industry generally undertakes most of its own technology development. Few private companies are willing to undertake the risk associated with long-term research and only develop projects close to commercialisation. In response to this situation, some governments have become more active in technology RD&D, particularly related to the components of the building envelope and to heating systems, often through public-private partnerships.

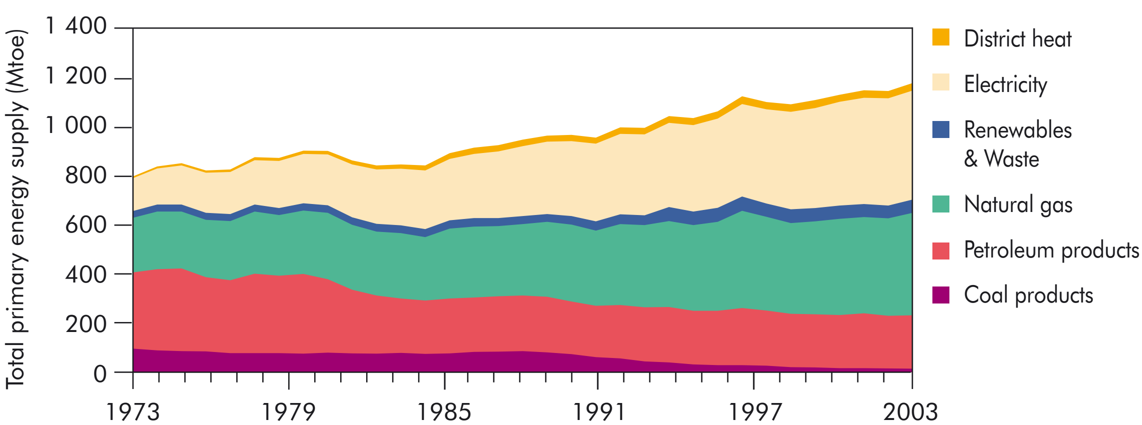
A significant increase in energy efficiency in buildings can be achieved with a greater deployment of existing technologies. In virtually every aspect of building energy use, there exist a large number of technical options that are available and generally cost effective. Individual technologies can make an important contribution, especially if integrated in a systems approach.

This chapter gives an overview of energy use in buildings, describes building energy technologies and their state of development, barriers to greater market penetration and options to overcome those barriers. Although the technologies are described separately, it is the interaction of the individual technologies in a building that determines energy use and potential energy savings.

Energy Consumption in Buildings

Today, energy use in residential and commercial/public buildings accounts for 35% of total global final energy consumption.[1] This compares to 32% for industry and 26% for transport. In OECD countries, energy use in buildings increased 39% between 1973 and 2003 (Figure 6.1). In 1973, oil was the dominant fuel in households, accounting for 40% of energy supply, but oil use in homes declined rapidly in the years following the oil price shock in 1973-74. Although oil consumption did grow during the 1990s in absolute terms, it continued to lose share and accounted for only 18% by 2003 in OECD countries. Natural gas consumption has steadily increased and is now the dominant fuel in residential buildings, whereas electricity is the main source in commercial buildings. Growth in electricity demand has been very strong since 1973. In 2003, electricity accounted for 38% of energy consumption in the commercial and residential sectors in OECD countries.

Figure 6.1 ▶ OECD final energy consumption for commercial and residential buildings, 1973-2003



Key point

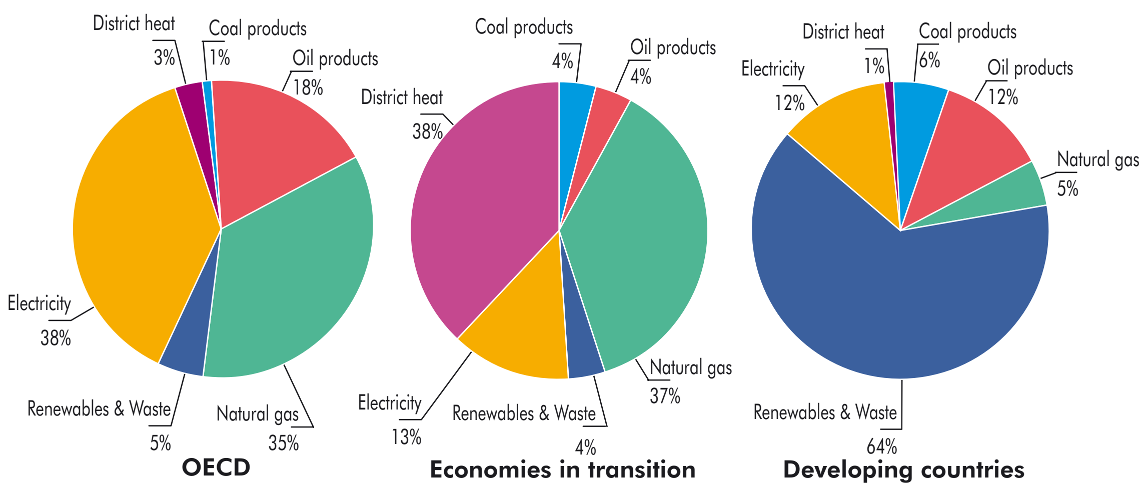
Strong growth in electricity demand has made it the most important energy carrier in buildings.

1. Strictly speaking not all energy in commercial and residential sectors is used within buildings. In many developing countries, significant shares of energy use for cooking and water-heating takes place outside on streets or markets.

6

In developing countries, traditional biomass for heating and cooking constitutes a major part of the 64% of total energy consumption in residential and commercial sectors that is supplied by renewables and waste (Figure 6.2). Electricity only accounts for 12% and reflects low electrification rates in many developing countries. In transition economies, district heating plays an important role and, with gas, accounts for three-quarters of total building energy use. The cold climate in most transition economies means that space heating is an important end-use. This helps explain why the share of electricity (which is mostly used for appliances and lighting) is only 13%.

Figure 6.2 ▶ ***Shares of final energy consumption for commercial and residential buildings in OECD, 2003***



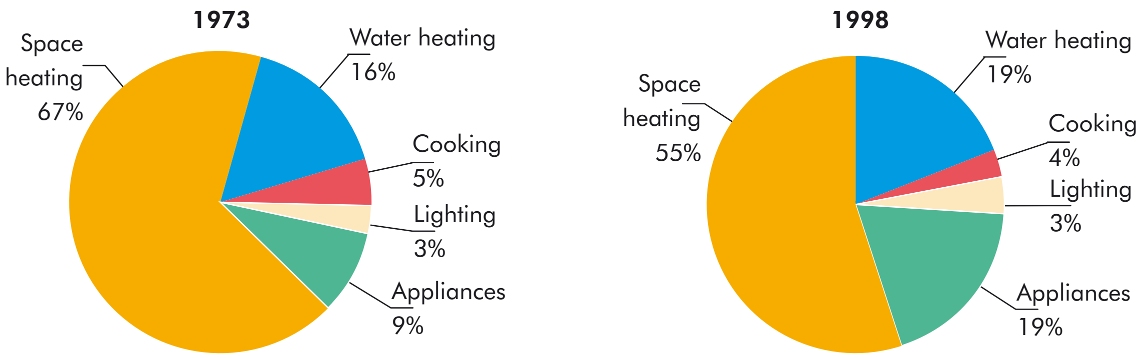
Key point

Renewables dominate building energy use in developing countries.

Changes in the fuel mix reflect both fuel substitutions and structural shifts among residential energy uses. For example, increased use of electricity for space heating underlies some of the strong growth in electricity demand in OECD countries, but more important is the significant growth of electric appliances. For a group of 11 IEA countries, the share of appliances in residential energy use more than doubled between 1973 and 1998 (Figure 6.3).[2] However, despite increasing shares of appliances, space heating is clearly the most important energy-end use in households, accounting for 55% of total residential energy consumption for this group of countries. Energy demand for space heating and cooling naturally varies with climate. In Australia, which has a relatively mild climate, space heating only accounted for 40% of residential energy use, while in much colder Finland, the share was 64% in 1998.

2. IEA-11 represents the countries for which the IEA has complete time series with detailed data for energy and energy consuming activities. The countries include: Australia, Denmark, Finland, France, Germany, Japan, Italy, Norway, Sweden, the United Kingdom and the United States. Together these countries accounted for about 79% of IEA total final consumption in 2003.

Figure 6.3 ▶ Shares of final energy use by end-use in residential buildings IEA-11[3]

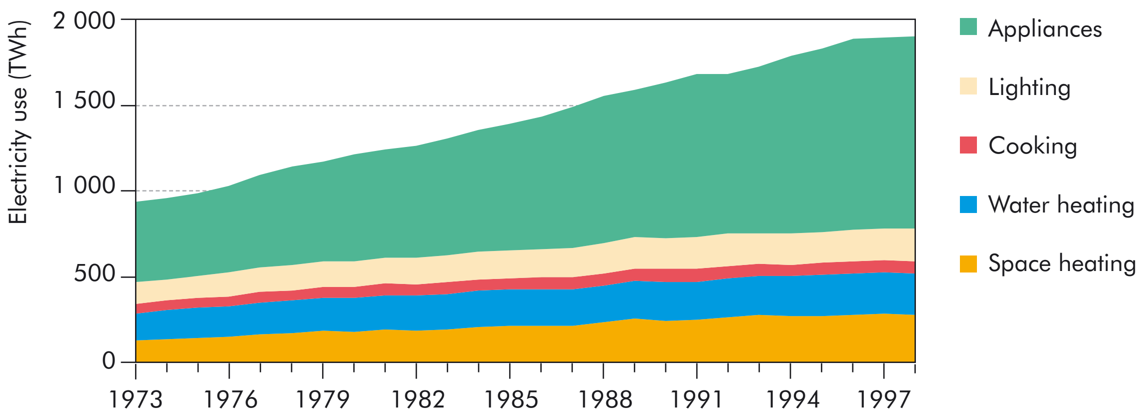


Key point

Space heating still dominates, but appliances are driving growth.

In 1973, appliances accounted for roughly half of the residential electricity use in the group of eleven IEA countries (IEA-11). By 1998, this share had increased to 58%. The share of electricity for space heating grew from 13 to 16%, while the shares for water heating fell from 17 to 12%, lighting from 14 to 10% and cooking from 6 to 4% (Figure 6.4). Roughly two-thirds of the doubling of IEA-11 electricity demand between 1973 and 1998 came from appliances, while space heating accounted for 18%, water heating 8%, lighting 6% and cooking less than 2%. Traditional "big appliances" such as dishwashers and refrigerators dominated the growth in appliance electricity consumption through the early 1980s, while much of the recent growth is due to the use of "miscellaneous" appliances, such as home electronics and small kitchen gadgets.

Figure 6.4 ▶ Residential electricity end-uses IEA-11, 1973-1998



Key point

Appliances are the main contributor to growth in electricity demand.

3. Space heating corrected for yearly climate variations.

Overview of Building and Appliance Technologies

The building envelope is an important starting point in reviewing the technologies used in buildings. There is much that can be done to upgrade existing buildings, although the most cost-effective approach is to build more efficient buildings in the first place. The most obvious changes to existing buildings include reducing air leakage, and upgrading lights and heating and cooling systems. A recent study shows that an effective refurbishment of the most inefficient high-rise residential buildings in Europe could see savings in heating energy of between 70% and 80% (Guertler and Smith, 2006). The measures included wall, roof and floor insulation, window replacement and improvements to the heating system. In commercial buildings, upgrading lighting and using more efficient information and communication technology are among the highest priorities. The potential for new buildings is enormous because it is easier and cheaper to build-in more efficient technologies than to retrofit. It is also possible to integrate building components more effectively in order to reduce energy demand to a mere fraction of average use. The availability of more energy efficient technologies for the building envelope allows for significant improvements from previous generations of buildings and, when done in combination with micro-generation technologies, can make buildings become virtually zero net users of commercial energy.

Building materials are important considerations for promoting more environmentally benign buildings. Building materials include bricks, concrete, steel, wood, plastics, glass and many more. Construction materials have not been chosen only for their thermal qualities. Fire, safety and durability concerns traditionally have been the major focus. Now there is increased interest in sustainable buildings and the materials used take on a different significance. For example, the US Department of Energy (US DOE) specifies that sustainable, low-impact materials are non-toxic, recycled and recyclable, renewable, local, standard sizes, modular, pre-cut to reduce waste, certified wood, durable and long lasting (US DOE EERE, 2004).

Heating, cooling and ventilation are major electricity uses in buildings. There have been significant technological improvements in these areas over the past two decades and more are promised. New technologies, as well as old technologies applied in new ways, *e.g.* district heating and heat pumps, can lead to major energy efficiency gains. Lighting technology has changed, bringing a new generation of lighting systems. These systems are more energy efficient and also provide better quality lighting services.

There are numerous appliances that are now a part of many modern societies: stoves and ovens, refrigerators and freezers, washing machines, dryers, dishwashers and domestic hot water heaters. But there are many more products on the market, ranging from home entertainment systems to kitchen gadgets and even electric shoe-polishers. Offices have changed completely with the dominance of the computer and all its peripherals. In OECD countries, the use of computers in the home has not reached saturation point, but is very high. The use of mobile phones has grown exponentially and so has that of chargers.

Other important developments include the use of energy management systems and sophisticated controls, mainly in the commercial sector, but also in some homes.

There has been greater emphasis on passive solar systems. Passive solar heating, and to a lesser degree, passive solar cooling (or passive cooling load reduction) has been commercially available for about 30 years. These systems can reduce the heating and cooling load by 50% with no additional cost. Meters have become more complex and can have an important impact on energy use. The use of renewables and small-scale combined heat and power systems (CHP) is becoming a more attractive option and many countries are actively promoting them. District heating and cooling, already a well-established technology in many countries, is gaining attention in many others and shows great potential.

New technology also provides the opportunity to reduce demand and make it flexible, rather than simply providing more generation and transmission capacity. Demand reductions may come as a response to price signals or they may be achieved by an agreed programme. Heating and cooling systems, lighting, appliances and some building services can all be elements of a "demand response" system.[4]

Technology Integration: Towards Zero Energy Buildings

A building is a complex system and all of its components contribute to overall energy demand. Therefore, they need to be considered as an integrated package. The interaction is only partially understood and researchers, designers and architects are trying to optimise the integration of the individual components in order to reduce energy consumption. A simple example helps to illustrate the interaction. Lighting creates heat that can reduce the heat load in winter or increase the cooling load in summer. More efficient lighting emits less heat and thus has a bearing on heating, cooling and ventilation requirements, which needs to be taken into account in the design of the heating, cooling and ventilation systems.

Box 6.1 ▶ Promoting better integrated design

The World Business Council for Sustainable Development (WBCSD) announced in March 2006 that it is forming an alliance of leading global companies to determine how buildings can be designed and constructed so that they use no energy from external power grids, are carbon neutral, and can be built and operated at fair market values.

The industry effort is led by United Technologies Corp., the world's largest supplier of capital goods, including elevators, cooling/heating and on-site power systems to the commercial building industry, and Lafarge Group, the world leader in building materials including cement, concrete, aggregates, gypsum and roofing. The WBCSD and the two lead companies are in discussions with other leading global companies that may join the project.

For further information, see: www.wbcsd.org

4. See the IEA DSM Programme http://dsm.iea.org

There is a growing number of building energy simulation tools available. Building energy simulation can model internal environmental conditions as a result of changes in the use of the building. For example, changes to heating schedules, ventilation rates, occupancy levels and repair/retrofit measures can also be included. Many of them are commercially available through specialist companies, engineering companies or architects (Box 6.2)

Box 6.2 ▶ Promoting building simulation

The International Building Performance Simulation Association (IBPSA) is a non-profit international society of building performance simulation researchers, developers and practitioners, dedicated to improving the built environment. IBPSA was founded to advance and promote the science of building performance simulation in order to improve the design, construction, operation and maintenance of new and existing buildings worldwide. IBPSA has 12 regional affiliates worldwide, mostly in OECD countries.

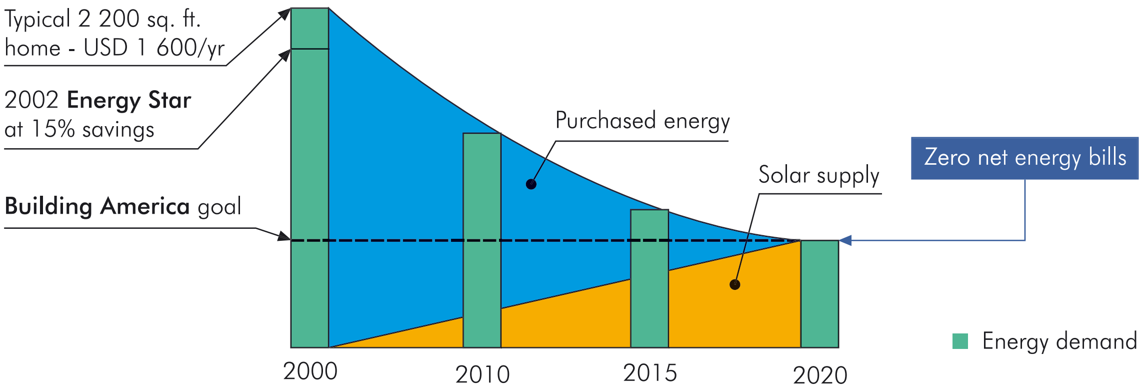
To take a leading role in the promotion and development of building performance simulation technology, IBPSA aims to provide a forum for researchers, developers and practitioners to review building model developments, facilitate evaluation, encourage the use of software programmes, create standardisation, and accelerate integration and technology transfer.

One example of a simulation tool is Delight (Daylighting and Electric Lighting Simulation Engine), a daylighting simulation tool for buildings. It is designed to efficiently and accurately calculate lighting levels and daylight factors at predefined positions in a room for specified exterior illumination environments ("daylight"). The tool includes a building input reader and parser, a multi-environment pre-processor that performs daylight simulations for a range of predefined external environments, a calculation of daylight factors, and an annual, hourly time step simulation of a lighting control model that determines hourly lighting electricity reductions due to daylighting. Delight features radiosity-based interreflection calculation and complex fenestration systems (CFS), such as blinds, modelled with bidirectional transmission distribution functions (BTDF). Delight will be linked to a new generation building energy simulation model (EnergyPlus) and will also be available as a stand-alone programme.

For further information, see: International Building Performance Simulation Association, www.ibpsa.org/ and Lawrence Berkeley National Laboratory, http://gundog.lbl.gov/

An example of effective technology integration is "zero-energy" buildings, which have been gaining great interest throughout OECD countries. Zero-energy buildings consume energy but their energy demand is balanced against the energy they produce so that there is no net purchase of energy. Figure 6.5 is a graphic illustration of the potential set out for a US zero-energy buildings programme (Building America). The goals for new residential buildings are to achieve a 50 to 60% energy use reduction by 2010 and 60 to 70% reduction by 2015. The final goal is to have zero-energy buildings by 2020. For commercial buildings, zero-energy buildings are expected to be possible by 2025.

Figure 6.5 ▶ **Zero energy buildings**



Source: LaFrance, 2004.

Key point

Zero energy buildings can be achieved over the next 20 years.

There are various voluntary standards to promote low- and zero-energy buildings. For example, Canada, Germany and Switzerland have standards that go beyond the normal thermal efficiency requirements in the building codes. All of them take a comprehensive approach, expecting savings in the building envelope, air permeability, the heating and ventilation systems and all appliances. The integration of the individual technologies maximises the energy and environmental benefits.

Box 6.3 ▶ **Showing what can be done: Near-zero-energy houses**

In 2004, workers completed the fourth Habitat for Humanity – US DOE "Building America" near-zero-energy house. These houses feature airtight envelope construction, advanced structural insulated panel systems, insulated pre-cast concrete walls, a heat pump water heater, geothermal systems, grid-connected solar photovoltaic, adaptive mechanical ventilation, cool roof and wall coatings with infrared reflective pigments and solar integrated raised metal seam roofs.

Construction of the house, located in Lenoir City, Tennessee was quick and the cost was less than USD 100 000. The first floor, a walkout basement, was constructed in six hours with pre-manufactured insulated concrete panels. The top floor walls, made of structural insulated panels, were installed in five hours, and the insulated cathedral ceiling was installed in a mere three hours.

The houses also provide high indoor air quality and mould, mildew and moisture control. In fact, the advanced construction techniques make these houses six times more airtight than similar houses with standard wood frame construction. This and mechanical ventilation, which brings in outside air, play a huge role in making the design effective.

The first such house has been occupied by a family of four since late 2002. The daily cost for heating and cooling this house with an air source heat pump was USD 0.45. Adding the cost of operating the water heater and all of the appliances brought the total average daily energy cost for this all-electric house to USD 0.82. This takes into account USD 291 for solar credits that are part of the Tennessee Valley Authority's Green Power Generation programme. In comparison, a conventional house in Lenoir City would use between USD 4 and USD 5 of electricity per day.

For further information, see: www.ornl/info/press_releases

Building Envelope

This section looks at the main building envelope components in relation to energy efficiency - windows and insulation.

Windows

Windows have an important impact on energy consumption. In the United States, an average house can lose 30% of its energy used for heat or air conditioning through the windows (Fisette, 2005).

Technology Description

Windows fulfil multiple functions: access to the building, outlook, entrance of daylight, and in many cases they are part of the ventilation and fresh air inlet. In most cases windows should let as much light in as possible, but in some cases the opposite would be better.[5] Windows can be a source of heat gain in winter and for heat loss in summer, when they can be opened.

While the aim is to enable light to enter a room, one of the challenges is to optimise the heat flow depending on the season. If the building is heated and the outdoor temperature is cold, the window should retain heat in the building, minimise losses and let in as much solar radiation as possible. On the other hand, if the temperature inside the building is too hot and cooling is needed, the windows should keep out the heat from the sun and if possible provide opportunities to shed heat from the building. This is typically the case in office buildings with high internal load of energy in a hot climate or in summer.

Window construction has an important impact on energy efficiency. It includes the design, the materials used for the frames and how the glass is assembled in multiple layered windows. There are many different types of windows on the market and the energy losses are very dependent on the number of layers, type of glass and the filling between the layers. Heat loss and solar gain can be reduced by the use of coatings on the glass.

5. Examples are when direct sunlight could give less comfort in rooms or that the daylight could cause problems with computer screens.

The challenge in increasing energy efficiency of windows is typically to optimise three window characteristics: to keep heat in, to keep heat out and to let light in.

Effective draught-proof windows are designed to let in as much light as possible. In some buildings, it may be necessary to bring daylight into inner areas and not only to the areas close to the windows. The challenge is to minimise the heat flowing back out through the window.

Keeping the Heat In

Efficient windows with a high resistance to heat flow (low R-values) are good in cold climates. For example, triple-glazed windows with low-solar-gain low-emission glass filled with argon or krypton gas are appropriate for very cold climates. They reduce heat loss in winter and also reduce heat gain in summer.

The window's resistance to heat flow is affected by a number of factors: the type of glazing material (glass or plastic); the number of layers of glass; the size of the air space between layers; the filling between the layers of glass and coating; the thermal resistance or conductance of the frame and spacer material; and the "tightness" of the installation. The thermal resistance of a window is also influenced by the design of the window: efficient windows with many small layers of glass will typically have higher R-values (more efficient) than windows with fewer but larger layers.

The use of double- or triple-glazed windows or low-emittance coatings can make a big difference. Double-glazed or triple-glazed windows are often filled with an inert gas such as argon or krypton. Double-glazed windows with coating and filling can reduce heat loss to a third compared to windows with one layer of glass. With triple-glazing the difference can be even larger. Low-emittance glass coatings reflect up to 90% of long-wave heat energy while allowing short wave, visible light to enter (Fisette, 2005). Effective weather stripping and replacement of poor quality window frames can also help reduce loss.

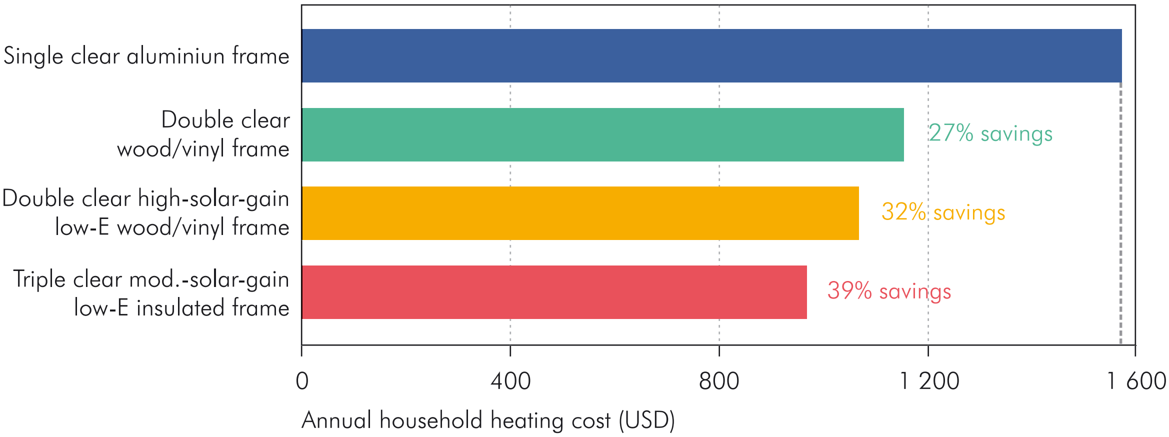
Keeping the Heat Out

In buildings in hot climates, those with high internal loads or those with glass facades may need cooling during the day. Coatings which prevent the high energy waves in the sunlight from penetrating and heating the building can be used in such situations. Protection from high heat gains can also be obtained by shadowing or by using shutters.

Status of Technology Development

Work is underway to develop a new generation of window products for different climates and building types. Much of the work has been undertaken by the glazing industry itself, sometimes in partnership with government. One promising area is that of coatings with optical properties that can be changed reversibly across a wide range, e.g. electro-chromatic or gas-chromatic glazing (WBGU, 2004).

Figure 6.6 ▶ **Savings potential of windows for heating energy costs: typical house in Boston, Massachusetts, United States**



Source: EWC, www.efficientwindows.org.

Key point

More efficient windows can save 27 to 39% of space heating energy costs.

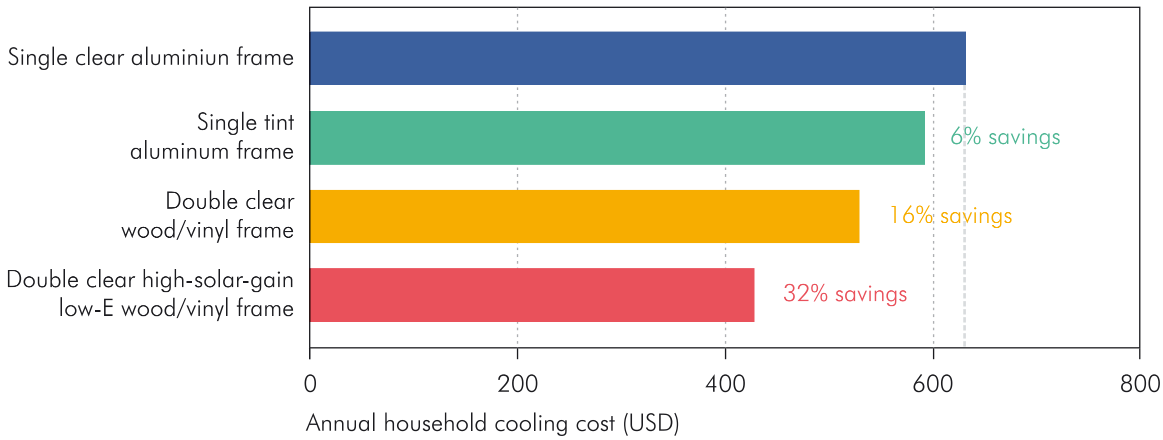
The best windows on the market insulate three times as well as their immediate predecessors. Advanced windows use a combination of double or triple glazing, low-emittance coatings, argon or krypton gas, and transparent insulation.[6] Figure 6.6 shows that switching from single-glazed windows to more efficient ones can achieve energy savings in the range of 27 to 39%, depending on whether double-glazed or triple-glazed windows are used.[7] Reduced cooling energy costs can range from 6 to 32% in a typical house in the southern United States by upgrading the windows (Figure 6.7).

There is still a need for further development of efficient glazing, but in modern windows the value of the glass alone is typically much better than the efficiency of the frames and spacer materials. More efficient spacers and frames need to be developed.

Some small problems with energy efficient windows still need to be solved. For instance, in humid climates or in periods with large differences between day and night, condensation can appear on the outside of the windows. This prevents one of the most important functions for windows – outlook to the surroundings.

6. NRCAN website: www.nrcan.gc.ca.
7. This is an example from Boston, Massachusetts, United States which has a moderately cold winter. See www.efficientwindows.org/energycosts.cfm.

Figure 6.7 ▶ **Savings potential of windows for cooling energy costs: typical house in Phoenix, Arizona, United States**



Source: EWC, www.efficientwindows.org.

Key point

More efficient windows can save 6 to 32% of space cooling energy costs.

Barriers to Greater Market Penetration

Some technical developments are still needed. However, there is a wide variety of options available on the market. Cost is a major barrier to replace old windows or doors, although windows are often replaced for reasons other than energy costs, such as noise reduction.

Consumers are largely unaware of the benefits of energy efficient windows. There is a need to balance the aesthetic qualities that glass provides against the environmental performance of the building envelope. Commercial buildings with large surfaces of glazed windows increase solar heat gains in winter, but they also increase the need for cooling in summer. The relatively slow rate of retrofit of buildings is also a hurdle. This is further compounded by the problem of the separation of expenditure and benefit, as seen in the rental market. Landlords are reluctant to invest in more energy efficient technologies when the beneficiary is the tenant.

Prospects for Overcoming Barriers

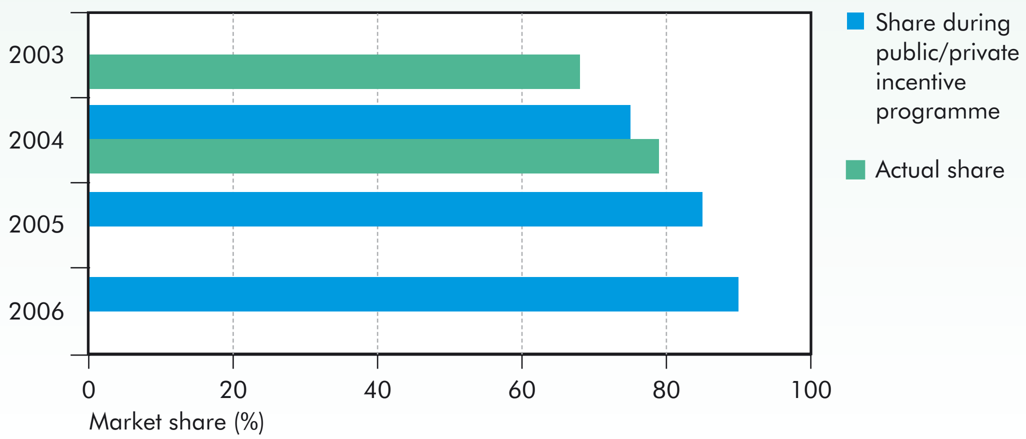
Long-term research into windows and frames is a very important area, as are continuing developments in building technology integration. Building regulations for new construction and their extension to major retrofits is probably the most effective way of deploying more-efficient technologies. Energy efficiency standards and voluntary agreements to improve the thermal quality of technologies are also valuable (see Box 6.4). Certification and labelling of the energy performance of windows make the energy performance of glazing products visible and comparable. Energy audits, which demonstrate to the consumer where major losses occur, have proven very successful and are important for prioritising the costs and benefits of various energy efficiency options.

Box 6.4 ▶ Incentives for efficient windows

In 2004, the Danish Energy Authority concluded an agreement with the glass industry, window producers and installers to phase-out traditional double-glazing over a three-year period and to improve windows solutions in general. The industry promised that the share of high-efficiency glazing should increase from less than 70% in 2003 to more than 90% in 2006. The remaining 10% represents windows in unheated buildings or in places where there is no need for efficient glazing. After the phase-out, highly efficient windows with low-energy double-glazing, or better solutions, are to be used.

As part of the agreement, the government provided subsidies for an information campaign, development of efficient window solutions and a voluntary labelling scheme. Today, most windows are labelled and energy efficient windows are gaining market share.

Figure 6.8 ▶ Energy efficient windows market share for low-energy glazing



Insulation

Technology Description

Proper insulation reduces heat loss in cold weather, keeps out excess heat in hot weather and helps maintain a comfortable indoor environment. There are many types of insulating materials, including mineral wool, polystyrene and polyurethane. Insulation is available for all parts of the building shell: roof, walls, floors and basement.

Some industry studies indicate that energy consumption in existing buildings in Europe can be reduced by more than 50% and that increased insulation could account for up to 78% of the total energy reduction potential for some types of buildings (European Mineral Wool Manufacturers Association, EURIMA). In Europe alone, the insulation industry states that 400 million tonnes of CO_2 emissions per year could be avoided by proper insulation (EURIMA). Investments in insulation can be amortised in less than six years in many residential buildings. Some of the most cost-effective deployment of insulation is in regions where there is a high demand for air-conditioning. In one study, insulating roofs in office buildings decreased cooling demand by 24% (ECOFYS, 2004).

The same study showed that insulating a terraced house in a warm region could reduce cooling demand by 85%. Insulation is often very cost-effective when combined with other measures during retrofits, such as improved windows. However, types of devises, control systems and window systems should be investigated and compared in the context of highly insulated houses with and without mechanical ventilation with heat recovery.

In new buildings there is still a large potential for energy savings. In best practice houses such as the "Passivhaus" concept from Germany and Austria, new houses are built with only 20 to 25% of the energy consumption that is typical for standard new houses.

Status of Technology Development

Building insulation performance has more than doubled over the past 25 years. Super insulation that will soon be on the market will be at least three times more effective than today's technology. These include vacuum-powder-filled panels, gas-filled and vacuum-fibre-filled panels, structurally reinforced beaded vacuum panels, and switchable evacuated panels.

The (IEA's) Implementing Agreement on Energy Conservation in Buildings and Community Systems has a specific work programme on high-performance thermal insulation systems. There is considerable attention being paid to improving insulation quality as standards for buildings become more rigorous.[8]

Barriers to Greater Market Penetration

There are no major technical barriers that affect deployment of insulation materials since there is a full range of insulation materials available on the market. Consumer reluctance to install insulation is one problem area, especially for houses that have no available cavity (space between inner and outer walls). In some areas a shortage of qualified installers is an important barrier to effective deployment.

8. For more information, see www.ecbcs.org

Public awareness of the need for greater insulation and of its potential for reducing energy costs is low. There is often a lack of awareness that proper insulation levels can also reduce cooling needs in hot climates. The consumer does not "see" the installed insulation and does not appreciate the benefits as readily.

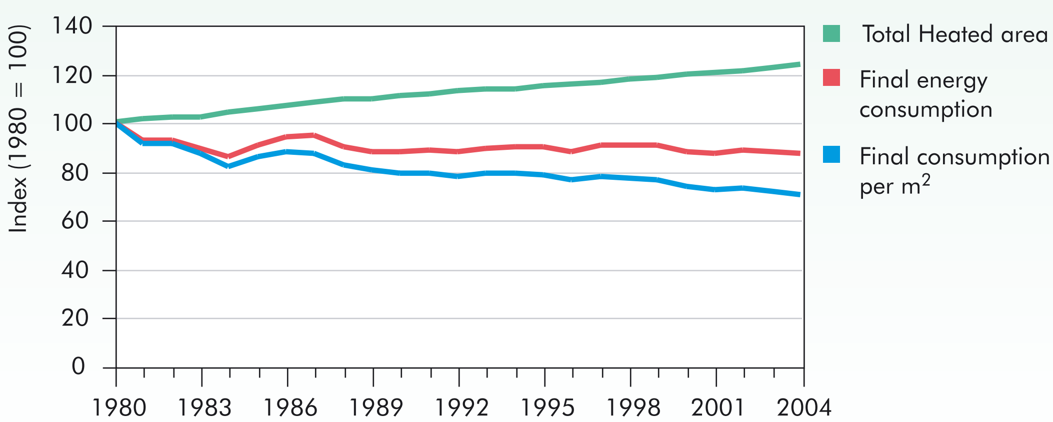
Incentives may be split, for example, in a landlord-tenant situation, or when a collective decision is needed in a co-operatively owned building. Even in an owner-occupied building, the proprietor may feel that they may not be the owner long enough to justify the inconvenience and cost of the upgrade. This can occur even when there is likely to be a huge return from such an investment over the life-cycle of the building.

Box 6.5 ▶ Housing insulation in Denmark

Denmark has had a strong policy for improved insulation and the general energy efficiency of housing since the 1970s. As a result, the overall final consumption for space heating in the residential sector has been declining even though the amount of heated area has been growing. Adjusted for climate, the energy consumption for space heating per square metre in all the existing building stock is only 70% of the consumption in 1980 (Figure 6.9). At the same time, the comfort level has been increasing.

More improvements are possible. New studies show that energy consumption for heating can be reduced by 40% on average for all existing buildings.

Figure 6.9 ▶ Residential space heating in Denmark



Source: Danish Energy Statistics, 2004.

Prospects for Overcoming Barriers

Financial incentives, improved information, making consumers aware of benefits, training, and making technical information available to the installation industry and designers are all important ways of overcoming the barriers. (See Box 6.5) A holistic approach looking at overall energy performance would also be an advantage in the insulation and better design of buildings.

Heating, Cooling and Ventilation

Conventional Heating Systems: Oil, Natural Gas, Electricity

Technology Description

In many countries, where there are significant heating loads, individual heating appliances are generally fuelled by oil, natural gas or electricity.

Dramatic progress in oil-fuelled heater efficiencies has been made since the mid-20th century. Efficiencies have risen from around 60% to more than 80%, first by the introduction of flame-retention head burners and high-static pressure burners. Today, condensing boilers offer the highest efficiency. Manufacturers claim operating efficiencies of up to 95%. However, there are relatively few condensing models on the market and they cost much more than other high-efficiency models.

A new generation of natural gas-fired heaters uses a secondary heat exchanger to recover the latent heat of water in the combustion-exhaust gases and then condenses it. Condensing releases an additional 10 to 20% of heat. Condensing gas boilers can achieve efficiencies of 90 to 97%. They can be used for integrated space and hot water heating.

The potential for savings in replacing traditional oil and gas heating systems is significant. Besides encouraging more efficient heaters, the correct sizing of the equipment is an important aspect. In some cases, replacement of an old inefficient and maybe oversized boiler can reduce the total consumption by 30 to 35%.

Electric-resistance heating systems include centralised forced-air furnaces and room heaters, for example baseboard and space heaters. Electric heating systems are more expensive to operate than other electric resistance systems because of their duct-heat losses and the extra energy required to distribute the heated air throughout a building. Individual space heaters are widely used, sometimes as a supplement to the main heating system.

Where electricity tariffs are lower at night, thermal-storage heaters are widely used. The most common type is a resistance heater with elements encased in heat storing ceramic. Central furnaces incorporating ceramic block are also available, although they are not as common as room heaters. Storing electrically heated hot water in an insulated storage tank is another thermal storage option. Standard heating plants in buildings include hot water storage tanks. Substantial progress has been achieved in recent years in reducing the thermal losses of the heating plants. In new advanced installations, such losses are negligible. Replacing old and inefficient hot water storage tanks with well-insulated systems still offers a tremendous energy saving potential. Replacing electric water boilers and electrically heated storage devices with highly efficient oil and gas boilers can save primary energy.

Status of Technology Development

While some technical improvements are still being made, particularly in controls, most conventional heating system technologies are mature. There is not much scope for efficiency improvements in the heating equipment itself. However, reduced energy use may be made through fuel switching.

With the declining needs for heating in more and more efficient buildings, there is a need for small, highly efficient boilers or boilers with double or multiple outlet power, to ensure a sufficient supply for hot water and at the same time to not be oversized for heating. These function best with intelligent control systems and automation features.

Barriers to Greater Market Penetration

There are no major technical barriers to deploying these technologies. The initial cost of a more efficient heating system can be a major barrier, even though the incremental cost of the more efficient model is not large. Often those making the investment decisions (developers, landlords, architects) are not those who will benefit from the energy savings. Available information on more advanced technologies, such as condensing boilers, has often been poor or lacking.

Prospects for Overcoming Barriers

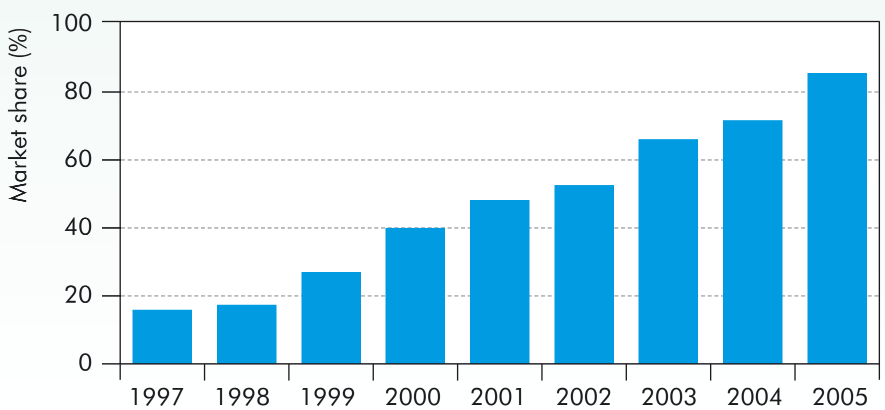
Appropriate advice on technology options is needed on issues such as the proper sizing of boilers to meet the heating load of the building. Many countries have minimum performance standards that can have a positive impact (Box 6.6).

Box 6.6 ▶ Incentives for efficient gas boilers in Denmark

Financing schemes have been used in Denmark to help new products penetrate the market and break through initial cost barriers. In 1999, a subsidy programme for condensing boilers was launched to improve the market share of gas-fired condensing boilers. The aim was to raise their market share from approximately 15% to more than 33%. The subsidy was about EUR 300 per boiler. The programme was terminated in 2001. By that time, the market share for condensing boilers had reached nearly 50%. This share has persisted and increased since the subsidies ended, because installers are now familiar with condensing boiler technology and are continuing to recommend them to home-owners (Figure 6.10).

From 2006, condensing gas boilers are mandatory in new houses and for major refurbishments, which is expected to increase their share even further.

Figure 6.10 ▶ Condensing gas boiler market penetration in Denmark



Advanced Heating Systems: Heat Pumps

Technology Description

A heat pump is a device that transforms low temperature heat from sources such as air, water, soil or bedrock, into high temperature heat that can be used for heating. Heat pumps can also be reversed and function as a space-cooling unit. Most heat pumps operate on a vapour-compression cycle and are driven by an electric motor. A growing number of heat pumps are driven by an internal combustion engine. Some heat pumps use the absorption principle with gas or waste heat as the driving energy. This means that heat rather than mechanical energy is supplied to drive the cycle. Absorption heat pumps for space conditioning are often gas-fired, while industrial installations are usually driven by high-pressure steam or waste heat.

Electric heat pumps typically use about one-fourth to one-half as much electricity as electric resistance heaters. They can reduce primary energy consumption for heating by as much as 50% compared with fossil-fuel-fired boilers. Geothermal heat pumps are even more effective than air-sourced systems. According to the US Environmental Protection Agency, geothermal heat pumps can reduce energy consumption up to 44 % compared to an air-source heat pump.[9]

The coefficient of performance (COP) of a heat pump is the ratio of heat supplied to energy used. Minimising the temperature lift, by drawing heat from a relatively warm source and by distributing the heat at the lowest possible temperature, can dramatically improve performance. A low distribution temperature in turn requires a large radiator surface, such as floor radiant heating systems. The COP of a conventional system is 2 to 2.5. It increases to 3.5 to 7.0 for a radiant heating system. Geothermal heat pumps can also serve as a low-temperature heat sink in summer to increase the efficiency of air conditioning as well.

Heat pumps have been gaining market share in some OECD countries. For example, in Sweden about 48% of all electrically heated homes have heat pumps.[10] Most are air-conditioning systems that operate as heat pumps when heating is required. Heating-only heat pumps have a significant market share in only a few countries, notably Sweden and Switzerland.

Status of Technology Development

A wide range of heat pumps is commercially available. While the technology is established, it has not yet reached full maturity. An IEA Implementing Agreement is studying ideas for improving the technical performance of ground-source heat-pump systems. Among its current projects are international collaborations on retrofitting residential heating systems.[11]

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9. For more information, see www.eere.energy.org/consumer/your_home/space_heating_cooling?index.cfm/
10. Communication with Mr. Egil Overholm, Swedish Energy Agency, November 2005.
11. For more information, see www.heatpumpcentre.org

Barriers to Greater Market Penetration

There are still some technical barriers, even though many technologies are available on the market. There is a lack of confidence in the technology which has resulted in a low deployment rate. This is often a result of inadequate information about the costs and benefits and because of the lack of a well-established supply and service industry. So far in the OECD region, only Scandinavia and Switzerland have a mature ground-source heat pump industry and an adequate installer base.

A promising future application of heat pumps is for producing domestic hot water. There are estimates that their use could save 1 500 kWh per year in as many as 40% of US homes. However, the technology was deemed insufficiently developed to date to qualify under the Energy Star programme.

Prospects for Overcoming Barriers

Demonstrations may be useful in countries or regions where the equipment has low market penetration. However, more R&D is needed for heat pump water heaters. Measures must be taken to ensure quality performance, guarantees, regulations and effective public information. Heat pumps often fall into the category of technologies that are economic for society, but are only attractive to individual consumers when the benefits are clearly communicated.

Advanced Heating and Cooling Systems: Active Solar

Technology Description

Active solar systems take the power of the sun and harness it to heat buildings. Solar collectors absorb solar radiation and change it into heat energy. This thermal energy can then be used to provide hot water for space heating or cooling. The main collector technologies include unglazed, glazed flat plate and evacuated tubes. The technology may be considered mature, but it continues to improve. Aluminium, being cheaper and lighter than copper, is being used in manufacturing absorbers. Laser welding technology makes it possible to have a perfectly smooth absorber surface and obtain a homogenous colour.

The efficiency of solar collectors (calculated as heat delivered divided by incident solar energy) depends on the design of the collector and on the system of which the collector is a part. "Combi-systems" are solar systems that provide space and water heating. Annual average collector efficiencies of 40 to 55% are feasible for domestic hot water, while annual average solar utilisation, which accounts for storage losses and heat that cannot be used, has reached 20 to 25% in combi-systems. Depending on the size of panels and storage tanks and the building thermal envelope, 10 to 60% of the combined hot-water and heating demand can be met in central and northern European climate conditions. An auxiliary or back-up system is usually needed to provide additional heat.

Solar collectors of all types have a nominal peak capacity of about 0.7 kW_{th} per m^2. However, the estimated annual solar thermal energy production from the collector areas in operation depends on the solar radiation available, the outside temperature and the solar thermal technology used. Estimated annual yields for glazed flat-plate collectors are 1 000 kWh_{th} per m^2 in Israel, 700 kWh_{th} per m^2 in Australia; 400 kWh_{th} per m^2 in Germany and 350 kWh_{th} per m^2 in Austria, where they reach 550 kWh_{th} per m^2 for vacuum collectors and 300 kWh_{th} per m^2 for unglazed collectors (Philibert, 2005).

Costs can also be very different. In Greece, a hot water thermo-siphon system for one family unit with a 2.4 m^2 collector and a 150 litre tank costs EUR 700. In Germany, where solar radiation is lower, a similar system of 4 to 6 m^2 and a 300 litre tank costs about EUR 4 500. Water heating systems are more profitable in sunny and hot areas, but this is not the case with respect to space heating. In warm sunny places, solar system output is larger, but mostly wasted since heating loads are small and the cold season is short. In colder areas, a lower output is better used because heating loads are higher and the cold season longer. The same solar system that provides 40% savings on heating expenses in northern France, *i.e.* EUR 730 to 900 per year; in southern France it provides 80% savings, *i.e.* only EUR 120 to 180 per year (Philibert, 2005).

Solar can also be used for cooling. A standard, single-effect absorption chiller can be driven with temperatures of around 90°C. This can be generated with standard flat plate solar collectors. Cooling technologies include single- and double-effect absorption chillers, adsorption chillers, and solid or liquid desiccant systems. There are about 45 solar air conditioning systems in Europe, with a total solar collector area of about 19 000 m^2 and a total capacity of about 4.8 MW cooling power.

Status of Technology Development

The technology is commercially available for domestic hot water. RD&D is underway in areas including advanced materials, advanced solar thermal collectors, large-scale solar heating systems, solar industrial processes systems, solar cooling systems, combined solar heating and cooling systems, and standards, regulations and test procedures.[12]

For example, in the small capacity range for solar cooling, component development of cooling equipment needs further RD&D in order to achieve higher performance, lower prices and more industrialised production. For all systems, including residential applications and small commercial buildings, as well as large-capacity systems for buildings and industrial applications, RD&D is required in the following areas: cooling machines for low capacities and machines able to adjust to the solar thermal heat supply; system design, integration and control; and providing best-practice solutions via demonstration projects.

Barriers to Greater Market Penetration

About 140 million m^2 of solar thermal collector area is currently in operation around the world; about 13 million m^2 were added in 2004, of which 10 million m^2 were added in China. The total installed capacity is thus approaching 100 GWth. China

12. The IEA's Solar Heating and Cooling Implementing Agreement has on-going projects related to buildings concern performance of solar facade components, solar sustainable housing, daylighting buildings, testing and validation of building energy simulation tools, and PV/thermal solar systems.

is by far the leading market, with one-third of global installed capacity made up almost exclusively of evacuated tube collectors with a total surface area of 22 million m^2. In Canada, Australia and the United States, swimming pool heating is the dominant application with an installed capacity of 18 GWth of unglazed plastic collectors, but this market has been characterised as “mostly dormant” (Jones, 2005). Europe and Japan have about 10 GWth of flat plate and 9 GWth of evacuated tube collectors. Most of these use water as the heat transfer fluid, with air collectors representing only 1% of the market. In Europe, lead markets are Germany, Greece and Austria. The highest collector surface area per inhabitant is Cyprus with 582 m^2, followed by Austria at 297 m^2; the European Union average is 33.7 m^2 per inhabitant.

There are many proven and cost-effective technologies available on the market, but information about costs is often inadequate. Consumers often lack confidence in the ability of the heating system to operate effectively throughout the entire heating season. Furthermore, technology’s high initial costs constitute a major barrier. Few countries have adequate installation and service providers.

Prospects for Overcoming Barriers

The barriers can be overcome by continuing RD&D and taking measures to ensure quality performance, guarantees, regulations and effective public information. Demonstrations may be particularly useful in countries or regions where the equipment has low market penetration. Third-party financing arrangements can also help. Some countries offer fiscal incentives, while others have national or regional regulations, which, for example, have been in place in Spain since 2006 on the national level and in Barcelona since 2003 on a regional level.

Advanced Heating and Cooling Systems: District Heating and Cooling

Technology Description

District heating (DH) is a network of pipes that transport heat to energy consumers. In many instances, DH systems use heat that would otherwise be wasted. Typical sources include combined heat and power systems, heat-only boilers using conventional fuels or biomass, industrial waste heat, waste-to-energy plants and geothermal heat. A district network can use a combination of these heat sources. Newly available low-carbon and renewable sources can be integrated easily. District heating schemes range from just a few buildings to huge schemes that connect thousands of residential and commercial buildings.

Solar energy can be used for district heating and cooling systems and combined with some form of thermal energy storage. By 2003, eight solar-assisted district heating systems had been constructed in Germany. They can provide between 30% and 95% of total annual heating and hot water requirements under German conditions, though at relatively high costs. Similar systems exist in other countries, such as Sweden, the Netherlands and Austria. The largest of these systems is in Denmark and includes 1 300 houses and a 70 000 m^3 gravel-pit for storage.

Box 6.7 ▶ **District cooling in Amsterdam**

District cooling has been a well-hidden secret in the Netherlands. There are a number of small institutional cooling systems all over the Netherlands. Most of the systems are aquifer storage solutions strictly for one or a few buildings and so small that they can not be defined as district cooling. In 2003, the energy company Nuon took the decision to establish a commercial district cooling system in Amsterdam, in a partnership with the Swedish management company Capital Cooling Europe.

The district cooling systems capacity is designed for a peak demand of 76 MW. The district cooling production is expected to reach 100 GWh in 2012 and will be a mixture of cooling from the bottom of Lake Neiuwe Meer and chillers.

Separate traditional chiller installations in buildings generally have a low COP of 2.5. Normally it takes 1 kWh of electricity to produce 2.5 kWh of cooling. With the planned production of district cooling in Amsterdam's international business hub, Zuidas, only 1 kWh of electricity is needed to produce10 kWh of cooling.

The district cooling system will reduce CO_2 *emissions by 75%, since less electricity will be needed to produce the cooling.*

For further information, see: www.iea-dhc.org

Status of Technology Development

District heating is a mature technology with good penetration in some countries but very little in others where the heat load could warrant its use. For example, in the Russian Federation, district heating supplies more than 70% of households with both heat and hot water. The total length of its district heating network is about 1.8 million km.[13]

Modern district heating systems use pre-insulated pipes and sophisticated moisture-surveillance techniques that can locate leaks before they become serious. Network and plant operation is monitored remotely and continuously. Current research is directed toward system optimisation, use of thermal storage, and the provision of cooling as well as heating. Further research focuses on applying the technology to low heat density areas and on optimising network size.

The current work of the IEA Implementing Agreement on District Heating and Cooling centres on the evaluation of a new all-plastic piping system; assessment of the actual annual energy efficiency of building-scale cooling systems; new materials and construction for improving the quality and lifetime of district heating pipes including joints, thermal, mechanical; and environmental performance.[14]

Barriers to Greater Market Penetration

There are no major technical barriers to the greater deployment of district heating schemes or the refurbishment of existing ones. Building new district heating systems

13. For more information, see www.earthscan.co.uk/news/article/mps/uan/592/V/4/sp/
14. For more information, see www.iea-dhc.org.

is very expensive. District heating does not always experience a level playing field, as well. For example, district heating schemes can be required to participate in emissions trading schemes in some countries because of their size, yet their direct competitors – individual heating – do not. In countries such as the Russian Federation, losses range from 20 to 70%, in part because of a lack of metering and in part because of the poor state of the systems.[15] There has been serious under investment in many countries to modernise their district heating systems.

Most of the Russian district heating network uses un-insulated pipes and, in many cases, boilers are in serious need of replacement and control systems need to be installed. In many transition economies, the DH companies have not modernised their management and pricing systems in order to be more sustainable. There is also a need for heat meters, individual control valves and heat cost allocators. The IEA recently estimated that USD 70 billion would be needed by 2020 to improve the district heating infrastructure in the Russian Federation alone (IEA, 2004).

Prospects for Overcoming Barriers

There are signs of renewed interest in district heating. Recent European Union directives have recognised its importance in achieving environmental targets. It is essential, however, that district heating be allowed to compete on a level playing field with other heating options.

International financial institutions have been active in financing district heating rehabilitation. For example, in one recent project in the Russian Federation, the European Bank for Reconstruction and Development (EBRD) is financing the rehabilitation and modernisation of the existing district heating distribution network and the introduction of new, compact individual heating sub-stations equipped with meters in residential apartment buildings in the city of Cherepovets. The investments are expected to achieve significant cost savings and greater energy efficiency for the residents.[16]

Advanced Heating and Cooling Systems: Thermal Energy Storage

Thermal energy storage is a key component in many energy efficient systems for heating and cooling buildings. Fossil fuels can be replaced by stored solar heat or by waste heat from combined heat and power plants. Surplus heat from industrial processes or even the heat and cold of the weather can be used to improve the match between energy supply and the varying heat demands of a building.

Technology Description

The concept behind all thermal storage systems is the same: heat is transferred to or from the adjacent ground by heat exchangers, which consist of vertical pipes and

15. For more information, see www.earthscan.co.uk/news/article/mps/uan/592/V/4/sp/
16. For more information, see www.ebrd.com/projects/psd/psd2006/36849.htm

ducts, or energy pillars that also serve as the building foundation. Heat storage in aquifers under suitable hydro-geological conditions can help to exploit the potential of surplus low temperature heat from combined heat and power plants. By the same token, solar heat that has been stored in summer can be recovered efficiently for heating in winter. Thermal storage can be used for district heating of small communities.[17]

Various new innovative energy storage systems have recently proven their effectiveness in pilot and demonstration plants. With thermal storage, the soil (or aquifers below the buildings) can be used not only as a natural heat and cold source for very energy efficient air conditioning systems, but also as a long term store of solar heat, in addition to free heat and cold from the atmosphere. These systems have become more and more widespread in many countries, mainly for heating and cooling systems with and without heat pumps.

In many commercial buildings, chilled water or ice storage systems provide air conditioning. These systems are managed to avoid paying peak-period electricity prices. A more advanced concept is based on the use of waste heat from electric power plants to replace electric chillers with thermally driven absorption chillers and cold storage.

The thermal capacity of lightweight building structures can be increased considerably by integrating phase change materials (PCM) into the building materials. Research is underway on the use of micro-encapsulated paraffins in plaster or gypsum boards or in the ceiling for heating and cooling. Overheating of the room can be reduced or completely avoided by increasing the thermal mass of the building structure.[18] Demand for cooling can be shifted to the night when the PCM material is then discharged by natural ventilation of cold night air. The high thermal mass of concrete floors equipped with air channels can also be used as a thermal buffer storage for air conditioning.

Thermo-chemical reactions present interesting new possibilities for energy efficient air conditioning systems. Ventilation air is dried and heated by the adsorption of water vapour in zeolites or silicagel nano-porous granulates. The adsorption process can be combined with indirect evaporation cooling to bring the air to the desired temperature. The adsorption process of water vapour in silicagel or zeolites can also be used to construct solid-adsorption heat-pump systems with a high annual performance.

Status of Technology Development

The status varies for different concepts and technologies and also varies among countries. The use of underground and aquifers for cooling and heating is already commercial in the Netherlands and Sweden. In other countries, however, where the concept has been embodied only in early demonstration plants, PCMs and thermo-chemical storage systems are still in the R&D phase.

The IEA Solar Heating and Cooling Implementing Agreement has a project on advanced storage concepts for solar thermal systems in low energy buildings.[19]

17. For more information, see www.iea-eces.org.
18. Thermal mass is the ability of a material to absorb heat energy.
19. For more information on the IEA Implementing Agreement on thermal storage, see www.iea-eces.org/

Barriers to Greater Market Penetration

The technical and economic feasibility of advanced new storage concepts still has to be demonstrated extensively to win the confidence of consumers. High initial costs and the lack of proof of long-term reliability are major barriers. Tools have to be developed for designers and architects to integrate advanced storage systems into the heating and cooling systems.

Prospects for Overcoming Barriers

There is a good chance to overcome the barriers within the next five to ten years, once the technologies are successfully demonstrated. The high initial costs may be lowered by economies of scale.

Advanced Heating Systems: Wood Heating

Technology Description

Many regions of the world rely on wood for space heating. The technologies range from fireplace inserts, wood stoves and pellet stoves to hybrid systems and more advanced boiler systems.

There are three highly efficient wood technologies: advanced combustion, catalytic stoves and densified-pellet systems. Advanced combustion systems burn the smoke before it leaves the heater. This improves efficiency and reduces pollution emissions. Catalytic stoves have a catalyst that helps burn the smoke before it leaves the appliance. The catalyst is a coated-ceramic honeycomb-shaped device through which the exhaust gas is routed. The catalytic coating lowers the ignition temperature of the combustion gases as they pass through it. This allows for a cleaner burn at low heat. Densified-pellet systems burn fuel made from dried wood or other biomass waste compressed into small cylinders. Pellet burners include a storage hopper that automatically moves the pellets into the combustion chamber. Catalytic stoves have advertised efficiencies of 70 to 80%. Advanced combustion stoves have advertised efficiencies of 60 to 70%. Pellet stoves can have efficiencies in the range of 78 to 85%.[20]

Pellets are considered to have an advantage because they are a consistent size, burn predictably and provide a consistent heat output. The pressure and heat created during their production binds the pellets together with the lignin in the wood without using additives. Pellets are standardised by agreements between pellet producers throughout Europe and North America. Most pellets have a moisture content of about 10%, less than the normal 25% to 55% for typical wood chips. Development is underway for larger systems.

Status of Technology Development

Advanced boilers are commercially available. Modern biomass boilers have efficiencies of 88 to 92% and near-zero net carbon emissions. The technology is

20. For more information, see www.eere.gov/consumer/your_home/space_heating_cooling

mature, although there are developments taking place in the area of controls. Demonstrations are needed for targeted uses and in countries where wood heating has only a negligible share of the market even though the potential is high. There are developments underway for large systems. Biomass combined heat and power is proven and reliable in central Europe.

Barriers to Greater Market Penetration

There are no major technical barriers, with a good range of technologies commercially available. Ready access to wood is important. There is a widespread impression that wood heating is very labour-intensive, but new pellet-burning appliances show that available mechanised processes provide a level of convenience available in conventional heating systems.

Prospects for Overcoming Barriers

Information campaigns are important. Many countries have provided financial incentives for consumers to switch from oil to wood heating.

Passive Solar

Technology Description

Passive solar heating, and to a lesser degree, passive solar cooling (passive cooling load reduction) have been commercially available for about 30 years. Effectively, it integrates various building technologies. Buildings designed for passive solar and daylighting incorporate design features such as large south-facing windows. They are built of materials that absorb and slowly release the sun's heat. No mechanical means are employed in passive solar heating. It can involve extensive glazing, wall- or roof-mounted solar air collectors, double-facade wall construction, air-flow windows, thermal mass walls and preheating of ventilation air through buried pipes. It is estimated that incorporating passive solar features into building design can reduce heating costs by as much as half with no additional cost.

Lighting and ventilation can be directly supplied through solar energy, interior light through a variety of simple devices that concentrate and direct sunlight deep into a building, and ventilation through the temperature and resulting pressure differences that are created between different parts of a building when the sun shines. The building facade can be used to generate and channel airflows that remove heat that otherwise adds to the cooling load, or which can be used to preheat ventilation air when heating is required.

The most common building component used in passive solar energy is windows. Over a year, most windows lose more energy than they gain. Low-emissive double-glazed windows are now state-of-the-art technology, and more than halve window heat loss. Advanced windows can actually be net energy suppliers, with better net annual energy performance than the most tightly insulated wall. Spectrally selective windows can maximise sunlight to replace artificial lighting while minimising increased cooling requirements from solar radiation. These can be very helpful in office buildings.

More innovative options for the future may be electro-chromatic windows, which have small voltages that cause the window to change from a clear to a transparent coloured state, or vice versa. They can minimise both winter heating requirement and summer cooling needs. Simulations of energy use in office buildings with New York climate conditions indicate that such windows can achieve savings of up to 60% of combined lighting and cooling electricity use, depending on the building characteristics and window area. Another technology under development is thermochromatic glazing, which automatically permits penetration of solar radiation when, and only when, heating is desired, thereby eliminating the need for sensors.

Status of Technology Development

Design components for passive solar technologies are generally well established, although new computer design techniques are under development. Passive solar depends on integrating many building technologies. Advances in passive solar, therefore, depend on developments in other areas, from windows to insulating materials.

Box 6.8 ▶ Passive solar research in Canada

Canada's Passive Solar Programme focuses on the development and adoption of high-performance windows, advanced window R&D, daylighting and systems integration to optimise solar energy gains. Activities include electrochromic window research and industry support through the development of computer design tools, window durability methods and energy performance rating standards.

The programme seeks substantial reductions in building energy consumption by making greater use of solar energy to offset heating requirements in residential buildings and lighting needs in commercial buildings. Canadian innovators are assisted in the development and rapid transfer of high-performance, energy efficient and environmentally responsible technologies to the marketplace. Sub-programmes address high-performance and advanced window R&D; industry support for accelerated adoption of efficient windows in the marketplace; daylighting and commercial building applications; and system integration and passive solar modelling. Projects range from product standards development and application assessment to technology transfer and quality assurance.

Activities are carried out on a cost-shared basis with industry and other organisations, including universities, trade associations, research councils, utilities and various levels of government. A major thrust of the programme is research and technical support leading to performance standards and labelling for more rapid consumer acceptance of new products. Support is also being provided for development of super high-performance windows, which may not yet be competitive but would further enhance the energy performance of the market's best designs. There is also support for ultra advanced windows based on emerging technologies such as electrochromics and aerogels. Durability research is underway to ensure that high-performance products are at least as good as conventional windows and that they maintain energy performance over their lifetime. The development of computer programmes to assist in window design, to compare and rate products and to select the best product for a particular application is another key area of activity.

For more information, see www. www.canren.gc.ca/programs/index.asp

Efficient passive solar architecture is as much an art as a science. There is no one-size-fits-all recipe. Each building requires a close adaptation to its natural environment and climate, and it must take into account the needs of its inhabitants. Buildings constructed during the era of cheap oil and standardised building materials and concepts are often the examples not to follow. Traditional materials and knowledge can be a great source of inspiration for designers and architects. This may be especially true in hot climates where a reasonable level of comfort can be provided with a variety of energy efficient devices and high-inertia materials to avoid using air conditioning systems.

The spatial organisation of buildings strongly influences cooling and heating loads. Lessons can be taken from many old cities in various climates. Modern urbanisation, with its large energy consumption, creates heat island effects that reduce winter power loads but increase summer power loads. In Tokyo, for example, there are efforts to increase plant cover in the city to reduce cooling loads.

Barriers to Greater Market Penetration

There are still some technical barriers to the full development and acceptance of passive solar buildings, particularly related to ongoing building technology research and the integration of the individual building components. Some architects fail to integrate passive solar features sufficiently. This can be a result of a lack of awareness on the part of either the developer or the architect. There are concerns about the incremental costs to integrate passive solar into the building design.

Prospects for Overcoming Barriers

Education, awareness and training programmes are useful, as are support for R&D and qualification of modern building materials (see Box 6.8). Training is important for designers and builders alike. Demonstration projects have proven effective in many countries and a better understanding of life-cycle costing is important.

Air Conditioning

Technology Description

Air conditioners have the same operating principles and basic components as refrigerators. A cold indoor coil is used as an evaporator, and a condenser releases the collected heat outside. A compressor moves a heat-transfer fluid (or refrigerant) between the evaporator and the condenser. A pump forces the refrigerant through the circuit of copper tubing and fins in the coils. The liquid refrigerant evaporates in the indoor evaporator coil, pulling heat out of the indoor air and thereby cooling the interior. The hot refrigerant gas is pumped outdoors into the condenser where it reverts back to a liquid and gives its heat to the air flowing over the condenser's tubing and fins.

The main types of air conditioners are single-package room air conditioners, split-system room air conditioners and packaged central air conditioners, such as roof-top unitary air conditioners. Larger non-packaged systems, *i.e.* ones where the various elements are sold as separate components, include chillers linked to air or water based heat distribution systems. Room air conditioners include window-mounted appliances, wall-mounted units with a sleeve to allow through-the-wall mounting and freestanding portable units that can easily be moved on wheels. They also include the most common split systems where the condensing unit is mounted on the outside of the building and linked to the evaporator and air distribution unit via a refrigerant circulation system.

Air conditioners can use air or water as the heat transfer vector. The water-based systems are inherently more efficient, but can be more costly to purchase and install. Among chiller-based systems there are significant additional energy requirements for the pump-distribution of water and for cold air distribution.

Central cooling systems that circulate chilled water through cool panels (sometimes called chilled-beam or chilled-ceiling systems) can be much more energy efficient and a good choice when condensation build-up is not a concern. Among standard air-to-air room air conditioners there are also great differences in efficiency. The least-efficient portable air conditioner might have an energy efficiency ratio of less than 1.5 W/W (watts cooling output per watts power input), whereas the most efficient split room air conditioners can achieve more than 6.5 W/W. Further energy savings in both room and central air conditioning systems can be realised by optimising their partial-load performance through the use of variable speed drive compressors. Savings in traditional air conditioners can be achieved by improving the heat transfer at the heat exchangers, optimising the refrigerant, utilising an efficient compressor and optimising the control.

There are also evaporative coolers that work well in hot, dry climates. These units cool the outdoor air by evaporation and blow it inside the building. When an evaporative cooler is in use, windows are opened part way to allow warm indoor air to escape as it is replaced by cooled air. Evaporative coolers cost about half as much to install as central air conditioners and use about a quarter as much energy.

Status of Technology Development

Air conditioners are commercially available, but the efficiency of models on the market varies substantially. New standards in effect in 2006 in the United States, for example, call for an improvement of 30% over the previous standard introduced in 1992.[21] Japan's Top Runner has set far higher performance requirements than those in place in other OECD countries. The use of heat pumps for air conditioning is still not fully developed, but it shows strong potential and is considered by many to be the most energy efficient form of air conditioning.[22] There are also developments underway to use solar power for cooling purposes.

Barriers to Greater Market Penetration

Air conditioners are gaining market share and it is important that consumers understand the benefits of more energy efficient appliances. Air conditioning can be a major energy consumer, often increasing running costs of a building by up to 50%.[23] Furthermore, air conditioning is the major driver of peak power loads in many OECD countries; due to its variability and the high cost of storing electricity, it is a highly

21. For more information, see www.aceee.org/consumerguide/topcac.htm
22. For more information, see www.greenconsumerguide.com
23. For more information, see www.flexiblespace.com/press21.htm

expensive load for utilities to serve. Identifying consumer needs and correcting imbalances in costs and pricing in electricity systems is key to technology deployment.

Prospects for Overcoming Barriers

Barriers can be overcome by effective information (including on whether air conditioning is needed), energy efficiency standards and labelling. Well-designed passive solar homes can often eliminate or minimise the need for air conditioning. For normal housing, well-designed buildings eliminate or reduce need for air conditioning in most climatic conditions.

Ventilation

Technology Description

Natural ventilation relies on windows opening and infiltration. The creation of natural ventilation that provides comfortable living and working conditions, but does not waste energy is a sophisticated process. It involves careful design that takes into account microclimatic conditions, including airflow patterns around the building.

Ventilation by extraction is used in rooms that are likely to be a source of moisture or odour, such as kitchens and bathrooms. It is usually provided by mechanical extraction fans that are either manually or automatically controlled. A more energy efficient system is passive-stack ventilation (PSV), which does not require power to operate and is "on" all the time. PSV can be controlled by humidity sensors, so that ventilation occurs only when needed.[24]

Conventional mechanical ventilation, air-distribution and heat-recovery systems have been used for many years in industrial and commercial buildings. Modern improvements include treatment of the incoming air to remove pollutants, better control of air movement and airflow, and various procedures to save energy. Removal of pollutants is generally accomplished by filtration. Energy savings can be achieved by conventional or more innovative heat-recovery systems, pre-conditioning of the supply air, energy efficient fans and dynamic insulation.

Use of mechanical supply and treatment systems is uncommon in homes, except in a few OECD countries. Mechanical ventilation systems are just beginning to be deployed in new housing. Classical mechanical ventilation units and air-distribution devices are widely used in non-residential buildings. But even the use of traditional heat-recovery systems is not yet universal. The adoption of modern methods has been slow. More innovative treatment and energy-saving methods are still at the development and demonstration stages. Deployment of new ventilation systems could lead to an energy reduction of 10 to 15%.

Status of Technology Development

Ventilation technology is commercially available today. Large ventilation units usually have a low total energy efficiency (under 25%). Through more efficient and variable-speed motors for fans, transmissions and radial fans, it should be possible to achieve 65% efficiency for such large systems.[25]

24. For more information, see www.est.org.uk.
25. For more information, see http://europa.eu.int/comm/energy_transport/atlas/htmlu/ventdfutpot.html

The European Union points out the need for additional developments in several areas: dynamic insulation through the development of new applications and through demonstrations; cost reduction through optimisation and mass production of efficient ventilators and fans; monitoring of various types of ventilation (natural mainly) to ascertain their running characteristics; and development of sensors to help for preventive maintenance.[26]

Barriers to Greater Market Penetration

There are gaps in technical knowledge about microclimatic impacts on natural ventilation systems and on innovative heat-recovery and energy saving systems. Architects are often unaware of the need to incorporate energy efficient ventilation into their designs. It is hard and costly to add ventilation systems late in the construction process, or to an existing building. Owners and operators of buildings are unaware of the energy-use implications of ventilation. They lack knowledge of what constitutes good indoor air quality and do not realise how energy efficient, pollution-free ventilation can be achieved and how the equipment should be maintained. Guidance is not readily available. Insufficient rates of air change are perceived to cause health problems, and this perception encourages the use of very high fresh-air flows, which can lead to higher energy consumption. In some building types, little use is made of recovered low-grade heat.

Prospects for Overcoming Barriers

The barriers can be overcome by better information for consumers and for the installation and service industries.

Lighting

In addition to different types of lamps, lighting technology includes control gear (ballasts and lighting control systems), fixtures, luminaires, and daylighting, which are all important components in efforts to increase the efficiency of lighting in buildings.

Technology Description

Fluorescent lighting in the form of linear fluorescent lamps provides the majority of lighting in non-residential buildings; high-intensity discharge lamps (including mercury vapour, metal halide and high-pressure sodium lamps) provide the majority of outdoor lighting. The range of efficacy (light output per unit power input) of these lamps is shown in Figure 6.11 and varies by more than a factor of ten. This implies that large energy saving can be made by selecting lamps with higher efficacy. However, other characteristics of the lamps, including the amount and distribution of the light they deliver, their warm-up times and colour properties, mean that only some kinds of lamps are interchangeable without there being a change in the quality of the lighting service.

26. For more information, see http://europa.eu.int/comm/energy_transport/atlas/htmlu/ventdtechdev.html

It is important to appreciate that lighting efficiency is not just a question of using efficient lamps, but also involves several other approaches, such as making better use of daylight; reducing waste through unwanted illumination due to lighting of unoccupied spaces and over-lighting; and using more efficient ballasts, better luminaires and better overall lighting design. Each of these factors can make an important contribution to lighting energy efficiency. For example, superior lighting controls that are able to sense occupancy and automatically dim lights in response to rising daylight levels are proven technologies and highly viable in many applications. Their use can save a substantial proportion of lighting energy, yet they are greatly under-deployed in comparison to their cost-effective potential.

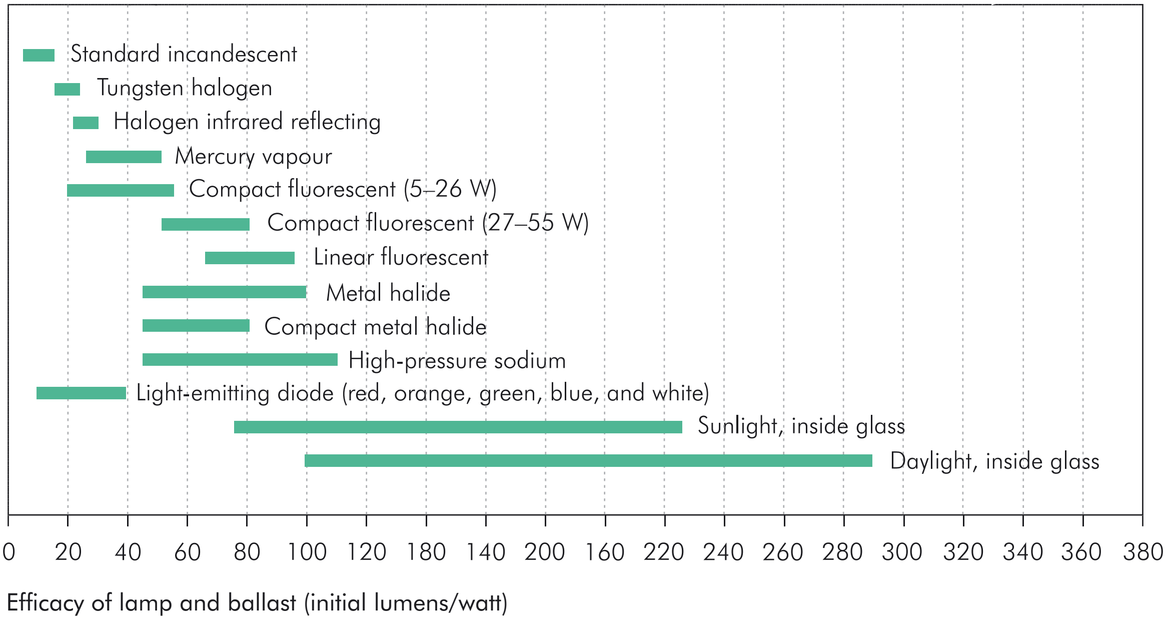
Building designs that optimise the use of daylight are also well-established means of saving lighting energy and are thought to bring other benefits, including enhanced productivity. There is a wide range of architectural devices to enhance the amount of usable daylight in a building; these include light wells, clerestories and light shelves, as well as intelligent blinds which reflect daylight deep into the building while minimising glare. As with other efficient lighting options, these techniques are significantly under used in relation to the savings opportunity they present.

The vast majority of lamps used in houses are incandescent and have an efficiency of around 10 to 15 lumens per watt. Incandescent lighting is the least efficient general lighting technology. In most economies, tubular fluorescent lamps, which are much more efficient at 70 to 100 lumens per watt, come in a distant second, but in some such as Japan and the Philippines, they are the dominant lighting technology. For example, in 2001 in the United States, incandescent lamps accounted for about 90% of household lighting hours and energy use, but just 68% of all delivered light, while fluorescent lamps accounted for about 10% of lighting hours and energy consumed, but 31% of delivered light (Navigant, 2001).

The range of system efficacy of different lamp-types is illustrated in Figure 6.11. Note that not all lighting technologies can be replaced by the other technologies in the figure. In general, standard incandescent lamps can be substituted by higher-efficacy compact fluorescent lamps (CFLs), and mercury vapour high-intensity discharge lamps can be substituted by higher-efficacy metal halide or high-pressure sodium lamps (the choice depends on the application). Halogen lamps used for display lighting can also be substituted by compact metal halide lamps, with a typical four-fold gain in efficiency. Otherwise, the largest gains arise from substituting lower-efficacy versions of a given lamp and ballast technology for higher efficacy equivalents from within the same technology. This can produce significant gains for linear fluorescent lamps, for example.

The evolution of lamp efficacy over time is shown in Figure 6.12. Lighting technologies such as incandescent, tungsten halogen and high-pressure mercury are considered mature technologies with little room for increased luminous efficacy, whereas semiconductor, *e.g.* light emitting diodes, and metal halide lamps are considered to offer high potential for further technical improvements. Semiconductor lighting is the most exciting new lighting technology because its performance has been increasing at a remarkable rate over the last few decades. It has the potential to set new records in terms of lighting efficacy and, if providing cost and light delivery

Figure 6.11 ▶ System efficacy of light sources for general lighting[27]



Source: IEA 2006; reproduced with permission from Advanced Lighting Guidelines, 2003.

Key point

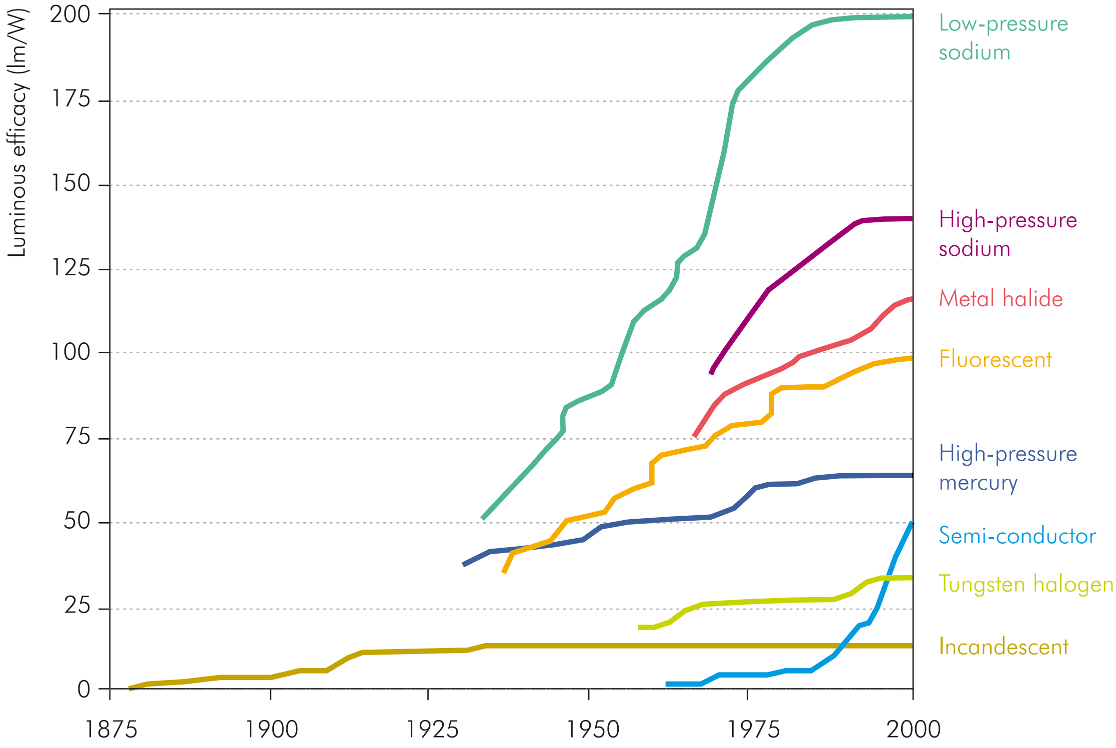
There is a wide range of efficacy across lamp types.

targets can be met, it could become a major high-efficiency source of general illumination within the next two decades. In the near term, however, the greatest gains from lamp changes are to be had from substituting new high-quality CFLs for inefficient standard incandescent lamps, from phasing out mercury vapour lamps, and from using higher efficiency ballasts and linear fluorescent lamps.

A recent Canadian study of lighting in 137 000 commercial buildings contains some valuable information. The survey found that more than 40 000 (29%) have energy efficient lamps; about 42% have energy efficient ballasts; some 20% have manual dimmer switches; 13% have daylight controls; 21% have reflectors; and 9 400 (0.06%) have occupancy sensors. While energy efficient lamps cover less than 30% of the building stock, they are used for almost 60% of the floor space. The survey showed that about 78% of buildings larger than 100 000 square feet had energy efficient lamps, while only 19% of buildings between 1 000 and 5 000 square feet had them. Also, 81% of buildings with more than 10 floors had energy efficient lamps, while only 25% of single-storey buildings had them. (NRCan, 2000).

27. Ballast watts included for discharge lamp systems. Sunlight and daylight ranges calculated inside of single pane clear glass and high performance glass.

Figure 6.12 ▶ Evolution of luminous efficacy of major light sources used for general lighting



Source: IEA 2006; reproduced with permission from www.lamptech.co.uk

Key point

The efficacy of certain lamp types has been significantly improved.

Box 6.9 ▶ Case study: Greenlights

The European Greenlights Programme documents hundreds of energy-saving lighting retrofit projects negotiated under a voluntary programme between government and the private sector. A typical example is the Norwegian enterprise Vital Eiendomsforvaltning AS, which replaced the existing T8 linear fluorescent lamps in their offices by new more efficient T5 linear fluorescent lamps. Prior to the retrofit the lighting system required 30.8 W of power per square metre of floor area; afterwards it only needed 10.2 W. Furthermore, the use of more sophisticated lighting controls allowed average lamp operating time to be reduced by 20%, leading to total energy savings of 75% (800 000 kWh per year) for a 13 000 m^2 building. The payback time for this retrofit was 4 years.

Status of Technology Development

There is sufficient potential for energy efficient lighting to justify further development. Some estimates show the cost-effective potential for efficiency improvements range from 30% to 60%. Further developments are underway. For example, the IEA's

Implementing Agreement on Energy Conservation in Buildings and Community Systems is documenting the effect of design on energy use, lighting quality and human performance and providing examples of good practice to find innovative solutions with existing and promising lighting technologies.[28]

Barriers to Greater Market Penetration

On average, lighting accounts for 34% of tertiary-sector electricity consumption and 14% of residential electricity consumption in OECD countries. These shares are normally higher in non-OECD countries. In the past few decades, new energy efficient lighting technologies have come to the market in all end-use sectors. The choice of lighting depends on the application. Lighting needs in homes are not the same as those in the commercial sector or in public facilities such as hospitals and schools. Still other lighting solutions are appropriate for manufacturing or for streets and highways.

Despite the availability of a whole array of energy efficient lighting technologies, in most countries the inefficient incandescent lamp still dominates domestic lighting, although fluorescent lighting and halogen lamps also make significant contributions.

In the residential sector, the very low purchase cost of incandescent bulbs is a disincentive for consumers to choose more efficient bulbs, such as CFLs, which are more expensive. Moreover, many domestic lighting fixtures are designed for incandescent or halogen lamps and may be inappropriate for typical compact fluorescents because they may not fit into them. In addition, inadequate quality assurance has sometimes allowed poor quality CFLs to be sold which do not achieve adequate lifespan, lumen maintenance, warm up time or colour characteristics, discouraging some consumers from returning to the product.

Newer CFLs are both more compact, available in a larger range of shapes, styles and sizes and can have much better light quality. Furthermore, the price differential between CFLs and incandescent lamps is now much lower and continues to decline. The main barriers are a lack of adequate enforcement and labelling to ensure poor-quality CFLs are distinguishable from high-quality CFLs; broad-based ignorance of the life-cycle cost and environmental benefits of CFLs; and a lack of domestic luminaires designed to take pin-based CFLs (those where the ballast is separate from the bulb).

In other lighting sectors there is a great lack of awareness of the potential to save energy and improve lighting quality through better lighting systems. Moreover, there persists the problem of split incentives between the group that pays the energy bill and that which procures the lighting system. This leads to a non-optimal focus on minimising the initial costs of the lighting system at the expense of much higher running costs. Developers naturally try to minimise their costs.

Major obstacles also include adapting to the user's requirements and the use of control systems. Lighting can contribute to over-heating interior spaces and thus increase the need for more cooling.

28. For more information, see www.ecbcs.org.

Prospects for Overcoming Barriers

There is a need to make the quality and life-cycle costs of lighting systems more apparent to the equipment procurers, to provide financing mechanisms that can overcome initial cost barriers and to provide better education to all those involved in the specification, design, procurement, installation and operation of lighting systems. Lighting provisions in building codes, energy label and efficiency standards, public procurement programmes, financial and fiscal incentives and awareness and capacity building measures can all help to overcome the barriers to energy efficient lighting. Attention also needs to be focused on maintaining product quality through better enforcement of quality standards and labelling.

Appliances

Cold Appliances: Refrigerators and Freezers

Technology Description

Almost all domestic refrigerators use a vapour compression refrigeration cycle to cool stored food. There is a small market for gas absorption-cooled appliances, particularly for mini-bars in hotels. There is also a small niche market for thermo-electrically cooled appliances for camping and mobile homes. Normally refrigerators have a single compressor and condenser and one or two evaporators operating in series in a single cooling circuit. In Europe, about 95% of refrigerators use natural convective cooling to transfer heat to the evaporator and from the condenser. In these appliances automatic defrosting works in the refrigerator compartment simply by periodically allowing the evaporator temperature to rise above zero, but defrosting of the freezer compartment requires user intervention. In North America and the OECD Pacific countries, forced convective-cooling combined with active defrosting by heating the evaporator, known as "no frost", is the more common approach. Worldwide, natural convective cooling is the most common and also the least energy-intensive refrigeration technology, but in some markets no-frost technology is gaining market share.

There is a large variation in the size and unit consumption of refrigerators in OECD countries. Overall, the average refrigerator used 625 kWh per year in 2000. This ranged from 872 kWh per year per unit in OECD Pacific to 850 kWh per year in North America to 432 kWh in OECD Europe (IEA, 2003).

Status of Technology Development

Refrigerators have been commercially available for decades, but improvements are on-going. New developments include vacuum insulation panels around freezer sections; the addition of polyurethane foam to doors; replacing AC motors with DC motors; replacing automatic defrost systems control with adaptive defrosters that operate only when needed; the application of electronic controls; increasing the evaporator and condenser heat-exchange area; increasing the efficiency of the compressor; and using low-energy fans for the heat exchangers. Today's most efficient domestic refrigerator-freezer uses 19% of the energy used by the equivalent appliance on the European market in 1992, but the average new appliance uses about 60% of the energy of the equivalent 1992 model. This indicates that there is still substantial room for improvement in domestic refrigeration appliances.

The same is true of commercial refrigeration. One Canadian study estimated the economic potential for energy savings at 31%, and the US Department of Energy foresees possible improvements of up to 60%. (Basilie, et al.,1998). Refrigeration in some types of commercial buildings, such as supermarkets, represents up to 50% of the building's energy consumption. Some researchers believe that refrigerators of the future will consume half as much energy as those today.

A recent IEA study assumed that there would be a 0.5% improvement per year after 2005 in OECD North America and no significant improvement in OECD Europe through 2020, without further policy measures (IEA, 2003). In fact, new measures have since been introduced in both markets. Improvements can be achieved, however, in a shift in the market towards the purchase of more efficient models.

Barriers to Greater Market Penetration

The biggest barrier is the lack of consumer awareness of the benefits of greater efficiency and of the potential to do better. Purchasing decisions are still often made with little regard to energy consumption, despite life-cycle energy costs often exceeding the purchase price. Furthermore, domestic refrigerators have grown larger, which all other things being equal would cause their energy use to rise.

Prospects for Overcoming Barriers

In some countries, barriers have been addressed by minimum energy performance standards. Energy labelling can complement the standards or be used in place of them to improve consumer awareness at the point of sale. Promotional programmes to highlight more efficient models can also be beneficial. Incentives from energy utilities to encourage early replacement of refrigerators have been effective. Financial incentives have also been used by governments and utilities to replace inefficient models.

Wet Appliances: Washing Machines

Technology Description

In Europe and North America, clothes are washed using a mixture of heated water, detergent action and mechanical action. If a washing machine heats up water internally, this process invariably accounts for the largest share of its total energy consumption. The main determinants are the final temperature of the heated water and the amount of water to be heated.

All washing machines use electricity to drive the motor and operate the control system. Despite the common application of heated water for clothes washing in Europe and North America, there are still some important differences. Most North

American washing machines draw from the home's hot water supply, whereas machines in OECD European countries, with the exception of some in the United Kingdom and Ireland, heat the water directly in the appliance. Until recently, almost all North American appliances used vertical drums, which are inherently less water- and energy-efficient than the horizontal drums traditionally used in Europe. Furthermore, the capacity of most North America washing machines is greater than in Europe and in other OECD countries. This in itself does not necessarily imply higher overall energy consumption, because the small machine may be used more frequently than the larger one.

The spin-drying efficiency of a washing machine can have an important bearing on the total energy consumption of the washing and drying process. Spin drying is a far more efficient means of moisture removal than heating in a clothes dryer. Spin drying may result in slightly higher energy consumption by the washing machine, but will reduce the energy consumed in the full wash and dry process.

In OECD countries, consumption (with electric water heating) averaged 363 kWh per unit per year in 2000. This ranged from 955 kWh per year per unit in North America to 221 kWh in OECD Europe to 96 kWh in the OECD Pacific (IEA, 2003).

Status of Technology Development

Washing machines are a mature technology, but advances are being made in reducing the temperature and quantity of water needed, reducing the size of the structure, optimising the power of the motor, implementing asynhron motor with phase regulation, applying electronic controls and optimising the agitation phase in the wash cycle. Recent IEA analysis assumed a slow rate of improvement without new policies. However, in both OECD Europe and North America there has been a substantial improvement in clothes-washer efficiency such that in Europe, manufacturers believe they are nearing the technical performance limit.

Barriers to Greater Market Penetration

There are no major technical barriers. Various factors prevent the true economic value of energy efficiency investments from being apparent to, or obtainable by, consumers. This is compounded by the fact that energy considerations are rarely a major element in the purchase decision. There is a lack of good data with which to compare appliances. Consumers are very much affected by the perceived risk of using a new or unfamiliar technology.

Prospects for Overcoming Barriers

The barriers have shown to be effectively addressed in countries that have implemented minimum energy performance standards. Energy labelling complements standards or can be used instead to improve consumer awareness at the point of sale. Promotional programmes to highlight more efficient models are also beneficial. Financial incentives have also been used by governments and utilities to replace inefficient models.

Wet Appliances: Clothes Dryers

Technology Description

Clothes dryers work by heating and aerating clothes. They can be powered either by electricity or natural gas. Electric dryers use heating coils and gas dryers use a gas burner to supply heat; otherwise they operate in the same way. All dryers have electric fans that distribute heated air. Natural gas appliances tend to be cheaper to operate than electric ones. Consumption, however, is affected by whether there are sensors to turn the dryer off automatically once the clothes are dry and the efficiency of the heat transfer to the clothes. In general, clothes dryer technology is essentially the same in OECD countries, although there are some regional differences in average dryer capacity and in the use of sophisticated sensing and end-of-cycle technology. There are also differences in the share of gas to electric dryers (in near equilibrium in North America, while electric dryers dominate in Europe).

The most efficient clothes drying technology is not actually in the dryer but is rather in the clothes-washer. Spinning clothes removes moisture for much less energy than does drying via heating, and there are significant differences in the spin speed and drying efficiency of washing machines. Thus, optimising this feature of the washing machine is one of the best means of reducing clothes dryer energy use. Aside from differences in the starting moisture content of clothes, annual average energy use for clothes dryers depends on many factors that influence the degree of use, which often reflect cultural and climatic differences. Throughout the OECD region, the average consumption per year per unit in 2000 was 619 kWh. It was 833 kWh in North America, 353 kWh in OECD Europe and 158 kWh in the OECD Pacific (IEA, 2003).

The best conventional dryers have moisture sensors in the drum. Most machines simply infer dryness by sensing the temperature of the exhaust air. The lower-cost, thermostat-controlled models may over-dry clothes, but even these machines are much better than timed-dryers. Compared with timed drying, about 10% of energy consumption can be saved with temperature-sensing controls and 15% with moisture-sensing controls.

Status of Technology Development

In some sense, clothes dryers are a mature technology, although improvements continue to be made. Developments include reducing the temperature of drying, optimising the heating element, reducing the thermal mass of the appliance, optimising ventilator and air-flow design, reducing waste air, applying electronic controls and installing heat pumps. The latter option leads to dramatic efficiency gains (>50%), but significantly increases the cost of the dryer. The IEA Implementing Agreement Demand-side Management (DSM) gave its first Award of Excellence to a heat-pump dryer that achieves a 50% reduction in energy use compared to earlier models. The dryer is available in Denmark, Germany, the Netherlands, Spain and Sweden and there are plans to market it in other European countries.[29] In many markets an almost equal gain in primary energy use can be obtained by using gas rather than electricity to dry, and in many of these markets the issue is the availability of gas-fired dryers.

29. For more information, see http://dsm.iea.org/NewDSM/awards.asp

Recent IEA analysis assumes a very slow rate of natural improvement without stronger policy measures: only a 0.1% efficiency improvement per year in OECD Europe and no improvement in OECD Europe after 2005 (IEA, 2003).

Barriers to Greater Market Penetration

There are a variety of barriers that obscure the true economic value of energy efficiency investments from residential equipment buyers. This is compounded by the fact that energy considerations are often not a major part of the purchase decision. There is a lack of good comparative data to distinguish among appliances. Consumers are very much affected by the perceived risk of using a new or unfamiliar technology. At present it is not easy for consumers to understand the magnitude of the operating cost savings from using more efficient dryers and thus incremental first cost barriers can be important.

Prospects for Overcoming Barriers

The barriers can be overcome by minimum energy performance standards. Energy labelling complements the standards or can be used instead to improve consumer awareness at the point of sale. Promotional programmes to highlight more efficient models are also beneficial, as well as targeted financial incentives.

Wet Appliances: Dishwashers

Technology Description

Most of the energy used by dishwashers is for heating the water. An efficient dishwasher uses less water to do the job. In North America, almost all dishwashers available today use booster heaters to further heat the water supplied by the water heater to the high temperatures required for dishwashing. In Europe, the input water is cold and is fully heated by the appliance.

There is a dearth of good data on the energy used in washing dishes by hand and on the proportion of dishes washed by hand or in a dishwasher. Without such information, it is hard to analyse average per household energy consumption for the dishwashing process. Nonetheless, modern dishwashers are generally significantly more efficient than they once were. They increasingly use sophisticated sensors to determine the quantity and dirtiness of the dishes to be washed, a technology that minimises the amount of energy required for water heating. Dishwasher manufacturers argue that cleaning dishes in a dishwasher consumes less energy than washing them by hand.

In OECD countries, energy consumption averaged 488 kWh per unit per year in 2000. This ranged from 850 kWh per year per unit in North America to 295 kWh in OECD Europe to 281 kWh in the OECD Pacific (IEA, 2003).

Status of Technology Development

Electric dishwashers are a mature technology, although the best available models continue to be much more efficient than the average in most markets. Developments continue to be made to reduce energy consumption particularly related to sensors and controls and minimised standby power requirements. In

Europe, the average efficiency of new dishwashers has increased by about 40% in the last decade and the technology is claimed to be near its technological limit. IEA analysis based on the impacts of policies in place in 2001 assumes a 0.5% per year increase in energy efficiency improvements in OECD North America and a 3.1% per year increase between 2005 and 2010, slowing to a 0.5% per year increase thereafter in OECD Europe (IEA, 2003).

Barriers to Greater Market Penetration

There are a variety of barriers that prevent the true economic value of energy efficiency investments in dishwashers being apparent to, or obtainable by, consumers. This is compounded by the fact that energy considerations are rarely part of the purchase decision. There is a lack of good comparative data with which to compare appliances.

Prospects for Overcoming Barriers

The barriers are primarily addressed by minimum energy performance standards. Energy labelling complements the standards or can be used instead of them to improve consumer awareness at the point of sale. Promotional programmes to highlight more efficient models are also beneficial.

Cooking

Technology Description

The energy used to cook food is strongly dependent on cultural factors and shows high variability within OECD regions, especially Europe, as well as between regions. In North America, OECD Europe, Australia and New Zealand, the most important cooking appliances are ovens, ranges and microwave ovens. Cook-top extractor hoods and miscellaneous kitchen devices, such as coffee and bread makers, can also use significant amounts of electricity. In Japan and in other Asian countries, rice cookers are an important cooking device. The majority of cooking energy is used to heat food. Smaller amounts are used for defrosting frozen food and the control of cooking appliances. Cooking is not an electricity-specific activity, and a significant share of primary cooking energy takes the form of natural gas or liquefied petroleum gas (LPG) in OECD countries.

In many developing countries, biomass, in the form of wood, agricultural residues and dung, is a common form of cooking and heating fuel. In urban areas, especially in Africa, charcoal is often favoured over these fuels for cooking despite being illegal in many countries due to unsustainable wood harvesting that leads to deforestation. Although biomass is a renewable source of energy (provided it is managed sustainably), traditional biomass-fired stoves fill the users' homes with smoke and cause serious health problems, especially for women and children. These stoves also cause significant greenhouse gas emissions due to the formation of products of incomplete combustion (PIC).[30] In many developing countries,

30. Biomass fuels that are grown and harvested in a sustainable fashion do not contribute to CO_2 emissions, because the released carbon is considered to be recycled through photosynthesis in growing the biomass that replaces the burned biomass. However, the gases released as products of incomplete combustion contribute to global warming because of higher radiative forcing per carbon atom than does CO_2. Thus, such fuels have the potential not contribute to global warming effects when grown on a sustainable basis. (Smith K., *et al.*, 2000).

particularly in Africa and Asia, the widespread use of wood for cooking and heating has lead to deforestation and erosion.

Cook stove efficiencies vary extensively and depend on a mixture of factors such as the type of fuel- wood used, the stove's characteristics and the type of cooking (simmering, frying or boiling). Two major factors influence the overall efficiency of a cook stove: the efficiency of combustion and the efficiency of heat transfer to the pot. There have been efforts both to improve the efficiency of wood stoves and broaden the use of efficient stoves. The Chinese Government undertook a substantial programme to disseminate improved cook stoves in the early 1980s. The goal was to improve wood stove efficiency from 10 to 20%, and then to 30%. Government statistics claim that by the late 1990s, more than 180 million households had installed cook stoves (90% of the total number of rural households in China). There have also been successful cook stove dissemination programmes in Kenya, Uganda and Ethiopia, to name a few. However, improvements thus far have focused on heat transfers and much less on efficient combustion.

In developing countries, there has also been interest in solar cookers. Different designs have been developed such as box cookers, panel cookers and parabolic cookers (Solar Cookers International, 2005). Solar cooking could save significant amounts of conventional fuel. On clear sunny days, it is possible to cook both mid-day and evening meals in a solar cooker. Solar cooking, however, does not fully replace conventional fuels, but can usefully supplement them.

LPG is the most common substitute for fuel wood in rural areas. It can be carried to isolated areas without major infrastructure investments and can be stored safely. There have been many multilateral and bilateral initiatives to increase the use of LPG, with varying degrees of success.

Status of Technology Development

There are many energy savings technologies for cooking in both OECD and non-OECD countries. In many OECD countries, gas cooking has an appreciably lower primary energy and CO_2 impact than electric cooking. Efficient gas burners convert 65% of their energy to the cooking process, but typical burners are far less efficient. Among electric cook-tops, those that work by induction can save more than 30% of the electricity used by conventional solid plate or coil elements, while halogen or ceramic hobs are typically 15% more efficient than conventional elements. Microwave ovens are also generally more efficient than conventional ovens, especially when small volumes of food are being prepared. They can also be used in efficient but flexible multiple cooking modes, which combine the benefits of microwave cooking with those of convective and radiative cooking. These technologies are all fully commercialised, but the benefits are often not clear to end-users. Most current developments are taking place in developing countries, where there are efforts to improve stoves using biomass or bottled gas.

Ethanol gelfuel and dimethyl ether (DME) are among new options that are designed to compete with LPG in rural areas. Ethanol can be obtained from renewable sources through the fermentation and distillation of sugars derived from molasses, sugar cane, sugar beets, or from starch crops such as maize. Brazil is the biggest producer of bio-ethanol and uses it as an automotive fuel. Ethanol-gel is a mixture of ethanol and a thickener added to increase its safety by diminishing its volatility. The large-scale replacement of firewood and charcoal by ethanol gelfuel in Malawi offers a good example of how it is possible to alleviate major problems such as the deforestation of vast areas of a country and widespread respiratory diseases caused by indoor charcoal use. Ethanol gelfuel provides a safe, spill-proof, non-toxic, smoke-free and efficient alternative energy source for the urban poor who are the main consumers of charcoal (Wynne-Jones, 2003). The World Bank has encouraged the development of gelfuel in Africa as a potential contributor to achieving the Millennium Development Goals. However, scaling up this development will necessitate a rigorous assessment of the "fuel versus food" dilemma (Utria, 2004).

DME has characteristics similar to LPG as a household cooking fuel. The production of DME follows the same techniques as that of methanol. It can be made from any carbonaceous feedstock (natural gas, coal or biomass) using established technologies. Coal is the most energy intensive of these sources, but the production of DME from coal is cleaner than households burning coal directly. Because of China's abundant coal resources, the production and use of coal-derived DME as a cooking fuel could be attractive.

Particularly since the 1980s, there have been many developments underway to improve the efficiency of woodstoves and to deploy them more widely. In some cases, efficiency has improved by 40% or more. About 90% of worldwide installations have been in China (WEC, 2000). As countries move up the development ladder, the trend is to switch away from biomass to kerosene or LPG. Biogas stoves are almost at the point of commercialisation (WEC, 2000).

Barriers to Greater Market Penetration

Diffusion of these technologies is slow. Approximately three billion people rely on traditional solid fuels for cooking and heating and lack access to clean modern fuel (WHO, 2006). The main reason is the initial cost of stoves and equipment, particularly in poor rural areas. Improved cook stove programmes do not require major funding, but they need a long-term commitment by implementing organisations.

Prospects for Overcoming Barriers

In developing countries, incentives are needed to introduce more energy efficient cookers. Such incentives are now being offered, often through bilateral and multilateral aid programmes. In OECD countries, much more could be done to make the energy efficient cooking appliances visible at the point of sale through expanded energy labelling, which currently is used for very few cooking products. Energy efficiency standards, awareness campaigns and financial incentives are other complementary options.

Domestic Hot Water Heating: Conventional Fuels

Technology Description

Efficient water heating technologies aim to optimise the use of both energy and water for a variety of household purposes. Providing domestic hot water is the major purpose. However, in North America and Australia, dishwashers and washing machines are also supplied from hot water systems. In Europe and Japan, appliances heat the water directly and thus lessen the need for water from separate hot water systems. There is a large variety of appliances commercially available. Some produce hot water for space heating and domestic sanitary purposes, others produce only hot water. In Europe, combination ("combi") boilers which provide sanitary hot water and hydronic heating systems are common, although water heaters dedicated to only providing sanitary hot water are also common. In North America and Japan, hydronic heating systems are rare and thus water heating is almost exclusively for sanitary hot water purposes.

Water is traditionally heated either by electricity or by natural gas. Water heating by electrical resistance means is nearly 100% efficient, but that does not necessarily make it a better option than alternatives as its primary energy and CO_2 requirement is usually higher than for natural gas-based water heating, although this depends on the fuel-mix for electricity generation. Most electrically-heated hot water used in OECD countries is delivered from storage water heaters whose tanks have standing losses which can amount to up to 30% of the input energy. Improved insulation will reduce these losses and most OECD regions now have either efficiency standards or industrial agreements aimed at reducing these losses. Most storage water heaters operate at water-tap pressure, but vented units, which are gravity-fed from raised feed tanks, are still quite common in the United Kingdom and Ireland. In central Europe, small point-of-demand electric water heaters are common and have the advantage of fewer losses in distribution but involve either higher storage losses or less off-peak heating. In some countries, utilities have introduced power line carrier ripple control of storage water heaters to reduce on-peak water heating demand. Finding the right balance between peak and off-peak heating and losses through the distribution system is one of the main areas for optimisation of conventional water heating systems.

In OECD countries, consumption averaged 3 189 kWh per unit per year in 2000. This ranged from 3 977 kWh per year per unit in OECD Pacific to 3 823 kWh in North America to 2 492 kWh in OECD Europe (IEA, 2003).

Status of Technology Development

A number of more efficient technologies are under development or have yet to achieve their market potential. At the low-tech end, there is considerable potential to reduce standing losses by better insulation of the water tank and the distribution network, and by optimising the distance to the point of demand against the choice of heating technology. Demand response ripple control technology can be applied where it makes sense for utilities to use water heating as a means of regulating their load profiles. In many economies, significant gains in primary energy and CO_2 emissions can be made by encouraging the use of gas in place of electricity. At the more advanced technological scale, heat-pump water heaters have considerable potential to reduce electricity demand for water heaters. This technology can reduce demand by up to a factor of three, but faces a number of barriers to full commercialisation. In the case of hydronic space heating systems using comb-boilers, there are considerable space and water heating savings to be had by using gas-condensing boilers in place of traditional models. Further significant electricity savings can be achieved by using variable speed pumps to circulate the water and by ensuring that the water circulation system is properly controlled. Another interesting option is the use of closed-loop water return systems that return hot water to the tank rather than leaving it resting in the distribution pipes if a small water draw-off has occurred.

Barriers to Greater Market Penetration

As with other energy efficient technologies, there are many barriers that discourage the use of life-cycle costing as the basis for choosing water heating technology and this favours the use of cheap but inefficient technologies. There is a lack of comparability of the life-cycle costs of water heating systems and as many systems are bought under severe time pressure during an emergency, *i.e.* when the hot water system has failed, there is a tendency for users to adopt whatever a plumber proposes. Much could be done to improve the quality and comparability of performance information and to ensure that professional installers are also motivated to offer products that lower the life-cycle cost to the end-user.

Prospects for Overcoming Barriers

Good information about fuel choice is important as is fully comparable information on system costs and performance over the life-cycle. Building code energy performance requirements, energy labelling, minimum energy performance standards and incentives can all help in overcoming the barriers to efficient water heating technology. Improved R&D for heat pump water heaters and low-cost circulation pumps would also be helpful.

Hot Water Heating: Solar

Technology Description

Solar hot water heaters use the sun to heat either water or a heat-transfer fluid in collectors. There are passive systems and active systems. A typical system will reduce the need for conventional water heating by about 70% and can reduce fuel use by 10 to 30%. Glazed flat-plate collectors are most commonly used for this application, although unglazed collectors tend to dominate in Australia and the United States. Vacuum tube collectors are also available and dominate in China's market. Other important components include the heat-transfer liquid, heat exchanger, control system and a pump to circulate the liquid. Most systems also have an auxiliary heater to ensure that hot water needs are met even when it is very cloudy.

Seasonal water heating may be more suitable for temperate climates or for applications with seasonal use, such as summer cottages. In this case, a system based on batch collectors can be a viable alternative, but the standard collectors are still used.

Hot water for a wide variety of commercial applications can be provided by liquid solar collectors. These systems have a collector area of 10 to 100 m^2. There are many potential applications, but the most common are for apartment buildings, hotels, car washes, restaurants, recreation centres and hospitals.

Status of Technology Development

Solar water heating systems are commercially available, although market penetration is relatively small. For example, more than 500 000 solar hot water systems have been installed in the United States, mostly on single-family homes. The majority of these systems are used to heat swimming pools.

For domestic hot water, the energy payback time is often less than one year. It is estimated that further cost reductions in the range of 40 to 50% are achievable through further development (WEC, 2000).

Barriers to Greater Market Penetration

There are concerns about the costs and reliability of hot water solar systems as well as about the need to have back-up systems. There is often a lack of a good distribution, installation and service companies. There are also some regulations about aesthetics that can prevent such systems from being installed.

Prospects for Overcoming Barriers

Many of the barriers can be overcome by good information. Standards, guarantees and certification of installers are useful.

Home Consumer Products: Televisions

Technology Description

Among the television technologies, plasma screens are significantly more energy intensive than cathode-ray tube (CRT) screens. Liquid crystal display (LCD) screens by contrast use much less energy to provide the same display function. Even among CRTs, energy efficiency can vary by more than 40%, so there are substantial technical savings potentials even using the traditional technology. Furthermore, not all of a television's energy use is linked to the visual display function; much is also used to decode the signal, provide the sound and other features. There are a number of technical options to reduce energy use in these functions, not least of which is to lower the amount of standby power such appliances require when not in operational mode. Standby power requirements can range from much less than 1 watt to 30 watts when the television is not in use. A French survey found the average standby power to be 7.3 watts (IEA, 2001), but due to co-ordinated policy and commercial developments, more recent televisions are likely to use less standby power than older sets.

Set-top boxes, which are used to decode commercially purchased satellite or cable television programmes are a major new source of electricity demand. More than a billion are projected to be purchased worldwide over the next decade. These appliances currently use 10 to 20 W while switched on, but almost as much when switched off. There is great potential to lower their power requirements through better technology and co-ordinated policy measures.

Status of Technology Development

Many types of televisions are commercially available, LCD screens and organic light emitting diode sets offer the greatest on-mode energy savings potentials in the near future. Despite the rapid progress of these technologies, more research effort is needed to minimise the power demand of high definition and large television screens. Greater research could also help to lower the future power demand requirements of pay-television decoders. A strong effort to lower the stand-by energy consumption of both televisions and set-top boxes is underway, but more could be done. Furthermore, high-definition television is under active development and this service will tend to increase television energy use. Manufacturers are working toward lowering energy consumption in the active mode in order to reduce the total use of materials and to become more price competitive (Horowitz, 2005).

Barriers to Greater Market Penetration

While energy used to power televisions is beginning to rival the level of major domestic appliances, the energy performance of televisions is not easily visible to consumers. In OECD countries, there are no comparative energy labels for televisions in place. The same observation applies to set-top boxes. Without this information, it is very difficult for energy use to enter a buyer's criteria for the choice of new TVs and set-top boxes.

Prospects for Overcoming Barriers

Energy advice, labelling and minimum energy performance requirements are important tools which could be deployed more fully. China is currently planning to implement standards and labelling for televisions, and only Australia, China and California are currently planning to regulate set-top box energy use.

Office Equipment: Computers and Printers

Technology Description

The average desktop computer uses about 120 watts per hour (the monitor uses 75 watts, and the central processing unit uses 45 watts). Laptop computers use considerably less, about 30 watts total. Personal computers and monitors consume approximately 40% of all energy used by office and telecommunications equipment in US commercial buildings.

Printers with automatic "power-down" features can reduce electricity use by more than 65%. These printers automatically power down to between 15 watts and 45 watts after specified periods of inactivity. Printers consume 30 to 40% of their peak power requirement even when in idle mode. If the printer is left idling for long periods of time, the power used outweighs consumption during the printing process. Energy efficient printers that power down can reduce energy use by 50% while idling. However, the largest energy impact of printers is not in their direct energy use but in the amount of paper they require to print documents because of the high-embodied energy in printer paper. The most efficient printers are thus those that make duplex (double-sided) printing both easy and the norm. At present this is not possible with many printers and unwieldy with many that do offer it as an option. Attention to the user interface is thus also an important energy saving issue for duplex printers.

Status of Technology Development

Computers vary considerably in their energy needs depending on a number of factors, including the user friendliness and default settings of the power management systems. Developments are under way in particular to reduce energy consumption during idle periods. More could be done to rationalise the software – hardware interactions to minimise computer processing power demand.

Barriers to Greater Market Penetration

Energy costs are a minor consideration for most computer users, although the total energy consumption can be significant for businesses. As with other commercial building loads, there is a double impact in many buildings due to the devices' contribution to air conditioning loads. This means that overall energy savings are often greater than the savings solely from the computer because of reduced air-conditioning loads. Efficiency is an important feature for laptops because of the need to re-charge the batteries.

Prospects for Overcoming Barriers

Energy labelling and comparative information are important options for improving awareness. Some countries have also implemented minimum energy performance specifications for computers and printers.

Micro-generation Systems

Solar Photovoltaics

Technology Description

A solar photovoltaic (PV) system is not an energy technology for buildings per se. PV systems can be used virtually anywhere the sun shines. Buildings, however, offer large areas with which to capture solar radiation for producing electricity, either for use in the building or to be fed into the electricity grid. Studies have shown that significant shares of electricity demand can be met by solar PV systems on buildings.[31] From the building perspective, solar PV systems provide electricity at the point of use.

Solar PV installations fall into two categories: systems that bolt onto an existing building; and integrated systems that replace roof tiles with PV tiles, or existing external cladding, with PV cladding.

A UK study of micro-generation found that a system of 2 kilowatts peaks (kWp) could provide between 40% and 50% of a typical domestic household's total annual electricity needs (DTI, 2005). The average cost is around USD 11 000 per kWp.[32] A 2 kWp system would generate around 1 500 kWh per year. This would reduce electricity costs by about USD 174 per year and would reduce CO_2 emissions by about 0.65 t CO_2 annually. An average 2 kWp household system could be

31. Potential for building integrated photovoltaics, IEA PVPS Task 7-4, 2002.
32. More recent information outside the United Kingdom shows that the typical price for small systems is USD 6-10 per Wp.

amortised in about 120 years, (based on current UK electricity prices). Solar PV is suitable for both urban and rural environments.

Status of Technology Development

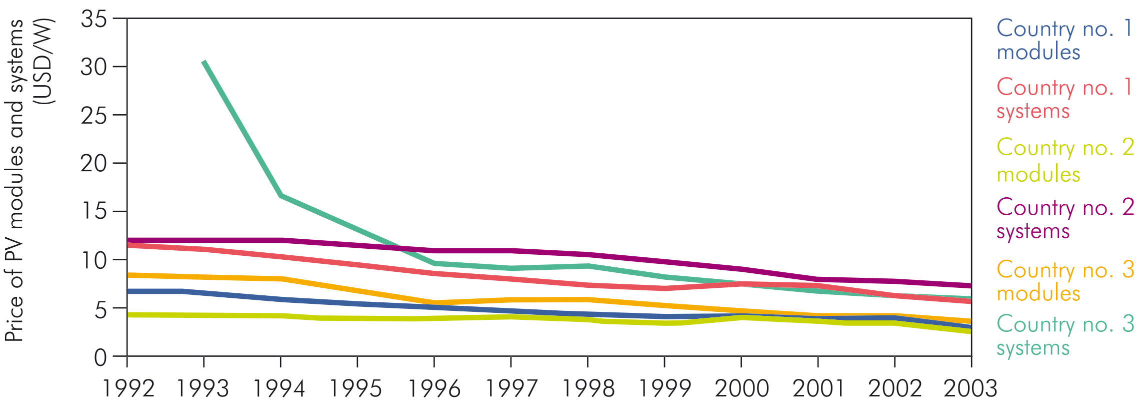
Solar PV is commercially available. The PV market is growing at a rate of 30 to 40% annually. Shipments in 2005 totalled more than 1.4 GWp. However, much more development is still needed to reduce costs and make the systems competitive with other options.

Current fundamental RD&D focuses on developing or improving PV solar cells and modules. Efforts are directed towards new materials and processes; new thin-film technologies; higher performance multi-layer and concentrating cells; improving efficiencies and reducing costs of crystalline silicon cells; better measurement and characterisation; and basic research into photon and materials interaction.

Ongoing applied RD&D is oriented more towards manufacturing and systems and aims to find ways to reduce costs and improve manufacturing; develop new concepts of wafer, cell or module production; maximise PV's value in grid support; improve access to new products; foster synergies and partnerships; and provide consumer information.

Figure 6.13 shows the evolution of the price of solar PV modules and systems in selected countries.

Figure 6.13 ▶ *Price evolution of solar PV modules and systems in selected countries, 1992-2003*



Source: IEA-PVPS, 2004.

Key point

The price of solar PV has declined.

Barriers to Greater Market Penetration

Initial costs and the length of the payback period are crucial issues. In some locales, it can be difficult to sell excess electricity to the grid. In many countries, there are not many PV distributors and installers, but the market is generally expanding rapidly.

Local officials lack experience in approving such systems. Some areas of historical or architectural preservation refuse to allow PV systems to be attached to a building. There are concerns about quality and standardisation because manufacturers and installers are small and have been in the business for only a short time.

Prospects for Overcoming Barriers

Feed-in-tariffs, subsidies and improved regulatory framework can serve as market introduction programmes to help reduce the initial costs of deploying photovoltaic technologies. Regulations, standards and labelling are important. More installers should be trained and certified. More R&D and demonstrations would be useful to reduce costs and improve system reliability.

Micro Wind Turbines

Technology Description

Micro wind turbines can power a single dwelling, a business or a whole community. There are examples of stand-alone turbines for schools, sports centres and business parks, but few for residences.

A wind turbine converts wind power to electricity. The blades drive a generator either directly or by way of a gearbox. The electricity can either feed into the grid or charge batteries. Small wind turbines, less than 20 kW, produce "wild" alternating current (AC) current, which is converted to direct current (DC) through a system controller. The DC is then converted to normal AC (240V 50Hz in Europe) current by inverters. One analysis shows that a 6 kWp system would be amortised in about 29 years, based on current electricity prices (DTI, 2005).

Status of Technology Development

Micro wind turbines are commercially available, although the market is under developed and there are not many companies in OECD countries providing the full range of services from design to installation and maintenance. Most small-scale turbines still need to reduce costs through a combination of further technical development and greater market deployment to lower production costs. There are research efforts underway to reduce both the cost of energy produced and the cost of installation.

Barriers to Greater Market Penetration

Initial costs and the length of payback time are crucial issues. It may be difficult to sell the electricity produced by small-scale wind turbines to the local grid. There is a small market with about 50 manufacturers worldwide, with total production at about 50 000 units per year.[33] There are growing interest in hybrid systems of micro wind turbines and solar PV.

Prospects for Overcoming Barriers

Subsidies to consumers can help to reduce initial costs. Regulations, standards and labelling are important. Installers should be trained and certified. More RD&D would be useful.

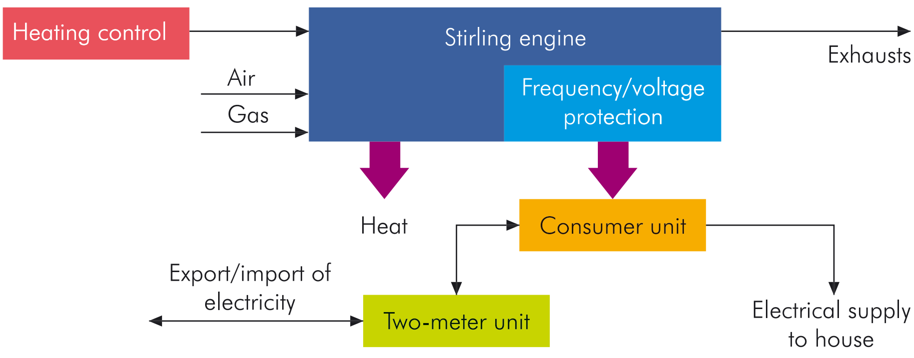
33. For more information, see www.windenergy.com

Micro Combined Heat and Power

Technology Description

Micro CHP produces heat and power simultaneously in plants of less than 50 kWe. The heat is used for space conditioning and water heating. The electricity is used

Figure 6.14 ▶ Stirling engine



Source: Cogen Europe, 1999.

within the building where it is produced or it is sold to the grid. Various conversion technologies are used in the residential sector, including reciprocating engines, Stirling engines, low- and high-temperature fuel cells and micro gas turbines (Figure 6.14). Micro CHP is similar to many conventional boilers in terms of installation, service and product life. The differences concern electrical connection and net metering.

Status of Technology Development

Reciprocating-engine technology is commercially available. Micro CHP using the Stirling engine is close to being ready for the market, but they still need more development to get costs down. Fuel cells are farther from market readiness. A recent survey by Cogen Europe shows a very small market.[34] For example, in the United Kingdom and Portugal, there are only four different units being sold. In the Netherlands, only about 100 units have been installed. However, the market potential is substantial.

Even with the small level of deployment, the simple payback is favourable. In the United Kingdom, in a three-bedroom home, an installed unit has a simple payback of 3.3 years, while in a house in Germany the payback was 7 years. In the commercial sector, the payback periods range from 3.9 years to 14 years.

34. For more information, see www.cogen.org. The countries reviewed were the Czech Republic, Germany, the Netherlands, Portugal and the United Kingdom.

Barriers to Greater Market Penetration

Micro CHP faces the same barriers as other energy efficient technologies. Because it is a new technology there is still need for more technical development. CHP needs to be incorporated into existing legislation, accreditation and rating frameworks. Initial cost is a major barrier.

Prospects for Overcoming Barriers

Micro CHP products will need to be manufactured in very large numbers if the price is to be lowered to a point which customers find it acceptable. This can be achieved with initial government support and with a stable policy and legislative framework.

Fuel Cells

Technology Description

A fuel cell is an electrochemical device that converts hydrogen and oxygen into water and produces electricity in the process. Fuel cells can be used for many purposes, including buildings. The unit consists of an electrolyte sandwiched between two electrodes. Oxygen passes over one electrode and hydrogen over the other. This process generates heat, water and electricity. Fuel cells can be fuelled by natural gas, LPG or biofuels. Natural gas has a widespread infrastructure which should help at the commercialisation stage. In the medium to long term, the increased use of renewables will further improve its low carbon attributes.

Status of Technology Development

The technology is still under development, although some versions have been deployed commercially or in demonstration projects. Several types of fuel cells that are appropriate for buildings are under development. Proton-exchange-membrane fuel cells can be used for buildings and they are considered a promising technology. Micro CHP systems using fuel cells require more R&D and pilot studies. Fuel cells will be competitive for both commercial and residential applications when capital costs are reduced to USD 1 350/kWe (Jones, 2005).

Barriers to Greater Market Penetration

Fuel cell technology is still under development and is not at the commercial stage yet. Linde AG in Germany is planning for mass production to begin in 2006.[35] The usual issues about reliability, cost and effectiveness must be overcome. Technical performance risk remains very high. As the European Union Atlas study showed, "most of these technologies do not guarantee minimum length of operation, require specialised personnel for operation, and cost much more (often by an order of magnitude) than competing technologies in the same markets.[36] Also the technology has not accumulated a substantial number of operating hours and an increase in operating knowledge and number demonstration units will be necessary before investors are willing to purchase fuel cells."[37] The distribution and service industry is still immature.

35. For more information, see www.sigen.co.uk/downloads/Shop/Notes/P-21-AppNote1.pdf
36. For more information, see http://europa.eu.int/comm/energy_transport/atlas/htmlu/bfcdmarbar.html
37. For more information, see http://europa.eu.int/comm/energy_transport/atlas/htmlu/bfcdmarbar.html

Prospects for Overcoming Barriers

More R&D and demonstrations are certainly needed. Financial incentives, better information, better public awareness, standardisation and certification are also important.

Miscellaneous Technologies

Energy Management Systems and Controls

Technology Description

Building management systems and controls are designed to control, monitor and optimise various functions and services provided in a building. These include heating and cooling, ventilation, lighting and the management of electric appliances.

Basic control technologies have been in existence for some time. Available systems range in complexity from simple timer-controlled water heaters or thermostatic radiator valves, to "smart buildings" which manage everything from security and safety systems to air conditioning, lighting and ventilation, to telematic services and most appliances. Computers are more and more often used in energy management systems and allow off-site management. The use of these control systems technologies can produce large energy savings.

Status of Technology Development

Control systems are commercially available. Advances are occurring as computer-based monitoring improves, sensors evolve, and as more equipment and appliances in buildings lend themselves to such management.

To a growing extent, energy systems are used to balance demand and supply and demand and to reduce expenditures on reserve capacity and peak-load supply.

A comprehensive building energy management system can reduce energy use by 10 to 20%. The potential is high for further market deployment. For example, in the United States it is estimated that only 5% of small businesses have energy management systems. There is also a recent trend in having information technology-based companies shift to the energy management systems field, thus bringing new technologies and systems that are used in other industries (Lesage, 2005).

Barriers to Greater Market Penetration

Lack of information and awareness of the potential benefits (especially among smaller users) are major barriers. Sometimes there is a lack of good distribution, installation and service support and often that support only targets larger users.

Prospects for Overcoming Barriers

A greater range of information is needed from a variety of sources. Energy audits are useful in analysing the potential for energy efficiency improvements and the various technological options. Specialised building energy management systems companies are important, especially in designing the appropriate system for the specific need.

Meters and Metering

Technology Description

So-called "smart" meters are becoming more common. Smart meters display and record real-time energy consumption data. The information can be made available to the energy company or the consumer at the meter itself or at a distance. With smart meters, the consumer can pay differentiated rates depending on the time of day or the season. Smart meters also allow accurate monitoring of excess electricity from micro-generation that is sold to the grid (net metering). Smart metering facilitates pre-payment or pay-as-you-go plans.

Studies have shown that smart meters can produce energy savings of 5 to 15%. Smart metering can be used for both electricity and natural gas. The fact that data is provided directly to the utility obviates the need for manual meter reading.

Status of Technology Development

Smart meters are commercial, but there is on-going development. In the United States, scientists at Pacific Northwest National Laboratory have developed a wireless system for electricity end-use metering, which permits near real-time measurement, tracking, and reporting for hundreds of different appliances and heavy electric equipment. Easy to install and use, the system provides cost-effective solutions for facility managers interested in proactive energy consumption management and researchers studying electricity use.

Individual power meters with 120 volt AC or 240 volt AC receptacles are connected directly to appliances and report data at intervals from ten seconds to several hours, depending on individual settings. The data are stored centrally and are available for viewing, printing, archiving, and downloading into spreadsheets.

Barriers to Greater Market Penetration

There is poor standardisation of smart meters. Existing meters have a long lifespan and it is often not cost-effective to replace them early, given their initial cost. In some countries, where deregulation allows for fairly quick switching of energy companies, the ownership and replacement of company-specific meters can cause major problems. The lack of any regulatory requirement for smart meters is a concern.

Prospects for Overcoming Barriers

The barriers can be overcome by regulations, certification and subsidies for installation. Information and awareness campaigns are important to explain the benefits of smart metering.

Chapter 7 INDUSTRY

Key Findings

- *Final industrial energy use was 106 EJ (2 530 Mtoe) in 2003, which is about one-third of total global energy use. Including coke ovens, blast furnaces and steam crackers, industrial CO_2 emissions amounted to 5.3 gigatonnes (Gt), or about 22% of worldwide CO_2 emissions. Of this, 26% came from the iron and steel industry, 25% from non-metallic minerals and 18% from petrochemicals.*

- *In primary steel production, there is considerable room for efficiency improvements, on the order of 20 to 30%, based on existing technology. Further savings can be achieved if new technology is considered. Fuel substitution in blast furnaces could also reduce CO_2 emissions. The potential for energy efficiency gains in aluminium production is limited, but a breakthrough in the use of inert anodes could reduce energy demand by up to 30%.*

- *In theory, production of paper from pulp can use close to zero energy, which leaves a significant potential for efficiency gains. Outdated small-scale paper plants in developing countries, notably China and India, use excessive amounts of energy. Larger plants, more-efficient drying technologies and black liquor gasification could reduce the energy needs of paper and pulp production substantially.*

- *The cement and chemicals industries are approaching the theoretical minimum energy use in many countries. However, China could improve the energy efficiency of its cement industry by almost 50%. Waste recycling reduces energy demand, but is limited by the availability of waste materials.*

- *The energy efficiency potential of the chemical industry is limited in all regions by the high feedstock intensity of its processes. Using biomass feedstocks and recycling more plastic waste could reduce life-cycle CO_2 emissions substantially.*

- *Improvements to steam supply systems and motor systems offer efficiency potentials on the order of 15 to 30%. Combined heat and power generation can bring 10 to 30% fuel savings over separate heat and power generation.*

- *CO_2 capture and storage could be applied to several industries on a gigatonne-scale, especially in the production of chemicals, iron and steel, cement and paper pulp. This option has received limited attention so far, so further RD&D is needed.*

- *Overall, industry offers a significant savings potential at low or even negative costs. This potential deserves more attention than it has received so far.*

- *More RD&D would be needed for solutions such as breakthrough process technologies, biomass feedstocks and life-cycle optimisation based on recycling and materials use efficiency. Clear long-term policy targets are needed that convince industry that investments in risky and costly technologies make economic sense.*

Overview

This chapter focuses on industrial energy use and the potential to reduce CO_2 emissions in the industrial sector. Industry accounts for nearly one-third of the world's primary energy use and emits approximately 22% of the world's CO_2. Carbon dioxide emissions can be reduced in three main ways: efficiency measures; fuel and feedstock substitution; and CO_2 capture and storage (CCS).

Although the industrial sector is also a source of non-CO_2 greenhouse gas emissions (such as perfluorocarbons from aluminium smelters and nitrous oxides from nylon and fertiliser production), these emissions are not directly related to energy use, and industry has already made great progress in reducing them. Such emissions, therefore, remain outside the scope of this analysis.

A great deal of energy is stored in materials, a fact that allows many possibilities for efficiency and CO_2 reduction improvements that do not exist in other sectors. Biomass feedstocks can be used instead of oil or natural gas, waste materials can be recycled, and products can be designed to require smaller amounts of material. Different categories of options emerge based on the emission reduction approach.

Improving energy efficiency plays a very important role. The energy intensity of most industrial processes is at least 50% higher than the theoretical minimum determined by the basic laws of thermodynamics. Many processes have very low energy efficiency, and average energy use is much higher than the best available technology would permit. In cases where the actual efficiency is close to the practical minimum, innovations in materials and processes would enable even further gains.

Cross-cutting technologies for motor and steam systems would yield efficiency improvements in all industries, with typical energy savings in the range of 15 to 30%. The payback period can be as short as two years, and in the best cases, savings can run as high as 30 to 50%. In energy-intensive industries such as chemicals, paper, steel and cement manufacturing, the cost-effective efficiency gains are on the order of 10 to 20% with commercially available technologies.

Many emerging technologies are being developed, demonstrated and adopted in the industrial sector. Technologies such as smelt reduction and near net-shape casting of steel, new separation membranes, black liquor gasification and advanced cogeneration can bring even further savings as they are commercialised and adopted by industries (Worrell, *et al.*, 2004). A study published in 2000 identified roughly 175 such emerging technologies, applicable to industries as diverse as petroleum refining, food processing, mining, glass-making and the production of chemicals, aluminium, ceramics, steel and paper (Martin, *et al.*, 2000). Of these, 54 were evaluated and more than half promised high energy savings, many with simple payback periods of three years or less.

Besides emerging technologies, completely new process designs and processing techniques are on the horizon, but they are not likely to be commercially available in the next 10 to 15 years. Compared to today's state-of-the-art processes, such new technologies could bring long-term energy efficiency improvements of 35% in steel production and 75 to 90% in paper production (De Beer, 1998). Similar potential improvements may be expected for many other industrial sectors.

Energy efficiency tends to be lower in regions with low energy prices. To some extent, regional differences in efficiency can be attributed to labour cost differences, outdated production equipment, energy subsidies, natural resource endowment and policies to limit imports. As a result, estimates of energy efficiency may exceed the real economic potential in some regions.

Research and development on energy-efficient industrial processes is declining world wide. This is especially worrisome because a continuously growing and developing menu of technology options is needed to meet the demand for energy services in an efficient and sustainable way.

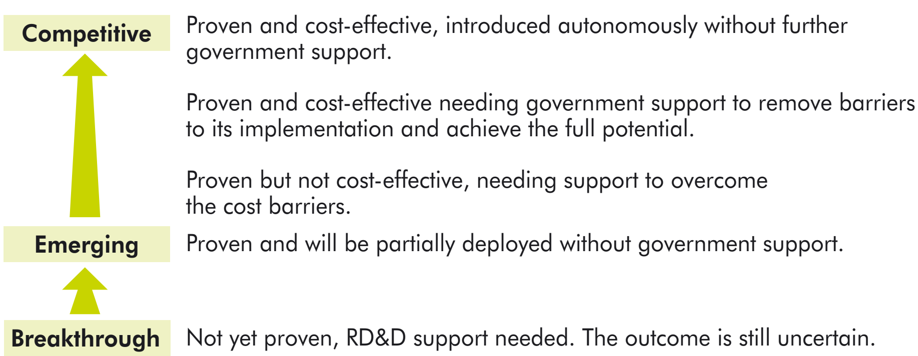
By necessity, only a limited selection of technology options can be included in this chapter. The technologies selected hold the promise of large changes or important energy savings, or both.

The emphasis in this chapter is on both new equipment and processes. New and innovative energy systems approaches based on conventional equipment can have at least as much potential as new equipment and processes. Although some of the best opportunities are in heat cascading, process integration and ecological industrial parks, these system-level solutions require a very special, analytical approach, and therefore will not be discussed in more detail in this analysis.

Technologies for CO_2 emission reduction can be categorised according to the development status of the technology and the level of government support needed to put it on the market (Figure 7.1):

- **Competitive** technologies are those that are already available today, such as membrane cells for chlorine production.
- **Emerging** technologies are not yet widely available; for example, smelt reduction processes for iron production.
- **Breakthrough** technologies can result in substantial emission reductions, but require much more RD&D, for example, black liquor gasification in the pulp and paper industry.

Figure 7.1 ▶ ***The development path of industrial technologies***



Competitive technologies can be further subcategorised according to their status: those that will be taken up by the market because they are clearly cost-effective;

those that are cost-effective but whose market adoption is hampered by barriers other than costs; and those that are technically ready but whose costs pose a barrier to their market penetration.

Proven, cost-effective technologies that are already commercialised may still need some government support if they are to realise their full potential. It is difficult to draw a clear distinction between technologies that need support and those that do not.

At some point, every business is faced with the decision of how to invest in new capital stock. At this decision point, new and emerging technologies compete for capital investment against more established or mature technologies. Understanding the dynamics of the decision-making process is important in order to identify what drives a given technology choice.

Industrial Energy Use and CO_2 Emissions

Global total primary energy supply was about 445 exajoules (EJ) (10 600 Mtoe) in 2003.[1] Adding in the losses from electricity and heat supply, industry accounts for more than 137 EJ (3 270 Mtoe), or nearly one-third of total primary energy supply. Total final energy use by industry amounted to 106 EJ (2 530 Mote) (Table 7.1).[2] These totals exclude energy use for the transportation of raw materials and finished industrial products, which is not negligible. Oil, natural gas and coal comprise 70% of the industrial energy used, roughly with equal shares, while 20% is electricity, about 5% is heat and about 5% is biomass. Reducing CO_2 emissions from industry and increasing the efficiency of industrial processes is a key element in any global CO_2 and energy security strategy.

Most industrial energy consumption is accounted for by industries that produce raw materials: chemical and petrochemicals, iron and steel, non-metallic minerals, paper and pulp, and non-ferrous metals. Together these industries consumed 75.8 EJ of final energy in 2003 (72% of total final industrial energy-use). The chemical and petrochemical industry alone accounts for 30% of industrial energy use, followed by the iron and steel industry with 19%. The food, tobacco and machinery industries, along with a large category of "other" industrial energy users, account for the remaining 28% of total final industrial energy use.

The United States, Western Europe and China together account for half of total worldwide industrial energy use, followed by the Former Soviet Union and Japan. An analysis of current energy use must therefore concentrate on these regions.

No detailed statistics are available regarding how global final industrial energy use can be allocated, but rough estimates suggest that 15% is for feedstock, 20% for process energy at temperatures above 400°C, 15% for motor drive systems, 15% for steam at 100 to 400°C, 15% for low-temperature heat and 20% for other uses, such as lighting and transport.

1. One exajoule equals 10^{18} joule or 23.9 Mtoe.
2. Final energy is the sum of all energy carriers that are used without accounting for energy conversion losses.

Table 7.1 ▶ *Final energy use for basic materials production (EJ/yr), 2003*

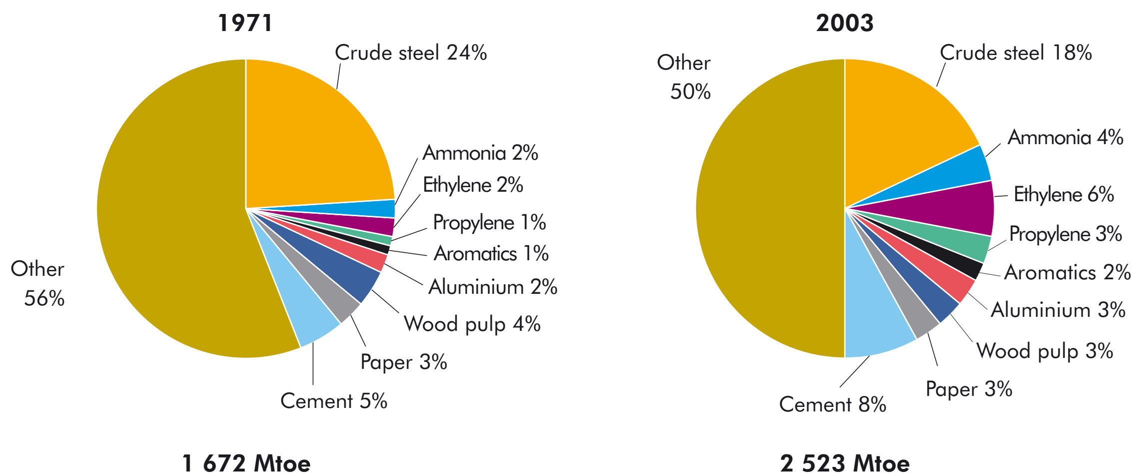
	AFR	AUS	CAN	CEU	CHI	CSA	FSU	IND	JPN	KOR	MEA	MEX	ODA	US	WEU	World
Chemical and petrochemical	0.57	0.20	0.78	0.63	**4.31**	**1.40**	**2.27**	**1.01**	**2.19**	**1.43**	**2.37**	**0.37**	**1.90**	**7.11**	**5.05**	31.58
Iron and steel	0.37	0.18	0.22	0.60	**6.30**	**1.14**	**2.70**	0.95	**1.90**	0.70	0.06	0.19	0.42	**1.39**	**2.79**	19.90
Non-metallic minerals	0.07	0.09	0.06	0.21	**2.84**	0.41	0.49	0.41	0.36	0.25	0.01	0.07	0.72	0.95	**1.67**	8.61
Paper, pulp and print	0.01	0.05	0.69	0.11	0.47	0.39	0.03	0.06	0.36	0.09	0.00	0.03	0.11	**2.18**	**1.50**	6.08
Food and tobacco	0.02	0.14	0.00	0.16	0.61	0.84	0.41	0.33	0.17	0.07	0.00	0.09	0.35	**1.13**	**1.27**	5.60
Non-ferrous metals	0.09	0.32	0.26	0.08	0.75	0.39	0.84	0.02	0.05	0.01	0.03	0.00	0.01	0.67	0.57	4.07
Machinery	0.00	0.02	0.00	0.08	0.92	0.01	0.65	0.03	0.20	0.14	0.00	0.00	0.15	0.93	0.82	3.95
Textile and leather	0.01	0.01	0.00	0.05	0.67	0.07	0.08	0.05	0.00	0.15	0.00	0.00	0.18	0.32	0.43	2.03
Mining and quarrying	0.20	0.11	0.43	0.03	0.32	0.12	0.08	0.04	0.03	0.01	0.01	0.06	0.06	0.11	0.12	1.72
Construction	0.07	0.03	0.05	0.04	0.32	0.02	0.17	0.00	0.16	0.02	0.00	0.01	0.03	0.07	0.32	1.31
Wood and wood products	0.00	0.05	0.02	0.04	0.09	0.00	0.37	0.00	0.00	0.01	0.00	0.00	0.01	0.48	0.22	1.29
Transport equipment	0.00	0.00	0.00	0.03	0.26	0.00	0.01	0.00	0.00	0.09	0.00	0.01	0.01	0.48	0.37	1.25
Non-specified	**2.12**	0.06	0.45	0.21	0.58	**1.48**	**1.74**	**1.98**	**1.42**	0.10	**2.19**	0.43	2.79	**1.05**	**1.59**	18.19
Total	3.52	1.25	2.96	2.27	18.44	6.25	9.85	4.86	6.83	3.06	4.68	1.26	6.75	16.86	16.71	105.57

Note: Includes coke ovens and blast furnaces. Sector values in excess of 1 EJ/yr are marked in bold. CSA - Central and South America; CEU - Central and Eastern Europe; FSU - Former Soviet Union; MEA - Middle East; ODA - other developing Asia; WEU - Western Europe.

Detailed information on energy and materials flow and on process activity is not readily available. In many cases these data are regarded as confidential, even in OECD countries. Better data are needed on the spread in energy efficiency and on the age and size of production equipment in all regions. The IEA Secretariat plans to commence new data collection activities in the framework of the G8 Dialogue on Climate Change, Clean Energy and Sustainable Development. The present study uses data from open literature, industry sources and analyses based on IEA energy statistics.

A snapshot of current energy use is one of many indicators on which policy-makers should focus their attention. The importance of sectors and regions may change quickly over time. Figure 7.2 shows a breakdown of industrial energy use in the period 1971 to 2003. Industrial sub-sectors which produce basic materials represent half of the worldwide industrial energy use in 2003 (53 EJ/yr). The other half is covered by other activities, either the processing of these materials (such as steel rolling or the production of plastics from ethylene and propylene) or activities in other sectors (such as food processing). The share of industrial energy used for basic materials production has been quite stable for the last 30 years, but the shares of individual sub-sectors have changed significantly. The share of iron and steel production, for example, has declined from 24% to 18% since 1971, while the share of ammonia, ethylene, propylene and aromatics has increased from 6% to 15%.

Figure 7.2 ▶ Final energy use by industry, 1971 and 2003



Key point

The share of energy-intensive basic materials production has increased to half of total final industrial energy use.

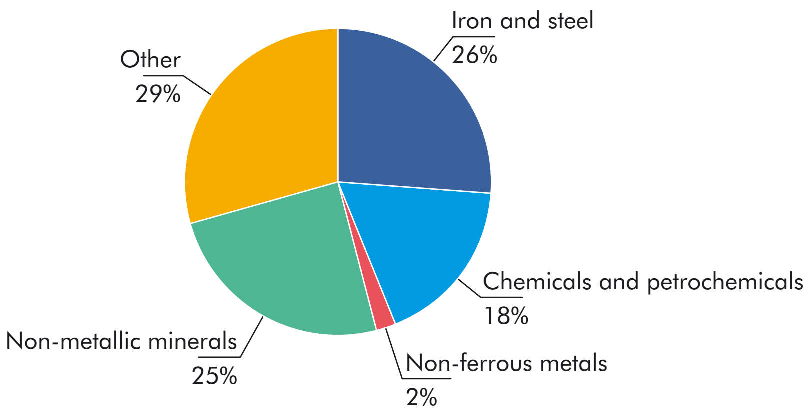
In most sectors CO_2 emissions are closely related to energy use, but the distribution of industrial CO_2 emissions is very different from the distribution of industrial energy use. The main reasons are:

- CO_2 emissions differ by fuel, and the use of fuels is not evenly distributed over the sectors.

- CO_2 emissions unrelated to energy use are large in some sectors, especially in cement production.
- Large amounts of fossil carbon are stored in petrochemical products.

Total CO_2 emission from industry amounted to 5.3 gigatonne (Gt) in 2003 (including coke ovens, blast furnaces and process emissions) and accounted for 22% of total global CO_2 emissions. Three sectors were responsible for nearly 70% of industrial emissions: iron and steel, non-metallic minerals, and chemicals and petrochemicals (Figure 7.3). These figures exclude upstream emissions from the production of electricity and downstream emissions from the waste treatment of synthetic organic products.

Figure 7.3 ▶ Industrial CO_2 emissions by sector, 2003[3]



Key point

Three sectors (iron and steel, non-metallic minerals and chemicals and petrochemicals) account for 69% of industrial CO_2 emissions.

Iron and Steel

Global steel production amounted to 1 129 Mt in 2005. Steel is either produced from iron ore or from scrap. Iron ore is used to make iron which is then converted into steel. Two types of iron products can be discerned: pig iron and Direct Reduced Iron (DRI). For nearly the past 20 years, almost 60% of steel has been derived from pig iron, although the share of steel produced from DRI has steadily increased during the past three decades. Pig iron is produced in blast furnaces. Today, about 5% of global steel is produced from DRI, while 35% of all crude steel is derived from

7

3. Includes coke ovens, blast furnaces and process emissions; assumes 75% carbon storage for all petrochemical feedstocks.

scrap.[4] These technology developments are important because they affect energy use and CO_2 emissions significantly.

The categorisation of steel production by process in Figure 7.4 is different from the conventional split between basic oxygen furnace (BOF) and electric arc furnace (EAF) production to allow a better analysis of the importance of DRI and steel scrap recycling. EAFs can use scrap, DRI or even pig iron. But important amounts of scrap are also recycled in BOFs. Total scrap consumption amounted to 406 Mt in 2003; significant amounts of steel scrap are also used for the production of cast iron.

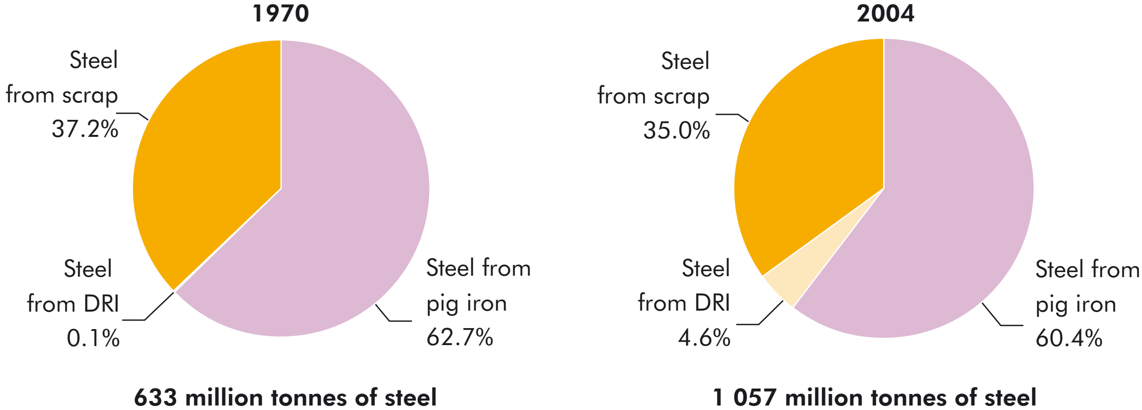
Sixty-three per cent of all steel was produced in basic oxygen furnaces, 34% in electric arc furnaces and 3% in open hearth furnaces. Total final energy use by the iron and steel industry (including coking and blast furnaces) was 19.9 EJ (475 Mtoe) in 2003. This gives an average energy intensity of 18.8 GJ per tonne of steel. Steel scrap recycling also mainly uses EAFs, though some steel scrap is added into BOFs (10 to 20% of the iron feedstock).

While the amount of scrap that is recycled into steel has increased significantly, its share in total steel production has decreased. The declining share of scrap recycling in steel production over the last 35 years is a result of the declining quantities of scrap within the iron and steel industry. The reduction of industrial scrap quantities is indicative of important efficiency gains, as less crude steel is needed to produce the same amount of finished steel products. Another explanatory factor for the declining share of scrap is the relocation of global steel production. The growth of steel production in the last decade has been concentrated in China, a country without scrap reserves. Nevertheless, the recycling of scrap from used products has increased substantially in absolute terms, as more products have reached the end of their useful life and scrap recovery systems have improved.

The blast furnace-basic oxygen furnace (BF-BOF) process and the DRI-EAF process are more energy intensive than scrap recycling because reducing iron ore requires about 6.6 GJ of chemical energy per ton of iron when hematite ore (the most abundant type) is used. This energy is not needed when steel scrap is recycled. However scrap recycling is limited by scrap availability, which is a function of past steel consumption and recovery rates. The amount of steel that is stored in buildings, capital equipment, cars and other goods is more than ten times annual steel production, and this stock increases continuously. Because this steel stock expands, scrap recycling can cover only a fraction of total steel production.

4. According to the International Iron and Steel Institute, the scrap recycling rate stood at 42.3% (IISI, 2005). However, this is based on a different definition. This recycling rate is calculated as the ratio of steel scrap used and crude steel produced. In the present study, the recycling rate is defined as the ratio of crude steel produced from scrap and total crude steel production. This results in a somewhat lower ratio because of material losses during scrap conversion into steel. However the basic material flows for both are the same. The contribution of scrap can also be calculated as the difference of total crude steel production and steel production from pig iron and DRI, which reconfirms the figures given in this study. It should be noted that it is not the actual recycling rate that is of interest, but the remaining additional recycling potential.

Figure 7.4 ▶ Global steel production by process, 1970 and 2004



Source: United Nations, 2003 and IISI, 2004.

Key point

The share of steel from scrap has decreased and DRI has balanced this decrease.

A typical BF-BOF process needs 13.3 GJ per tonne of liquid steel, provided 20% scrap is added in the BOF (Hornby Andersen, *et al.*, 2001). According to IEA statistics, coking is 75 to 90% energy efficient and adds from 1 to 5 GJ per tonne iron, depending on how much coke is used. The blast furnace (where the chemical reaction takes place) typically uses 14.4 GJ per tonne of iron. The practical minimum energy use for a blast furnace is 10.4 GJ per tonne, which is the sum of the chemical energy, the carbon content of the hot metal (about 5%), the energy in the hot metal and the energy needed for limestone calcination. The blast furnace, therefore, is about 72% efficient. The energy efficiency of the whole BF-BOF process is lower. More scrap can be added in the BOF, which reduces the energy use for this route. However, this implies less scrap recycling in EAFs, so the CO_2 benefit is limited for the iron and steel industry as a whole. Moreover, an important feature of primary steel is its purity, which is essential for certain applications, and a higher use of scrap reduces steel quality.

The relatively low efficiency of the BF-BOF approach can be attributed to losses at each of the various steps; DRI-EAF is more efficient because it requires fewer steps. The industry has recognised the importance of energy loss in coke-making and ore agglomeration and has been trying to develop alternative coal-based production processes that avoid these steps. These include:

- Injection of pulverised coal into the blast furnace as a substitute for coke.
- New reactor designs that can use coal instead of coke (such as the COREX process).
- New reactor designs that can use coal and ore fines (such as FINEX and cyclone converter furnaces).

Considerable differences in the energy efficiency of primary steel production exist among countries and even individual plants. These differences can be explained by factors such as economies of scale, the level of waste-energy recovery, the quality of iron ore and quality control. Certain plants still use such outdated technologies as open-hearth furnaces and iron-and-steel-ingot casting, although their use is declining rapidly.

At 13 to 14 GJ per tonne, the primary production of crude steel uses about three times as much primary energy as does recycling, which uses 4 to 6 GJ per tonne. An electric-arc furnace uses about 1.6 GJ of electricity per tonne of steel for 100% scrap feedstock. In actual operation, however, EAF energy use is somewhat higher. To be truly comparable, however, the electricity should be expressed in primary energy terms. With electricity generation efficiency ranging from 35% to more than 50%, EAF primary energy use is in the range of 4 to 6 GJ per tonne liquid steel. Thus, significant energy savings can be made by switching from blast furnace-BOF processes to scrap-EAF. However, scrap recycling is limited by scrap availability, and the saving potentials are therefore limited.

Table 7.2 sets out actual energy use and compares it to the practical minimum energy use for various steel products and processes. It shows that there are important efficiency potentials in all steps of the process, although the main gains for liquid hot metal would have to come from fundamental process change.

About one-third of global steel production is based on EAF, but the scarcity of scrap limits the expansion of EAF use. EAF recycling is much higher in the United States and Europe, because much more scrap is available than in developing countries. This difference should gradually disappear as other economies mature.

Table 7.2 ► ***Actual energy use and practical minimum use of key processes in iron and steel making***

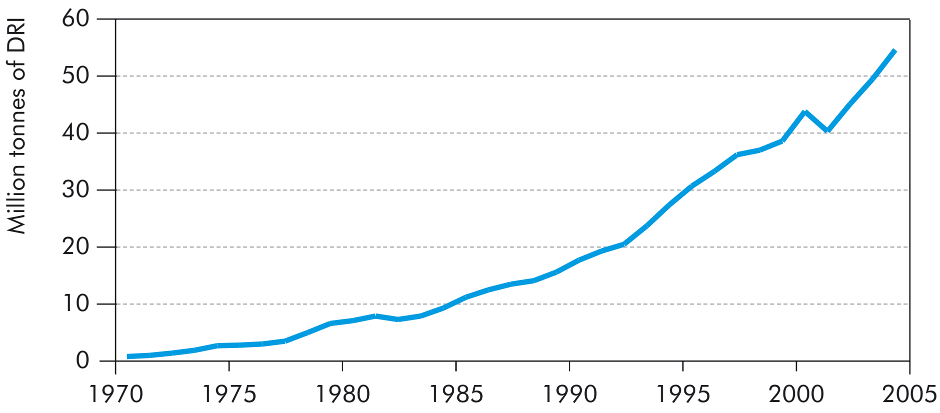
Product/process	Actual use (GJ/t)	Practical minimum energy use (GJ/t)	Actual emissions (t/t)	Practical minimum CO_2 emissions (t/t)	Reduction potential (%)
Liquid pig iron (5% C)	13 – 14	10.4	1.45 – 1.56	1.16	20 – 26
Liquid steel (EAF)	2.1 – 2.4	1.6	0.36 – 0.42	0.28	24 – 33
Hot rolled flat steel	2.0 – 2.4	0.9	0.11 – 0.13	0.05	55 – 62
Cold rolled flat steel	1.0 – 1.4	0.02	0.17 – 0.24	0	98

Source: Fruehan, *et al.*, 2000.

The rolling and finishing of crude steel adds to the energy needs for steel production. The thinner the steel product, the more energy for rolling is required. Certain applications will also require additional energy to remove impurities and reduce carbon content. While crude steel costs about USD 150 per tonne, finished steel can cost between USD 300 and USD 700 per tonne. The trend toward more complex products results in increased energy use per tonne, but reduces energy use per unit of value added.

A limited amount of steel is produced through processes other than BF-BOF and scrap-EAF. Direct reduced iron (also called sponge iron) is the most widely used of these processes, yielding 56 Mt in 2004. In the DRI process, iron ore is reduced in its solid state (unlike in blast furnaces, where liquid iron is produced). DRI can use coal or natural gas as feedstock, although more than 90% of the production is based on natural gas. DRI production is widespread in the Middle East, South America, India (where it is coal-based) and Mexico. Most DRI production is based on cheap, stranded natural gas, and DRI can be converted into steel in EAFs. Global DRI production has increased rapidly over the past three decades (Figure 7.5). The MIDREX process is used for about 63% of total DRI production and requires approximately 10.5 GJ natural gas per tonne of DRI (for a product that contains 2.5% carbon) and about 1.8 GJ of electricity for the EAF (assuming cold charging). Because natural gas is used instead of coal, CO_2 emissions are much lower. If 0.1 tonne of CO_2 is emitted per GJ of electricity, a total of 0.77 tonne of CO_2 is emitted per tonne of steel (with zero scrap additions). Where scrap is added, emissions will be less.

Figure 7.5 ▶ ***Global direct reduced iron production, 1970-2004***



Source: MIDREX, 2004.

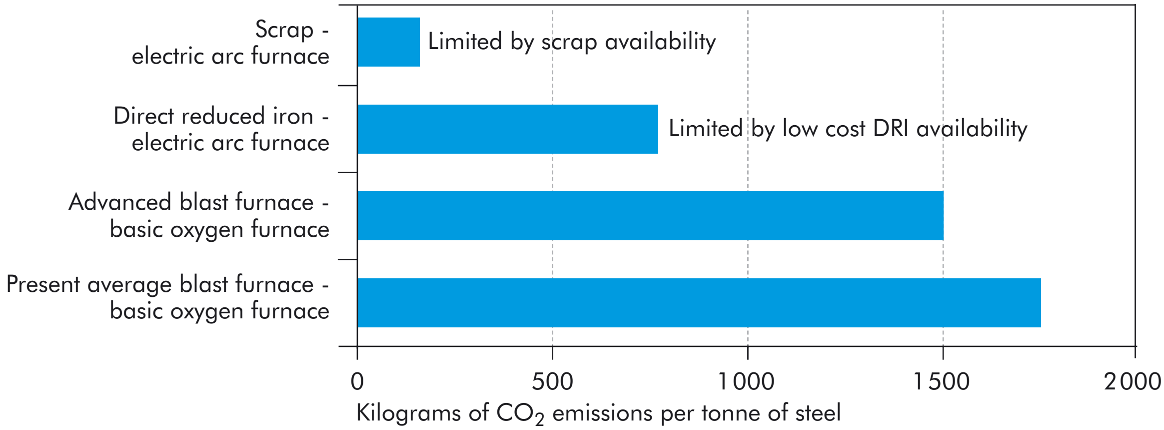
Key point

DRI production has grown exponentially during the past 35 years.

7

Figure 7.6 compares the CO_2 emissions for the three key processes now in general use (BF-BOF, DRI-EAF and scrap-EAF). It suggests a potential for emissions reduction of 50 to 95%, though this does not account for options such as CO_2 capture from blast furnaces. However, scrap recycling is limited by scrap availability and therefore its potential is limited.

Figure 7.6 ▶ CO_2 emissions per unit of product



Source: MIDREX, 2004.

Key point

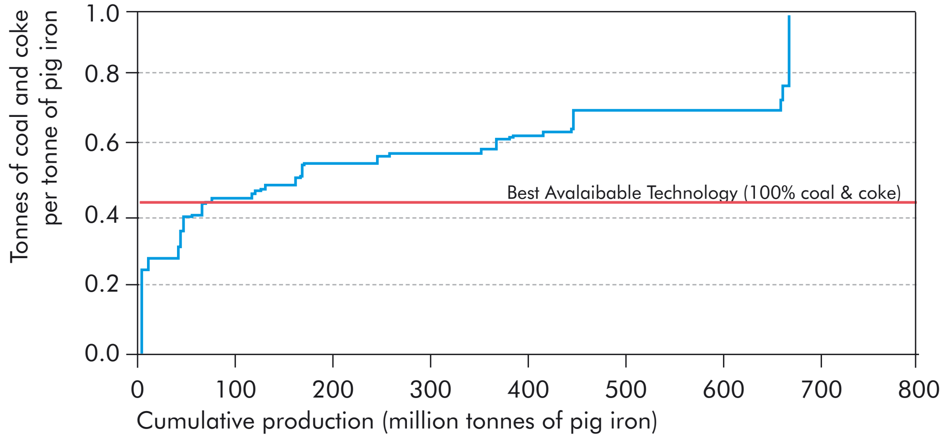
Emissions can be reduced significantly by using scrap or DRI, but the potential of these options is limited.

Typical carbon use for a blast furnace (both coal and coke) is about 550 kg per tonne iron. Global coal use for powder injection amounted to 0.7 EJ in 2003, or less than 10% of the total carbon use in blast furnaces. In many OECD countries, average coal and coke use for blast furnaces is in the range of 500 to 600 kg per tonne.

Figure 7.7 shows the distribution of coal and coke use in blast furnaces per tonne of iron. The x-axis indicates cumulative pig iron production, with a worldwide total of 670 Mt; each horizontal segment between two points reflects a given country's contribution to annual pig iron production. Since the theoretical minimum carbon use is about 0.45 tonne carbon per tonne of iron, significant efficiency potential remains. For some countries, the quantity of coal and coke used is less than 0.45 tonne per tonne iron, which can be explained either by statistical difficulties (some countries have very small pig iron production volumes) and by the existence of countries like Brazil that use charcoal as a carbon source. But there are a substantial number of countries with an energy savings potential in the range of 25 to 35%, and another group with a savings potential of almost 50%. This implies an overall emissions reduction potential on the order of 200 Mt of CO_2. Realising this potential would require extensive restructuring of the industry and the introduction of larger and better blast furnaces.

Not all blast furnaces are the same. Figure 7.8 shows the fuel rates for Chinese blast furnaces and blast furnaces in OECD countries. The fuel rate of the Chinese furnaces is 36% higher for mini blast furnaces and 15% higher for large furnaces. Moreover, the Chinese rate of pulverised coal injection (PCI) is lower, resulting in a higher share of coke in the fuel mix. The figure suggests that a switch to large blast furnaces would result in energy savings. But the trend in China and in India is the opposite, with mini blast furnaces being used to feed electric arc furnaces. This allows small-scale steel production, which is better adjusted to local market circumstances and requires less capital. So, there is a trade-off between energy efficiency and the optimal business strategy.

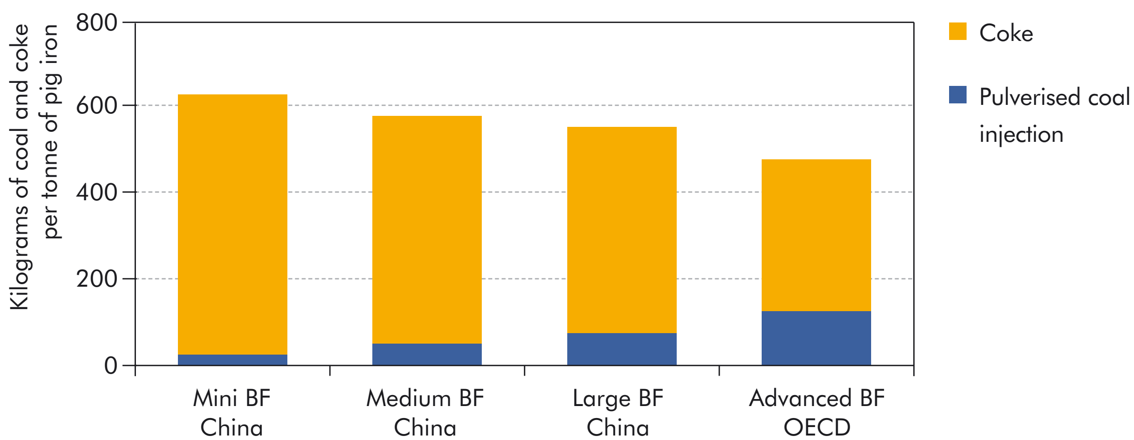
Figure 7.7 ▶ **Coal and coke use in blast furnaces, 2003[5]**



Key point

Coal and coke use in blast furnaces varies widely among countries.

Figure 7.8 ▶ **Fuel rates of Chinese blast furnaces compared with advanced furnaces[6]**



Key point

Coal and coke use in blast furnaces depends on the furnace size and the pulverised coal injection rate.

5. Each horizontal line segment represents a single country.
6. Mini blast furnaces are smaller than 500 m^3, medium-size blast furnaces are 500-2000 m^3 and large blast furnaces are more than 2000 m^3 (Chiang, *et al.*, 1998).

Even within the different categories of blast furnaces, considerable differences in energy efficiency exist, depending on the quality of the resource and the productivity of the furnace. For mini blast furnaces, an increase in the iron content of the ore from 50% to 55% reduces fuel use from 750 to 600 kg per tonne hot metal (THM) - a 20% savings. An increase in daily furnace productivity from 1 to 1.5 t/m^3 reduces the fuel rate from 750 to 600 kg/THM.

The quality of the iron ore and the quality of the coal influence the energy needs for iron production. A proper comparison should account for such quality differences that may result in up to 20% difference in energy efficiency. However, such analysis would require better data that are not readily available.

Box 7.1 ▶ *Small-scale heavy industry: a special Chinese issue*

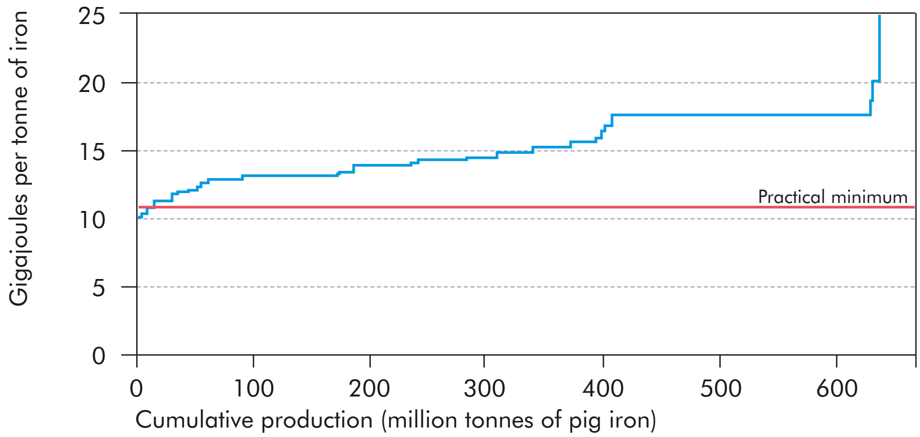
China accounts for a very large share of total global industrial production, but much of Chinese production capacity is in small-scale plants. This is the case in several industries, including paper and pulp, cement, aluminium and iron and steel.

In 2004, a quarter of China's coke production came from primitive beehive ovens. Thirty percent of the energy China uses for coking could be saved, and even large-scale Chinese ovens use about 20% more energy than similar ovens in other countries. For energy efficiency and environmental reasons, the Chinese government has been trying to ban the use of small-scale coke-producing facilities, but the rapid economic expansion and a resulting scarcity of materials has countered this effort. Nonetheless, patterns are changing very quickly. In 2004, China's coke output reached 224 Mt, or 56% of the world's total, up 25.8% from 2003. Existing production capacity is 250 Mt, and new equipment with capacity of 80 Mt is under construction. China is now a net importer of coking coal.

Figure 7.9 shows the distribution of energy use in pig-iron production including coke production, iron ore agglomeration and blast furnaces. Where surplus residual gas from pig-iron production is used elsewhere in the iron and steel industry, or is used in other sectors, such energy flows have been subtracted. The figure suggests a very large potential for energy savings, about 20% if all production were as efficient as the best available technology. This suggests emissions reduction potentials of about 200 Mt CO_2 at current production volumes. Reduction potentials vary from 15% (in Korea and Japan) to 40% (in India, China and the United States) if best-practice technology were to be applied throughout the steel industry in these countries (Kim and Worrell, 2002).

Options for CO_2 reduction include the introduction of residual gas-and-heat recovery systems, dry-coke quenching, top-pressure turbines for blast furnaces, BOF gas recovery, and residual heat recovery for sintering plants, BOF and hot stoves. These technologies are widely applied in some countries, but virtually absent in others. The total potential is about 100 Mt CO_2 reduction per year worldwide.

Figure 7.9 ▶ **Distribution of energy use in pig-iron production as a function of iron-production volume, 2003**[7]



Key point

20 to 30% efficiency potential remains in large parts of the world.

About 3 EJ of blast-furnace gas was produced worldwide in 2003. This gas is a by-product of the blast furnace process, as the coal is converted into a mixture of carbon monoxide (CO) and CO_2. As the blast furnace gas has an energy content that is about one-tenth that of natural gas, its efficiency of use is low. Therefore, a minimisation of blast furnace gas production will reduce CO_2 emissions. The chemical reaction in existing blast furnaces can be described by the equation:

$$Fe_2O_3 + 4\,C + 3\,O_2 \rightarrow 2\,Fe + 2\,(CO + CO_2)$$

Ideally the coal should be completely converted into CO_2:

$$Fe_2O_3 + 1.5\,C \rightarrow 2\,Fe + 1.5\,CO_2$$

Important R&D efforts are aimed at better understanding of the processes within the blast furnace. The goal is to improve coke reactivity at lower temperatures. This could allow a reduction of coal and coke use in the blast furnace by 10% (something closer to the ideal reaction equation), which would represent a CO_2 reduction potential of more than 100 Mt worldwide. It has been shown that using cement-bonded carbon-composite agglomerates (CCAs) instead of sinter can enhance the reactivity. However, the disintegration behaviour of these CCAs is different from sinter and further work is needed before they can be applied on a large scale (Naito, *et al.*, 2006). Sintering pre-reduction processes using CCAs can also reduce CO_2 emissions by about 10%.

7. Each horizontal line segment represents a country. Includes coke making, iron ore agglomeration and blast furnaces.

Box 7.2 ▶ How industry policy can affect energy use: the case of India

India's iron and steel industry has a unique structure. In the past, the government has intervened to bar the private sector from opening large-scale primary steel plants. As a consequence, a large number of mini blast furnaces and DRI plants sprang up. These plants produce sponge iron, which is either fed into electric arc furnaces or is used in large-scale blast furnaces. In 2000, India produced 3.4 Mt of pig iron and 5.5 Mt of DRI. Of the pig iron, 2.4 Mt was produced by secondary steel makers in mini blast furnaces. One drawback of this industry structure is high energy use.

There are seven major integrated steel plants in India and about 41 EAF units. DRI production from gas and coal is widely used, in combination with hot charging into electric arc furnaces. COREX technology is also applied. Most of these technology developments are an unintended side effect of the government's industrial policy.

An interesting trend is the installation of smaller integrated steel plants with capacities of about 300 000 tonnes per year and using the BF-BOF approach for long products. This represented about three-quarters of India's pig iron production in the year 2000. The rate of coke use of these mini blast furnaces ranged from 650 to 800 kg per tonne of hot metal. These rates are close to those for Chinese mini blast furnaces. The product is sold as merchant pig iron, so its use in electric-arc furnaces demands remelting, which adds from 1.5 to 2 GJ per tonne, an increase of 10 to 20%.

In coal-based sponge iron kilns, depending on the quality of the coal used, about 60% of the total heat input is utilised in the reduction process; the other 40% is discharged with the kiln waste gases in the form of heat. The potential for achieving energy savings is considerable. Approximately 400 to 500 kWh of electric energy could be produced per tonne of iron by exploiting the heat content of the kiln waste gases. This electricity could potentially halve the current external power requirement (900 kWh per tonne) for melting sponge iron in electric arc furnaces or in induction furnaces.

The case of India shows how industry policy can decisively affect industrial structure, industrial energy use and, ultimately, the nation's greenhouse gas profile.

A large number of other options for reducing CO_2 emissions in the iron and steel industry can be envisaged. Among them are:

- Fuel substitution, notably pulverised and plastic-waste injection in blast furnaces.
- CO_2 capture.
- Smelt reduction.
- Direct-slab casting.

Injection of Pulverised Coal and Plastic Waste

Coal injection is already a widely applied technology. It is financially attractive because it obviates the coke-making process. Moreover, it results in substantial energy savings, as one energy unit of coke is replaced by one energy unit of coal. Trials have shown that coal injection can replace up to half the coke now used in blast furnaces. Assuming that coal and coke have the same energy content, that half of all coke is replaced by injected coal, and that the energy used in coke production is 8 GJ per tonne coke, the potential for coal savings would amount to 1 EJ per year and reduce CO_2 emissions by 100 Mt.

Plastic waste can also be injected into blast furnaces as a substitute for coke and coal. The technology has been developed and applied in Germany and Japan. Plastic waste can also be added to the coking oven. This technology is applied commercially in Japan. In total about 0.4 Mt of plastic waste is used per year by the Japanese iron and steel industry, which equals about 20 PJ per year.

Important barriers to the increased use of plastics as injection fuel are the need to control the polyvinyl-chloride content of the plastic pellets, legislation in various countries that regulate the use of waste as a fuel, the need to obtain environmental permission for the use of waste fuel and the capital needed to reconstruct the fuel-injection system of the blast furnace.

CO_2 reductions and energy-efficiency savings from using plastic waste depend on the allocation of CO_2 emissions and on the energy content of the plastic waste used. The burning of waste plastic releases CO_2 emissions from a fossil fuel source. However, this CO_2 is released anyway, if the waste plastic is incinerated in waste combustors. Much more energy can be recovered by injection in blast furnaces than by disposal and conventional waste incineration. The option is limited by the availability of plastic waste and by the claims of other uses, such as recycling and incineration.

Table 7.3 ▶ ***Global technology prospects for coal injection***

Injection of coal	2003-2015	2015-2030	2030-2050
Technology stage	Commercial	Commercial	Commercial
Investment costs (USD/t)	50-55	50	50
Energy reduction (%)	5%	7%	10%
CO_2 reduction (Gt/yr)	0 – 0.05	0.05 – 0.1	0.1 – 0.2

Other energy carriers such as charcoal, hydrogen and electricity would also be injected. This would result in a substantial emissions reduction, provided they are produced in a CO_2-free way. However, the cost of such mitigation measures would in most cases exceed USD 50 per tonne CO_2. Therefore they have not been considered in more detail. Tables 7.3 and 7.4 provide an overview of fuel injection prospects.

Table 7.4 ▶ Global technology prospects for plastic waste injection

Injection of plastics	2003-2015	2015-2030	2030-2050
Technology stage	Demonstration	Commercial	Commercial
Investment costs (USD/t)	60-70	60	55
Energy reduction (%)	50%	75%	90%
CO_2 reduction (Gt/yr)	0 – 0.02	0 – 0.03	0.03 – 0.1

CO_2 Capture

Worldwide iron production is about 700 Mt and is responsible for around 1 250 Mt of CO_2. If blast furnaces were re-designed to use oxygen injection instead of enriched air with top gas recycling, the CO_2 could be removed with physical absorbents. The use of oxygen results in a 23 to 28% reduction in the blast furnace carbon needs, and CO_2 capture could result in an 85 to 95% emissions reduction. It is estimated that physical absorbents would be 30% more cost-effective than chemical absorbents (Hallin, 2006). Total cost for capture, transportation and storage would be in the range of USD 20 to USD 30 per tonne CO_2.

The production of direct reduced iron (DRI) allows CO_2 capture at low cost, below USD 25 per tonne CO_2. Global DRI production amounted to 56 Mt in 2004, resulting in CO_2 emissions of approximately 40 to 50 Mt. DRI facilities are mainly concentrated in countries with cheap stranded gas, including the Middle East. So far, this approach has received only limited attention. If CO_2 capture were applied to iron and steel production, its potential would be on the order of 0.5 to 1.5 Gt of CO_2 per year. Given a projected rapid growth of DRI production, the potential for CO_2 capture may increase accordingly to 400 Mt per year by 2050 (Table 7.5). The industry is currently studying how best to reduce its emissions. A European project has started, known as ULCOS (Ultra Low CO_2 Steelmaking), which is conducting new engineering studies of CO_2 capture and sequestration strategies for iron production. But such efforts may well be hampered by the industry's need to remain internationally competitive and the possibility that some companies may relocate their activities to countries without ambitious CO_2 policies.

Table 7.5 ▶ Global technology prospects for CO_2 capture in blast furnaces and DRI plants

CO_2 capture and storage	2003-2015	2015-2030	2030-2050
Technology stage	Engineering studies	Pilot/demonstration	Commercial
Investment costs (USD/t CO_2)	N/A	120	110
CO_2 reduction (%)	75%	80%	85%
CO_2 reduction (Gt/yr)	0	0.1	0.4

Smelt Reduction

Advanced large-scale blast furnaces are already quite energy efficient, but small-to-medium-scale plants can reduce their energy use appreciably through smelt reduction. The preparation of coke and ore is an energy-intensive step in iron production. Important research has been devoted to the problem of integrating these processes with iron-ore reduction. This work has led to the development of the commercially available COREX plant design, which uses coal fines and agglomerated ore. This concept is only marginally economic, but it is the only smelting-reduction process in current industrial use. In 2002, four commercial plants in South Africa, Korea and India produced 2.66 Mt of hot metal. In July 2005, China's Baosteel ordered a new 1.5 Mt per year C-3000 COREX module.

The lifetime of blast furnaces is very long. The furnace is relined every ten or twelve years, but the structure itself may last many decades. This longevity severely limits the opportunities for timely adoption of new technology. Furthermore, the blast furnace is part of an integrated infrastructure including coke ovens, sintering and blast furnaces. The energy and material flows of all these processes are interlinked and their complex interfaces constitute still another barrier to the introduction of new technology. The current version of smelt reduction technology is most suitable for medium-scale integrated plants, which are mainly found in developing countries. But these countries lack capital and support infrastructure, and they are often discouraged by the perceived risks involved in new technologies

While the COREX process still requires agglomerated ores, more recent designs aim at eliminating this step. FINEX is an advanced version of COREX that uses iron-ore fines instead of agglomerated ore and thereby reduces production costs. Developed by Korea's POSCO, a new 1.5 Mt per year FINEX plant is to be built at the producer's Pohang Works. Another smelt-reduction process using ore fines is the HiSmelt process. The first commercial plant of this type is being built in Australia, with other major research projects launched in Japan (a direct iron ore smelting process), in Europe (a cyclone converted process) and in the United States. Next steps include the commercialisation of second-generation smelting-reduction processes through demonstration on a near-commercial scale. While the net energy use for smelt reduction processes is lower than for blast furnaces in combination with coke ovens and ore agglomeration, the amount of surplus off-gas is substantial, typically about 9 GJ per tonne of product. The efficient use of this gas determines the CO_2 effect of smelt reduction processes.

An interesting combination is that of a smelt-reduction process with direct reduction using the off-gases of the smelt-reduction plant. Such a plant, using the COREX process, has been in operation in South Africa since December 1998. The average energy use (pig iron and DRI) is about 10.3 GJ per tonne of metal. This is a significant reduction from the 17 GJ per tonne needed for a blast furnace, including coking and ore preparation. It is important to note, however, that DRI can only be used in electric arc furnaces as a substitute for scrap. The use of the EAF will increase the energy use of the overall steel-making process. With a significant expansion of smelt reduction, as much as 200 to 500 Mt CO_2 emissions can be avoided by 2050 (Table 7.6).

Table 7.6 ▶ **Global technology prospects for smelt reduction**

Smelt Reduction	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration, commercial	Commercial	Commercial
Investment costs (USD/t)	350	250	220
Energy reduction (%)	0-5%	10-15%	10-19%
CO_2 reduction (Gt/yr)	0 – 0.1	0.1 – 0.2	0.2 – 0.5

Note: the investment costs for a new blast furnace, coke battery and sinter plant would be about USD 350 per tonne of hot metal.

Direct Casting

Near-net-shape casting and strip casting are the most recent developments in metal shaping. Currently, metals are cast into ingots or slabs, which have to be reheated after casting and then rolled into the final shape. Today, 90% of all steel is cast continuously. Near-net-shape casting and strip casting integrate the casting and hot-rolling of steel into one step, thereby reducing the need to reheat the steel before rolling it. In the case of flat products, strip is cast directly to a final thickness between 1 and 10 mm rather than being cast into slabs 120 to 300 mm thick.[8] This technology leads to considerable savings of capital and energy. Energy savings may amount to 1 to 3 GJ per tonne steel. Direct casting may also lead to indirect energy savings because of reduced material losses.

Bessemer patented strip casting in 1856, but early attempts to develop the technology failed. In the end, it took almost 140 years to commercialise the process. Starting in 1975, several clusters of steel producers, technology suppliers and research groups developed near-net-shape and strip casting in Europe, Japan, Australia, United States and Canada. Since then, three separate commercial technologies have emerged. The major advantage of strip casting is the significant reduction it achieves in capital costs stemming from its high productivity and the integration of several production steps. The technology was first applied to stainless steel and two plants have demonstrated the viability of its application to carbon steel.

The main challenges for the further development of this technology relate to the quality of the product and its usability by steel processors and users. Increased reliability, control and the adaptation of the technology to larger-scale production units (now limited to 500 000 tonne per year) will benefit its wider application. Thin-slab casters were initially developed on the same small scale, but they have since been scaled up to capacities greater than 1 Mt per year and are now used by integrated mills in Germany and the Netherlands.

A thin-strip caster consumes much less energy than continuous casting. For the intermediate thin-slab casting process, energy consumption is 0.9 GJ of fuel per

8. Thin-slab casting is an intermediate technology which casts slabs 30-60 mm thick and then reheats them (the slabs enter the furnace at higher temperatures than they do with current technology thereby saving energy). Thin slab casting technology is already used commercially.

tonne and 43 kWh of electricity. Near-net-shape casting is expected to consume even less energy. The energy use of a strip caster is estimated at 0.2 GJ per tonne of steel. Compared to a current state-of-the-art casting and rolling facility, the specific energy savings are estimated at about 90%. Total energy savings will depend on the speed at which strip and near-net-shape casters enter the market. The potential energy savings are estimated at 1.7 EJ. Capital costs for near-net-shape casting plants are expected to drop due to the elimination of the reheating furnaces, so estimates for the possible reduction of capital costs range from 30% to 60%. Therefore, if the use of direct casting can be expanded, emissions can be reduced by up to 100 Mt per year while costs are reduced simultaneously (Table 7.7).

Table 7.7 ► **Global technology prospects for direct casting**

Direct casting	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration	Commercial	Commercial
Investment costs (USD/t)	200	150-200	150-200
Energy reduction (%)	80%	90%	90%
CO_2 reduction (Gt/yr)	0 – 0.01	0 – 0.03	0 – 0.1

Note: Investment costs for a traditional continuous caster and hot rolling mill are about USD 70 per tonne higher than for direct casting.

Non-metallic Minerals

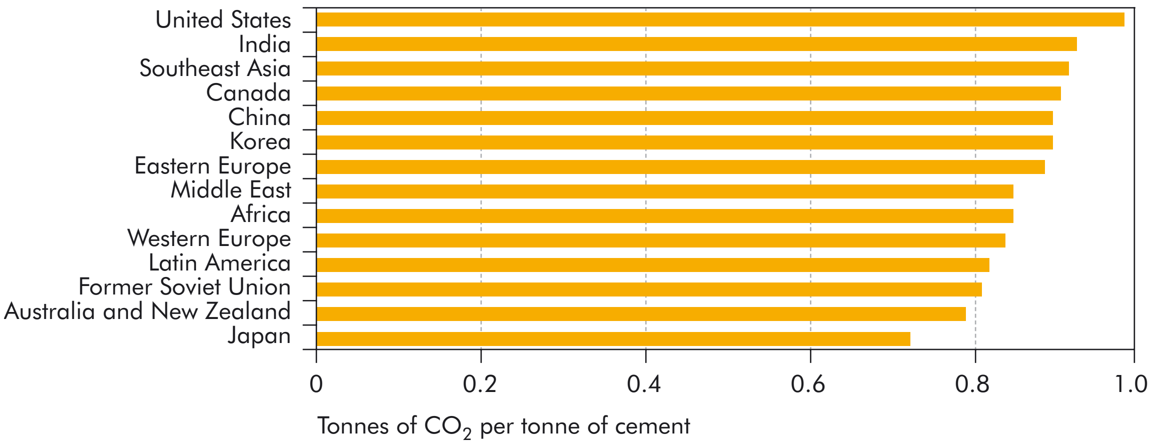
Non-metallic minerals include cement, lime, glass, soda, ceramics, bricks and other materials. Cement accounts for two-thirds of total energy use in the production of non-metallic minerals. In terms of CO_2 emissions, cement production is by far the most important activity in this category. Worldwide cement production was around 2 000 Mt in 2004. Since cement production consumes 4 to 5 GJ per tonne cement, this industry uses 8 to 10 EJ of energy annually. The production of cement clinker from limestone and chalk is the main energy consuming process in this industry. The most widely used cement type is Portland cement, which contains 95% cement clinker. Clinker is produced by heating limestone to temperatures above 950° Celsius.

Cement production is an energy-intensive process in which energy represents 20 to 40% of total production costs. Global cement production grew from 594 Mt in 1970 to 2 000 Mt in 2004, with the vast majority of the growth occurring in developing countries, especially China. In 2003, developed countries produced 503 Mt (30% of world cement production) and developing countries 1 447 Mt (70% of world output). Most of the energy used is in the form of fuel for the production of cement clinker and electricity for grinding the raw materials and finished cement.

The clinker-making process also emits CO_2 during the calcination of limestone. This industrial process CO_2 emission is unrelated to energy use and accounts for about 3.5% of CO_2 emissions worldwide and for two-thirds of the total CO_2 emissions from cement production. Emissions from limestone calcination cannot be reduced through energy efficiency measures or fuel substitution. Total emissions from the industry in

2003 were around 1.6 Gt CO_2. Figure 7.10 compares CO_2 emissions per tonne of cement for various countries and world regions. The narrow emissions range of 0.72 to 0.98 tonne CO_2 per tonne cement can be attributed to the importance of process emissions in cement clinker production that are not dependent on energy efficiency.

Figure 7.10 ▶ Average CO_2 emissions per tonne of cement by country and region



Source: World Business Council for Sustainable Development (WBCSD), 2002.

Key point

The range of average CO_2 emissions per tonne of cement is very limited.

Higher Energy Efficiency Using Existing Cement-Kiln Technology

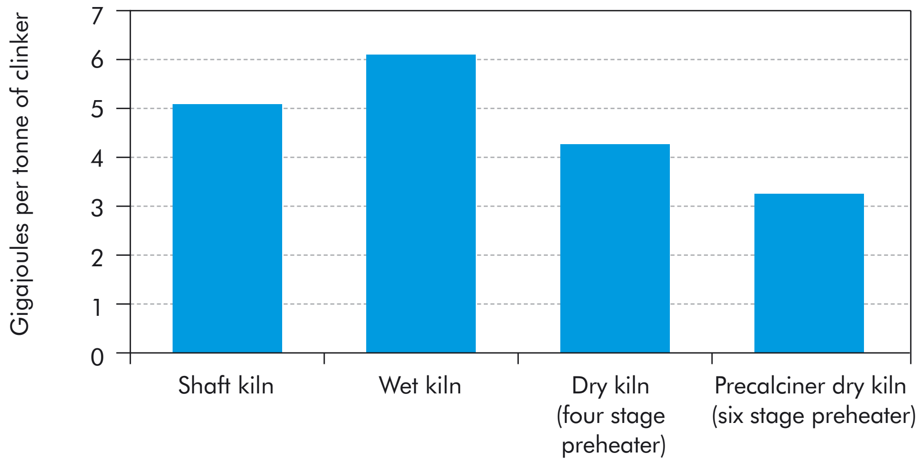
The technology used in the cement industry in developing countries (notably in China) differs from the one used in industrialised countries. While small-scale vertical kilns predominate in China, large-scale rotary kilns are most common in industrialised countries. Large-scale kilns are considerably more energy efficient. The most widely used production process for Portland cement clinker is the relatively energy efficient dry process, which is gradually replacing the wet process. In the last few decades, pre-calcination technology has also been introduced as an energy-saving measure (Figure 7.11).

In the European Union, the average energy consumption per tonne of Portland cement is currently 3.7 GJ per tonne. Cement producers are gradually replacing conventional dry kilns with dry kilns incorporating pre-calcining and six-step pre-heaters. This trend is likely to continue with no need for government support. The theoretical minimum energy use is 1.76 GJ per tonne of cement clinker. Efficient pre-heater and pre-calciner kilns use approximately 3.06 GJ of energy per tonne of clinker, while a wet kiln uses 5.3 to 7.1 GJ per tonne of clinker (WBCSD, 2002).

One way to improve the energy efficiency of rotary kilns is to increase the number of pre-heaters. An increase from 4 to 6 cyclone pre-heaters results in a reduction of rotary kiln fuel consumption by about 10%.

Process types and fuel shares differ considerably by region (Table 7.8), which explains to a large extent the regional differences in CO_2 emissions per tonne of cement.

Figure 7.11 ▶ **Energy efficiency of various cement-clinker production technologies**



Key point

Best cement-clinker technologies are 30 to 40% more efficient than others.

Table 7.8 ▶ **Cement technologies and fuel mix by region**

	Process type				Fuel share			
	Dry (%)	Semi-dry (%)	Wet (%)	Vertical (%)	Coal (%)	Oil (%)	Gas (%)	Other (%)
United States	65	2	33	0	58	2	13	26
Canada	71	6	23	0	52	6	22	15
Western Europe	58	23	13	6	48	4	2	42
Japan	100	0	0	0	94	1	0	3
Australia and New Zealand	24	3	72	0	58	<1	38	4
China	43	0	2	55	94	6	<1	0
Southeast Asia	80	9	10	1	82	9	8	1
South Korea	93	0	7	0	87	11	0	2
India	50	9	25	16	96	1	1	2
Former Soviet Union	12	3	78	7	7	1	68	<1
Eastern Europe	54	7	39	0	52	34	14	<1
Latin America	67	9	23	1	20	36	24	12
Africa	66	9	24	0	29	36	29	5
Middle East	82	3	16	0	0	52	30	4

Source: WBCSD, 2002, IEA estimates.

New Clinker-kiln Designs

Today's state-of-the-art dry-rotary clinker kilns are fairly fuel efficient, consuming about 3.0 GJ per tonne of clinker. The thermodynamic minimum to drive the endothermic reactions is approximately 1.8 GJ per tonne. For years, research has concentrated on developing an alternative to the current rotary kiln, using fluidised bed technology. A pilot fluidised-bed plant with a 20 tonne per day capacity has been operated successfully in Japan. Such technology produces efficiency gains for small plants, but the gains are small or even non-existent for large plants. As a result, no commercial use has yet been made of this technology. The superior performance of rotary kilns makes them the likely technology for the next decades. However, implementation of existing kiln technologies can result in 200 to 400 Mt CO_2 savings by 2050 (Table 7.9).

Table 7.9 ▶ **Global technology prospects for kiln improvements**

Kiln improvements	2003-2015	2015-2030	2030-2050
Technology stage	Commercial	Commercial	Commercial
Investment costs (USD/t)	50-80	40-60	30-50
Energy reduction (%)	10-15%	10-15%	10-25%
CO_2 reduction (Gt/yr)	0.01 – 0.02	0.1 – 0.2	0.2 – 0.4

Efficient Grinding

Grinding is the largest electricity consumer in the cement industry. The current state-of-the-art technologies, using roller presses and high-efficiency classifiers, are much more efficient than previous ones. Still, the energy efficiency of grinding is typically only 5 to 10%, with the remainder converted to heat.

Fuel Substitution

Another way to reduce emissions and fossil fuel use is to burn waste or biomass as fuel. Cement kilns are well-suited for waste combustion because of their high process temperature and because the clinker product and limestone feedstock act as gas-cleaning agents. Used tires, wood, plastics, chemicals and other types of waste are co-combusted in cement kilns in large quantities. Providers in Belgium, France, Germany, the Netherlands and Switzerland have reached average substitution rates from 35% to more than 70% of the total energy used. Some individual plants have even achieved 100% substitution using appropriate waste materials. However, very high substitution rates can only be accomplished if a tailored pre-treatment and surveillance system is in place. Municipal solid waste, for example, needs to be pre-treated to obtain homogeneous calorific values and feed characteristics.

The cement industry in the United States burns 53 million used tyres per year, which is 41% of all tyres that are burnt and equivalent to 0.387 Mt or about 15 PJ. About

50 million tires, or 20% of the total, are still land filled. Another potential source of energy is carpets, the equivalent of about 100 PJ per year are dumped in landfills and could instead be burnt in cement kilns. Although these alternative materials are widely used, their use is still controversial, because cement kilns are not subject to the same tight emission controls as waste incineration installations. According to IEA statistics, the OECD cement industry used 66 PJ of combustible renewables and waste in 2003, half of it industrial waste and half wood waste. Worldwide, the sector consumed 112 PJ of biomass and 34 PJ of waste. There is apparently little use of alternative fuels outside the OECD. From a technical perspective, the use of alternative fuels could be raised to 1 to 2 EJ, although there would be differences among regions due to the varying availability of such fuels.

Cement-clinker Substitutes

Another way to reduce emissions from clinker production is to switch to cement types which contain other feedstocks, such as pozzolana (volcanic ash), fly ash or granulated blast-furnace slag. Producing these alternative cement types is far less energy intensive and avoids process emissions.

The composition of various cement types is shown in Table 7.10. Quicklime and pozzolanic mixtures are important alternatives to clinker for Portland cement. They are widely used in Germany and Italy. But the resulting concrete is water-sensitive and therefore cannot be used for all applications. Moreover, the availability of waste slag is limited, and pozzolana can be obtained only in certain locations. Long-distance transportation of cement or cement feedstocks would result in significant additional energy use, which is not especially an attractive option given the low value of the product. Nonetheless, there is an appreciable potential for clinker substitutes, even in OECD countries. In the United States, about 5% of all clinker could be replaced.

Table 7.10 ▶ Composition of different cement types

Cement type	Portland cement (%)	Portland fly-ash cement (%)	Blast-furnace cement (%)	Activated slag cement (%)
Clinker	95	75	30	–
Fly ash	–	25	–	45
Blast-furnace slag	–	–	65	–
Synthetic slag	–	–	–	45
Water glass	–	–	–	10
Gypsum	5	–	5	–

Source: Gielen, 1997.

The use of blended cement varies widely from country to country. It is high in continental Europe, but low in the United States and the United Kingdom. Blended cement offers a major opportunity for energy conservation and emission reductions. In the long term, new cement types may be developed that do not use limestone as a primary resource. These new types are called "geopolymers", but the technological feasibility, economics and energy effects of such alternative cements remain speculative.

In total, the savings potential for blended cements and geopolymers amounts to 200 to 400 Mt CO_2 by 2050.

Table 7.11 ▶ ***Global technology prospects for blended cement and geopolymers***

Blended cement and geopolymers	2003-2015	2015-2030	2030-2050
Technology stage	Commercial	Commercial	Commercial
Investment costs (USD/t)	0 – 10	0 – 10	0 – 10
CO_2 reduction (%)	<35%	35 - 65%	35 – 65%
CO_2 reduction (Gt/yr)	0 – 0.15	0.05 – 0.2	0.2 – 0.4

Energy savings can be achieved through energy efficiency improvements through the use of waste fuels and through reductions in the clinker content of cement. The combined technical potential of these approaches is estimated at 30%, with a range of 20 to 50% in different regions.

CO_2 Capture and Storage (CCS)

Worldwide, cement kilns emit about 1.6 Gt of CO_2 per year. Cement production is increasing, and hence related CO_2 emissions are rising. Concentrations of CO_2 off-gas from cement kilns are higher than those from conventional furnaces in other sectors because more than half of the CO_2 in the off-gas comes from the calcination of limestone. This high concentration could allow the use of physical absorption systems (using Selexol or other absorbents). The capture technology used could be similar to that for an integrated-gasification combined-cycle power plant or a pulverised-coal-fired plant with CO_2 capture from the flue gas. It might also be possible to use oxygen instead of air in cement kilns, which would result in a pure CO_2 off-gas. Potentially higher process temperatures would require a process re-design in order to avoid excessive equipment wear. CCS for cement kilns is a challenge because it could raise production cost by 40 to 90%. Further design studies are needed to establish the optimal capture technology.

The technology prospects for CCS in cement production are shown in Table 7.12.

Table 7.12 ▶ **Global technology prospects for CO_2 capture and storage**

CO_2 capture and storage	2003-2015	2015-2030	2030-2050
Technology stage	R&D	R&D, demonstration	Demonstration, commercial
Investment costs (USD/t CO_2)	500	250	150-200
Emission reduction (%)	95	95	95
CO_2 reduction (Gt CO_2/yr)	0	0-0.25	0.25-0.75

Chemicals and Petrochemicals

More than half (16 EJ/yr) of the total energy used in this sub-sector is accounted for by feedstocks (also called non-energy use). Most of the carbon from oil and natural gas feedstock is "locked" into final products such as plastics, solvents, ammonia and methanol. Some of the locked-in energy value can be recovered at a later stage when the product is incinerated, which results in CO_2 emissions at the waste-treatment stage. Thus, the chemicals and petrochemicals sector is responsible for much more CO_2 than its share of industrial CO_2 emissions would suggest.

Three-quarters of all feedstock is oil and is used for the production of intermediate chemical products like olefins (ethylene and propylene) and aromatics (benzene, toluene and xylenes). These chemicals are further processed into a wide range of plastics, rubbers, resins, solvents and other petrochemical products. The gross energy requirement of these products ranges from 25 to 50 GJ per tonne.

Natural gas, the other major feedstock, is used for the production of ammonia, methanol and other products. Ammonia is mostly used for fertiliser production. Ethane, propane and butane are natural gas components that are used to produce olefins.

The chemical industry is highly diverse, with thousands of companies producing tens of thousands of products in quantities varying from a few kilograms to thousands of tonnes. Because of this complexity, reliable data on energy use are not available. It is clear, however, that the chemical industry is a large energy user that heats and cools large process streams for conversion and separation. Integrating the separation and conversion processes, for example, in membrane reactors, may drastically reduce energy use. It allows chemical reactions to take place at lower temperature or lower pressure, and it can make distillation superfluous. Other options in chemical process design are process intensification (more compact reactor designs that limit energy losses) and biochemical production routes that use, for example, enzymes or bacteria. New process routes and new feedstocks can reduce the need for the manufacture of energy-intensive intermediates.

It is estimated that the energy intensity of key chemicals (ammonia and petrochemicals) can be reduced by at least 20%, if current state-of-the-art technologies are applied.

However, but this potential varies from region to region and from plant to plant (Phylipsen, *et al.*, 2002).

Only a limited number of processes are significant in terms of the energy requirements for production. The following activities account for 22.5 EJ of final energy use, which is more than 70% of total energy in the chemical and petrochemical industry:

Petrochemicals

- Steam cracking of naphtha, ethane and other feedstocks to produce ethylene, propylene, butadiene and aromatics.
- Aromatics processing.
- Methanol production.

Inorganic chemicals

- Ammonia production.
- Chlorine and sodium-hydroxide production.

Petrochemicals

Oil and gas feedstock is commonly converted into monomers and building blocks such as ethylene, propylene, aromatics and methanol, which are further processed into polymers, solvents and resins. Large amounts of heat are used by distillation columns (for product separation) and other high-temperature processes, such as steam cracking. Electricity is used for certain conversion processes such as chlorine production, but also for pumps and other auxiliary processes.

Steam Cracking

About 110 Mt of ethylene was produced in 2004. Of this, 55% was derived from naphtha, 30% from ethane, 10% from liquefied petroleum gas and 5% from gas oil. Ethane cracking predominates in North America, while naphtha cracking predominates in most other regions.

Depending on the feedstock, varying amounts of by-products are generated (Table 7.13). Methane and hydrogen by-products are used to fuel the cracking furnace, or they are separated and used elsewhere. Pyrolysis gasoline by-product (fuel grade products with five or more carbon atoms) is recycled to the refinery industry. About 155 GJ of naphtha are needed for the production of 1 tonne of ethylene. About 17% of the energy content of naphtha (25 GJ per tonne of ethylene produced) is used for energy purposes. The theoretical minimum for this process (*i.e.*, the energy that is needed solely for the chemical conversion) would be 5 GJ per tonne, or about one-fifth of what is actually used. Energy-efficiency measures will not significantly reduce the required amount of feedstock, however, since the carbon and most of the feedstock energy is embedded in the products. Other approaches (such as feedstock substitution) would be needed.

Table 7.13 ▶ **Ultimate yields of steam crackers with various feedstocks (kg of product per tonne of feedstock)**

	Naphtha	Gas oil	Ethane	Propane	Butane
High-value chemicals	*645*	*569*	*842*	*638*	*635*
Ethylene	324	250	803	465	441
Propylene	168	144	16	125	151
Butadiene	50	50	23	48	44
Aromatics	104	124	0	0	0
Fuel-grade products and backflows	*355*	*431*	*157*	*362*	*365*
Hydrogen	11	8	60	15	14
Methane	139	114	61	267	204
Other C4 components	62	40	6	12	33
C5 and C6 components	40	21	26	63	108
C7 and non-aromatic components	12	21	0	0	0
Losses	5	5	5	5	5

Source: Neelis, *et al.*, 2005

About 13.3 EJ of feedstock is used for steam cracking worldwide. This represents almost 44% of the chemical and petrochemical industry's final energy use. Out of this total, only 2.1 EJ is used for energy purposes. Steam-cracking products contain about 11.2 EJ, of which about 1.5 EJ is recycled to the refining industry in the form of by-products for further processing into gasoline and other products.

Typical crackers use 25 to 30 GJ per tonne ethylene for the furnace and product separation, while state-of-the-art crackers use 20 to 25 GJ per tonne, which is about 25 to 30% less (Ren, *et al.*, 2005). Improvements in cracking could yield large gains in energy efficiency in the long term. Options include higher-temperature furnaces (with materials able to withstand more than 1 100 °C), gas-turbine integration (a type of high-temperature combined-heat-and-power unit that generates the process heat for the cracking furnace), advanced distillation columns, and combined refrigeration plants. Together, these steps could result in 3 GJ per tonne of ethylene savings. The total potential for improving energy efficiency from existing technology to the best possible technology is about 1 EJ (24 Mtoe).

Some propylene is recovered from the refinery off-gases of fluid catalytic crackers (FCC). This process is less energy-intensive because the energy used in the cracking furnace can be saved. Capital costs for FCC recovery are also lower than for steam cracking. As a result, FCC propylene production has been growing at a faster rate than propylene production from steam cracking, but there is a limited supply of refinery propylene. Given the demand for ethylene and the steam cracking product mix, part of the propylene will come from steam cracking.

World propylene production is around 65 Mt per year, 63% of which is derived from steam cracking, 34% from petroleum refineries (FCC) and 3% from purpose-designed production processes. Conventional FCC units yield about 5 to 12% propylene in the off-gas, depending on the mode of operation. New deep-catalytic cracking processes can increase the yield to 16 to 22%, but at the expense of naphtha and gasoline yields.

Aromatics Production

Aromatics are hydrocarbons that contain cyclic chemical structures. Benzene, toluene, xylene and ethylbenzene are all aromatics. Aromatics are produced from three types of resources:

- Hydrotreated coke-oven benzole.
- Hydrotreated pyrolysis gasoline (from steam cracking).
- Reformate (from catalytic reformers in refineries).

At present, 72% of all aromatics are recovered from reformate, 24% from pyrolysis gasoline and 4% from coke-oven light oil. Thirty-nine percent of all benzene is recovered from pyrolysis gasoline, 33% from reformate, 6% from coke ovens and 22% from the hydrodealkylation (HDA) of heavier aromatics and toluene disproportionation (TDP).

The global market is about 30 Mt per year for benzene, 14.5 Mt per year for toluene, 24 Mt per year for mixed xylenes and 17 Mt per year for p-xylene. About 40% of the toluene is used to make benzene, while p-xylene production using the selective toluene disproportionation process (STDP) consumes 19%. About 75% of the mixed xylene produced is used to make p-xylene. Some mixed xylene is used as solvent, and o-xylene is recovered for chemical processing. The total annual quantity of end products in this grouping amounts to about 60 Mt.

A modern benzene extraction unit uses about 1.5 GJ per tonne of energy in the form of low-temperature heat. The electricity needed for p-xylene separation through crystallisation is about 0.8 GJ per tonne. If the average energy used in aromatics processing is 5 to 10 GJ per tonne, then aromatics production accounts for 0.4 to 0.8 EJ. The 61% of feedstock which does not derive from steam cracking accounts for another 1.7 EJ of energy use. Depending on the process configuration, other steps may add to the energy consumption of the aromatics plant. Since most of the oil ends up in the product, the potential for reducing CO_2 emissions from aromatics production processes is limited. Heat cascading or new separation technologies may be applied to save energy.

Methanol

Global methanol production was 32 Mt in 2004. One-third of all methanol is used for the production of methyl tertiary butyl ether (MTBE), a gasoline additive, and one-third for formaldehyde. A typical methanol plant uses 26 GJ of natural gas and 1.2 GJ of electricity per tonne of product (making total gas use around 30 GJ per tonne). The minimum energy use, equivalent to the lower heating value (LHV) of methanol, is 20 GJ per tonne. Natural gas used in methanol production amounts to approximately 1 EJ world wide. The newest plants have a capacity of 1.5 Mt per year and virtually all of them use Lurgi MegaMethanol technology (six such plants have been built so far).

Biomass Feedstock

Using feedstock energy is different from conventional energy use in that it is not possible to produce the product without the feedstock. But the feedstock type can be changed. Biomass is the only carbon-neutral primary feedstock option.

Currently, biomass is used in significant quantities only to produce detergents and lubricants. The minor role of bio-based products can be explained by the relatively high production cost they entail. But this could change in the future, as the cost of fossil feedstocks increases and the production costs of bio-products drop.

In the 1980s and 1990s, RD&D in the field of biochemicals was driven by oil prices. Recent interest, however, is driven not only by high oil prices, but also by concerns about the security of oil supply, climate policies, a search for new markets for agricultural products and rapid progress in the biological sciences. So far, there is no clearly "superior" approach to biomass feedstocks, and the economic viability of the approach is still not clear. Nonetheless, various biorefinery processes are being investigated that use different types of feedstock and fermentation and gasification processes. Four types of biomass-based system options are emerging:

- Feedstock substitution.
- Production of existing monomers from biomass feedstocks.
- Production of new biopolymers with similar properties as existing plastics.
- Radically different product design based on new biomaterial properties.

Europe could reduce its CO_2 emissions by 10 Mt per year as early as 2010 if adequate policies and measures were introduced in support of bio-based products. Another recent study has analysed three scenarios for Europe, in which between 5 and 100 Mt of synthetic chemicals (or one-third of all synthetic chemicals) would be produced from biomass in 2050. Half of this amount would be biopolymers, and half would be synthetic polymers from biomass feedstock (Patel, *et al.*, 2005). At the same time the US government is spending considerable funds on the development and demonstration of biorefinery concepts.

If naphtha were produced from biomass feedstock, CO_2 emissions could be reduced without altering existing petrochemical production infrastructure. One option is Fischer-Tropsch (FT) synthesis of naphtha from biomass. Another option is the so-called "high-thermal upgrading" (HTU) process, in which biomass (wet chips or a slurry) is treated with water in a mixed reactor at temperatures of 300 to 350°C and pressures of 120 to 180 bar for 5 to 10 minutes. The crude oil product can be upgraded to naphtha or diesel. The overall systems efficiency from biomass to products is 64%.

In general, biomass processes are limited to small-scale production due to the dispersed nature of the biomass feedstock. If the biomass is valued at USD 3/GJ (energy crops), the HTU crude oil product would cost USD 9/GJ (equivalent to approximately USD 50/bbl). The upgraded HTU naphtha product would cost in the range of USD 12 to USD 14/GJ.

Following successful tests of pilot plants, a USD 20 million demonstration plant that will process 25 kt of biomass per year is scheduled to start production in the Netherlands in 2007, with an expansion to 4 Mt (75 PJ) projected by 2020 and to 0.5 EJ by 2040 (Naber, *et al.*, 2004).

Ethylene is the most important monomer and can be produced from ethanol through a process called dehydrogenation. The production cost of ethanol from sugar cane is projected to decline to between USD 0.25 and USD 0.32 per litre gasoline equivalent, which equals USD 7/GJ. If lignocellulosic ethanol can be produced for USD 0.40/l ethanol (USD 19/GJ), the cost of biomass ethanol feedstock would be USD 8.30/GJ of ethylene. One ethanol molecule is needed for the production of one ethylene molecule, which translates into 0.4 GJ ethanol per GJ ethylene. Important amounts of additional energy will be needed for this reaction (Patel, *et al.*, 2005), and the process only becomes attractive at oil prices above USD 50/bbl.

Another option is to convert biomass into methanol by using the methanol-to-olefins (MTO) process. Methanol can then be used to produce ethylene and propylene. Current methanol production costs are USD 8 to USD 12 per GJ, but this could decline to USD 5 to USD 7 by 2030, or USD 100 to USD 140 per tonne methanol. A recent study concluded that the production cost of methanol from black liquor would amount be USD 225 per tonne methanol, or USD 11/GJ (Ekbom, *et al.*, 2003). Between 75% and 80% of the carbon in the methanol ends up in the ethylene and propylene product. The technology has been used in a demonstration plant in Norway. Two plants, with a total capacity of 1 Mt per year and which will use methanol produced from cheap "stranded" gas, are currently under construction in Nigeria and Egypt. The cost of MTO could be reduced by technology learning and this would help to make the biomethanol route more viable.

There also seems some possibility of producing monomers from biomass in the medium to long term. At the moment, no clearly preferable technology stands out among ethanol-to-ethylene, methanol-to-olefins and FT/HTU naphtha-steam cracking. Carbon credits could provide real incentives, provided such credits are also granted for carbon savings from fossil fuels that accrue in waste incineration. The prospects for such credits, especially for feedstocks, are uncertain. Higher oil prices will also favour biomass feedstocks, while a bioethanol feedstock strategy could piggy-back on the development of ethanol as a transportation fuel. These technologies could be implemented from 2020 at the earliest. Pilot plants will have to be built soon in order to achieve the necessary cost reductions and prove the technology feasible.

Biopolymers

The production of biopolymers received much attention in the 1990s. However, but a number of materials failed commercially, mainly because of their high production cost compared to polymers from oil feedstocks.

Polylactic acid (PLA) is a polyester produced from lactic acid, which is derived from corn or sugar beets. The current price for PLA is around USD 7.50/kg (commodity plastics such as polypropylene and polyethylene cost USD 1 to USD 2/kg). In recent years, the quality of PLA has improved significantly and its physical characteristics are now similar to those of polystyrene, a commodity plastic. PLA is suitable for bottles, films, fibre products and extrusion-thermoformed containers. It is also biodegradable, but it is not clear to what extent it is recyclable.

In the United States, the firm Cargill has operated a 140 kt per year polylactic acid plant since 2001. So far, the business has lost money, as customers have been unwilling to pay a premium for biopolymers. Dow Chemicals withdrew from this activity at the beginning of 2005. CSM, a Dutch food conglomerate, is the largest lactic-acid producer in the world, mainly for food applications, with 135 kt per year of capacity, and has announced plans to build a new 100 kt lactic acid plant in Thailand. The polymerisation step used in such plants is straightforward and requires limited new technology. In Europe, about 50 kt of bioplastics are sold each year, comprising about 0.1% of all plastics.

The carpet fibre market, historically dominated by nylon and to a lesser extent by polyester-based products, is now looking to polytrimethylene terephthalate (PTT) fibres. DuPont and Tate & Lyle have developed a genetically modified bacterium that can convert corn into 1,3-propanediol, the feedstock for PTT production. Biogenic production has 40% lower capital costs than production from oil feedstock and 25% lower operating costs, allowing production at a price of around USD 1.80/kg.

Polyhydroxyalkanoates (PHAs) are microbial polyesters. PHAs can be used for coatings and as a substitute for petrochemical plastics such as polypropylene. It is either directly produced by plants or through fermentation. Any starch-containing feedstock can be used, and genetically modified bacteria are used to ferment the starch. At the end of 2004, the companies Metabolix and Archer Daniels Midland formed an alliance to commercialise PHA from fermentation. Archer Daniels Midland has started building a USD 100 million plant that will produce 50 kt of this plastic, starting in 2008. The plastic will be sold at USD 3/kg.

An overview of the CO_2 benefits of bio-based polymers is provided in Table 7.14. With a production volume of several hundred Mt per year in 2050, the emission-reduction potential is several hundred Mt of CO_2. However, the cost-effectiveness of these technologies is uncertain. Table 7.15 provides an overview of their technology outlook.

Table 7.14 ▶ ***Energy and CO_2 savings for bio-based polymers***

Product	Energy savings (GJ/t biopolymer)	CO_2 emission reduction (t CO_2/t biopolymer)
Thermoplastic starch pellets	51	3.7
Polylactic-acid pellets	19	1.0
Printed wiring boards	5	n/a
Lacquer	195	8.3
Flax- fibre mat	45	n/a
Interior side panel for passenger car	28	0.9
Transport pallet	33	1.6

Source: Patel, *et al.*, 2003.

Table 7.15 ▶ Global technology outlook for biomass feedstocks and biopolymers

	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration	Demonstration	Demonstration, commercial
Investment costs (USD/t)	5 000-15 000	2 000-10 000	1 000-5 000
Life-cycle CO_2 reductions	50%	70%	80%
CO_2 reduction (Gt/yr)	0 – 0.05	0.05 – 0.1	0.1 – 0.3

Inorganic Chemicals

Ammonia

Global ammonia production was 132 Mt in 2003. Production growth is limited and is mainly concentrated in Asia, which accounts for almost half of global production. About 80% of world production is based on natural gas steam reforming, 15% on coal gasification (mainly in China) and 5% on the partial oxidation of oil products (mainly in India and China). A typical heavy-oil-based process uses 1.3 times as much energy as a gas-based process. A coal-based process uses 1.7 times more energy than a gas-based process. In 2003, total energy and feedstock use for ammonia production amounted to about 3.8 EJ of natural gas and 1.3 EJ coal (Table 7.16). This is almost 20% of all the energy used in the chemical industry.

Table 7.16 ▶ Energy consumption in ammonia production, 2003

Region	Production (Mt ammonia/yr)	Energy intensity (GJ/t ammonia)	Energy intensity index	Gas use (PJ/yr)	Oil use (PJ/yr)	Coal use (PJ/yr)
Western Europe	11.8	36	100	426	–	–
North America	14.9	37.9	105	565	–	–
Former Soviet Union	18.7	39.9	111	746	–	–
Other Europe	5.4	43.6	121	235	–	–
Asia	61.4	40	111	636	500	1 320
Latin America	7.9	36	100	285	–	–
Africa	1.4	36	100	49	–	–
Middle East	9.8	36	100	351	–	–
Oceania	1.1	36	100	40	–	–
World	*132.4*	*39.4*	*109*	*3 333*	*500*	*1 320*

Source: European Fertilizer Manufacturers Association (2003) and IEA data.

The average natural gas steam reforming plant in the United States or Europe uses 35 to 38 GJ per tonne ammonia; the best available technology uses 28 GJ per tonne. The theoretical minimum energy and feedstock use for the process is 21.2 GJ per tonne ammonia, given that three atoms of hydrogen are needed per molecule of ammonia and hydrogen has a lower heating value of 120 GJ per tonne. But the LHV of ammonia is only 18.7 GJ per tonne. As a consequence, 2.5 GJ of residual heat is generated in the production process and may be used for other purposes. Given the theoretical minimum, current gas-based ammonia production achieves about 60% efficiency.

Table 7.17 provides an overview of energy efficiency options and of the potential for retrofitting existing ammonia production facilities, where the average potential is between 1 and 3 GJ per tonne, which would mean an improvement of less than 10%.

Table 7.17 ▶ ***Ammonia energy-saving potential of retrofitting gas-fuelled steam-reforming plants***

Retrofit measure	Average improvement (GJ/t)	Range (GJ/t)	Cost (USD/t capacity)	Applicability EU (%)	US (%)	India (%)
Reforming large scale retrofit	4.0	±1.0	30.0	10	15	10
Reforming modernization	1.4	±0.4	6.3	20	25	20
Improved CO_2 removal	0.9	±0.5	18.8	30	30	30
Low pressure synthesis	0.5	±0.5	7.5	90	90	90
Hydrogen recovery	0.8	±0.5	2.5	0	10	10
Improved process control	0.7	±0.5	7.5	30	50	30
Process integration	0.3	±1.0	3.8	10	25	20

Source: Rafiqul, *et al.*, 2005.

In most existing ammonia plants, CO_2 is separated from the hydrogen at an early stage. Much of the CO_2 separated is used for the production of urea (CH_4N_2O), a popular type of nitrogen fertiliser. It takes 0.88 tonnes of CO_2 to produce each tonne of urea. At current production levels, even allowing for the continued use of CO_2, about 150 Mt CO_2 could be recovered and placed in underground storage.

Chlorine and Sodium Hydroxide

Salt is decomposed electrochemically to yield sodium hydroxide (NaOH) and chlorine. In the process of chlorine production, hydrogen is generated as a by-product. World chlorine production was 44 Mt in 2004, and annual demand for chlorine is forecast to rise to 52 Mt in 2010. The industry currently uses 0.44 EJ of electricity per year in three production methods:

- mercury process.
- diaphragm process.
- membrane process.

The energy efficiency of these processes differs, depending to some extent on the process design (Table 7.18). The energy efficiency of current membrane cells is 63% of the theoretical minimum.

Each process generates a sodium hydroxide product of a different quality. The mercury cell produces NaOH in a 50% concentration and needs no further processing. The diaphragm process requires considerable amounts of heat to upgrade the NaOH concentration, which is initially only 12%. The membrane process produces a 30% NaOH product which then needs to be concentrated.

Table 7.18 ▶ ***Energy efficiency of chlorine production processes***

	Electricity consumption (GJ_{el}/t Cl_2)	**Steam consumption** (GJ/t Cl_2)
Mercury process	11.8	0
Diaphragm process	10.0	2.2
Membrane process	8.6-9.2	0.6

Note: Membrane process range reflects current densities of 0.3 and 0.4 A/cm^2, respectively.
Source: Gielen, 1997 and Bommajaru, *et al.*, 2001.

Regional differences in production processes affect the energy savings potential in each area. In Europe, about half of chlorine production is by the mercury process. In the United States, three-quarters is by the diaphragm process. In Japan, the membrane cell process represents more than 90% of production capacity.

The main opportunity for energy savings lies in converting mercury-process and diaphragm-process plants to membrane technology. New technological developments, such as the combination of an electrolytic cell with a fuel cell that uses the hydrogen by-product, could significantly decrease energy use. New cells all use membrane technology, which is less costly to operate. But this technology is unlikely to be commercially available in this decade. The replacement of hydrogen-evolving cathodes with oxygen-consuming cathodes can result in additional 30% electricity saving for membrane cells, but such electrode materials need further development.

Membranes

One of the most energy-intensive operations in the chemical industry is separation. Separation technologies include distillation, fractionation and extraction. Separation processes use up to 40% of all the energy consumed in the chemical industry and can account for more than 50% of plant operating costs.

Membranes selectively separate one or more components from a liquid or gas, and they can replace energy-intensive separation processes in a number of industrial sectors, including food processing, chemicals, paper, petroleum refining and metals industries. Several key membrane separation processes are microfiltration (MF), ultrafiltration (UF), nanofiltration (NF), reverse osmosis (RO), electrodialysis (ED), gas separation and pervaporation.

In the United States, approximately 40% of membrane sales are for water and wastewater treatment applications. Another 40% are for food and beverage processing, pharmaceuticals and medical applications. The remaining 20% are used in the production of chemicals and industrial gases (Wiesner and Chellam, 1999). Membrane separation technology is increasingly utilised in the chemicals industry for a wide range of applications, such as removing water from organics. Gas membranes that separate organic mixtures, and liquid membranes that separate both aqueous and organic mixtures offer a more energy efficient alternative to liquid-liquid extraction. The membrane-based process of pervaporation is gaining importance and is now routinely used in the chemicals industry for splitting azeotropes. Membranes have a long track record in the chemicals industry, as they were first demonstrated about twenty years ago for recovering hydrogen in ammonia plants. Membranes are also used in various state-of-the-art plant designs and a large potential for membranes remains in the chemical industry.

Current production is small, however, and no suitable membranes exist at the moment for many processes. In some important separations (most notably in water treatment), suitable membranes do exist. Moreover, new membranes with different qualities are being developed for the separation of specific gas mixtures, although more research is needed to improve their performance. The cost of a new membrane system is often higher than that of currently used separation technologies, but the life-cycle costs of many membrane systems are lower than those of the systems they replace. The annual operating costs of membranes tend to run a bit higher than those of other separators, mainly because membranes foul easily and must be replaced rather frequently.

Membrane technologies now in the R&D phase will bring substantial cost reductions (Steigel, *et al.*, 2003). Liquid and gas membranes for separation offer an alternative to liquid-liquid extraction and cryogenic air separation. Liquid membrane separators tend to cost about 10% less than traditional separators (Martin, *et al.*, 2000). In general, gas and liquid membrane applications can be amortised in about ten years, but shorter payback times may be possible for certain applications.

Energy savings from the use of membranes vary widely depending on the application and the separation efficiency of the membrane, but can be between 20% and 60%. Membranes are gaining a foothold in the food processing industries and, more slowly, in the some parts of the chemical industry. Membranes for important energy consuming separations in the chemical industry may need a few decades for development and deployment (Table 7.19). The development of membrane reactors (combining chemical conversions and separation in a single reactor) is an area that still needs considerable research.

Table 7.19 ▶ Global technology prospects for membranes

Membranes	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration	Demonstration, commercial	Commercial
Internal rate of return	8%	10%	15%
Energy savings (%)	15%	17%	20%
CO_2 reduction (Gt/yr)	0 – 0.03	0.1	0.2

Paper and Pulp

Paper and pulp production consumes 5.9 EJ of energy per year. Energy use in this industry is divided among a number of different pulp production processes and paper production. The main processes are:

- Chemical and thermochemical pulping.
- Mechanical pulping.
- Paper recycling.
- Paper production.

Wood or other fibre is converted into pulp, which is formed into paper sheets and then dried. Mechanical pulp is used for newspapers and is produced by mechanically grinding wood. This pulp contains large amounts of lignin, is not purely white and possesses limited strength. Chemical and thermochemical pulp is made by separating the lignin from the fibre in a cooking process. The most widely employed cooking process uses sulphate chemicals and results in a product called sulphate pulp.

Total paper and paperboard production was 337 Mt in 2004. Chemical pulp production was 126 Mt, mechanical wood-pulp production was 36 Mt and non-wood pulp production was 19 Mt. Total fibre supply (pulp and waste paper) amounted to 339 Mt. Recycled paper accounted for 149 Mt, or 44% of the total fibre supply, but does not account for losses in waste paper processing. Out of the 126 Mt of chemical pulp produced, the vast majority (121 Mt) was sulphate pulp. Half of the paper and board product mix is packaging and wrapping paper and board. About a third is printing and writing paper. The remainder is newsprint, household and sanitary paper.

Mechanical pulping uses large amounts of electricity. Chemical pulping, on the other hand, yields black liquor as by-product, which is then incinerated in a recovery boiler to produce heat and electricity.[9] Roughly 22 GJ of black liquor per tonne of pulp can be burnt. Depending on its recovery efficiency and its configuration, a mill that uses chemical pulping can be a net energy producer. Typical energy use data for various types of processes and products are shown in Table 7.20.

9. Black liquor is the combination of the lignin residue with water and the chemicals used for the extraction of the lignin.

Table 7.20 ▶ **Typical energy use for pulp and paper production**

		Steam (GJ/t product)	Net electricity import (GJ/t product)
Mechanical pulp	Pulp		7.3
Thermo-mechanical pulp	Pulp	–3.4	8.3
Market chemical pulp mill – softwood	Pulp	14.3	0.7
Market chemical pulp mill - hardwood	Pulp	13.0	0.9
Integrated chemical pulp and fine paper mill – softwood	Paper Pulp	19.3 12.1	2.8 1.8
Integrated chemical pulp and fine paper mill – hardwood	Paper Pulp	16.1 12.9	2.5 2.0
Waste-paper preparation	Pulp	0.3	0.7
Extensive waste-paper preparation	Pulp	1.2	0.5
Papermaking (average)	Paper	5.1	2.2

Source: Jochem, *et al.*, 2004; STFI, 2005.

The industry's heavy reliance on bioenergy means that the CO_2 intensity of the energy is not very high, and the CO_2 reduction potentials in the pulp and paper industry are limited. But more efficient use of bioenergy still makes sense from an energy systems perspective, as it frees up scarce bioenergy resources to replace fossil fuels elsewhere.

Pulp mills are usually located close to the feedstock resource, often in remote regions with large forest areas. This explains the global distribution of pulp and paper mills, with very large production facilities in Brazil, Canada, Finland, Sweden and the United States. These five countries accounted for 60% of all pulp production in 2003.

The main production facilities are either pulp mills, or integrated paper and pulp mills, depending on the proximity to markets and transport facilities. An integrated mill is more energy efficient than the combination of a stand-alone pulp mill and paper mill. However, such an integrated plant requires electricity from the grid, as well as additional fuel. A large modern chemical pulp mill is self-sufficient in energy terms, using only biomass and delivering surplus electricity to the grid. Such a mill typically has a steam consumption of 10.4 GJ/adt (air dry tonne pulp) and an excess of electricity production of 2 GJ/adt. A future integrated chemical pulp and fine paper mill has a typical steam consumption of 13.6 GJ/adt paper (*i.e.*, a small biofuel surplus) and a deficit in electricity production of 1.8 GJ/adt paper (STFI, 2005).

Almost half of all paper is produced from waste paper, with recycling usually taking place close to where the waste paper is generated. Recycling plants tend to be smaller and more dispersed than primary paper production facilities and their energy needs for paper making are higher. On the other hand, the energy that would have gone into pulp-making is saved. This saving by far exceeds the additional energy used. In many developed countries, paper recycling actually exceeds paper production from primary biomass.

In 2003, the paper and pulp industry used 1.9 EJ of bioenergy, mainly in the form of black liquor. Indeed, the actual use may be somewhat higher, as a significant amount of bioenergy is reported in IEA statistics under "non-specified industry use", part of which may actually be paper and pulp production. Industry sources report 2.3 EJ of black liquor use in 2003.

The energy intensity of producing various types of paper varies widely. Table 7.21 shows best-practice values for major categories. In Canada, only the top 10% of plants achieve these values. Efficiencies in North America are somewhat lower than in Scandinavia.

Table 7.21 ▶ ***Energy consumption in pulp and paper production (top 10 % of performers)***

	Total heat (GJ/t)	Total power (GJ/t)	Paper-making heat (GJ/t)	Paper-making power (GJ/t)	Pulping heat (GJ/t)	Pulping power (GJ/t)
Market pulp	12.25	2.08	0.00	0.00	12.25	2.08
Recycled linerboard	5.39	1.62	4.22	1.12	1.16	0.50
Fine paper	5.07	1.91	4.12	1.48	0.95	0.43
Coated 1-3	5.70	2.59	4.75	2.12	0.95	0.47
Coated 4-5	7.08	4.54	4.96	2.16	2.11	2.38
Recycled tissue	14.68	3.46	11.62	2.09	3.06	1.37

Source: Schepp and Nicol, 2005.

Production quantities and the process energy requirements in Table 7.21 imply 3.1 EJ of biomass use, 1.2 EJ of steam use and 1.1 EJ of electricity use for 2004. Based on the assumption of an 85% efficiency rate for steam generation, the total final energy use amounts to 5.7 EJ.

Most energy used in paper-making is for pulping and paper drying. New processes have been proposed that would reduce the energy needs for drying. The need for large amounts of steam makes combined heat and power (CHP) an attractive technology in this sector, and most modern paper mills have their own CHP unit. As a result of the large amount of black liquor produced and the relatively low energy recovery from this liquor, new technologies that promise higher conversion efficiency could have important energy benefits for this sector.

In principle, it is possible to develop a paper and pulp sector without CO_2 emissions, provided sufficient biomass is used and black liquor is converted with sufficient efficiency. This would imply minimal recycling, with recycling replaced by energy recovery from waste paper. This may not, however, be the optimal use of scarce biomass resources. From the viewpoint of the energy system as a whole, it might make more sense to recycle as much paper as possible, while using the wood surplus to produce biofuels or electricity. Moreover, more intensive use of forests could bring further environmental degradation. The best pathway depends on system boundaries and complex trade-offs.

Important differences in energy efficiency exist between OECD and developing countries. Chinese rural paper mills use about 23 GJ per tonne of primary energy. Total average energy use for paper and paperboard making in China, including pulping, stands at 45 GJ per tonne. Even higher figures are reported for India. Small-scale plants based on imported second-hand equipment and the use of coal for steam generation contributes to this very low energy efficiency.

Black-liquor Gasification

Various industries produce low-grade fuels as a by-product, and in the paper industry, chemical pulping produces black liquor. In standard kraft pulp mills that use the sulphate process, the spent liquor produced from de-lignifying wood chips is normally burned in a large recovery boiler (Tomlinson boiler). Because of the high water content of black liquor (it is usually burned at a solids content of 65% to 75%), the efficiency of existing recovery boilers is limited. Electricity production is also limited, because the recovery boilers produce steam at low pressures for safety reasons.

Gasification offers opportunities to increase the efficiency of using black liquor. In gasification, hydrocarbons react to syngas, a mixture mainly of carbon monoxide and hydrogen. The synthesis gas can be used in gas-turbine power generation or as a chemical feedstock. This technology, called black liquor gasification-combined cycle (BLGCC), allows the efficient use not only of black liquor, but also of other biomass fuels such as bark and wood chips. Each of these fuels can be used to produce synthesis gas, which after cleaning, is combusted in a gas or combined–cycle turbine with high electrical efficiency. Alternatively, the synthesis gas can be used as a feedstock to produce chemicals, in effect, turning the paper mill into a “bio-refinery.” In Europe, policies aimed at increasing the share of biofuels in transportation have sparked interest in using black liquor gasifiers to produce dimethylether (DME) as a replacement for diesel fuel.

Apart from the energy efficiency gains it provides, the gasification process makes it possible to enhance pulping by modifying conventional pulping liquors. The main developers of black liquor gasification are in the United States, Sweden and Finland, and teams from all three countries are collaborating in the development of the technology. In the United States, development has focused on both air- and oxygen-based processes. Demonstration gasifiers (without a combined cycle) have been installed or are being built at several pulp mills in the United States and Sweden. The Chemrec Company, in Sweden, expects to see the commercial demonstration of its technology in 2008. But both the low-temperature (air) and high-temperature (oxygen) processes face technical problems. Further research is needed to increase the reliability of the gasifier. The use of a gasifier with a gas turbine has not yet been demonstrated, and the total capital costs of a BLGCC-system are estimated to be 60 to 90% higher than those for a standard Tomlinson boiler system. The internal rate of return of an investment in a BLGCC has been estimated at 16 to 17%, if the electricity can be sold at USD 0.04/kWh.

Black liquor production was 185 Mt in 2003, equivalent to 2.3 EJ. It is projected to grow to 3.3 EJ by 2025. Based on the performance of a typical kraft plant in the southeastern United States, a pulp plant will be able to produce and then sell excess electricity on the order of 220 to 335 kWh per tonne of pulp. If the overall electric efficiency were raised by 10 percentage points, and the steam efficiency remained the same, 3 EJ of black liquor per year would yield an additional 300 PJ of electricity annually. The savings in terms of primary energy would be in the range of 0.5 to 0.8 EJ, depending on whether a gas- or coal-fired power plant was displaced. The CO_2-savings potential is in the range of 30 to 75 Mt per year (Table 7.22).

Table 7.22 ▶ ***Global technology prospects for black liquor gasification***

Black liquor gasification	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration	Demonstration, commercial	Commercial
Investment costs (USD/t)	300-400	300-350	300
Energy reduction (%)	10-15%	10-20%	15-23%
CO_2 reduction (Gt/yr)	0 – 0.01	0.01 – 0.03	0.03 – 0.1

Black liquor IGCC technology is similar to coal-fired IGCC technology, and black liquor plants could be equipped with CO_2 capture. The electric efficiency of a black-liquor IGCC would be 28%, which declines to 25% with CO_2 capture. The steam efficiency would remain at 44% in both cases. Capital costs would increase by USD 320/kW of electricity if CO_2 capture is installed. Biomass in combination with CCS results in an energy chain that removes CO_2 from the atmosphere, a unique feature that may offset emissions in other parts of the energy system. This may become especially important if ambitious low emission targets are established. (In the scenario analysis of this study, black-liquor gasification is classified as a power sector option.)

Efficient Drying in Paper Machines

In theory, the production of paper from pulp can be designed to use virtually no external energy. In practice, however, water is needed to process the fibres and energy is needed to remove the water from the fibres in a drying process. Technical potentials to reduce energy use in the paper industry by 30% or more have been identified in various countries, with cost-effective potentials of at least 15 to 20%. The measures include small incremental improvements in machines and steam and motor systems. They also include such major improvements as the long-nip press for paper machines, process integration of the steam system and heat recovery from paper machines.

Paper-making (as opposed to pulp production) is usually divided into four basic steps: stock formation and forming, pressing (mechanical de-watering), evaporative drying and finishing. Of these steps, the drying is the most energy-intensive. In current drying practices, once the paper sheet is formed and pressed to remove excess water, it moves through a series of 40 to 50 steam-heated cylinders, resulting in a final consistency of about 90 to 95% solids.

New process designs focus on more efficient water-removal techniques by combining increased pressing with thermal drying (the long-nip press, the condebelt design or impulse drying). The long-nip press (or shoe press) is the current state-of-the-art approach to de-watering. In the long term, the need to use water can be re-evaluated, and other ways of managing the fibre orientation process for optimal paper quality, such as super-critical CO_2 and nanotechnology, may be possible.

In the condebelt design, the paper is dried in a drying chamber by contact with a continuous hot steel band (heated either by steam or hot gas) rather than being run through the steam-heated cylinders. The condensate is removed by pressure and suction. The advantages of the condebelt technology are that it can completely replace the drying section of a conventional paper machine and that it has a drying rate 5 to 15 times higher than conventional methods. The first commercial installations of the condebelt technology were in Finland and Korea. These two plants produce industrial and packaging paper, and their technology could be used for continuous paperboard production. The two plants were built as add-ons to existing facilities, with minimal energy savings. Larger savings would be possible if the condebelt system were built as an independent unit.

The development of impulse-drying started in the 1980s. It improves the mechanical de-watering of paper and reduces the amount of water that needs to be removed in the drying process. In impulse drying, the paper web is subjected to very high temperatures at the press nip in order to drive moisture out of the web. The moisture content is reduced to 38% or less before the web enters the drying phase. The technology involves pressing the paper between one very hot rotating roll and a conventional static concave shoe press. The pressure is about ten times higher than that applied in traditional press and condebelt drying. Development of impulse-drying technology is progressing slowly, but no commercial system has yet been developed.

Two forming technologies, high-consistency and dry-web, lower the water content of the paper-machine feed and thereby reduce the need for drying in the paper machine. During the forming process, the slurry pulp is formed into a uniform web. In high-consistency forming, the slurry enters the forming stage at a higher consistency and energy is saved due to reduced de-watering requirements. The process also increases paper strength and decreases material inputs, but it is only applicable to heavyweight papers such as cardboard and liquid containers. This technology (commercially available as either a unique installation or as an add-on) has been slow to catch hold and there are only a few large-scale installations.

While originally conceived as a paper technology, dry-web forming has found its own industry niche in the manufacture of non-woven paper-like materials used in personal hygiene products. In dry-web forming, the non-woven product is produced without the addition of water. The fibres can be disbursed either through a carding technique, whereby the fibres are disbursed mechanically, or through an air-layering technique, in which fibres are suspended in air. The air-laying technique allows for a higher production rate and better control, and is the predominate dry-web forming process. These dry-sheet forming techniques create significant energy savings.

The use of ethanol or even super critical carbon dioxide has been suggested to replace water as the forming medium. Removal of these chemicals would make the process much less energy intensive, but there are no current R&D programmes on the use of alternative media in the pulp and paper industry. Most research is still focused on the fundamental understanding of mechanisms that form fibre into paper.

Paper drying consumes about 25 to 30% of the total energy used in the pulp and paper industry. Assuming that energy efficiency improvements of 20 to 30% are possible in this production stage, overall energy savings are estimated at 0.7 EJ.

Table 7.23 ▶ ***Global technology prospects for energy efficient drying technologies***

Efficient drying	2003-2015	2015-2030	2030-2050
Technology stage	R&D	Demonstration, commercial	Commercial
Investment costs (USD/t)	800-1100	700-1000	600-700
Energy reduction (%)	20% - 30%	20% - 30%	20-30%
CO_2 reduction (Gt/yr)	0 – 0.01	0.01 – 0.02	0.02 – 0.05

Non-ferrous Metals

Non-ferrous metals include aluminium, copper and a number of other materials (such as zinc, lead and cadmium). Aluminium is by far the most relevant material from an energy perspective. Aluminium production can be split into primary aluminium production and recycling. Primary production is about 20 times as energy intensive as recycling and represents the bulk of energy consumption.

The steps for primary aluminium production consist of the production of alumina (Al_2O_3) from bauxite ore, the production of carbon anodes, electrolysis and rolling. Electrolysis is the most energy intensive process, with the electricity use of modern Hall-Héroult smelters using about 50-55 GJ of electricity per tonne of product. Older types (Søderberg smelters) may use up to 60 GJ per tonne of aluminium. The theoretical minimum energy use is about 20 GJ per tonne.

The main primary producers of aluminium are located in China, North America, Latin America, Western Europe, Russia and Australia. Japan has phased out its primary aluminium production over the last thirty years and now imports most of its needs from Australia. The aluminium industry is the single largest industrial consumer of electricity in Australia, accounting for about 15% of industrial consumption (Department of Industry, Science and Resources Australia, 2000). The industry is of similar importance in other countries with low-cost electricity, such as Norway, Iceland, Canada and Russia. In recent years, several new smelters have been built in Africa and use electricity from hydropower.

Bauxite mining uses about 45 MJ per tonne ore. Generally, the ore contains at least 40% Al_2O_3. Bauxite is refined into alumina using the Bayer process, which is based on the reaction of the ore with sodium hydroxide. The majority of energy consumed in alumina refineries is in the form of steam used in the main refining process. The calcining (drying) of the alumina also requires large amounts of high temperature heat. Because of their high demand for steam, modern plants use combined heat and power systems. Average energy consumption of Australian plants is 11 GJ per tonne of alumina produced. This could be reduced to 9.5 GJ per tonne through better heat integration and improved CHP systems. The global average was 11.4 GJ per tonne in 2004, with a range from 10.0 to 12.6 (Table 7.24). The production of 1 kg of aluminium requires about 2 kg of alumina. With world alumina production at 60 Mt, total energy use was 0.68 EJ. In the energy statistics, alumina production is counted as part of the chemical industry.

Table 7.24 ▶ ***Regional average energy use of metallurgical alumina production, 2004***

	(GJ/t alumina)
Africa and South Asia	12.6
North America	10.4
Latin America	10.0
East Asia and Oceania	11.9
Europe	12.4
Weighted average	11.4

Source: World Aluminium, 2006a.

The main energy use in aluminium production is related to the electrochemical conversion of alumina into aluminium. The main cell-types are Søderberg, which uses in-situ-baked electrodes, and the Hall-Héroult process, which uses pre-baked electrodes. Electricity consumption for Søderberg smelters is about 15 to 18 kWh/kg of aluminium, while pre-baked smelters use 14.0 to 16.5 kWh/kg (European Commission, 2001b). The Hall-Héroult electrolysis process is a mature technology, but gradual improvements of its productivity and environmental performance are still possible. The difference in efficiency between the best and worst plants is approximately 20% and can be attributed to different cell types and to the size of the smelters, which is generally related to the age of the plants. The global average performance is 15 268 kWh per tonne of aluminium (Table 7.25). Primary aluminium production amounted to 30.2 Mt in 2004. Therefore 1.66 EJ is used by aluminium smelters, or about 3.5% of the world's total electricity use. 7

About 18 GJ of pitch and petroleum coke (petcoke) is needed per tonne of aluminium for the production of the pre-baked anodes. Moreover, 7.4 Gt of energy is consumed per tonne of aluminium for other uses in the smelters. Multiplied by the aluminium production volume, this represents another 0.80 EJ of industrial energy use.

Table 7.25 ▶ ***Regional average electricity use for primary aluminium production, 2004***

	(kWh/t aluminium)
Africa	14 337
North America	15 613
Latin America	15 551
Asia	15 427
Europe	15 275
Oceania	14 768
Weighted average	15 268

Source: World Aluminium, 2006b.

The industry plans to retrofit or replace existing smelters in order to reduce energy consumption to 13 kWh/kg (46.8 GJ per tonne) in the short term, and then to 11 kWh/kg (39.6 GJ per tonne of Al), which would be based on the use of inert cathodes and anodes. In the long run, electrolysis process designs using aluminium chloride or carbothermic processes could become the most energy efficient way to produce primary aluminium.

Inert Anodes

The development of inert anodes could end CO_2 emissions stemming from the use of carbon anodes and also eliminate emissions of perfluorocarbons (a category of powerful greenhouse gases) from the electrolysis process. Electricity consumption could also be reduced, but the technology is suited only for new smelters, because the cell design has to be changed fundamentally. The ultimate technical feasibility of inert anodes is not yet proven, despite 25 years of research. More fundamental research on materials will be needed and anode wear-rates of less than 5 mm per year will have to be attained.

The net effect of successfully deploying inert anodes could be a reduction in electricity consumption of 10 to 20% compared to advanced Hall-Héroult smelters (from 13 to 11 kWh/kg aluminium). Apart from the electricity savings, oil and coal consumption would be reduced by 18 GJ per tonne of aluminium, because the use of carbon anodes would be avoided. The electricity consumption for the chemical reaction to produce aluminium would increase, but the aluminium cell could be redesigned to reduce electricity losses. The so-called bipolar cell design, which requires inert anodes, is a typical example of a breakthrough technology that would be rapidly adopted once it was commercially proven.

Table 7.26 ▶ Global technology prospects for inert anodes and bipolar cell design in primary aluminium production

Inert anodes	2003-2015	2015-2030	2030-2050
Technology stage	R&D	Demonstration	Commercial
Investment costs (USD/t)	N/A	Cost savings	Cost savings
Energy reduction (%)	N/A	5% - 15%	10% - 20%
CO_2 reduction (Gt /yr)	N/A	0 – 0.05	0.05 – 0.2

General Equipment and Recycling

Steam Supply

A large share of industrial energy use is in the form of low-temperature heat and steam is usually the preferred energy carrier. The efficiency of steam boilers can be as high as 85%, but average efficiency is lower due mainly to low load factors and poor maintenance. Average boiler efficiency in China is about 65%, but the boiler is often only one part of a steam supply system. Steam and heat losses from pipes and ducts can be quite important as well. There are no detailed statistics regarding overall system efficiencies. Each system must be evaluated on a case-by-case basis.

The main efficiency options are to replace the steam boiler with a combined heat and power system or a heat pump. Calculating the actual efficiency gains, however, is very site-specific and complicated. An efficient steam supply system can result in higher efficiencies, but even greater emissions savings may be achievable by reductions in steam demand. In the last few decades, for example, the chemical industry has successfully developed new catalysts and process routes that avoid much steam use.

The US Department of Energy (US DOE, 2002) lists a number of energy saving measures for steam production and steam distribution systems:

- Inspect and repair steam traps.
- Insulate steam distribution and condensate-return lines.
- Use feedwater economisers for waste-heat recovery.
- Improve boiler combustion efficiency (to avoid excess air).
- Clean heat transfer surfaces.
- Return condensate to the boiler.
- Minimise boiler blowdown and recover heat from boiler blowdown.
- Use vapour recompression to recover low-pressure waste steam.
- Flash high-pressure condensate to regenerate low-pressure steam.

- Use a vent condenser to recover flash steam energy.
- Minimise boiler short-cycling losses.
- Install removable insulation on uninsulated valves and fittings.

The relevance of each measure depends on the specifics of a particular steam system. The figures in Table 7.27 indicate the savings potentials for steam systems only and do not include any possible measures related to reducing steam demand.

Table 7.27 ▸ Steam system efficiency measures

	Typical savings (%)	Typical investment countries (USD/GJ steam)	Use in OECD countries (%)	Use in non-OECD (%)
Steam traps	5%	1	50%	25%
Insulation pipelines	5%	1	75%	25%
Feedwater economisers	5%	10	75%	50%
Reduced excess air	2%	5	100%	50%
Heat transfer	1 – 2%	–	75%	50%
Return condensate	10%	10	75%	50%
Improved blowdown	2 – 5%	20	25%	10%
Vapour recompression	0 – 20%	30	10%	0%
Flash condensate	0 – 10%	10	50%	25%
Vent condenser	1 – 5%	40	25%	10%
Minimise short cycling	0 – 5%	20	75%	50%
Insulate valves and fittings	1 – 3%	5	50%	25%

Source: US DOE, 2002 and IEA estimates.

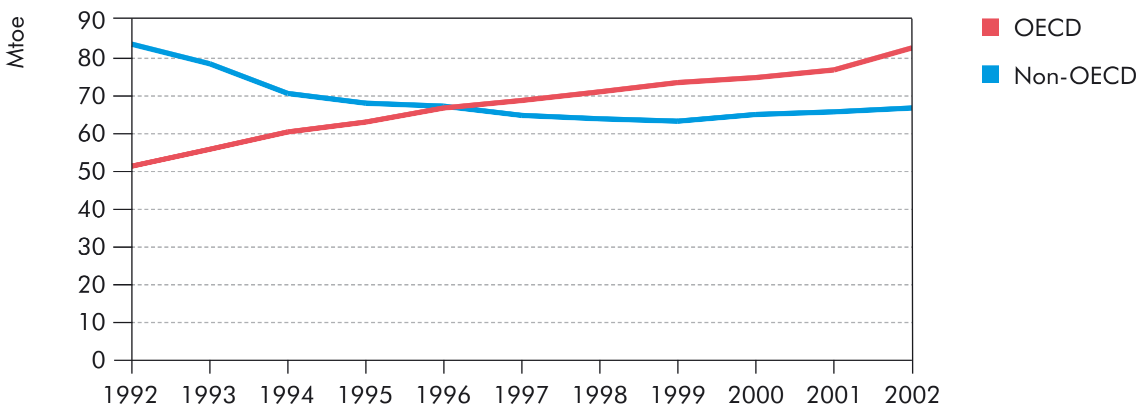
Much of this potential has already been implemented in OECD countries, but inadequate attention to routine maintenance of some measures, such as steam traps, valves, and heat transfer surfaces, significantly reduces the benefit derived from these measures. Furthermore, in many developing countries, the losses from steam supply systems remain substantial. Insulation is often non-existent in Russia, for example. In China, many small-scale boilers operate with considerable excess air and incomplete combustion of coal. Poor coal quality is the main cause for the low efficiency of Chinese boilers.

Combined Heat and Power

Combined heat and power (CHP) is not a specific technology, but rather an application of technologies that cogenerate heat and electricity. Steam turbines, gas turbines, combined-cycle systems and reciprocating engines are the major technologies used for power generation and in CHP. New technologies such as fuel cells are under development, while research is contributing to increased efficiencies and new applications for existing cogeneration technologies in industry.

The cogeneration of steam and heat can reduce total energy needs where the energy efficiency of stand-alone electricity production and heat production is relatively low. The greatest gains come when low-temperature heat production from fossil fuels is replaced with a CHP system. But CHP competes in this market segment with other options, such as heat pumps. The higher the temperature of the heat that is needed, the lower the electricity yield and the lower the efficiency gain. Typically, the introduction of CHP results in fuel savings of 10% to 20%. The amount of electricity that is produced from CHP has been increasing gradually and has now reached more than 6 EJ per year, which is more than 10% of total global electricity production (Figure 7.12). The amount of heat that is cogenerated is not exactly known, but it is in the range of 5 to 15 EJ per year, which represents an important share of industrial heat supply. If the heat is not sold, but used by the producer, part of the fuel use of the cogeneration plant is reported under industrial fuel use, rather than under CHP. Half the electricity production from cogeneration is in OECD countries, and the main growth in the past ten years, took place in OECD countries.

Figure 7.12 ▶ Global cogeneration trends, 1992-2003



Key point

Main growth in CHP production has been in OECD countries.

The Potential for CHP to Improve the Efficiency of Natural Gas-fired Generation

The use of CHP improves the overall efficiency of natural gas-fired generation by increasing the efficiency of heat production. Generation of electricity in CHP units can lower CO_2 emissions by up to 60% in systems of more than 100 MW. The share of CHP in total gas-fired generation in industry increased from 7.5% in 1971 to 29.5% in 2003. Decentralised CHP plants achieve lower *electric* efficiency, but higher *overall*

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efficiency than centralised large-scale power plants that generate only electricity. The efficiency gain depends on the efficiency of heat generation by a gas boiler.

The efficiency gained by a switch to CHP is determined by calculating the ratio of the natural gas used in CHP to the gas used in combined cycles or gas boilers that provide the same service. If a CHP system has 31% electric efficiency and 49% heat efficiency (as is the case in a 45 to 75 kW reciprocal CHP unit), then 3.23 GJ of natural gas is needed to produce 1 GJ of electricity and 1.58 GJ of heat. If the efficiency of stand-alone electricity production is 55% and that of stand-alone boilers is 85%, then 3.56 GJ of natural gas would be needed to produce the same output. Natural gas use is thus 12.3% lower in the CHP system.

The efficiency gains achieved by switching from stand-alone power plants and boilers to CHP systems range from 11.1% for small-scale systems to 27.3% for large-scale systems (Lemar, 2001). The trend toward CHP for natural-gas-fired systems has contributed significantly to an overall efficiency gain over the last three decades.

The penetration of CHP in the power generation sector varies widely from country to country. Countries like Denmark and the Netherlands already have high penetration rates, but many other countries have significant potential to expand the use of CHP. Principal CHP applications are steam and hot-water production, but at the same time, the adoption of CHP by industry may be limited by a number of factors. Key issues include the regulatory framework (buy-back tariffs, exit fees, backup fees) and cost-effectiveness (relative fuel and electricity prices).

In the United States alone, the future potential of large-scale conventional CHP systems is estimated at 48 GW, with potential energy savings of more than 1 EJ. An increase in turbine-inlet temperature has led to increasing efficiencies in gas turbines and industrial-sized turbines are available with efficiencies of 40 to 42%. The current industry standard is the GE LM2500 turbine, with an efficiency of 34 to 40%. It is expected that the efficiencies of aero-derivative and industrial turbines can be increased to 45% by 2010. The higher inlet temperature also allows a higher outlet temperature, so that flue gas from the turbine can be used to heat a chemical reactor. One option is the so-called "re-powering" option, in which the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen and can thus be used as combustion air for the furnaces, while the gas turbine can deliver up to 20% of the furnace heat. The re-powering option has been used at two refineries in the Netherlands, with a total combined capacity of 35 MW.

Another CHP option, with a larger potential market and associated energy savings, is high-temperature CHP. In this case, the flue gases from a CHP plant are used to heat the input to a furnace. There are various potential applications of the technology in the chemical and refinery industries. The major processes being considered for high-temperature CHP are atmospheric distillation, coking and hydrotreating in petroleum refineries and ethylene and ammonia manufacture in the chemical industry. In 1990, General Electric filed a patent for the integration of a gas turbine and a steam reformer used in ammonia manufacture. High-temperature CHP requires replacing existing furnaces, since the radiative heat transfer from gas-turbine exhaust gases is much smaller than from combustion gases, due to the lower temperature of the exhaust gases.

Two different types of high-temperature CHP are available. In the first type, the exhaust gases heat the process feed directly in a furnace. In the second, exhaust heat is led to a heat exchanger, where thermal oil is heated as an intermediate. The heat content of the oil is transferred to the process feed and gives greater process flexibility. In the long term, the integration of industrial processes, such as reforming in the chemical and petroleum refining industries, with high-temperature solid-oxide fuel cells (SOFC) could lead to revolutionary design changes and to the direct cogeneration of power and chemicals. But SOFC-integrated processes are not expected to be commercially available before 2025.

CHP integration allows increased use of CHP in industry by employing the heat in more efficient ways. As a process input for drying or process heating, the flue gas of a turbine can often be used directly in a drier. This option has been used successfully for the drying of minerals and food products. Tri-generation of electricity, heat and cooling has been used in food-processing plants in Europe for margarine and vegetable oils, dairy products, vegetable and fruit processing, freezing and meat processing.

For small-scale industrial applications, major developments include improved designs for reciprocating engines, fuel cells and microturbines, as well as better integration of the CHP unit into the processes to allow more efficient operation. In both the United States and Europe, research is aimed at developing medium-scale (under 20 MW) gas turbines with high efficiencies. In Europe, the development and demonstration of a 1.4 MW gas turbine with a single-cycle efficiency of 43% is being undertaken as part of a European Union programme. But this is still too large for many applications. Microturbines and fuel cells represent the most exciting developments in small-scale CHP technology. Microturbines (25 to 500 kW) are expected to have an efficiency of 26 to 30%. Although this is lower than the efficiency of power generation in large grid-connected power plants, CHP units can provide substantial energy savings. The primary energy savings of a microturbine CHP system have been estimated at 17%. Current development is aimed mainly at retail stores, offices and multi-family housing, but small-scale industrial facilities may prove an attractive market.

Fuel cells generate direct-current electricity and heat by combining fuel and oxygen in an electrochemical reaction. In practice, electric efficiencies of 35 to 45% are achieved with proton exchange membrane (PEM) fuel cells and 40 to 50% for molten carbonate (MCFC) and solid-oxide fuel cells (SOFC).

Existing PEM fuel cells are not very well suited for industrial cogeneration, as they produce only hot water as a byproduct. MCFC and SOFC offer the greatest potential for industrial applications. Among others a beer brewery in Japan and a rubber-processing facility in Germany use MCFCs. These demonstration systems still cost around USD 11 000/kW. Stand-alone SOFCs have achieved system efficiencies of more than 40%, and in combination with a gas turbine in a pressurised system, they have achieved efficiencies of 53%. Unfortunately, the production costs of SOFCs are still high (Table 7.28). For a capacity of 200 kW of electricity, SOFCs are currently much more expensive, but the investment cost for an SOFC CHP system could come down to the level of a conventional system by 2030. The electrical efficiency of SOFCs is much higher than that of the conventional, but the overall efficiency of the two systems is the same. The efficiency quoted for fuel cell systems is for DC electricity. The conversion to AC results in substantial losses. The overall system efficiency may be as high as 93% at peak load, but will drop below 80% if the load drops below 20%.

Table 7.28 ► **Comparison of conventional and fuel-cell CHP systems**

	Conventional CHP	SOFC CHP 2010	SOFC CHP 2030
Specific investment cost (per kW)	USD 1 000	USD 5 000	USD 1 000
Electrical power (kW el)	200	200	200
Thermal power (kW th)	326	244	164
Electrical efficiency (%)	38%	45%	55%
Overall efficiency, electricity plus heat (%)	90%	85%	90%
Cost share of stack in total investment (%)	–	first stack 30%	first stack 25%
Stack life (hours)		40 000	70 000
Operating time (hours per year)	5 000	5 000	5 000

Source: Lokurlu, *et al.*, 2003.

Dow Chemical and General Motors will collaborate on a large-scale PEM fuel cell located in Freeport, Texas, which will use hydrogen byproduct from chlorine production. PEM fuels cells are to be demonstrated at an AKZO chlorine plant in the Netherlands. It is expected that the performance of fuel cells between 100 kW and 5 MW will surpass the efficiency of engine-based CHP and that costs will come down through better cell design, improved fabrication techniques and mass production.

Worldwide, there is a very large potential for CHP, but an array of barriers has limited its adoption, including direct and indirect subsidies for centralised power generation, problems with inter-connections, unfavourable tariffs for power sales, high back-up rates and exit fees. Policies aimed at enhancing the acceptance and facilitating the inter-connection of cogeneration are needed. Major barriers can be overcome if further research and demonstration improve the performance of cogeneration technologies, demonstrate their reliability and reduce the investment costs. The main R&D needs for each of the technologies are:

- High-temperature CHP – The inlet (and outlet) temperatures of gas turbines need to be increased, as well as the reliability of the turbines in order to allow longer running times.
- Medium-scale applications – The integration of medium-scale turbines needs to be demonstrated at various scales and in various industrial settings. Development of integrated technologies to reduce the nitrogen oxides in flue gases would allow the use of process-integrated applications in the food industries.

- Small-scale systems - The efficiency of microturbines needs to be improved and their cost brought down through improved manufacturing techniques. Fuel cell research aims at bringing down the costs through improved durability and better materials (lower catalyst needs and improved lifetime) and through better manufacturing processes.

Table 7.29 ▶ Global technology prospects for CHP systems

Cogeneration (CHP)	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration, commercial	Demonstration, commercial	Commercial
Internal rate of return	10%	10% - 15%	10% – 15%
Energy reduction (%)	under 20%	10 %– 20%	15% – 30%
CO_2 reduction (Gt/yr)	0 – 0.05	0.01 – 0.1	0.1 – 0.4

CO_2 Capture from Combustion Installations

General boilers and furnaces could be equipped with CO_2 capture technologies. CHP systems that represent an energy-efficient alternative to stand-alone boilers and furnaces can also be equipped with CO_2 capture. CO_2 concentrations in the flue gases of gas-fired boilers are about 7% compared to about 14% in coal-fired boilers. Because of these low concentrations, chemical absorption is the only feasible capture strategy. As in the case of power plants, oxy-fuelling may be applied to concentrate the CO_2. Pre-combustion reforming, followed by CO_2 capture and hydrogen combustion, could also be tried. Such strategies will be limited to large plants (at least 10 MW).

Table 7.30 ▶ Global technology prospects for CO_2 capture from combustion installations

CO_2 capture & storage	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration	Demonstration, commercial	Commercial
Investment (USD/t CO_2)	200-500	150-400	100-250
CO_2 reduction (%)	90%	90-95%	90-99%
CO_2 reduction (Gt/yr)	0	0 – 0.5	0.5 - 1.5

Electric Motor-drive Systems

Motor-driven equipment accounts for 60% of the electricity consumed in the industrial sector and for more than 30% of all electricity use. Motor systems are made up of a range of components centred on a motor-driven device such as a compressor, pump or fan. These systems can be divided into the speed drive, motor, transmission and equipment that is driven by the motor (pumps, fans, conveyor belts, compressors, etc.), the distribution piping or ductwork and the end use (tools, production machinery, heat exchangers, etc.).

Improved motors could save significant amounts of energy on a continual basis. In Europe alone, studies suggest that the implementation of energy efficiency options for motors could result in 29% savings. The total investment cost of such a programme would be USD 500 million, while the annual saving would amount to USD 10 billion (Keulenaer, *et al.*, 2004).

The performance of motor systems can be improved by optimising them to meet end-use requirements. The opportunity for energy savings derives from the fact that the power consumption of the drive varies based on the cube of the motor rotation speed, while the flow varies linearly. As a result, small changes in motor speed can yield large energy savings. Moreover, in many industries, when there is no electronic variable-speed control, the bulk of the electricity is simply converted into heat and wasted.

Many efficiency improvements could be effected today, but companies often fail to seize the opportunity. In the long term, new motor technologies may improve the energy efficiency even further.

Large savings can often be achieved by analysing and then optimising the complete motor system. Based on worldwide experience, it is estimated that industries can cost-effectively reduce the electricity use of motor systems by at least 15 to 20%, although the potential will vary from plant to plant. The potential efficiency improvements are well known. They include:

- Matching the scale of the motor service to the work demand.
- Providing efficient control strategies to respond to variations in load, including the ability to incrementally respond to increased loads, as well as speed control devices such as adjustable speed drives (ASDs).
- Reducing demand for energy services (for example, substituting a blower for compressed air or turning off steam supplied to inactive equipment).
- High-efficiency motors.
- Improved maintenance practices, with focus on filters, valves, system leaks, and equipment lubricants.
- High-efficiency transmission systems.
- Re-design of the equipment that is driven by the motor.
- Reduced system losses (pipeline systems with lower friction that require less pumping energy).

High-efficiency motors use better quality materials, are made more precisely and are about 85 to 95% efficient, depending on size. Although the cost is 20% more than standard motors, motor losses decrease by 20 to 30%. In most applications, the pay-back time is less than three years. Using new motors instead of rewinding used ones is another efficiency option, as rewinds cause an overall efficiency reduction of 1.5%.

Emerging motor system improvements can be categorised into three areas of development opportunities. First, the motor itself can be upgraded, with such technologies as superconductive motors, permanent magnet motors, copper rotor motors, switched reluctance drives and written pole motors. Second, the motor-driven equipment, such as pumps and compressors, can be improved through variable speed controls and the use of premium lubricants, system design optimisation, and improved management practices like engineering for energy efficiency, proper sizing and operational best practices. Third, improvements can be made to the controls on existing systems, for example with pressure/flow controllers, dedicated storage, master controls for compressed air systems, sensor-based controls and advanced adjustable speed drives with improvements like regenerative braking, active power factor correction and better torque/speed control.

Although energy efficient motors are 20 to 30% more expensive than standard motors, pay-back times can be very short for motors with high annual load factors. A motor that costs USD 2 000 may use USD 50 000 of electricity during its life span. In France in the early 1990s, for example, 88% of industrial compressors, 75% of pumps and 70% of fans ran for more than 4 000 hours per year, a utilisation rate typical for most regions. The distribution of motor sizes may vary across sectors and regions. For example, in China two-thirds of motor electricity demanded is by motors of less than 100 kW (Brunner and Niederberger, 2006). This is the category where policies should be focused.

An adjustable-speed drive varies the feeding frequency and voltage of the supply to the motor, thus controlling its speed. This can result in significant energy savings. But the savings potential depends critically on the load. Systems operating at around full load would be *worse* off by about 3% if they used ASD electronics. The savings potential therefore needs to be assessed for each individual motor system. In general, savings of 10 to 20% can be achieved, but savings up to 60% are possible for specific systems if ASD is applied instead of throttling.

The application part of the motor system (transmission, equipment, energy services and motor sizing) offers by far the largest savings potential. The replacement of the belts in belt-drive systems with energy efficient belts results in a 4% efficiency gain and about a third of all motors use belt-drive systems.

Compressors, pumps and fans are the main energy consumers among industrial motor applications. They use more than half of the total energy consumed by motors (compressors use 15 to 30%, pumps 20 to 25% and fans 13 to 14%), but the shares vary widely across specific sectors and plants. Pumps are very important in the chemical industry, where they use 37 to 76% of motor power, but compressor consumption varies widely in the same industry, from 3 to 55%. Pump systems, compressor systems and fans are often over-designed (they use too-powerful motors), especially for small and medium power users. As a consequence, the systems operate most of the time at only a fraction of their optimal load. This results in significant efficiency losses. In industrial pumps, energy efficiency can vary between 40 and 90%, depending on the design and the application.

In Europe, it is estimated that high-efficiency motors could account for about 10% of the potential savings, ASD for 25% and the application part of the motor systems (pumps, compressors and fans) for about 60%. More than 90% of all industrial motors in the EU operate at or below standard efficiency, while more than 70% of all motors in the United States and Canada are high- or premium-efficiency motors (Brunner and Niederberger, 2006).

The main barriers to potential savings are:

- Split budgets for energy efficiency investments and energy bills.
- Industry focus on production, not energy efficiency.
- Reluctance to change a working system.
- Market and policy focus on components, not systems.
- Lack of training on design and operation for system energy efficiency.

Lesser barriers include:

- Lack of defined standards of practice for motor system efficiency, especially for the application part.
- Over-sizing due to the unknown characteristics of the load.
- Limited availability of energy-efficient motors in some locations.
- Lack of management time.
- Conflicts between procurement specifications and energy-efficiency goals.

So far, the optimisation of motor systems in order to save energy has received only limited attention. In countries where government programmes on energy-efficient motors have been in place (Canada and United States), the prevalence of energy efficient motors has substantially increased, but the potential increase in motor *system* efficiency remains largely unrealised due to the lack of national standards and policies that encourage companies to integrate energy efficiency into their management practices. The US programme has been partially successful in building awareness through voluntary approaches such as training, case studies, publications and technical assistance, but these are time-intensive, plant-by-plant efforts that fall far short of the total savings potential (McKane, *et al.*, 2005). Given the 5 to 10% savings potential on total electricity use, a much more comprehensive approach is warranted and needed.

New Motors

Superconductivity is the ability of certain materials, when cooled to extremely low temperatures, to conduct electrical current with near-zero resistance and hence with extremely low losses. Motors with high-temperature superconductors (HTS) operate at temperatures between –173°C and –195°C, with liquid nitrogen cooling. These motors have longer operating lives, improved safety, higher overload thresholds and reduced friction, as well as reduced noise, size, volume and weight. Rockwell Automation has successfully demonstrated and tested a cryogenically cooled 1 000-HP HTS motor. A prototype 5 000-HP HTS motor has been developed by American Superconductor and utilises an off-the-shelf cryogenic cooling system. The main current barrier to its adoption is cost, particularly the cost of wire. HTS generators are currently being used in ship propulsion generators.

Permanent-magnet (PM) motors either replace the stator winding on a motor with a permanent magnet or they contain a stator with three windings that produces a rotating field and a rotor with one or more permanent magnets that interact with the rotating field of the stator. The most common type of PM motor is the electronically commutated permanent magnet motor (ECPM), also known as the brushless DC motor. These motors can achieve varying speeds by adjusting the rate at which the magnetic fields are reversed (or commutated). ECPMs eliminate rotor-resistive losses, brush friction and some of the maintenance work associated with conventionally commutated motors. Other advantages include precise speed control, lower operating temperature and a higher power factor than those found in induction motors.

Two new motors have been developed based on identifying the best materials to use in the casting process. Copper rotor motors and magnetic steel motors replace aluminium in the rotor "squirrel cage" structure of the motor. The electrical conductivity of these materials is up to 60% higher than aluminium, resulting in a more energy efficient induction motor.

Written pole (WP) motors are hybrids and act as induction motors during start-up, but then become synchronous motors when they reach full operating speed. The single-phase motor combines the starting characteristics of a high-slip, high power-factor cage motor with the energy efficiency of an AC permanent magnet motor without using power electronics, reduced voltage starters or phase converters. Switched-reluctance drives are simple, compact, brushless, electronically commutated AC motors that offer high efficiency and torque. Their advantages include variable-speed regulation and high efficiency over a wide range of speeds (from 50 rpm to 100 000 rpm), precision control, high vibration tolerance, high power density and simple construction (Worrell, *et al.,* 2004).

Optimising the System Design for End-users

Designing a system (or correcting the performance of an existing system) so that supply properly matches demand is crucial to energy efficiency. All components of the motor system, including compressors, pumps, fans and motors, should be considered relative to the load pattern. Trained personnel can conduct system assessments to identify potential improvements. For compressed air systems, improvements can include minimising leaks, identifying inappropriate uses of the air, determining proper pressure levels and developing efficient control strategies. While the engineering associated with pump systems is well understood, many engineers are not experienced in conducting the energy efficiency analyses that their system requires, so careful screening is required before outsourcing. Pump systems may require slowing of the pumps, trimming of the impellers or the replacement of an existing pump. Free software tools are available that can identify system requirements for energy efficiency. Selecting a premium lubricant for the equipment can reduce friction losses, particularly in end-use equipment such as compressors, pumps and gear drives, and therefore increase system efficiency.

Controls

Many controls are available for motors and motors systems and they are continuously being improved. Adjustable speed drives (ASDs) have already been fitted to 9% of US motor systems. A new class of ASDs, magnetically coupled adjustable speed drives (MC-ASDs), offers a large new range of possibilities. Other advanced ASDs now under development include various inverter technologies.

In addition to ASDs, system controls can be applied to full motor systems or to components to minimise energy consumption, to distribute wear and tear more evenly, and to operate entire systems more smoothly. Advanced compressor controls can handle multiple compressors that communicate with each other. One network has the ability to control as many as 31 drives at once. Sensor controls can monitor end-uses and feed the information back to the motor for adjustment (Worrell, *et al.*, 2004).

Table 7.31 ▶ **Cost estimates for emerging motor technologies**

Technology	Current capital costs	Capital costs by 2025	Operating & management costs	Payback by 2025	Notes
New motors					
Super-conductor	Higher than existing motors	Lower than existing motors	Lower than existing motors	Up to one year	If wire costs decrease, payback period will be short to none. At present only for large motors.
Permanent magnet	Roughly equal	Roughly equal	Lower	1-3 years	
Copper rotor	Higher	Potentially lower	Lower	Up to one year	If die casting costs decrease, payback periods will be short to zero.
Written pole	60% higher	30% higher	Lower		
Switched reluctance (SR)	50% higher	25% higher	Unclear		Controls are more complex, but SRs are more efficient. The choice will be driven by reliability.
System and end-use improvements					
Optimisation by experts	None	None	Higher initially, then lower	≤ 1 year	Cost of expertise outweighed by energy-efficiency savings.
Optimisation tools	None	None	Higher initially, then lower	≤ 1 year	Cost of time spent on tools outweighed by energy-efficiency savings.
Training programmes	None	None	Higher initially, then lower	About 1 year	Cost of employee time (in training) outweighed by energy-efficiency savings.
Premium lubricants	50-150% higher	50-150% higher	Lower	About 1 year	Premium lubricants last three to four times as long.
Controls					
Advanced ASDs	Higher	Higher	Significantly lower	<1-4 years	Initial capital costs are comparable to those for conventional ASDs. Advanced ASDs that provide sag control pay for themselves once they prevent a single shutdown.

Source: Worrell, *et al.*, 2004.

The total energy-savings potential for upgrades in motors and motor systems has been estimated to be from 15 to 25% and it could be higher when emerging technologies are included. Specific electricity savings for particular motor applications are summarised in Table 7.32. The total energy savings will depend on the market penetration of new motors, controls and system improvements. In turn, this rate will depend on the success of government programmes to support their adoption and of technology transfer programmes. Depending on the application, some measures can be applied as retrofits to existing motors and motor systems, while others can only be applied to new motors. Most systems can be adapted in some way to improve energy efficiency.

Table 7.32 ▶ Global energy efficiency estimates for emerging motor technologies

Technology	Energy savings	Notes
New motors		
Superconductor	2% to 10%	Higher efficiencies at partial load
Copper rotor	1% to 3%	Gains of 5% have been reported
Switched reluctance	3%	
Permanent magnet	5% to 10%	
Written pole	3% to 4%	
System and end-use improvements		
Systems management	17% to 25%	Efficiency improvements for compressed air are likely to be greater than for pumping systems or motors.
Premium lubricants	3%	
Controls		
Advanced ASDs	0 – 60%	Savings are great compared to non-ASDs. Compared to ASDs, energy savings will be less.

Source: Worrell, *et al.*, 2004.

Table 7.33 ▶ Global technology prospects for motor systems

Motor systems	2003-2015	2015-2030	2030-2050
Technology stage	R&D, demonstration, commercial	Demonstration, commercial	Commercial
Internal rate of return	20 – 40%	30 – 50%	60%
Energy reduction (%)	under 20%	10 % – 20%	15% – 20%
CO_2 reduction (Gt/yr)	0 – 0.05	0.05 – 0.1	0.1 – 0.4

Increased Recycling

For many materials, recycling results in a significant reduction in both energy use and CO_2 emissions. The problem here is that the costs of recycling waste are often high, while waste landfill or incineration is comparatively cheap. Incineration can recover some of the energy from combustible waste, but its efficiency is generally low. The best waste combustion plants achieve less than 25% electric efficiency. However, not all recycling makes sense from an energy and CO_2 perspective. Certain recycling processes are energy intensive; moreover, the energy used in waste collection must be taken into account. Optimal recycling rates (in energy efficiency and CO_2 terms) will differ for each material, each waste flow and each region.

One of the materials where recycling could have a substantial impact is plastics. Europe is the region with the longest history of plastic waste recycling policies. Consumption of primary plastics in Western Europe was 38.1 Mt in 2003, while 23.3 Mt of plastics waste was generated. Of this amount, 4.4 Mt (19%) was mechanically recycled, 0.4 Mt (2%) was used for feedstock recycling and 4.8 Mt (21%) was used for energy recovery. Mechanical recycling has been increasing rapidly in the last decade, while energy recovery has doubled. The increase in mechanical recycling has reduced the need for primary plastics production by 2.5 Mt over the past ten years, an energy saving of about 125 PJ, or 2.5% of the total energy used in the European chemical and petrochemical industry.

The United States generated 26.7 Mt of municipal solid plastic waste in 2003. Of this amount, 1.4 Mt (5.2%) was recovered and 14% was incinerated. Total plastics production amounted to 41 Mt in 2000, so the post-consumer recycling rate was 3.7%. The recycling of plastic bottles increased to about 0.73 Mt in 2000. Plastic waste recovery in the United States has stabilised over the past ten years. In Japan, plastic resin production stood at 13.9 Mt in 2002. Domestic resin consumption was 10.6 Mt and waste creation amounted to 9.1 Mt (with 0.9 Mt of processing and production losses). Therefore, there was 10 Mt total of plastic waste in Japan, with 1.5 Mt (15%) recycled mechanically, 0.25 Mt (2.5%) used for feedstock recycling and in blast furnaces, and 3.64 Mt (37%) used for energy recovery.

The general trend seems to be toward more mechanical recycling and energy recovery. The development of back-to-monomer and back-to-feedstock recycling technologies during the 1990s has not resulted in any major applications. But with worldwide plastics consumption running at about 150 Mt/yr and assuming an energy content on the order of 30 to 40 GJ per tonne of waste, the energy saving potential is somewhere between 5 and 8 EJ per year.

Steel is the most widely recycled material in the world. If consumption were constant, the scrap potential would equal the apparent steel consumption. However, in 2004, 401 Mt of steel scrap was recycled by the steel industry, compared to an apparent steel consumption of 968 Mt (IISI, 2005). Total scrap use for steel and cast iron production amounted to 578 Mt. The gap between apparent consumption and scrap collection suggests further potential for steel recycling. However, no detailed statistics exist regarding what the additional recycling potential would be. A better understanding of the global steel materials balance is needed in order to assess the additional recycling potentials.

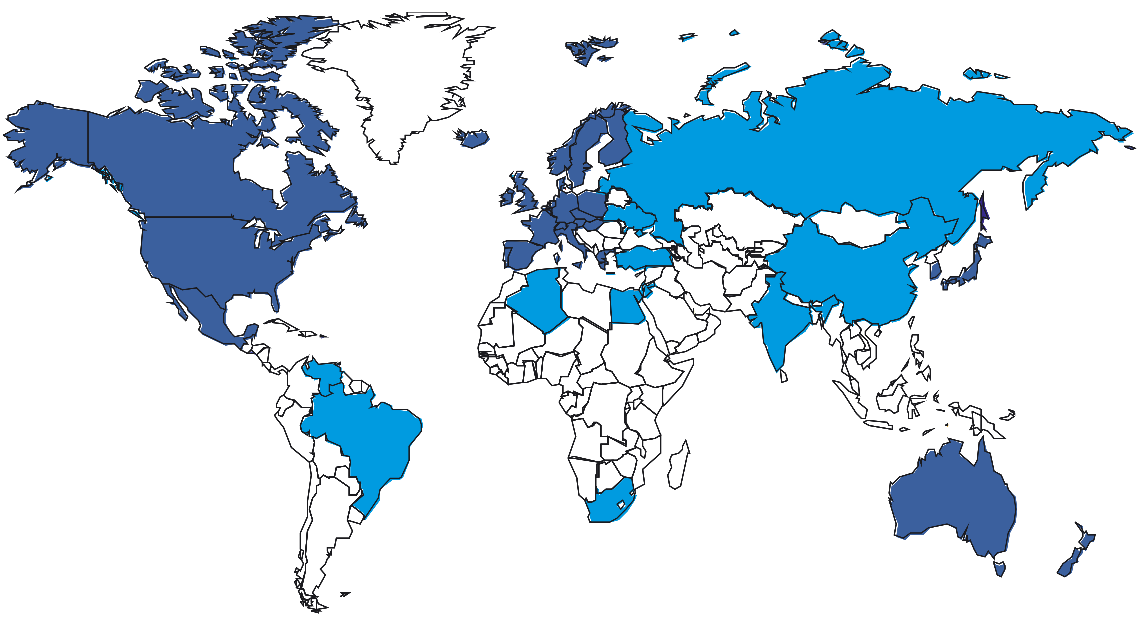
Paper recycling is another important contributor to potential energy savings. Paper recycling rates are already high in many countries, varying between 30% in the Russian Federation to 64% in China. But increased recycling of paper is feasible. The recovery rate in most non-OECD countries is 15 to 30 percentage points lower than in OECD countries. However, the rate at which waste paper is actually recycled in developing countries is higher than the recovery rate suggests. Large amounts of waste paper are imported from OECD countries. Between 10 and 20 GJ can be saved per tonne of paper recycled, depending on the type of pulp and the efficiency of the pulp production it replaces. The net effect on CO_2 emissions is less clear, as some pulp mills use biomass, while recycling mills may use fossil fuels. However, biomass that is not used for paper production could potentially be used for dedicated power generation.

Annex A IEA ENERGY TECHNOLOGY COLLABORATION PROGRAMME

Global Energy Research

For over 30 years, energy experts from around the world have been participating in the IEA Energy Technology Collaboration Programme (ETCP), advancing the research, development, demonstration and deployment of energy technologies.

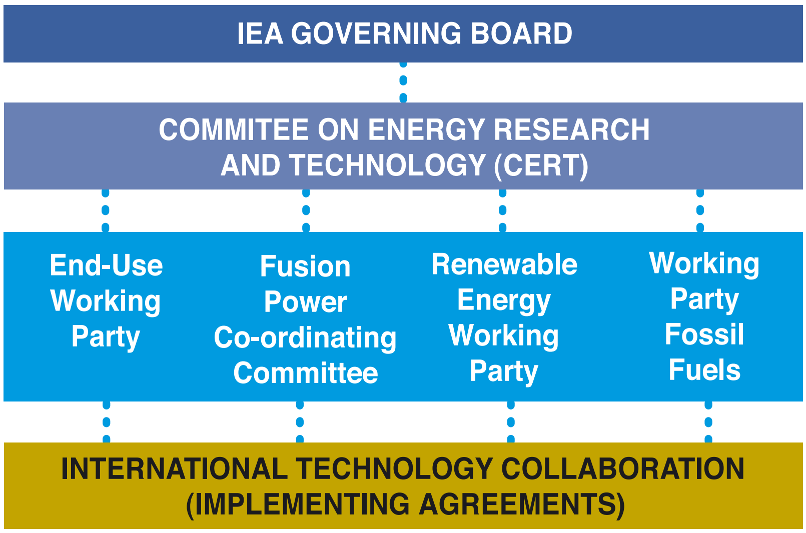
Figure A.1 ▶ **Countries participating in the IEA ETCP (May 2006)**



Currently, more than 5 000 scientists, engineers, policy makers and industry experts from government, research institutes, universities, and energy technology companies are involved in the 40 voluntary, jointly funded research groups, called Implementing Agreements.

Results and benefits from the Implementing Agreements, including intellectual property, are shared equally among the participants. Research topics cover all aspects of the energy chain – supply, transformation and demand – and may include basic energy science, applied research, analysis, modeling, symposiums and information exchange.

Implementing Agreements are overseen by the Committee on Energy Research and Technology (CERT) and its relevant Working Parties.



Implementing Agreements

Fossil Fuels

IEA Clean Coal Centre	www.iea-coal.org.uk
Clean Coal Sciences	http://iea-ccs.fossil.energy.gov
Enhanced Oil Recovery	www.iea.org/eor
Fluidised Bed Conversion	www.iea.org/tech/fbc/index.html
Multiphase Flow Sciences	www.etsu.com/ieampf
IEA Greenhouse Gas R&D Programme	www.ieagreen.org.uk

Renewable Energies and Hydrogen

Bioenergy	www.ieabioenergy.com
Geothermal	www.iea-gia.org
Hydrogen	www.ieahia.org
Hydropower	www.ieahydro.org
Ocean Energy Systems	www.iea-oceans.org
Photovoltaic Power System	www.iea-pvps.org
Hydrogen	www.ieahia.org
Renewable Energy Technology Deployment	(contact Piotr.Tulej@iea.org)
Solar Heating and Cooling	www.iea-shc.org
SolarPACES	www.solarpaces.org
Wind Turbine Systems	www.ieawind.org

End-Use

Transport

Advanced Fuel Cells	www.ieafuelcell.com
Advanced Materials for Transportation	http://ia-amt.ornl.gov
Advanced Motor Fuels	www.iea-amf.vtt.fi
Hybrid and Electric Vehicles	www.ieahev.org

Buildings

Buildings and Community Systems	www.ecbcs.org
Demand-Side Management	http://dsm.iea.org
District Heating and Cooling	www.iea-dhc.org
Energy Storage	www.iea-eces.org
Heat Pumping Technologies	www.heatpumpcentre.org

Industry

Emissions Reduction in Combustion	www.im.na.cnr.it/IEA
Superconductivity Electric Power Sector	http://spider.iea.org/tech/scond/scond.htm
Industrial Energy-Related Technology Systems	www.iea-iets.org

Fusion

Environmental, Safety, Economy of Fusion	www.iea.org/techagr
Fusion Materials	www.iea.org/techagr
Large Tokamaks	www-jt60.naka.jaea.go.jp
Nuclear Technology of Fusion Reactors	www.iea.org/techagr
Plasma Wall Interaction in TEXTOR	www.iea.org/techagr
Reversed Field Pinches	www.iea.org/techagr
Stellerator Concept	www.iea.org/techagr
Toroidal Physics in, and Plasma Technologies of Tokamaks with Poloidal Field Divertors (ASDEX-Upgrade)	www.iea.org/techagr

Cross-sectional Activities

Climate Technology Initiative (CTI)	www.climatetech.net
Energy and Environmental Technologies Information Centres (EETIC)	www.eetic.org
Energy Technology Data Exchange (ETDE)	www.etde.org
Energy Technology Systems Analysis Programme (ETSAP)	www.etsap.org

To access all links to Implementing Agreement websites, see www.iea.org/techagr.

For More Information

- The free brochure ***Frequently Asked Questions*** provides a brief overview of the energy technology collaboration programme.

  English www.iea.org/Textbase/Papers/2005/impag_faq.pdf
  Spanish www.iea.org/Textbase/papers/2005/impag_faqespagnol.pdf
  Chinese www.iea.org/Textbase/papers/2005/impag_faqchinois.pdf
  Russian www.iea.org/Textbase/papers/2005/impag_faqrusse.pdf

- For highlights of the recent activities of the Implementing Agreements, see the free publication, ***Energy Technologies at the Cutting Edge.***

  www.iea.org/Textbase/nppdf/free/2005/IAH2005mep–Full–Final–WEB.pdf

- For the mandates and strategies of Committee on Energy Research and Technology, its Working Parties and Ad Hoc Groups, see the free publication, ***Mobilising Energy Technology.***

  www.iea.org/Textbase/nppdf/free/2005/MobilsingEnergyTech–WEB.pdf

- To review the rules and regulations under which Implementing Agreements operate, see the free brochure, ***IEA Framework***.

  www.iea.org/Textbase/techno/Framework–text.pdf

- To receive regular updates of Implementing Agreement activities, subscribe to the free newsletter, ***OPEN Energy Technology Bulletin.***

  http://spider.iea.org/impagr/cip/index.htm

Annex B GDP AND POPULATION GROWTH ASSUMPTIONS

GDP Assumptions[1]

Global GDP growth is expected to slow gradually in all regions to 2050, with the annual average growth rate slowing from 3.2% in the period 2003 to 2030 to 2.6% in 2030 to 2050. This compares to an average rate of 3.3% per year between 1971 and 2003. China, India and other Asian countries are expected to grow faster than others. Growth will pick up in Africa and the transition economies. The combined GDP of developing countries will double over the period to 2050.

North America is expected to have the highest GDP growth among the OECD regions over the 2003 to 2050 period, at 2.1% per year on average, while OECD Pacific is assumed to grow by 1.8% per year and OECD Europe by

Table B.1 ▶ ***Economic growth assumptions (% average annual growth rate)***

	1971-2003	2003-2030	2030-2050	2003-2050
OECD	**2.9**	**2.2**	**1.3**	**1.8**
OECD North America	3.1	2.4	1.6	2.1
OECD Europe	2.4	2.1	0.7	1.5
OECD Pacific	3.5	2.0	1.6	1.8
Transition economies	**0.7**	**3.7**	**3.4**	**3.6**
Developing countries	**4.7**	**4.3**	**3.5**	**3.9**
China	8.4	5.0	3.8	4.5
India	4.9	4.7	3.6	4.2
Other Asia	*5.2*	*4.1*	*3.1*	*3.7*
Middle East	2.9	3.0	2.9	3.0
Latin America	2.9	3.2	2.8	3.0
Africa	2.7	3.8	3.6	3.7
World	**3.3**	**3.2**	**2.6**	**2.9**

1. These draw upon assumptions made for *WEO 2004* and *2005*.

1.5% per year. All regions are expected to experience a continuing shift in their economies away from energy-intensive heavy manufacturing towards lighter industries and services.

Population

Global population expanded on average by 1.6% per year from 1971 to 2003. It is set to grow by an average of 0.9% per year to 2050, from an estimated 6.4 billion in 2003 to almost 9.1 billion in 2050.[2] Population growth will slow over the projection period, from 1% per year in 2003 to 2030 to 0.7% per year in 2030 to 2050.

The population of the developing regions will continue to grow most rapidly, by 1.1% per year from 2003 to 2050. This is lower than the average rate of 2% in the last three decades. Population in the transition economies is expected to decline. The OECDs population is expected to grow by an average of 0.1% per year out to 2050, with North America contributing much of the increase. The share of the world population living in developing regions, as they are classified today, will increase from 76% now, to 80% in 2030 and to 83% in 2050.

Table B.2 ▶ ***Population growth assumptions (% average annual growth rates)***

	1971-2003	2003-2030	2030-2050	2003-2050
OECD	**0.8**	**0.4**	**-0.2**	**0.1**
OECD North America	1.3	0.9	0.5	0.7
OECD Europe	0.5	0.1	-0.9	-0.3
OECD Pacific	0.8	0.0	-0.2	-0.1
Transition economies	**0.5**	**-0.3**	**-0.1**	**-0.2**
Developing countries	**2.0**	**1.2**	**0.9**	**1.1**
China	1.4	0.4	0.1	0.3
India	2.0	1.1	0.5	0.9
Other Asia	2.1	1.3	0.9	1.1
Middle East	3.1	1.9	2.0	1.9
Latin America	1.9	1.0	0.7	0.9
Africa	2.7	1.9	1.8	1.9
World	**1.6**	**1.0**	**0.7**	**0.9**

2. Population growth assumptions are drawn from the most recent United Nations population projections contained in *World Population Prospects: the 2004 Revision*.

Annex C DEFINITIONS, ABBREVIATIONS, ACRONYMS AND UNITS

This annex provides information on definitions, abbreviations, acronyms and units used throughout this publication.

Fuel and Process Definitions[1]

API gravity
Specific gravity measured in degrees on the American Petroleum Institute scale. The higher the number, the lower the density. 25 degrees API equals 0.904 kg/m^3. 42 degrees API equals 0.815 kg/m^3.

Aquifer
An underground water reservoir. If the water contains large quantities of minerals, it is a saline aquifer.

Associated gas
Natural gas found in a crude oil reservoir, either separate from, or in solution with, the oil.

Biomass
Biomass includes solid biomass such as wood, animal products, gas and liquids derived from biomass, industrial waste and municipal waste.

Black liquor
A by-product from chemical pulping processes which consists of the lignin residue combined with water and the chemicals used for the extraction of the lignin.

Brown coal
Sub-bituminous coal and lignite. Sub-bituminous coal is defined as non-agglomerating coal with a gross calorific value between 4 165 kcal/kg and 5 700 kcal/kg. Lignite is defined as non-agglomerating coal with a gross calorific value less than 4 165 kcal/kg.

Clean coal technologies (CCT)
Technologies designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.

1. More detailed information can be obtained by consulting the annual IEA publications *Energy Balances of OECD Countries, Energy Balances of Non-OECD Countries, Coal Information, Oil Information, Gas Information* and *Electricity Information*.

Coal
Unless stated otherwise, coal includes all coal: both coal primary products (including hard coal and lignite, or as it's sometimes called "brown coal") and derived fuels (including patent fuel, coke-oven coke, gas coke, coke-oven gas and blast-furnace gas). Peat is also included in this category.

Coking coal
Hard coal with quality that allows the production of coke suitable to support a blast furnace charge.

Coke-oven coke
The solid product obtained from carbonisation of coal, principally coking coal, at high temperature. Semi-coke, the solid product obtained from the carbonisation of coal at low temperatures is also included, along with coke and semi-coke.

Electricity generation
Electricity generation shows the total amount of electricity generated by power plants. It includes own use and transmission and distribution losses.

Energy intensity
Energy intensity is a measure of total primary energy use per unit of gross domestic product.

Enhanced coal-bed methane recovery (ECBM)
ECBM is a technology for recovery of methane (natural gas) through CO_2 injection into uneconomic coal seams. The technology has been applied in a demonstration project in the United States, and is being tested elsewhere.

Enhanced gas recovery (EGR)
EGR is a speculative technology where CO_2 is injected into a gas reservoir in order to increase the pressure in the reservoir, so more gas can be extracted.

Enhanced oil recovery (EOR)
EOR is also known as tertiary oil recovery. It follows primary recovery (oil produced by the natural pressure in the reservoir) and secondary recovery (using water injection). Various EOR technologies exist such as steam injection, hydrocarbon injection, underground combustion and CO_2 flooding.

Fischer-Tropsch (FT) synthesis
Catalytic production process for the production of synthetic fuels. Natural gas, coal and biomass feedstocks can be used.

Fuel cell
A device which can be used to convert hydrogen into electricity, although various fuel inputs can be used. Various types exist that can be operated at temperatures ranging from 80°C to 1 000°C. Their efficiency ranges from 40 to 60%. For the time being their application is limited to niche markets and demonstration projects due to their high cost and the immature status of the technology, but their use is growing fast.

Gas
Gas includes natural gas (both associated and non-associated, but it excludes natural gas liquids) and gas works gas.

Gas-to-liquids (GTL)
The production of synthetic crude from natural gas using a Fischer-Tropsch process.

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.

Heat
In the IEA energy statistics, heat refers to heat produced for sale only. Most heat included in this category comes from the combustion of fuels, although some small amounts are produced from geothermal sources, electrically-powered heat pumps and boilers.

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.

Hydrogen fuel cell
A hydrogen fuel cell is an efficient electrochemical energy conversion device that generates electricity and produces heat, with the help of catalysts.

Integrated gasification combined cycle (IGCC)
IGCC is a technology where a solid or liquid fuel (coal, heavy oil or biomass) is gasified, followed by use for electricity generation in a combined cycle power plant. It is widely considered as a promising electricity generation technology due to its potential for achieving high efficiencies and low emissions.

Liquefied natural gas (LNG)
LNG is natural gas which has been liquefied by reducing its temperature to minus 162°C at atmospheric pressure. In this way, the space requirements for storage and transport are reduced by a factor of over 600.

Light petroleum products
Light petroleum products include liquefied petroleum gas, naphtha and gasoline.

Middle distillates
Middle distillates include jet fuel, diesel and heating oil.

Non-conventional oil
Non-conventional oil includes oil shale, oil sands-based extra-heavy oil and bitumen, derivatives such as synthetic crude products, and liquids derived from natural gas (GTL).

Nuclear
Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an assumed average thermal efficiency of 33%.

Oil
Oil includes crude oil, natural gas liquids, refinery feedstocks and additives, other hydrocarbons, and petroleum products (refinery gas, ethane, liquefied petroleum gas, aviation gasoline, motor gasoline, jet fuel, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, paraffin waxes, petroleum coke and other petroleum products).

Other petroleum products
Other petroleum products include refinery gas, ethane, lubricants, bitumen, petroleum coke and waxes.

Other renewables
Other renewables include geothermal, solar, wind, tide, and wave energy for electricity generation. The direct use of geothermal and solar heat is also included in this category.

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

Power 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.

Renewables
Renewables refer to energy resources, where energy is derived from natural processes that are replenished constantly. They include geothermal, solar, wind, tide, wave, hydropower, biomass, and biofuels.

Purchasing power parity (PPP)
The rate of currency conversion that equalises the purchasing power of different currencies. It makes allowance for the differences in price levels and spending patterns between different countries.

Steam coal
All other hard coal not classified as coking coal. Also included are recovered slurries, middlings and other low-grade coal products not further classified by type. Coal of this quality is also commonly known as thermal coal.

Synthetic fuels
Synthetic fuel, or synfuel, is any liquid fuel obtained from coal or natural gas. The best known process is the Fischer-Tropsch synthesis. An intermediate step in the production of synthetic fuel is often syngas, a mixture of carbon monoxide and hydrogen produced from coal which is sometimes directly used as an industrial fuel.

Traditional biomass
Traditional biomass refers mainly to non-commercial biomass use.

Total final consumption

Total final consumption is the sum of consumption by the different end-use sectors. TFC is broken down in to energy demand in the following sectors: industry, transport, other (includes agriculture, residential, commercial and public services) and non-energy use. Industry includes manufacturing, construction and mining industries. In final consumption, petrochemical feedstocks appear under industry use. Other non-energy uses are shown under non-energy use.

Total primary energy supply

Total primary energy supply is equivalent to total primary energy demand. This represents inland demand only and, except for world energy demand, excludes international marine bunkers.

Regional Definitions

Africa

Comprises: Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Cote d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia, and Zimbabwe.

Central and South America

Comprises: Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, the Dominican Republic, Ecuador, El Salvador, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Anguilla, Saint Lucia, St. Vincent-Grenadines and Suriname, Trinidad and Tobago, Uruguay, and Venezuela.

China

Refers to the People's Republic of China.

Developing countries

Comprises: China, India, Central and South America, Africa, the Middle East and other developing Asia.

Former Soviet Union (FSU)

Comprises: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Ukraine, Uzbekistan, Tajikistan and Turkmenistan.

Annex I Parties to the Kyoto Protocal

Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, the Czech Republic, Denmark, Estonia, the European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russia, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, the United Kingdom and the United States.

Middle East
Comprises: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates and Yemen. For oil and gas production it includes the neutral zone between Saudi Arabia and Iraq.

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

Organisation of Petroleum Exporting Countries (OPEC)
Comprises: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Other developing Asia
Comprises: Afghanistan, Bangladesh, Bhutan, Brunei, Chinese Taipei, Fiji, French Polynesia, Indonesia, Kiribati, Democratic People’s Republic of Korea, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, the Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Vietnam and Vanuatu.

Transition Economies
Comprises: Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, the Federal Republic of Yugoslavia, the former Yugoslav Republic of Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Western Europe
Comprises: Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Abbreviations and Acronyms

AC	Alternating current
AFC	Alkaline fuel cell
AFR	Africa
API	American Petroleum Institute
ASU	Air separation unit
ATR	Autothermal reforming
AUS	Australia and New Zealand
bcm	Billion cubic metres
BKB	Brown coal briquettes
boe	Barrels of oil equivalent
BOP	Balance of plant
CA	Chemical absorption
$CaCO_3$	Calcium carbonate
CAN	Canada
CaO	Calcium oxide
CAT	Carbon abatement technologies
CBM	Coal-bed methane
CC	Combined cycle
CCC	Clean coal centre
CCS	CO_2 capture and storage
CDM	Clean Development Mechanism
CDU	Crude distillation unit
CENS	CO_2 for EOR in the North Sea
CERT	Committee on Energy Research and Technology
CFB	Circulating fluid bed
CHI	China
CHP	Combined heat and power
CHOPS	Cold heavy oil production with sand
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CRUST	CO_2 re-use through underground storage
CSA	Central and South America
CSLF	Carbon Sequestration Leadership Forum
CSS	Cyclic steam stimulation
CTL	Coal-to-liquids
CUCBM	China United Coal-bed Methane Corporation
CUTE	Clean Urban Transport for Europe
DC	Direct current
DICI	Direct-injection, compression-ignition
DISI	Direct injection spark ignition
DME	Dimethyl ether
DMFC	Direct methanol fuel cell

DOE	Department of Energy, United States
DRI	Direct reduced iron
EC	European Commission
ECBM	Enhanced coal-bed methane recovery
EDI	Energy development index
EEU	Eastern Europe
EGR	Enhanced gas recovery
ELAT®	Solid polymer electrolyte electrode
EPA	Environmental Protection Agency, United States
EOH	Ethanol
EOR	Enhanced oil recovery
EPR	European pressurised water reactor
ESPOO	ECE convention on trans-boundary impact assessment
ETP	Energy Technology Perspectives
ETSAP	Energy Technology Systems Analysis Programme
EU	European Union
EUR	Euro
FCB	Fuel cell bus
FCC	Fluid catalytic cracker
FCV	Fuel cell vehicle
FDI	Foreign direct investment
FGD	Flue gas desulphurisation
FSU	Former Soviet Union
FT	Fischer-Tropsch
GB	Governing Board, International Energy Agency
GDE	Gas diffusion electrode
GDL	Gas diffucion layer
GDP	Gross domestic product
GEF	Global Environment Fund
GHG	Greenhouse gases
GIS	Geographical information system
Gt	Gigatones (1 tonne x 10^9)
GTL	Gas-to-liquids
GWh	Gigawatt-hour
GWP	Global warming potential
H_2	Hydrogen
HHV	Higher heating value
HMFC	Hydrogen membrane fuel cell
HRSG	Heat recovery steam generator
HSA	Hydrogen storage alloy
HTGR	High temperature gas-cooled reactor
IBAD	Ion beam assisted deposition
ICE	Internal combustion engine
IEA	International Energy Agency
IET	International Emissions Trading

IGCC	Integrated gasification combined-cycle
IND	India
IPP	Independent power producer
IPCC	Intergovernmental Panel on Climate Change
IPHE	International Partnership for a Hydrogen Economy
JI	Joint implementation
JPN	Japan
kWh	Kilowatt-hour
KOH	Sodium hydroxide
LDV	Light duty vehicle
LH_2	Liquid hydrogen
LHV	Lower heating value
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTF	Low temperature flash
mb/d	Million barrels per day
Mbtu	Million British thermal units
MDG	Millennium Development Goals
MCFC	Molten carbonate fuel cell
MEA	Middle East
MEA	MonoEthanol amine
MeOH	Methanol
MEX	Mexico
$MgCl_2$	Magnesium chloride
MgO	Magnesium oxide
MOF	Metal-organic framework
mpg	Miles per gallon
MSC	Multiple service contract
MTBE	Methyl tertiary butyl ether
MWh	Megawatt-hour
NGCC	Natural gas combined-cycle
NGL	Natural gas Liquid
NGO	Non-governmental organisation
NO_x	Nitrogen oxides
ODA	Other developing Asia
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
ORMOSILs	Organically modified silicates
OSPAR	Oslo Convention and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic
OxF	OxyFueling
PA	Physical absorption
PAFC	Phosphoric acid fuel cell
PCSD	Pressure cyclic steam drive

PEC	PhotoElectrochemical cell
PEMFC	Proton exchange membrane fuel cell
PFBC	Pressurised fluidised bed combustion
PISI	Port injection spark ignition
PM10	Particulate matter of less than 10 micron diameter
POX	Partial oxidation
PPA	Power purchase agreement
PPP	Purchasing power parity
PSA	Pressure swing absorption
Pt	Platinum
PV	PhotoVoltaics
R&D	Research and development
RD&D	Research, development and demonstration
RPS	Renewables portfolio standards
SACS	Saline aquifer CO_2 storage
SAGD	Steam assisted gravity drainage
SC	Supercritical
SCSC	Supercritical steam cycle
SECA	Solid State Energy Conversion Alliance
S-I cycle	Sulfur-iodine cycle
SMR	Steam methane reforming
SO_2	Sulfur dioxide
SOEC	Solid oxide electrolyser cell
SOFC	Solid oxide fuel cell
SUV	Sports utility vehicle
TFC	Total final consumption
toe	Tonne of oil equivalent
TPES	Total primary energy supply
TWh	Terawatt-hour
UNCLOS	United Nations Convention for the Law of the Sea
UNDP	United Nations Development Programme
UNEP	United National Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change
USA	United States of America
USC	Ultra supercritical
USCSC	Ultra supercritical steam cycle
USD	United States dollars
VHTR	Very high temperature reactor
WBCSD	World Business Council for Sustainable Development
WEM	World Energy Model
WEO	World Energy Outlook
WEU	Western Europe
WHO	World Health Organisation
WTO	World Trade Organisation

Units

MJ	megajoule = 10^6 joules
GJ	gigajoule = 10^9 joules
PJ	petajoule = 10^{15} joules
EJ	exajoule = 10^{18} joules
t	tonne = metric ton = 1000 kilogrammes
Mt	megatonne = 10^3 tonnes
Gt	gigatonne = 10^9 tonnes
W	watt
kW	kilowatt = 10^3 watts
MW	megawatt = 10^6 watts
GW	gigawatt = 10^9 watts
TW	terawatt = 10^{12} watts
kW_{th}	kilowatt thermal capacity
kW_{el}	kilowatt electric capacity
bar	a unit of pressure nearly identical to an atmosphere unit. 1 bar = 0.9869 atm (Normal atmospheric pressure is defined as 1 atmosphere)
bbl	barrel
BOE	Barrels of oil equivalent. 1 BOE = 159 litres
°C	degrees Celsius
kWh	kilowatt-hour
Nm^3	Normal cubic metre. Measured at 0 degrees Celsius and a pressure of 1.013 bar
ppm	parts per million
Pa	pascal
A	Ampère
V	Volt

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